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BROADER PERSPECTIVE

Technology advances needed for photovoltaics to achieve widespread grid price parity

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ABSTRACT

To quantify the potential value of technological advances to the photovoltaics (PV) sector, this paper examines the impact of changes to key PV module and system parameters on the levelized cost of energy (LCOE). The parameters selected include module manufacturing cost, efficiency, degradation rate, and service lifetime. NREL's System Advisor Model (SAM) is used to calculate the lifecycle cost per kilowatt-hour (kWh) for residential, commercial, and utility scale PV systems within the contiguous United States, with a focus on utility scale. Different technological pathways are illustrated that may achieve the Department of Energy's SunShot goal of PV electricity that is at grid price parity with conventional electricity sources. In addition, the impacts on the 2015 baseline LCOE due to changes to each parameter are shown. These results may be used to identify research directions with the greatest potential to impact the cost of PV electricity. Copyright © 2016 John Wiley & Sons, Ltd.

KEYWORDS
economics; LCOE; photovoltaics

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1. BACKGROUND AND INTRODUCTION

Today in 2015, the real levelized cost-of-energy (LCOE) for new utility scale solar systems in the contiguous United States is between \$0.07 and \$0.13/kWh, depending upon system location and not including federal and state incentives [1]. The US Department of Energy's SunShot Initiative, which seeks to make solar-generated electricity cost competitive with conventional electricity sources by 2020 [2], sets a utility scale target of 6 cents per kWh for a location having only a moderate solar resource (for example, Kansas City, Missouri, which is around \$0.10/kWh today without incentives). For the commercial and residential sectors, the SunShot initiative sets targets of 7 and 9 cents per kWh, respectively. These values are believed to represent photovoltaic (PV)-generated electricity becoming cost competitive with conventional electricity across most of the United States. Should these targets be realized, estimates are that solar energy could grow to produce 14% of the US electricity supply by 2030, as compared to just 0.4% in 2014 [2,3]. For PV-generated electricity to achieve these SunShot targets, technological innovation is needed.

To demonstrate the degree of technological innovation needed to reach the SunShot goals, this paper identifies sets of selected PV parameters that enable \$0.06/kWh utility scale electricity with moderate solar resource by 2020. Specifically, we focus upon manufacturing costs, efficiency, and reliability and durability. The potential impacts on LCOE because of independent changes to selected parameters are shown. Finally, a scenario for the technological progress needed to reach even lower electricity costs, in order to enable even greater PV deployment beyond the 2020 targets, is demonstrated. These analyses may be used to inform and prioritize future research directions according to their impact on the cost of PV-generated electricity.

2. METHODS FOR CALCULATING THE LCOE OF PHOTOVOLTAICS

The LCOE metric, which is a present value assessment of total system lifetime costs and returns, is what we use to assess and compare the impacts of technology advancements. The LCOE for most energy generation technologies is generally expressed in dollars-per-kilowatt hour ($/kWh) or dollars-per-megawatt hour ($/MWh) [4].

Any factor that leads to lower total lifecycle costs, or that yields greater kWh over the chosen analysis period, lowers the LCOE of a PV system. In this expression, the total lifecycle cost in the numerator is a function of the initial capital cost (which primarily includes the module, the installation hardware and labor, and transaction costs for system installers and financers), as well as ongoing operation and maintenance expenses (which oftentimes includes inverter replacement), and decommissioning costs including module collection and recycling. The total lifecycle energy production (the kWh in the denominator) is a function of location as well as module and system reliability and performance. Module performance is controlled by the rated efficiency (typically defined under standard test conditions), as well as factors related to the operating conditions, such as spectral sensitivity and temperature coefficient. A full LCOE calculation also incorporates appropriate discount rates—to account for the time value of money in the net present value calculation—as well as any federal or state incentives that can help to offset the project's total lifecycle costs. In this paper, real LCOE values are used rather than nominal. The federal investment tax credit (ITC) is not included as a subsidy (except within Figure 1 that shows LCOE with and without the ITC), but the current tax codes that allow for five year modified accelerated cost recovery schedule (MACRS) for depreciation of the initial systems costs are included throughout.

Table I details some of the most critical inputs needed to calculate LCOE using NREL's System Advisor Model (SAM), which is a software program available for free download [5]. The published citations in the table detail 2015 benchmark $\$/W_{(DC)}$ systems costs and are also available. A SAM model with the inputs set according to the table can be found within the Supporting Information of this paper.

Figure 1 shows the range of results from SAM for three locations from across the contiguous United States. The energy yield for a given system—often expressed as the annual amount of kWh produced per kW installed—depends upon system location, mounting configuration, and technology choice. For Daggett, California, which has one of best climates for PV in the country, the SAM model returns 1880 kWh/kW for a typical multicrystalline silicon utility scale system in a fixed-tilt configuration. For Seattle, Washington, the same systems are calculated to return 1120 kWh/kW. Very close to the average between Daggett and Seattle, a fixed-tilt utility scale system in Kansas City, Missouri, could yield around 1480 kWh/kW in the first year of production. These differences in kWh produced because of different system location then yield different expectations for LCOE, as seen by the LCOE ranges shown in Figure 1.

System configuration and tilt angle relative to the ground are other important factors affecting kWh production. For utility scale systems, the tilt angle is flexible and modules can be set to the optimal value based on latitude (30° south-facing tilt gives the greatest kWh for Kansas City). There is also the option at utility scale to deploy modules in one-axis tracking mode, which is calculated to yield a 21% improvement in power production (from 1480 to 1790 kWh/kW for Kansas City). Photovoltaic modules installed in residential and commercial systems, however, have additional design constraints, and trackers are not generally used. Residential systems are most typically installed at an angle set by the pitch of the roof, and commercial systems on flat roofs must consider module-to-module shading. These constraints lead to non-optimal tilt angles and therein slightly lower kWh relative to utility scale systems: Residential systems in Kansas City set to a typical roof pitch of 25° tilt angle yield 1470 kWh/kW and commercial systems set to minimize shading at 15° yield 1430 kWh/kW. Other designs, such as east-west facing arrays at commercial scale, give lower energy yields but offer the potentially offsetting benefit of greater constrained-area system size because of greater module packing density.

For comparison to current electricity rates within the contiguous United States, Energy Information Administration (EIA) data representing the range of statewide average residential, commercial, and industrial rates is also included within Figure 1 [6]. For $1.10/W fixed-tilt utility scale systems in Kansas City, and with the other SunShot 2020 input assumptions outlined in the table, a real 2015 LCOE around 5.7 cents per kWh is calculated. A $1.20/W utility scale system with one-axis tracking in the same location is calculated to yield 5.1 cents per kWh, as the LCOE benefits of the additional kWh produced by tracking offsets the added $0.10/W cost of the tracking hardware.

With inclusion of the ITC, the lower end of the 2015 utility-scale LCOE in Figure 1 reaches $0.05/kWh. In comparison, recent 2015 pricing under power purchasing agreements (PPA) has been reported as low as $0.04/kWh in Nevada and Texas. This difference can be explained by the inclusion of additional state incentives as well as cutting edge financing vehicles that enable very low discount rates, in addition to the good climate for PV [7].

3. IMPACTS OF PHOTOVOLTAIC TECHNOLOGY PARAMETERS ON LCOE

3.1. Pathways to the SunShot goal

There are many different pathways, beyond those illustrated in Table I, to reach the SunShot LCOE goals. When

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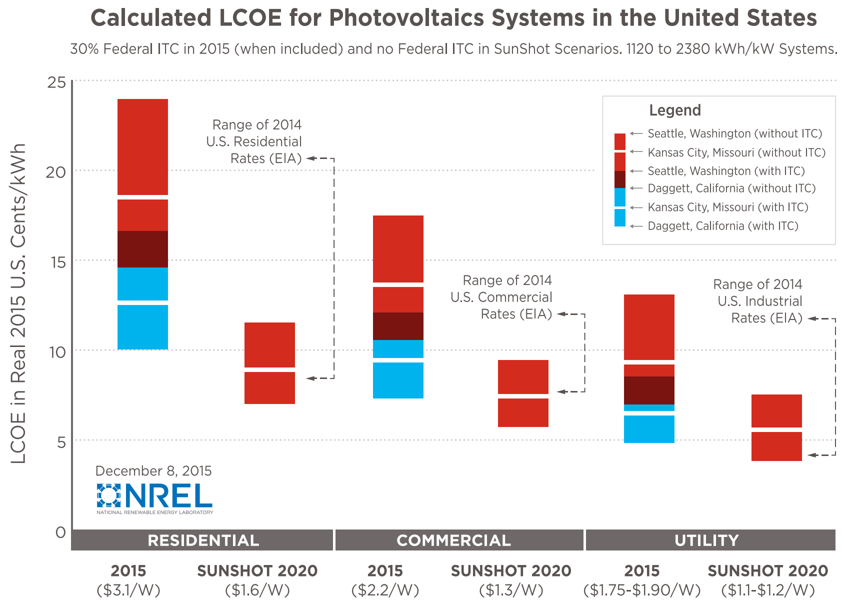

Figure 1. LCOE calculations using baseline 2015 and SunShot 2020 systems costs. A 30% federal ITC is included in the 2015 "With ITC" cases. The other assumptions are detailed in Table I. The white lines indicate the LCOE results for Kansas City, Missouri. The bottom of each red or blue bar corresponds to the LCOE value calculated for Daggett, while the top of each bar corresponds to the LCOE values calculated for Seattle. The utility scale cases range from fixed-tilt in Seattle (upper end) to one-axis tracking in Daggett (lower end). EIA data for the 2014 range of average residential, commercial, and industrial electricity rates across the continental United States is also shown [6].

the initiative was launched in 2011, the targets that were envisioned to enable the utility scale PV LCOE goal of 5 to 6 cents per kWh across most of the United States were: module prices of \$0.50/W, inverter prices of \$0.10/W, balance-of-system and overhead costs of an additional \$0.40/W, degradation rates of 1%/year, discount rates of 8.6%, system lifetimes of 30 years, and module efficiencies of 20% [2]. To reflect the recent technological progress in the industry, and also a small increase in what is considered to be grid price parity, the updated SunShot scenario of 6 cents per kWh for fixed-tilt, utility scale PV systems could be achieved with module prices of \$0.40/W, inverter prices of \$0.10/W, balance-of-system and overhead costs of \$0.60/W, degradation rates of 0.2%/year, discount rates of 7.0%, system lifetimes of 30 years, and module efficiencies of 20%. These updated targets represented in Figure 1 and as the circle in Figure 2 allow for slightly higher overnight systems costs in comparison to the original targets (\$1.10/$W_{(DC)}$ versus the original \$1.00/$W_{(DC)}$) because nominal project financing rates lower than 8.6% are already being realized by the industry [8] and because of new reliability targets. There are, of course, numerous other permutations that could achieve the same end of 6 cents per kWh.

The iso-LCOE curves in Figure 2 demonstrate a number of different technology pathways that would enable the SunShot utility scale PV goal of 6 cents per kWh. Analogous curves could also be derived for the targets in the commercial (7 cents per kWh) and residential (9 cents per kWh) sectors. Traveling along any of the given iso-LCOE curves shows the pairing between module price and efficiency that could yield the SunShot utility scale target, for a fixed degradation rate, system lifetime, and financing rate. The differences between curves also illustrate the impact of changes to lifetime and degradation rate. While PV system lifetime is sometimes assumed to be the point at which performance reaches 80% of its initial rated value, here the system lifetime is specified separately, at 10, 30, or 50 years, as noted in the figure. The lifetime determines the financial analysis period used in the LCOE calculations, and not necessarily the time to 80% of original performance. For 2.0% and 0.2% per year degradation rates, for example, the time to 80% of original performance is actually around 11 and 110 years, respectively.

Figure 2 illustrates how a less efficient or higher degradation rate module would need to have a lower module price in order to meet the SunShot utility scale goal, as well as what the price premium could be for modules offering additional efficiency or reliability improvements. It shows that extending the system lifetime from 30 to 50 years—assuming that investors and project developers could be convinced of that increase—yields an allowance for higher module prices across the range of efficiencies. Very high efficiencies and reliability could even support module prices as high as \$1.00/W and still achieve the 6 cents per kWh goal, which can be seen on right of the topmost curve. Conversely, for a technology that has very poor reliability, it becomes more challenging to realize the 6 cents per kWh goal. With a system lifetime of 10 years and a degradation rate of 2.0%/year (red curve), even a free module would need to have an

Table I. Inputs for the SAM model used throughout this paper (unless noted otherwise). The references give the sources for the 2015 system cost benchmarks. The 2020 values encompass the \$/W system price targets that enable the SunShot goals for the different sectors (rounded to the nearest whole cent per kWh). The range of LCOE values at the bottom represents the results from SAM using the inputs in Table I for locations within the continental United States, ranging from Daggett, CA (highest known energy yield and lowest LCOE values) to Seattle, WA (lowest known energy yield and highest LCOE values).

	Residential		Commercial		Utility	
PV system costs inputs(2015 US dollars)	2015	SunShot 2020	2015	SunShot 2020	2015	SunShot 2020
Direct capital costs (\$/$W_{(DC)}$)						
System size	2.0 – 20.0 kW		20.0 kW – 1.0 MW		1.0 MW – 1000. MW (and beyond)	
Module price	\$0.70	\$0.50	\$0.68	\$0.45	\$0.65	\$0.40
Inverter price	\$0.30	\$0.15	\$0.15	\$0.12	\$0.15	\$0.10
Costs associated with 1-axis tracker	—				\$0.15	\$0.10
Balance-of-system equipment	\$0.50	\$0.30	\$0.35	\$0.25	\$0.35	\$0.25
Direct installation labor	\$0.35	\$0.20	\$0.20	\$0.15	\$0.20	\$0.10
Land costs	—				\$0.03	\$0.03
Grid interconnection and transmission	—				\$0.05	\$0.03
Indirect capital costs (\$/$W_{(DC)}$)						
Permitting and environmental studies	\$0.10	\$0.05	\$0.05	\$0.04	\$0.03	\$0.03
Customer acquisition and system design	\$0.35	\$0.10	\$0.05	\$0.03	\$0.04	\$0.02
Installer overhead and profit	\$0.70	\$0.25	\$0.65	\$0.22	\$0.20	\$0.10
Sales taxes	\$0.10	\$0.05	\$0.07	\$0.04	\$0.05	\$0.04
Installed system price (\$/$W_{(DC)}$):	**\$3.10** [17,18]	**\$1.60**	**\$2.20** [18]	**\$1.30**	**\$1.75/ \$1.90** [1] **Fixed tilt/tracker**	**\$1.10/\$1.20 Fixed tilt/ tracker**
Operation and maintenance parameters and costs						
Tilt angle for module	25°	25°	15°	15°	Optimal tilt angle (e.g., 30°)	Optimal tilt angle
Degradation rate (%/year)	0.75%	0.2%	0.75%	0.2%	0.75%	0.2%
Average annual soiling loss (%/year)	5.0%	5.0%	5.0%	5.0%	5.0%	5.0%
O&M annual cost by capacity (\$/kW·yr)	\$20	\$10	\$15	\$7.5	\$15 (Fixed tilt) \$18 (Tracking)	\$7 (Fixed tilt) \$10 (Tracking)
DC-to-AC power ratio	1.4	1.4	1.4	1.4	1.4 (Fixed tilt) 1.2 (Tracking)	1.4 (Fixed tilt) 1.2 (Tracking)
Total DC and AC power loss	4.5% and 2.0%	4.5% and 2.0%	4.5% and 2.0%	4.5% and 2.0%	4.5% and 2.0%	4.5% and 2.0%
Inverter lifetime (years)	15	30	15	30	15	30
Inverter replacement (real 2014 \$/$W_{(DC)}$)	\$0.15	—	\$0.12	—	\$0.10	—
Financial parameters and incentives (all using the SAM template of PPA single owner)						
IRR target (%)	7.5%	7.5%	7.5%	7.5%	7.0%	7.0%
PPA price escalation (%/yr)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Analysis period and IRR target (years) (effective system lifetime)	30	30	30	30	30	30
Inflation rate (%/year)	2.5%	2.5%	2.5%	2.5%	2.5%	2.5%
Real discount rate (%/year)	4.9%	4.9%	4.9%	4.9%	4.4%	4.4%
Nominal discount rate (%/year)	7.5%	7.5%	7.5%	7.5%	7.0%	7.0%
Federal income tax rate (%/year)	35%	35%	35%	35%	35%	35%
State income tax rate (%/year)	7.0%	7.0%	7.0%	7.0%	7.0%	7.0%
Annual insurance rate (% of capital cost) and property tax rate (%/year)	0%	0%	0%	0%	0%	0%
System salvage value (% of capital cost)	0%	0%	0%	0%	0%	0%

(*Continues*)

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Table I. (Continued)

	Residential		Commercial		Utility	
PV system costs inputs(2015 US dollars)	2015	SunShot 2020	2015	SunShot 2020	2015	SunShot 2020
Percentage of debt or project debt service coverage ratio	0.0	0.0	0.0	0.0	0.0	0.0
Depreciation class	5-year MACRS	5-year MACRS	5-year MACRS	5-year MACRS	5-year MACRS	5-year MACRS
Federal ITC qualification	30% or 0% as noted	0%	30% or 0% as noted	0%	30% or 0% as noted	0%
State ITC qualification	0%	0%	0%	0%	0%	0%
Real 2015 LCOE (without ITC) Daggett, CA to Seattle, WA (US cents/kWh)	14.5–23 9	7.0—11.5	10.6—17.5	5.8—9.5	8.0—13.1 Fixed tilt 6.9—12.1 1-axis tracking	4.5—7.4 Fixed tilt 3.9—6.8 1-axis tracking

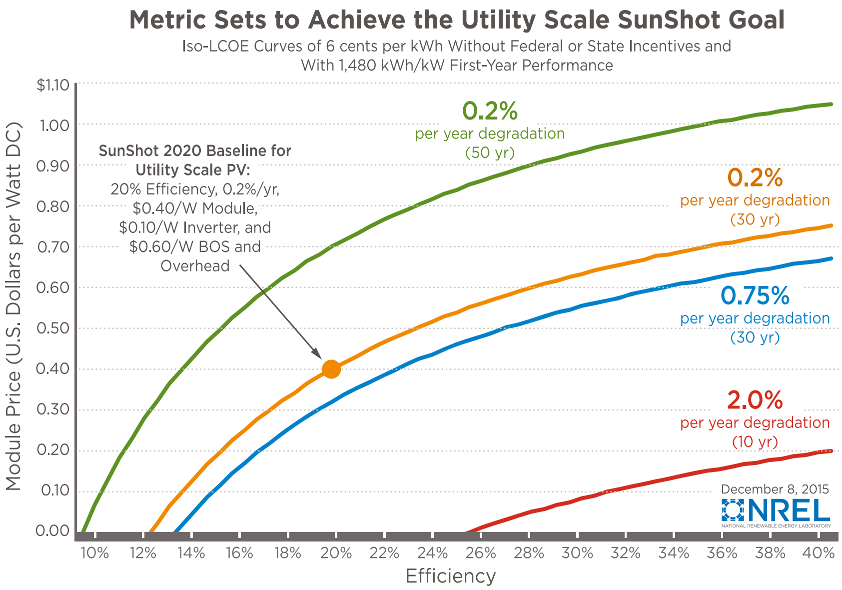

Figure 2. Permutations of the key metrics of module price, efficiency, degradation rate, and system lifetime that could enable the utility scale SunShot target of 6 cents per kWh with energy yield around 1480 kWh/kW. The inverter, balance-of-systems, and overhead contributions are held constant at \$140/m^2, which corresponds to \$0.70/W at 20% efficiency, and which is a 35% reduction from 2015 costs. Thus, some concurrent innovation in the non-module components is also assumed. The SunShot baseline case described in the text is shown as an orange circle. Impacts because of changes in the discount rate are not included within this particular figure but are shown later (in Figure 7).

efficiency of at least 26% and, at 40% efficiency, could not cost more than \$0.20/W in order to reach the SunShot goal. If, however, a 10 year, 2.0%/year degradation rate system also enabled reductions in installation costs, then the efficiency and module price requirements relax somewhat (although they are still challenging). While not shown on Figure 2, a 10-year lifetime, 2% degradation rate system with 50% lower labor and hardware costs (which gives a budget of \$110/m^2 total inverter, BOS, and overhead costs) could afford a \$0.10/W module price at 25% efficiency, or a \$0.30/W module price at 40% efficiency. It should be noted that reductions in labor and hardware costs could also help higher reliability systems as well—a 50% reduction in those costs affords roughly a \$0.10/W increase in module price for all curves.

The remainder of this paper looks separately at the specific impacts on LCOE because of reductions in module production cost and improvements to efficiency and reliability. The analysis is built upon the 2015 baseline case (without ITC) from Table I, in order to illustrate how PV technology innovation can drive today's LCOE values toward and beyond the SunShot targets. To reach the SunShot goal of 6 cents per kWh for utility scale systems in Kansas City, the LCOE needs to decline by about 4 cents per kWh from the 2015 value. For residential systems, LCOE needs to be reduced by 9.5 cents per kWh to reach the SunShot residential goal of 9 cents per kWh. It will be shown that module price, efficiency, and reliability are all important contributors to LCOE reduction, but none is likely sufficient on their own to reach the SunShot goals. Thus, improvements are sought in all of these areas. Reductions in non-hardware "soft costs" (such as permitting, customer acquisition, and installer overhead and margin) can also make significant impacts on LCOE, but are beyond the scope of this paper.

3.1.1. Impacts of PV module costs on LCOE.

While the price of PV modules has fallen significantly, they remain a significant component of PV systems cost. In Figures 3 and 4 we present an aggregated breakdown of module production costs for crystalline silicon (about 94% of the 2014 module market [9]) and cadmium telluride (CdTe, about 4% of the 2014 market [9]), in order to illustrate how reductions in different areas can impact the overall module cost. These costs do not include a margin for the manufacturer, which is an additional important contributor to a long-term sustainable module price. Figure 3 profiles the most common technology format (around 50% of the total PV module market) of silicon modules using *p*-type, multicrystalline base cells with screen-printed metal pastes on the front (Ag) and back (Al and Ag) and without advanced surface passivation techniques.

It is noteworthy that, at nearly 40% of the total, module assembly and packaging costs—including the front glass, backsheet, two encapsulant sheets, and the electrically conductive ribbons and busbars used to interconnect cells—are calculated to be the single largest contributor to costs [10]. From polysilicon to a complete module, materials costs are 54% of the total, and depreciation expenses (that is, the equipment and manufacturing facilities) are 20%. The other major costs are electricity (16%), labor (4%), and maintenance (6%).

In Figure 4 we show current estimated costs for CdTe module manufacturing. Materials costs are 64% of the total, and equipment and manufacturing facilities expenses are 21%. The other major costs are electricity (5%), labor (3%), and maintenance (7%). The total cost for module assembly and packaging, including the front and back glass, is also the largest contributor, at 58% of the total module costs [9]. It may surprise the reader to discover that the cost for the CdTe layer and its electrical junction partner CdS is calculated to be just 21% of the total, and that this is the same as the cost for the transparent conducting oxide (TCO) and back contact. While not shown here, the contribution of the absorber to the total cost is similar for copper indium gallium (di)selenide, or CIGS, and amorphous silicon modules. Thus, lowering thin-film module costs entails much more than just research and development of the semiconductor active layers.

Reducing depreciation expenses, which are derived from the upfront capital expenditure ('CapEx') for manufacturing equipment and facilities, could be addressed through improvements in throughput, equipment uptime, and yields. Such process improvements could also reduce the electricity, maintenance and labor expenses. In addition to its contribution to module price, CapEx may also

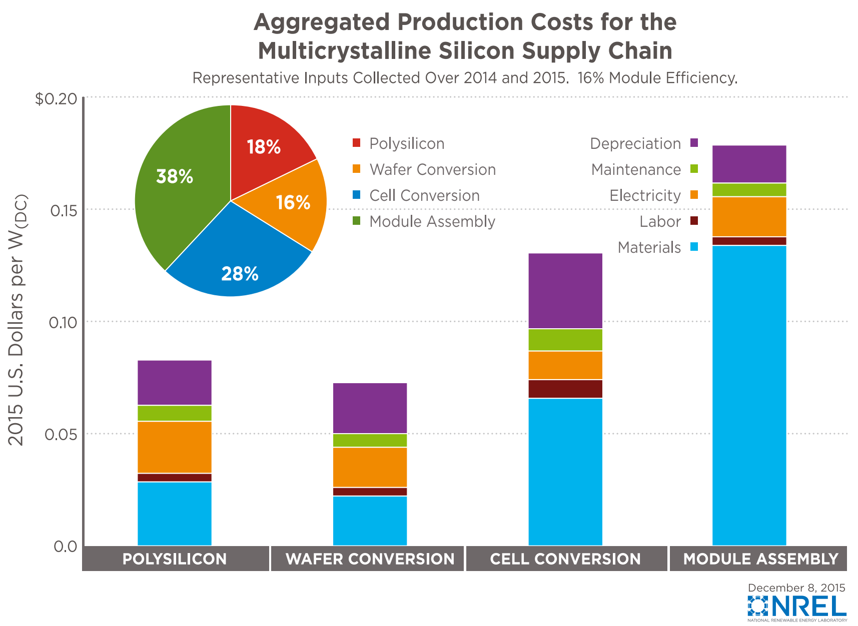

Figure 3. The major categories of costs for standard multicrystalline silicon modules. Monocrystalline silicon modules made from *p*-type cells with screen-printed metallizations have a similar cost structure, although the equipment and facilities expense is around 30% higher for the wafer conversion step [16]. Source: Internal NREL bottom-up costs analysis.

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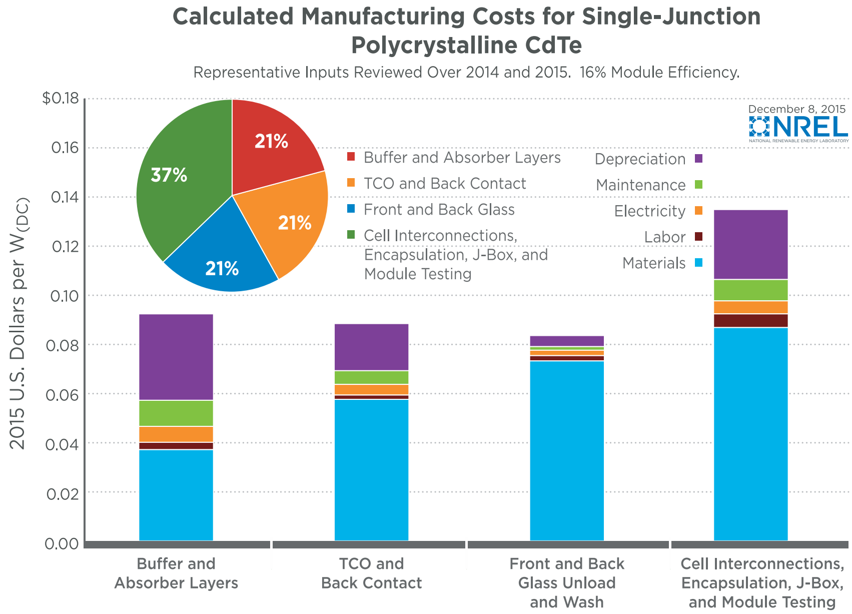

Figure 4. Costs by component for CdTe modules. Source: Internal NREL bottom-up costs analysis.

become an important issue for scaling PV manufacturing capacity across the globe, as it is the CapEx that defines the amount of investment required to expand manufacturing capacity [11]. Relative to the years at the beginning of this decade, CapEx spending was down in 2014. But, to become a significant fraction of the global energy mix, much greater deployment of solar will be needed—as will the amount of investment required to expand manufacturing capacity. To give an idea of the amount, with a current upfront cost of around \$0.70 per watt for new polysilicon through module manufacturing capacity for multicrystalline silicon, and with a similar CapEx currently expected for thin-film technologies, expanding global manufacturing capacity from 50 GW to 500 GW would require over \$300 Billion. Thus, innovations in module technology should also consider the impact of associated changes to manufacturing CapEx.

3.2. Impacts of PV efficiency upon upfront systems costs (\$/W) and LCOE (\$/kWh)

In this section we look at the impact of rated module efficiency on systems costs and LCOE. While it is the total performance (kWh produced) that directly impacts LCOE, we focus on efficiency because it is an influential and heavily cited metric. Other parameters that impact performance include operating temperature, temperature coefficient, and spectral sensitivity, as well as concentration level and tracking [12].

The cost benefits of improved efficiencies at the systems level are easy to imagine: If tasked with installing a PV system of a certain size (say 5 kW for a typical household, or 100 MW for a large utility scale project), having more efficient modules simply means that fewer modules must be installed. Generally speaking, the relationship for changing systems costs when the power-rated size is fixed, but the area is unbounded and can be adjusted accordingly, can be represented as:

$$\$/\mathrm{W}\,(\text{fixed power rating}) = \frac{\$ - \Delta\$}{\mathrm{W}}$$

where the incremental reductions in cost per unit of efficiency (Δ\$) are because of the hardware, labor, and overhead costs reductions expected from installing fewer modules as efficiencies are improved.

In other situations, there is only a limited space within which to install PV systems. In these cases, more efficient modules allow more Watts to be produced within the fixed area. The general relationship for changing systems costs when the system area is fixed, but the size is unbounded and can be adjusted accordingly, can be represented as:

$$\$/\mathrm{W}\,(\text{fixed area}) = \frac{\$}{\mathrm{W} + \Delta\mathrm{W}}$$

where costs are reduced as efficiency improves because the fixed systems costs in the numerator are divided by more Watts (ΔW).

As efficiency increases, the incremental impact of additional efficiency improvements reduces, as shown in Figure 5. The figure shows the sensitivity of total system costs to efficiency for six different cases, as well as for the module alone. It is worth noting that the slope of the curves—that is, the incremental impact of efficiency in reducing systems costs—is greatest for the case of residential fixed area. The significant difference between the residential fixed size and fixed area cases is largely because of the electrical components and electrical work, which is a single fixed cost

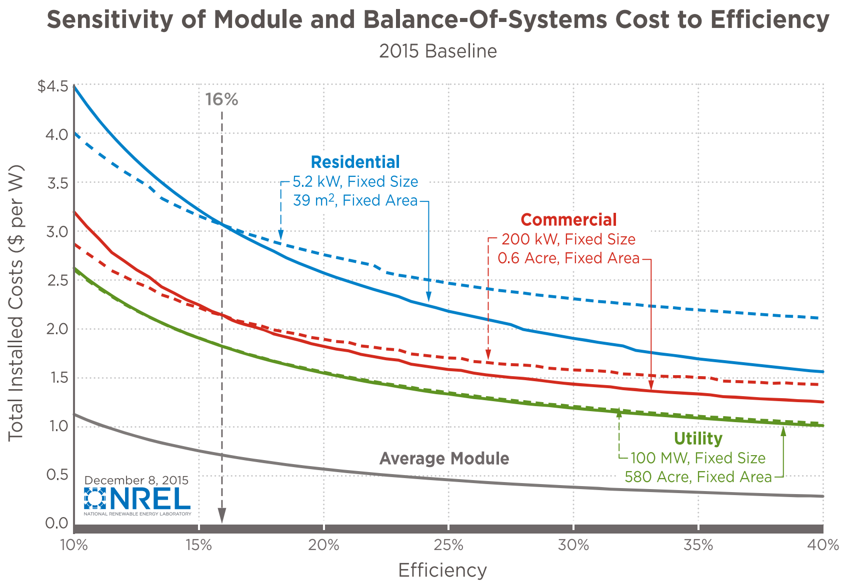

Figure 5. Dollars-per-Watt sensitivity of module and systems costs to changes in efficiency. The module price represented is for multicrystalline silicon. Systems costs are shown for fixed area and fixed size systems for representative residential, commercial, and utility-scale systems. The kinks in the residential and commercial lines represent step changes in cost because of changes in inverter price points. A vertical line is shown at the 2015 benchmark module efficiency of 16%.

regardless of power output. In the utility scale case, the electrical requirements scale with size and there is negligible difference between fixed area and fixed size cases.

The dollars-per-watt systems costs in Figure 5 demonstrate the impact of efficiency on full system costs. Using the additional necessary inputs outlined in Table I, and these systems costs, in Figure 6 we show the corresponding LCOE values from SAM. Including the contributions of module cost reductions, improving residential system efficiencies gives the greatest absolute reductions in cost for the fixed area (39 m^2) case, while smaller reductions can be seen for the fixed size (5.2 kW) case. As a percentage change in LCOE, however, the impact of efficiency is greatest for utility-scale systems. While efficiency improvements can significantly impact LCOE, this metric by itself would not enable the SunShot goal of 9 cents per kWh for residential systems; furthermore, by considering only the efficiency metric on its own, the utility scale

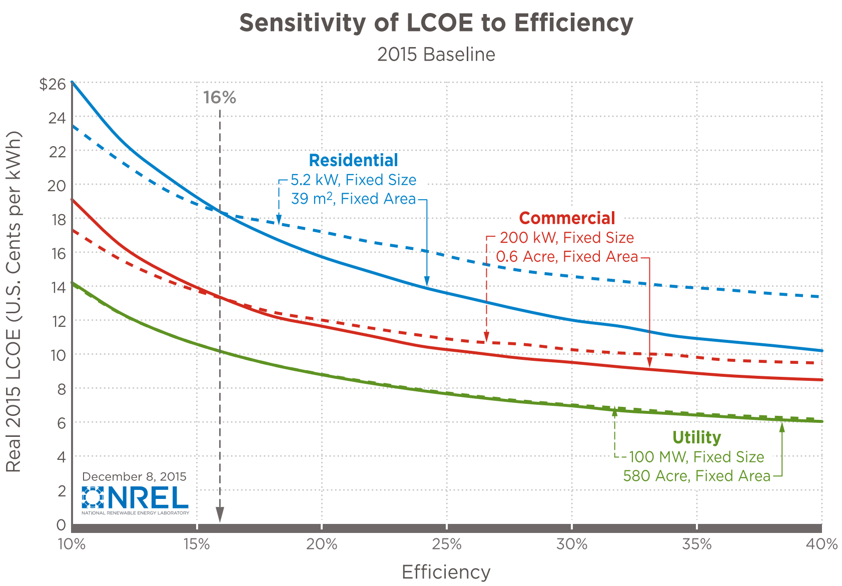

Figure 6. Efficiency versus 2015 real LCOE for fixed size and fixed area PV systems, without ITC. The systems costs used as inputs are shown in Figure 5.

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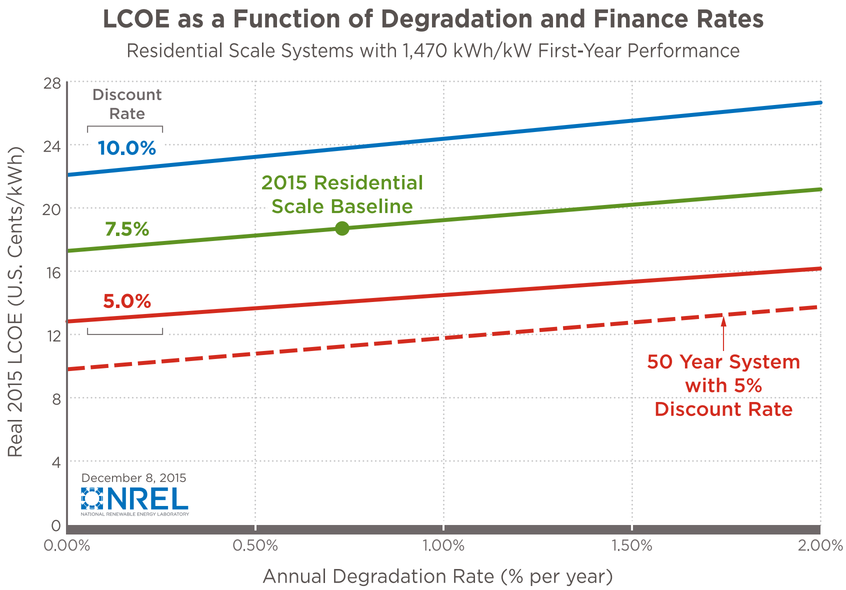
goal of 6 cents per kWh could only be realized at efficiencies approaching 40%.

3.3. Impacts of PV reliability upon LCOE

The reliability and durability of a PV technology impact LCOE through a number of different mechanisms. These include influencing how much energy is produced over a PV system's lifetime. These factors can also affect the costs for project financing. The ability to predict PV system performance over time, which depends significantly upon the degree of confidence in the reliability and durability, influences the perceived risk of financing PV projects. System financiers generally require higher rates of return when assuming higher risk. (Other factors that also influence the discount rate include the credit worthiness of the system owner and the system financing structure and terms.) As can be seen in Figure 7, the discount rate has a strong impact upon LCOE. For the 30-year residential systems shown, a 2.5% absolute change in discount rate raises or lowers the LCOE by around 5 cents per kWh. For the 30-year utility systems shown, a 2.0% change in discount rate corresponds to around 2 cents per kWh.

The total energy output of a PV system is influenced by the degradation rate and the system lifetime. Degradation rate is oftentimes expressed as a linear decrease in system



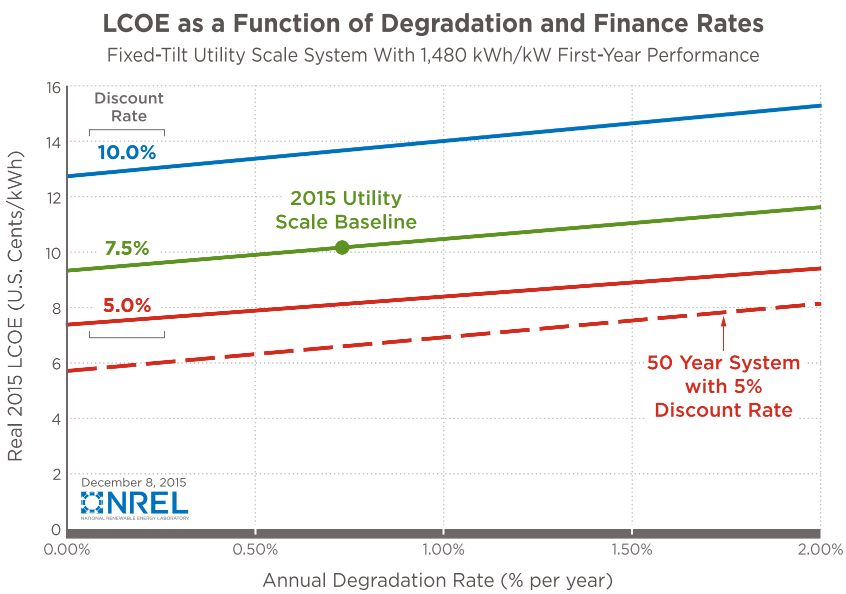


Figure 7. Lifetime, degradation rate, and financing impacts upon LCOE for 2015 residential (top—Figure 7a) and fixed-tilt utility scale systems (bottom—Figure 7b) in Kansas City without any ITC. With the exception of the bottommost curves, 30-year system lifetimes are used.

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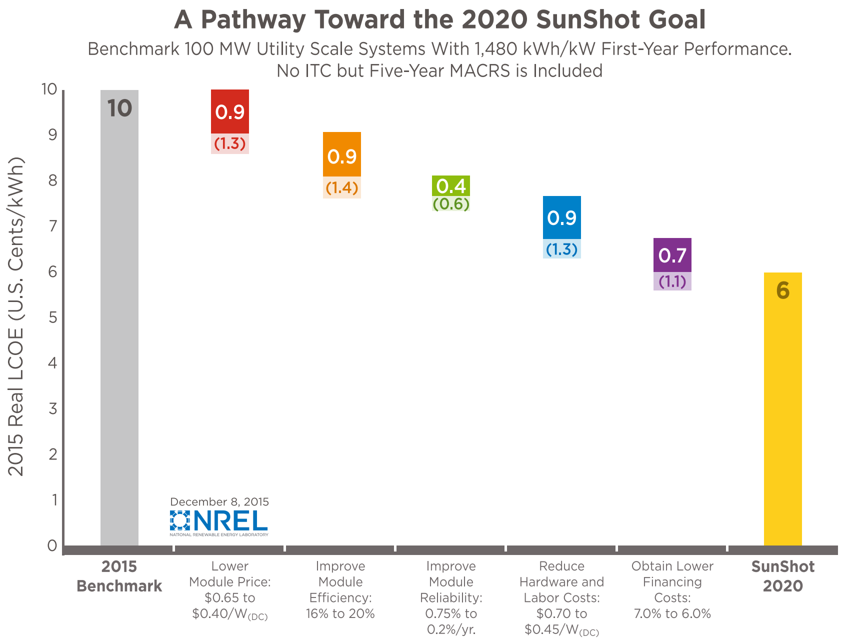

Figure 8. Progress toward the SunShot 2020 goal for 100-MW utility scale systems with 1480 kWh/kW first-year performance and 30-year system lifetimes.

performance per year. For example, for a system that applies a 1% per year linear degradation rate assumption, production after 20 years is expected to be 80% of the initial kWh/kW value. Some LCOE models including SAM apply a compound degradation rate assumption: Production after 20 years is expected to be $0.99^{20} = 82\%$ of the initial value. In truth, the exact trajectory of degradation over a system's lifetime may not fit either of these models perfectly, and research is underway to better characterize the trends [13]. In the calculations herein, the PV system lifetime is varied

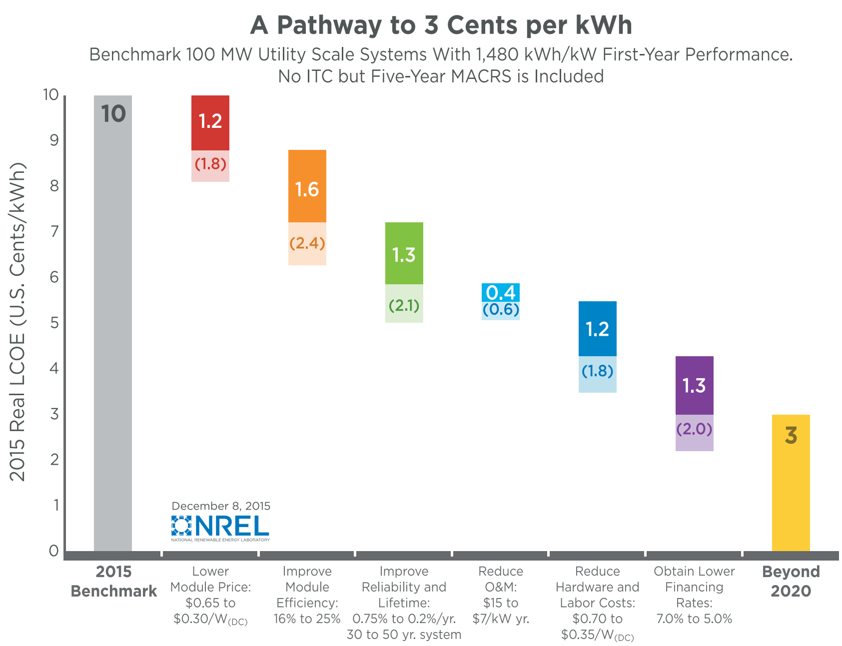

Figure 9. Progress toward an LCOE target of 3 cents per kWh for 100-MW utility scale systems with 1480 kWh/kW first-year performance. Please see the discussion on interdependencies in Section 4, and also note that further reductions in operations and maintenance (O&M) expenses, and a longer system lifetime analysis period (from 30 to 50 years), are called upon in this scenario.

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independently from the degradation rate. The lifetime is the period of time over which the system is assumed to operate for the purpose of the financial analysis. In contrast, system lifetime is sometimes assumed to be the point at which performance reaches 80% of its initial rated value (such as for a typical warranty period). Energy produced earlier in a system's lifetime is valued more in the LCOE calculation, according to the discount rate. Thus, reductions in degradation rate in earlier years have a greater impact upon LCOE than subsequent reductions in later years.

The curves of Figures 7a and 7b show how different degradation rates impact LCOE for several discount rates. Comparing the bottommost curves within 7a and 7b to the curves directly above them illustrates the impact of a 50-year system lifetime as compared to 30 years for the other cases. This change in analysis period translates to increases in the total assumed kWh produced over the system lifetime (and, therefore, a lower calculated LCOE). It is also important to note that this LCOE sensitivity extends in both directions. By decreasing the total kWh, and by potentially raising the discount rate because of greater uncertainty in performance, LCOE increases as module reliability worsens (for example, if choices made to decrease manufacturing cost are done at the expense of reliability).

4. FURTHER DISCUSSION

Figures 3–7 have assumed that changes to one metric do not impact another. In practice, overall future LCOE reductions may require cost tradeoffs between the metrics.

As an example of such a tradeoff, deploying trackers in utility scale systems adds between \$0.10/W and \$0.20/W [1]. However, there is also a 21% increase in annual energy production (1480 kWh/kW for fixed-tilt versus 1790 kWh/kW for tracking systems in Kansas City). This is why there is a lower calculated LCOE of 9.5 cents/kWh for a tracking system as compared to 10.1 cents/kWh for a similar fixed tilt system in Kansas City. This also explains the recent trend toward increased use of one-axis tracking in utility scale systems [1].

As discussed above, progress in one individual metric is generally not sufficient to reach the SunShot goals. Thus, it is necessary to consider combined effects that can lead toward overall progress to the SunShot goals. Figure 8 begins with the baseline LCOE of 10 cents per kWh for fixed tilt utility scale systems in Kansas City and then, after accounting for each item shown, arrives at a final real 2015 LCOE of 6 cents per kWh. Labor and system hardware costs are also included, as is innovation to PV module and system designs that have the potential to impact those costs. This pathway illustrates one possible route to achieving the SunShot utility scale target of 6 cents per kWh. It is a slightly different pathway than depicted in Table I, which also includes reductions in non-hardware soft costs. As also exemplified by the curves of Figure 2, there are many other permutations of sensitivity for each metric that could also be assembled in order to arrive at the SunShot goals.

If the reader wishes to replicate the results of Figures 8 and 9 using the SAM model contained within the Supporting Information, it is important to note that putting in all of the SunShot input assumptions at once will yield a slightly different final result than if adding the results of each metric varied individually. For example, improving module efficiency also contributes some reductions to the module price and hardware and labor costs, so there are interdependencies that can be double-counted if each parameter is varied only independently. These interdependencies are represented as the overlap (in the direction of the y-axis) between buckets. The number within each bucket represents the scaled contribution of each item to the final result, while the number in parentheses represents the contribution one would see if varying each item individually within SAM.

Reaching the SunShot goals is expected to enable LCOE-equivalence between PV systems and conventional electricity sources. It would represent dramatic technological progress by the PV field over the course of a decade. Such an endpoint is expected to result in much greater deployment levels of PV, which could enable PV to supply significant, regular fractions of electricity generation. But, for an intermittent energy source like PV to reach very high penetration on the electrical grid, there will likely be additional costs to facilitate grid integration and increased flexibility, such as for energy storage, advanced power electronics for monitoring and controls, and for demand-side management [14,15]. To budget for these extra costs at high penetrations levels, the LCOE goals for PV systems may need to be even lower than the SunShot 2020 goals of 6 to 9 cents per kWh for utility to residential scale systems. In Figure 9 we show a conceivable pathway to 3 cents per kWh for utility scale systems (without including reductions in other "soft costs", such as permitting and grid interconnection that are harder for PV technology innovation to impact). As can be seen by comparing Figures 8 and 9, the need for technology advancements in all of the key metrics becomes even greater in the 3 cents per kWh case.

5. CONCLUSIONS

This paper provides a quantitative view of the impact on LCOE due to changes in key PV technology metrics, focusing on module cost, efficiency, and reliability. Different technology pathways to reach the SunShot goals, represented by different sets of these technical metrics, have been explained. In order to reach the SunShot goals, and to subsequently realize the even greater cost reductions that may be needed to accommodate high penetrations of PV on the electricity grid, innovation is needed to lower module costs and to improve efficiency and reliability. The analyses presented here may be used to evaluate the potential impact of research directions on the cost of PV electricity, and thus to prioritize areas of research. There is opportunity as well for innovation in PV module and system design to impact hardware, labor, and O&M costs, and for targeted financing structures that may enable even lower LCOEs beyond the SunShot 2020 goals.

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