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The prospects for cost competitive solar PV power ☆

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HIGHLIGHTS

- ►Assessment of the cost competitiveness of new solar Photovoltaic (PV) installations.
- ► Utility-scale PV installations are not yet cost competitive with fossil fuel power plants.
- ► Commercial-scale installations have already attained cost parity in certain parts of the U.S.
- ► Utility-scale solar PV facilities are on track to become cost competitive by the end of this decade.

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ABSTRACT

New solar Photovoltaic (PV) installations have grown globally at a rapid pace in recent years. We provide a comprehensive assessment of the cost competitiveness of this electric power source. Based on data available for the second half of 2011, we conclude that utility-scale PV installations are not yet cost competitive with fossil fuel power plants. In contrast, commercial-scale installations have already attained cost parity in the sense that the generating cost of power from solar PV is comparable to the retail electricity prices that commercial users pay, at least in certain parts of the U.S. This conclusion is shown to depend crucially on both the current federal tax subsidies for solar power and an ideal geographic location for the solar installation. Projecting recent industry trends into the future, we estimate that utility-scale solar PV facilities are on track to become cost competitive by the end of this decade. Furthermore, commercial-scale installations could reach "grid parity" in about ten years, if the current federal tax incentives for solar power were to expire at that point.

1. Introduction

New installations of solar photovoltaic power have experienced rapid growth in recent years. In 2010 alone, almost 17 GW of new photovoltaic (PV) power was installed worldwide. This addition not only represented a 250% increase relative to 2009, it was also roughly equal to the total *cumulative* amount of solar PV power installed since the commercial inception of solar PV technology in the 1970s.[1] While the impressive growth rates for new solar energy deployments are uncontroversial, there is considerable disagreement regarding the economic fundamentals of this energy source. In particular, there appears to be no consensus as to whether solar PV power is approaching *grid parity*, which would require the cost of solar photovoltaic generated electricity to be on par with that generated from other energy sources, including fossil fuels such as natural gas or coal.

Proponents of solar power see the rapid growth of the solar PV industry and the dramatic drop in the price of panels as evidence of increasing competitiveness of this energy source. In contrast, skeptics attribute the rapid rise of solar PV power primarily to generous public policies in the form of tax subsidies and direct mandates for renewable energy. Furthermore, this camp in the public debate argues that the precipitous decline in solar panel prices is not a reflection of favorable economic fundamentals, but rather reflects distress pricing caused by massive new entries into the solar panel manufacturing industry. As further evidence of lacking economic fundamentals, the skeptics point out that the equity market value of virtually all solar panel manufacturers has imploded in recent years.

This paper provides an assessment of the cost competitiveness of electricity generated by solar power. We first base this assessment on the most recently available data. In light of the dramatic

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[1] See, for instance, the 2011 BP Statistical Review of World Energy. For 2011, newly installed capacity of solar PV is estimated to be near 29 GW.

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price reductions that solar PV panels have experienced in recent years, we also seek to extrapolate the prospects for further cost reductions that could be obtained with currently available technology. This part of our analysis speaks to the question of whether a continuation of the significant learning-by-doing process that has characterized this industry is likely to result in 'grid parity' in the foreseeable future without the need for a technological breakthrough. Our analysis also examines the sensitivity of our cost assessment to several crucial input variables, such as panel prices, geographic location of the facility and public subsidies in the form of preferential tax treatment.

The central cost concept in this paper is the *Levelized Cost of Electricity* (LCOE). It represents a life cycle cost per kilowatt hour (kWh) and is to be interpreted as the minimum price per kWh that an electricity generating plant would have to obtain in order to break-even on its investment over the entire life cycle of the facility. This break-even calculation essentially amounts to a discounted cash flow analysis so as to solve for the minimum output price required to obtain a net-present value of zero. Unfortunately, the method used for calculating the LCOE in the literature is far from uniform. We discuss this aspect in more detail in Section 2 below and in Appendix A2.[2]

With regard to PV technology platforms, our analysis covers both the more established crystalline silicon and so-called thin-film solar cells. Crystalline silicon cells are known to be more efficient in terms of the potential energy converted to electricity. Yet, efficiency of the cell is not a criterion per se in our cost analysis as differences in efficiency are subsumed in both input cost and electricity output figures. In terms of the scale of electricity generation, we consider both utility-scale installations (commonly defined as those larger than 1 MW) and installations of commercial scale (in a range of 0.1 to 1 MW). The latter installations would typically be mounted on large rooftops of office buildings and warehouses. While smaller commercial-scale installations cannot attain the full scale economies of utility-scale projects, the benchmark of grid parity is also more lenient to the extent that the applicable cost needs to be compared with retail electricity prices for commercial users rather than wholesale prices at the utility-scale level.

Our point estimates for the Levelized Cost of solar PV electricity are based on favorable, albeit realistic scenarios. In particular, we assume that the electricity generating entity can procure solar panels and other equipment components at the lowest transaction prices observed in the market in late 2011. We also assume that the investor in the solar PV project can benefit from the federal incentives available for these types of projects in the United States—namely a 30% investment tax credit and an accelerated depreciation schedule. Furthermore the location of the facility is assumed to be an ideal one, for instance, in the southwestern United States. The favorability of a location is defined both in terms of insolation and systems degradation, that is, the decay over time in the electricity output of a solar cell.

We find that that crystalline silicon enjoys a slight cost advantage over thin-film, though the two appear generally neck-and-neck for all the scenarios we consider. At around 8 cents per kWh, we find that the LCOE of utility-scale installations is currently not cost competitive with electricity generation from fossil fuels, in particular from natural gas plants. In contrast, at around 12 cents per kWh, commercial-scale installations appear to have reached grid parity, at least in locations like Southern California that are both geographically favorable for solar installations and subject to high retail electricity prices. Given that this appears to be the most favorable scenario for solar PV, we use it as the reference case for further comparisons throughout the paper.

The conclusions we obtain for utility-scale projects suggests that the recent growth in such installations is in large part a consequence of additional public subsidies or government mandates for renewable energy. The Renewable Portfolio Standard in California represent such a mandate, while countries like Germany rely on 'feed-in-tariffs' which oblige grid operators to buy solar electricity at pre-specified prices.[3]

Our conclusion of grid parity for commercial-scale solar PV is shown to be highly dependent on several crucial assumptions. First, absent the current tax subsidies under the Economic Stabilization Act of 2008, our LCOE estimate would increase by over 75%. Secondly, if the power generating facility were to be located in New Jersey rather than Southern California, the applicable LCOE estimate would increase by about 25%. Third, the dramatic recent drop in solar panel prices, in particular the 40% drop in 2011 alone, is likely to be a temporary artifact caused by excess production capacity in the solar PV panel industry. Based on the observed long-term price trend for PV modules, we form an estimate of 'sustainable' panel prices. We estimate that if solar panel prices were priced today at the levels suggested by their long-term price trend, our LCOE figures would increase by about 12–15%.

In examining the sensitivity of our cost estimates to these factors, it should be noted that collectively these factors have a 'super-modular' effect on the resulting cost estimate. To witness, for a facility based in New Jersey that would have to acquire PV modules at sustainable prices and whose tax treatment is identical to those of fossil fuel electricity generating plants, the estimated LCOE would increase by about 150% relative to our baseline reading of 12 cents per kWh.

Since its inception in the 1970s, prices of solar panels have fallen at a rate that is remarkably consistent with the traditional 80% learning-by-doing curve. As documented by Swanson (2006, 2011) the market prices for solar panels have on average declined by approximately 20% every time the cumulative volume of solar PV power installations has doubled. Swanson provides evidence that a range of variables related to thinner silicon wafers, higher semiconductor yields, improvements in the efficiency of the solar cell and other manufacturing process improvements have all contributed to substantial and sustained cost reductions. These reductions in cost have, in turn, translated into corresponding price reductions.

If one postulates the continuation of the established learning curve for photovoltaic modules in the future, it is natural to ask how long it would take current technology—continuously optimized over time—to become fully cost competitive. In making this projection, we assume that in the future crystalline silicon modules will indeed be able to maintain the 80% learning factor they have experienced consistently over the past 30 years. Yet, this pace of learning appears too optimistic for so-called Balance-of-Systems (BoS) components related to cabling, wiring, racking, and permitting. For these BoS costs, which presently account for more than half of the total systems price of new solar installations, we hypothesize a constant percentage reduction each year rather than the exponential learning curve applicable to modules.

[2] Our interpretation of cost competitiveness is that for the party investing in a solar PV facility the levelized cost per kWh, after inclusion of all tax benefits, does not exceed the applicable grid price. The latter varies depending on whether the investing party seeks to sell the electricity output to a distributor at wholesale prices, or whether it seeks to avoid the retail price of electricity that it would have pay for its own consumption.

[3] The Renewable Portfolio Standard in California commits the state to a quota of generating at least 33% of all electricity from renewable energy sources by the year 2020.

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Our projections suggest that solar PV will also become cost competitive for utility-scale facilities by the end of this decade. Furthermore, commercial-scale installation will be able to generate electricity at cost levels that are competitive with current retail electricity prices within the next ten years, even if the current preferential treatment in the tax code were to expire. From a policy perspective, our analysis therefore suggests that a continuation of the "continuous growth" that the solar PV industry has experienced since its inception should be sufficient. Put differently, even without any 'technological breakthrough', solar PV power should to become economically viable within a decade provided the industry 'stays the course'.

One caveat of our levelized cost calculations is that they do not reflect two important features of solar PV power: intermittency and time-of-day peak load patterns. It is well recognized that the intermittency of solar power is one of the principal obstacles for this source of electricity generation to serve base-load needs, unless it can be combined with some energy storage device. On the other hand, solar PV installations generate a substantial portion of their daily power in the afternoon at hours when electricity demand from the grid tends to be relatively high, in particular in locations where air conditioners account for a substantial share of the daily electricity consumption. Our cost calculations make no attempt to quantify the economic value, or discount, associated with these countervailing features of solar PV power.[4]

The remainder of this paper is organized as follows. Section 2 presents the details of the LCOE methodology. This section also highlights how our implementation of this lifecycle cost concept differs from that in other studies. Section 3 presents our basic point estimates for the levelized cost of solar PV. In that section we also examine the robustness of our cost estimates to variations in the most crucial input parameters. Future cost reductions that are likely to be obtained if current solar PV technologies maintain their past ability for learning-by-doing, are analyzed in Section 4. We conclude in Section 5. Throughout, our calculations are obtained via an Excel spreadsheet which is available online and referred to as the *Solar-LCOE Calculator* (Reichelstein and Yorston, 2012).

2. The levelized cost of electricity concept

The Levelized Cost of Electricity (LCOE) is a life-cycle cost concept which seeks to account for all physical assets and resources required to deliver one unit of electricity output. Fundamentally, the LCOE is a break-even value that a power producer would need to obtain per Kilowatt-hour (kWh) as sales revenue in order to justify an investment in a particular power generation facility. The 2007-MIT study on "The Future of Coal" elaborates on this break-even interpretation of the LCOE with the following verbal definition: "*the levelized cost of electricity is the constant dollar electricity price that would be required over the life of the plant to cover all operating expenses, payment of debt and accrued interest on initial project expenses, and the payment of an acceptable return to investors*".

The preceding definition makes clear that LCOE is a break-even figure that must be compatible with present value considerations for investors and creditors. Despite widespread references to the LCOE concept, the energy literature does not seem to make use of a common formula for calculating this average cost. For instance, the MIT study operationalizes the capacity related component of the levelized cost of electricity by simply "*applying a 15% carrying charge to the total plant cost*". A number of working papers and unpublished reports develop their own version of the LCOE concept, for instance, Short et al. (1995); Kammen and Pacca, 2004, Campbell (2008, 2011); Kolstad and Young (2010). A common approach is to define LCOE as the ratio of "lifetime cost" to "lifetime electricity generated" by the facility. Below, we examine the consistency of this approach with our formulation.

Consider a single investment in a new power generating facility. To assess the life cycle cost of producing electric power at this facility, we aggregate the upfront capacity investment, the sequence of electricity outputs generated by the facility over its useful life, the periodic operating costs required to deliver the electricity output in each period and any tax related cash flows that apply to this type of facility.

Since the LCOE formula yields an *output price* which leads equity investors to break-even, it is essential to specify the appropriate discount rate. A standard result in corporate finance is that if the project in question keeps the firm's leverage ratio (debt over total assets) constant, then the appropriate discount rate is the Weighted Average Cost of Capital (WACC).[5] In reference to the above quote in the MIT study, equity holders will receive "*an acceptable return*" and debt holders will receive "*accrued interest on initial project expenses*" provided the project achieves a zero Net-Present Value (NPV) when evaluated at the WACC. We denote this interest rate by r and denote the corresponding discount factor by $\gamma \equiv 1/(1+r)$.[6]

For a simplified representation of the LCOE of a new power generating facility, suppose initially that there are no periodic operating costs and no corporate income taxes. The LCOE formula is then based on the following variables:

- T: the useful life of the power generating facility (in years)
- SP: the acquisition cost of capacity (in \$/kW)
- x_t: system degradation factor: the percentage of initial capacity that is still functional in year t.

We abstract from any quantity discounts and scale economies that in practice can be obtained if the installed capacity reaches a certain threshold size. Thus, there will be no loss generality in normalizing the investment in power capacity to 1 kW. For solar photovoltaic installations, prices are commonly quoted as "dollars per peak Watt DC" (abbreviated as \$ per W_p).

The system degradation factor, x_t, refers to the possibility that some output generating capacity may be lost over time. In particular with solar photovoltaic cells it has been observed that their efficiency diminishes over time. The corresponding decay is usually represented as a constant percentage factor which varies with the particular PV technology and the location of the installation.[7]

The power generating facility is theoretically available for $8760 = 365 \cdot 24$ h, but due to technological, environmental and economic constraints, practical capacity is only a percentage of the theoretical capacity. This percentage is usually referred to as the capacity factor, *CF*. We define *the cost of capacity for one*

[4] See Borenstein (2012) and Joskow (2011) for further discussion of the intermittency and peak-load premium aspects of solar power.

[5] See, for instance, Ross et al. (2005).

[6] Our analysis ignores inflation. In an inflationary environment the LCOE would compound at the rate of inflation. Yet, provided that all production inputs are subject to the same, constant inflation rate, and this rate is also reflected in the nominal discount rate, the resulting (initial) LCOE will be unchanged. Thus our concept of the levelized cost is to be interpreted as a real, rather than a nominal output price.

[7] In contrast, for other renewable energy sources, for instance, biofuels, analysts typically anticipate yield improvements which would result in a sequence of x_t that is increasing over time. See, for instance, NREL (2009).

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kilowatt hour (kWh) as:

$$c = \frac{SP}{8760 \cdot CF \cdot \sum_{t=1}^{T} x_t \cdot \gamma^t}. \tag{1}$$

The expression in (1) reflects that the original investment yields a stream of output levels over T years, with $x_t \cdot 8760 \cdot CF$ kilowatt hours delivered in year t due to the potential loss of capacity over time. If the firm were to receive the amount c as the revenue per kilowatt-hour, then revenue in year t would be $c \cdot x_t \cdot 8760 \cdot CF$. Absent any tax effects and annual operating costs, the firm would then exactly break-even on its initial investment of SP over the T-year horizon.

Corporate income taxes affect the LCOE through depreciation tax shields and debt tax shields, since both interest payments on debt and depreciation charges reduce the firm's taxable income. As mentioned above, the debt related tax shield is already incorporated into the calculation of the WACC. The depreciation tax shield is determined jointly by the investment tax credit (ITC), the effective corporate income tax rate and the depreciation schedule that the IRS allows for the particular type of power generating facility. We represent these variables as:

- i: investment tax credit (in %),
- α: effective corporate income tax rate (in %),
- T^o: facility's useful life for tax purposes (in years),
- d_t: allowable tax depreciation charge in year t (in %).

For certain types of investments, the tax code allows for an *Investment Tax Credit*, calculated as a percentage of the initial investment. We denote this percentage by i. For instance, under the Economic Stabilization Act of 2008, new solar installations receive a 30% tax credit, which means that the taxpayer's corporate income tax liability is reduced by 30% of the initial investment.[8] For most businesses, the investment tax credit thus becomes a direct cash subsidy by the government. The tax code specifies a useful life, T^o, dependent on the type of power generating facility. This assumed useful life is generally shorter than the projected economic life and thus $T > T^o$ in our notation. The depreciation charge that the firm can deduct from its taxable income in year t is given by $d_t \cdot SP$, with $\Sigma_{t=1}^{T^o} d_t = 1$. However, if the investing party does take advantage of an investment tax credit in the amount of i % of the initial investment SP, the corresponding asset value for tax purposes is reduced by a factor $\delta \cdot i$. In other words, for tax purposes the investing firm can only capitalize the amount $SP \cdot (1-\delta i)$. Under the Economic Stabilization Act of 2008, $\delta = .5$. For the purposes of calculating the Levelized Cost of Electricity, the overall effect of income taxes is then summarized by the following *tax factor:*

$$\Delta = \frac{1 - i - \alpha \cdot (1-\delta i) \cdot \sum_{t=1}^{T^o} d_t \cdot \gamma^t}{1-\alpha}. \tag{2}$$

Absent any investment tax credit, the tax factor amounts to a "mark-up" on the unit cost of capacity, c. Specifically, the tax factor Δ exceeds 1 but is bounded above by $1/(1-\alpha)$ if $i = 0$. It is readily verified that Δ is increasing and convex in the tax rate α. Holding α constant, a more accelerated tax depreciation schedule tends to lower Δ closer to 1. In particular, Δ would be equal to 1 if $i = 0$ and the tax code were to allow for full expensing of the investment immediately (that is, $d_0 = 1$ and $d_t = 0$ for $t > 0$).

To complete the description of the LCOE model, let w_t denote the variable operating cost of power generation in period t, per kWh. Costs in this category include fuel, labor and other cash conversion costs. It will be convenient to define the following "time-averaged" variable cost per kWh:

$$w = \frac{\sum_{t=1}^{T} w_t \cdot 8760 \cdot CF \cdot x_t \cdot \gamma^t}{8760 \cdot CF \cdot \sum_{t=1}^{T} x_t \cdot \gamma^t} = \frac{\sum_{t=1}^{T} w_t \cdot x_t \cdot \gamma^t}{\sum_{t=1}^{T} x_t \cdot \gamma^t}. \tag{3}$$

For one kW of installed capacity, the numerator in (3) represents the discounted value of future variable costs, while the denominator (as in Eq. (1)) measures the discounted value of future kilowatt hours available from installing one kW of power. Finally, let F_t denote the periodic fixed costs per kilowatt of power installed. These costs comprise primarily operating and maintenance costs that are independent of the amount of energy generated by the facility. Since capacity is subject to systems degradation, it will again be convenient to define the following "time-averaged" fixed cost per kWh:

$$f = \frac{\sum_{t=1}^{T} F_t \cdot \gamma^t}{8760 \cdot CF \cdot \sum_{t=1}^{T} x_t \cdot \gamma^t}. \tag{4}$$

The numerator in (4) represents the present value of fixed operating costs associated with a capacity installation of one kW, while the denominator again represents the discounted value of the stream of future kilowatt hours available from the installed kW.

Combining the preceding components, we arrive at the following expression for the Levelized Cost of Electricity (LCOE):

Proposition 1. *The Levelized Cost of Electricity is given by:*

$$LCOE = w + f + c \cdot \Delta, \tag{5}$$

with c, Δ, w and f as given in (1)–(4).

To see why the expression in (5) does indeed satisfy the verbal description of LCOE provided above, let p be the sales price per kWh. For one kilowatt of capacity installed, taxable income in period t is then given by the contribution margin in that period minus fixed operating costs minus the depreciation expense allowable for tax purposes:

$$I_t = 8760 \cdot CF \cdot x_t \cdot (p - w_t) - F_t - SP \cdot (1 - \delta i) \cdot d_t. \tag{6}$$

All terms in (6), other than the one last corresponding to depreciation, are also cash flows in period t. If the firm pays an α share of its taxable income as corporate income tax, the annual *after-tax* cash flows, CFL_t are:

$$CFL_t = 8760 \cdot CF \cdot x_t \cdot (p - w_t) - F_t - \alpha \cdot I_t. \tag{7}$$

Initially, there is the cash outflow corresponding to the initial investment expenditure, reduced by the investment tax credit, that is, $CFL_0 = -SP(1-i)$. In order for the firm to break even on its investment, the product price p must be such that the present value of the after-tax cash flows is zero:

$$0 = -SP \cdot (1-i) + \sum_{t=1}^{T} CFL_t \cdot \gamma^t. \tag{8}$$

Solving this linear equation for p, one obtains precisely the LCOE identified in Eq. (5).

We conclude that the Levelized Cost of Electricity per kWh is given by the sum of three components: the (time averaged) unit operating fixed cost, f, the (time averaged) unit variable cost, w, and the unit cost of capacity, c, marked-up by the tax factor Δ. For solar PV power, the component affiliated with the cost of capacity, c, will be by far the dominant factor. In contrast, for a natural gas power plant, the unit variable cost, w, is the largest cost component, reflecting the expenditure for natural gas as the fuel.

To conclude this section, we note that our derivation of the Levelized Cost of Electricity appears different from that in a number of other studies and publications which define LCOE as a full cost measure, given by the ratio of "lifetime cost" to

[8] In practice, the investor does not receive the tax credit upfront, but after the first year of operation. For simplicity, we ignore this feature since the difference is negligible.

"lifetime electricity generated".[9] The notion of "lifetime" refers to the present value of cash expenditures or units of electricity output, respectively. We demonstrate in Appendix A2 that this conceptualization is indeed consistent with our formulation in Proposition 1 provided that both the numerator ("lifetime cost") and the denominator ("lifetime electricity") are calculated on an after-tax basis. Unfortunately, this tax adjustment has no immediate economic interpretation for the measure of the denominator electricity output.[10]

The lack of proper recognition of tax effects appears to be the major source of discrepancy between our LCOE calculation and that available from the *System Advisor Model*, a software program that the National Renewable Energy Laboratory (NREL) and the Department of Energy (DOE) have made available online to simulate the economics of different renewable energy generation plants. Specifically, we find that, for any given set of parameter inputs, the *System Advisor Model* understates our measure of the LCOE precisely by the factor $1-\alpha$. For a combined federal- and state income tax rate of $\alpha=.4$, this discrepancy obviously constitutes a 'first-order' effect.[11]

In connection with coal-fired power plants, the MIT (2007) study takes a shortcut in the calculation of the LCOE concept by simply applying a 15% carrying charge to the original total plant cost. Thus, a 15% charge is applied to the initial investment expenditure on a per kWh basis, (that is, $SP/(CF \cdot 8760)$), in order to obtain a levelized charge for the capacity cost required to generate one kWh. To calibrate this carrying charge, we adjust the above parameter choices in accordance with those of coal-fired power plants. Specifically, suppose that $T=30$ years, depreciation is calculated according to the 150% declining balance rule, the weighted average cost of capital is 8% and there is no system degradation ($x_t=1$). In our framework, this results in a carrying charge of $c\,\Delta=.11$. We conclude that our LCOE component that corresponds to the cost of capacity is about 36% lower than that employed in the MIT shortcut calculation in connection with coal-fired power plants.

3. Current levelized cost of solar PV power

3.1. Parameter estimates

We first detail our input parameters for the LCOE calculation corresponding to the four different scenarios of solar PV installations we consider. Throughout, we will pursue a "best case scenario" insofar as we choose each point estimate according to a most favorable, albeit realistic, scenario. Our sensitivity analysis in Section 3.2 allows the reader to evaluate the impact of each of these parameter specifications on the resulting LCOE.

3.1.1. Upfront capacity investment

Solar photovoltaic systems produce electricity as distributed current (DC). Yet, this current must be converted into alternating current (AC) for practical electricity use. The conversion requires inverters and transformers and involves a loss of power which is commonly accounted for by the so-called *DC/AC Derate Factor*. We will denote this factor by *DF* and assume for simplicity that it is invariant to different PV technologies.[12] Formally, *DF* is expressed as a percentage which represents the AC power output for each kW of nominal DC power the system is rated at. Our calculations follow the common industry practice of quoting investment expenditures and capacity measures on a DC basis.

The *system price* represents the present value (or "overnight cost") of installing the system. It comprises a *module price*, expressed in \$ per peak Watt DC (\$/W_p-DC), and a *balance of system* price, also expressed in \$/W_p-DC. This second category includes all non-module costs of a solar PV installation, including wiring, racking, inverter, labor, land and permitting. The AC System Price, or simply *SP* in the LCOE model, is obtained by dividing the DC system price by the derate factor:

$$SP=\frac{SP_{DC}}{DF}. \tag{9}$$

Our choice of \$1 per W_p-DC in Table 1 for modules seems remarkably low, in particular for panels based on crystalline silicon cells. We base this choice on widely quoted price figures in the fourth quarter of 2011, see, for instance, Swanson (2011). As mentioned above, it is widely accepted that these prices reflect current distress pricing in the industry, due to a large infusion of new manufacturing capacity. We revisit this issue in Section 3.2 below.

The *DC-to-AC capacity factor* is a percentage value that indicates how much of the maximum theoretical power that the system could generate in a given timeframe (e.g. per year) is actually generated. The capacity factor for solar PV electricity generating systems is dependent on a variety of different factors, with the most important being the insolation (or irradiance) level of the site. Clearly, this factor will vary with the latitude and the local climate (e.g., cloud cover) of the site. For a given location, the capacity factor will also vary with the module technology: different modules respond differently to incident light and temperature variations. Finally, the capacity factor is affected by tilt and orientation of the solar module.[13] Our source for obtaining capacity factors is NREL's 'System Advisor Model' (http://www.nrel.gov/rredc/pvwatts).

Overall, the projected annual electricity output of the system is obtained by multiplying the capacity factor by 8760—the number of hours in a year. The capacity factors shown in Table 1 are roughly consistent with the "Insolation Map" in Fig. 2, which shows the 'effective' number of hours of sunlight in a particular location.[14] Given our assumption of an installation in the southwestern U.S., the capacity factor would then roughly be obtained as $2100/8760=.24$. The lower figures for commercial scale installations in Table 1 reflect that most sites, in particular commercial sites, are not ideal in terms of site slope or shading.[15]

We assume that an investor in either a utility-scale or a commercial-scale solar PV installation has other income tax expenses and thus can take advantage of the 30% investment tax credit that is allowable under the Economic Stabilization Act of 2008. Yet, as pointed out above, the 2008 Act stipulates that if the investing party does take advantage of the 30% investment tax

[9] See, for instance, IEA/NEA (2010), EPIA (2011), Campbell (2008, 2011) and Werner (2011).

[10] As shown in Appendix 2, an alternative formulation expresses future costs and energy on a pre-tax basis, but multiplies the initial system price by the tax factor in eq. (2).

[11] For details of how the *System Advisor Model* approaches the LCOE calculation, see Short et al. (1995).

[12] For a full description of the parameters that influence the derate factor, see: http://www.nrel.gov/rredc/pvwatts/changing_parameters.html.

[13] We consider the potential value of trackers as part of our sensitivity analysis below.

[14] *Source*: Division of Energy Efficiency and Renewable Energy, U.S. Department of Energy.

[15] It should be noted that the DC-to-AC capacity factors reported in Table 1 are already adjusted for the derate factor (DF). For instance, the 19.9% capacity factor for Utility-Silicon installations in Table 1 corresponds to a setting where the capacity factor that pertains to the generation of distributed current (DC) is in fact 23.4% (since $23.4 \cdot .85=19.9$). This feature explains why the cost figures in our *Solar-LCOE* calculator are seemingly invariant to changes in DF.

Table 1
LCOE parameter values.

Parameter	Scenario			
	Utility—Silicon	Utility—Thin film	Commercial—Silicon	Commercial—Thin film
Derate factor			85%	
Module price (S/W_p-DC)			1.00	
BoS price (S/W_p-DC)	1.00	1.15	1.50	1.65
DC-to-AC capacity factor	19.9%	20.6%	17.70%	18.10%
Degradation factor	99.65%	99.50%	99.50%	99.25%
Fixed O&M costs ($S/W_p-DC/yr$)	.015	.020	.023	.030
Discount rate	7.50%	7.50%	8.00%	8.00%
Useful life			30 years	
Investment tax credit			30%	
Depreciation type			5-Year MACRS schedule	
Tax rate			40%	

credit, the corresponding tax base (asset value) is reduced by a factor of 15%.

3.1.2. Annual parameters

The electricity output produced by solar PV systems is subject to degradation over time. The *degradation factor* is usually expressed as a percentage of initial capacity that remains available in a later year. For simplicity, we assume a constant degradation rate, though the degradation rate is arguably higher in the first few years and then tapers off. Consistent with the notation introduced in Section 2, we denote the degradation factor by x_t, which in the case of constant decay becomes x^t. Table 1 below shows that for the utility-scale scenarios considered in our analysis the assumed degradation factor x exceeds .995, which effectively supposes a desert location. The figures in Table 1 also reflect the commonly held view that Thin Film technologies are subject to higher degradation than crystalline silicon PV.

In the category of annual *operating costs*, the variable cost component (the parameters w_t) is arguably negligible for solar PV installations. In contrast, the component of fixed operating and maintenance costs, F_t, constitutes a non-trivial share of the overall LCOE. Our estimates in Table 1 below are consistent with NREL (2010) and Campbell (2011). Consistent with the model set-up in Section 2, these fixed cost numbers are to be interpreted as annual costs per kW of power installed. Because of system degradation, the fixed cost per kWh *generated* is therefore increasing over time. As one might expect, the estimates in Table 1 suggest that utility-scale projects experience economies of scale for this fixed cost component. Furthermore, silicon based solar panels require less maintenance expenditure than thin film panels because the latter require more square footage per kW.

With regard to income taxes, we rely on a "blended" marginal tax rate of 40% which reflects both state and federal income taxes. As part of the Economic Stabilization Act of 2008, solar installations are also entitled to a highly accelerated depreciation schedule, commonly referred to as *Modified Accelerated Cost Recovery System* (MACRS). The specific depreciation percentages are given by $(d_1,\ldots,d_6)=(.2, .32, .192, .115, .115, .058)$. However, the 2008 Tax Act also requires the allowable depreciation charges to be deflated by $(1-.5i)$, so that with the maximum allowable investment tax credit of $i=.3$ the above depreciation charges are deflated by.85. This assumption is maintained throughout in our *Solar-LCOE* calculator.[16] The following table summarizes the discussion in this section and identifies for each of the four scenarios the parameter choices that feed into the LCOE calculation. We emphasize again that these values are in almost all respects "best-case scenarios" for the U.S. in the fourth quarter of 2011.[17]

The applicable input values for the cost of capital (WACC) will obviously vary with firm-specific characteristics. Our sensitivity results below suggest that a 10% increase in the assumed cost of capital would increase the corresponding LCOE by approximately 8%.

3.2. LCOE estimates

Proposition 2. *The parameter choices in Table 1 give rise to the following Levelized Cost of Electricity estimates (in cents per kWh):*

PV Technology/Scale	Utility-scale	Commercial-scale
Silicon	7.97	12.17
Thin film	8.62	13.35

According to these findings, silicon based solar PV is, at least in the current environment, slightly more cost effective than thin film technology. We submit that both technologies already achieve the standard of grid parity for installations on a commercial scale, at least in some U.S. locations. For instance, small and medium-sized commercial users in Southern California in recent years paid 14–15 cents per kWh on average.[18]

Despite our choice of a most favorable scenario for solar PV, we conclude that utility-scale installations result in LCOE figures that are around 35–50% higher than comparable base-load rates associated with fossil fuels. As shown in Appendix A3, our LCOE model yields a value of 5.8 cents per kWh for a 550 MW power generating facility that relies on natural gas as its fuel.[19] Arguably this comparison does not account for the 'clean-tech' features of solar power. Yet, even if one were to impute a rather high charge for CO_2 emissions, say $60 per metric ton, the resulting LCOE a natural gas plant would still be below the solar LCOE figures in Proposition 2.[20]

[16] To highlight the importance of federal tax incentives associated with the Economic Stabilization Act of 2008, the *SolarLCOE* calculator also allows for the traditional 20-year 150% declining balance depreciation method that is applicable to other (fossil fuel) power generation facilities.

[17] Our use of input variables in DC terms is in keeping with the custom of reporting DC figures in the solar PV industry.

[18] See, for instance, the California Public Utilities Commission (2011) Website.

[19] The input parameters in Appendix 2 are based on Islegen and Reichelstein (2011). The slight difference in the reported LCOE figure (5.8 cents versus 5.6 cents per kWh) is attributable to the fact that Islegen and Reichelstein (2011) consider only the federal income tax rate of 35%, rather than the blended rate of 40% used in this paper. It should also be noted that the 5.8 cents per kWh figure is based on a multiyear average of natural gas prices in the U.S., rather than the exceptionally low prices observed recently.

[20] NETL (2007) provides CO_2 emission rates for Natural Gas Combined Cycle power plants.

The use of trackers will further improve the capacity factor since the solar cells will be exposed to direct sunlight for a longer portion of the day. The cost effectiveness of trackers is difficult to assess in general, since both the incremental systems cost and the yield improvements will tend to be location specific. It is generally accepted that utility-scale installations based on crystalline silicon modules in sunny locations will tend to benefit most from trackers. Estimates for the cost of trackers vary widely, ranging from about .2 to 1.4$/W that have to be added to the system price. To project the LCOE impact of trackers, we consider 1-axis trackers at an additional cost of .2$/W in system price and 8% higher fixed maintenance costs.[21] These trackers are assumed to increase the capacity factor from 19.9% to 26.8% for the favorable location we have assumed throughout.[22] Keeping all other parameters constant, we obtain the following:

Corollary to Proposition 2: *For crystalline silicon-based installations on a utility scale, the use of trackers can potentially reduce the Levelized Cost of Electricity by 19%.*

The wording in the preceding corollary indicates that the marginal effect of trackers is rather location specific and we have arguably again picked a most favorable scenario. If one performs the same calculation for a less ideal location, such as New Jersey, the reduction in LCOE will be less than 8%.

Module prices have come down some 40% in 2011 alone. In light of the massive capacity investments by Chinese panel manufacturers (Bradsher, 2011), there is little reason to attribute this price drop primarily to technological improvement and corresponding manufacturing cost reductions. To estimate the long-term 'equilibrium' value of PV modules, we refer to the trajectory of module prices in Fig. 1.[23] A constant elasticity learning curve of the form $y = a \cdot x^{-b}$ can be fitted to the data, where 'y' is the module price, 'x' is the cumulative installed capacity, while 'a' and 'b' are parameters. Timilsina et al. (2011), for instance, obtain the regression estimates $a = 5066.9$ and $b = .331$. The implied 'learning factor' is $1\text{-}2^{-b} = .21$, which means that every time cumulative capacity doubles, module price drops by 21%. This is consistent with other literature that puts the learning curve factor for solar PV at between 19% and 22%.

The long-term experience curve for solar PV modules yields an estimate for an economically sustainable module price—one that would give module manufacturers an adequate profit margin so as to cover their cost of capital. The implicit assumption is that if the market has been able to sustain this trend for over 30 years, module manufacturers must at least on average have received acceptable profit margins and returns on their investments, or else they would have exited the industry. Using the above regression estimates and considering that cumulative installed capacity at the end of 2011 was about 63 GW, we arrive at a "sustainable" price of 1.35$/W for year-end 2011—about 35% higher than the 1$/W observed in markets at that time. On the basis of 'economically sustainable' module prices, we obtain the following modification of the LCOE figures in Proposition 2:

Proposition 2′ *Our estimate of economically sustainable module prices raises the Levelized Cost of Electricity figures in Proposition 2 to:*

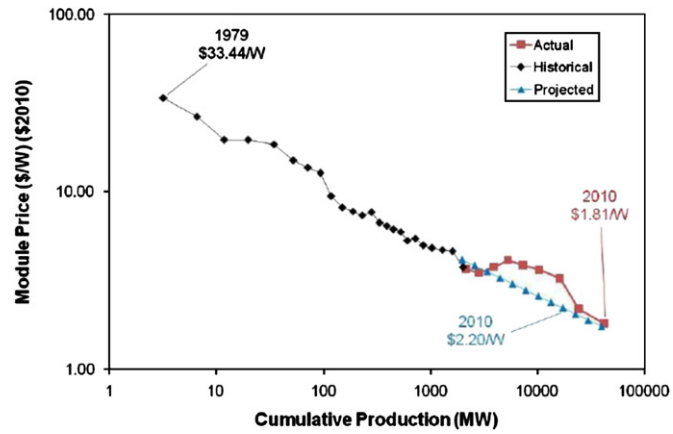

Fig. 1. Module prices as a function of global cumulative installed capacity. Source: Swanson (2011).

	Utility-scale	Commercial-scale
Silicon	9.21	13.66

The resulting LCOE figures exceed the ones reported in Proposition 2 by 12–15%. We have chosen to exclude thin film modules from this analysis since the long-term learning curve for this technology is not as well documented as it is for crystalline silicon.

The massive deployment of utility-scale solar PV in the past few years, in particular in non-ideal locations, may seem surprising given the significant cost difference with base-load rates attained by fossil fuel sources. We attribute this trend to additional subsidies and mandates at the state and local level which are not captured in our analysis. The case of California′s Renewable Portfolio Standard, which establishes a specific goal for solar PV penetration by 2020, is a good example of such a mandate. Utilities are willing to pay premium for Power Purchasing Agreements (PPA′s) that meet these renewable energy goals, thus making solar PV projects more attractive to developers.

Currently, about half of all U.S. states have renewable portfolio standards in place with specific 'carve-outs' for solar power.[24] These standards enable investors in new solar installations to sell *Renewable Energy Credits* (REC′s) to utilities which are the obligated parties under the standard. The spot market price of REC′s varies widely both over time and from state to state. Recent auction prices have ranged from lows of 1 cent per kWh in Pennsylvania to over 60 cents per kWh in New Jersey.[25] Finally, the recent surge in solar PV may be explained by the fact that the supply curve of solar power generation tends to match up well with the intraday demand schedule: solar PV generates a substantial portion of its daily output in the afternoon when electricity consumption levels tend to be relatively high.

3.3. Sensitivity analysis

We next perform a sensitivity analysis for five of the most crucial parameters of the model. The analysis in the "spider" chart below is confined to the case of silicon PV installations on a commercial-scale. The other three scenarios considered in Section 3 show a similar behavior.

[21] See GTM Research (2011). In particular, higher fixed maintenance costs are a consequence of the fact that trackers require moving parts.

[22] This estimate is based on NREL′s *Solar Advisor Model* for 1-axis trackers in Tucson, Arizona.

[23] The 'bulge' in the red curve in Fig. 1 is generally attributed to a shortage of raw silicon that started in 2004.

[24] More details are available at: http://www.srectrade.com/background.php

[25] Hoyt and Reichelstein (2011) observe that for the retailer REI the magnitude of the Renewable Energy Credits was a significant factor in justifying the investment in solar rooftop installations.

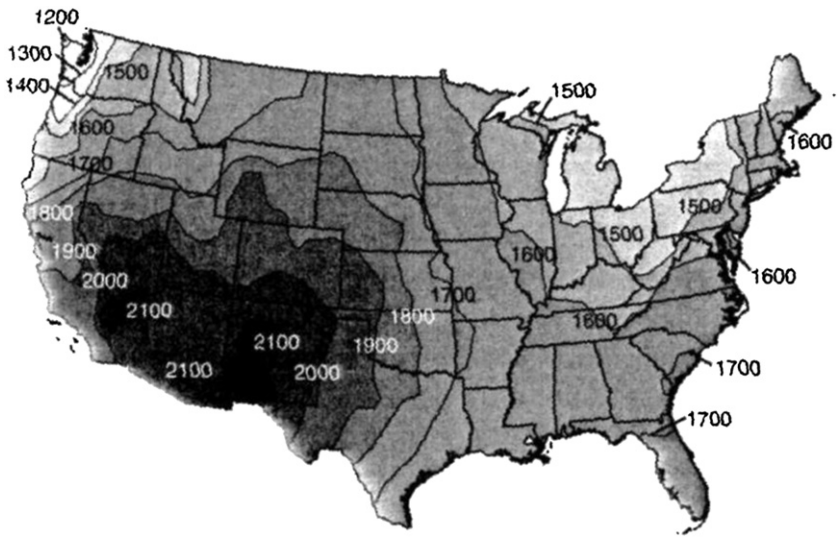

Fig. 2. Insolation map for the U.S.

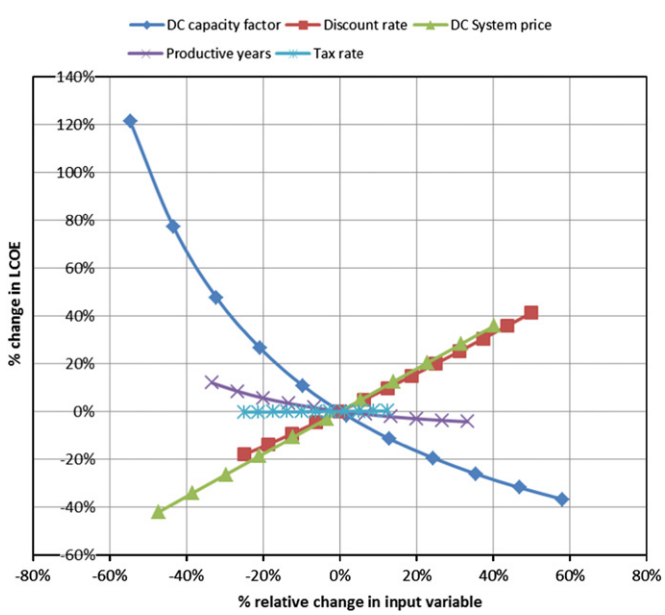

Fig. 3. "Spider" chart showing sensitivity of LCOE estimates.

Each line in Fig. 3 represents one of the key parameters of the model. The parameters are allowed to vary within certain predefined tolerance levels which represent a reasonable range. The slope of the lines in Fig. 3 indicates how sensitive the LCOE estimates are to the underlying parameter. For example, the DC Capacity factor′s base case value was 17.7% for commercial-scale crystalline silicon. We allowed the capacity factor to vary between 8% and 28% while keeping all other parameters constant. As one would expect, the relationship with LCOE is negative in so far that an increase in the capacity factor translates to a lower LCOE. In contrast, a higher system price or discount rate does ceteris paribus raise the LCOE.

The main conclusion from this analysis is that the Capacity Factor (CF) is by far the most sensitive parameter: decreasing it by half implies roughly doubling the LCOE. In conjunction with the insolation map in Fig. 2, this analysis indicates that solar PV will fail to be cost competitive for decades to come in many northern locations around the world, including Germany. The next most sensitive parameters are the system price and the discount rate. On the other hand, the LCOE shows low sensitivity to the assumed useful life of the facility.

For the set of parameters we have chosen, changes in the tax rate yield almost no change in the LCOE. This is because the decrease in after-tax income associated with a higher tax rate is almost exactly offset by a greater depreciation tax shield. This conclusion is largely an artifact of the 30% Investment Tax Credit (ITC) and the 5-year accelerated depreciation schedule applicable for new solar installations. For the tax rules that apply to fossil-fuel based power generating facilities, the LCOE will tax rate increase at a significant rate with the tax rate.

The following result shows how the LCOE value changes when the two main federal tax subsidies that solar PV installations currently enjoy – the 30% ITC and the accelerated depreciation schedule under the 5-year MACRS- are removed. We focus on the most attractive scenario of silicon PV installations at commercial scale, taking the finding in Proposition 2′as our baseline figures.

Proposition 3. *The Investment Tax Credit and the 5-year Modified Accelerated Cost Recovery System have the following impact on the Levelized Cost of Electricity estimates (in cents per kWh):*

Tax Credit/Depreciation	5-year MACRS	20-year DDB
30% ITC	13.66	16.44
No ITC	20.86	24.12

The sensitivity results in this subsection have only considered unilateral variations in one of the underlying parameters. The LCOE formula in Proposition 1 indicates that these parameters jointly have a super-modular effect on the overall cost. We illustrate this point by noting that according to Proposition 3 the absence of the current federal tax incentives would raise the LCOE by about 75%. Moving the facility from the southwestern U.S. to New Jersey would lower the capacity by about 20% and therefore, according to Fig. 3, increase the LCOE by about 25% relative to our base scenario. In addition, a sustainable module price would unilaterally increase the LCOE by 12%, as observed in Proposition 2′. Yet, if all three of these variations were to happen simultaneously, the overall LCOE would increase by about 150%.

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4. Projecting future cost reductions

The cost estimates reported in Propositions 2–3 are based on input values that are applicable at the end of 2011.Given the steady decline in the price of solar PV systems in recent years, it suggests itself to project this trend into future so as to gauge the competitiveness of solar PV by the end of the coming decade.

4.1. System prices

The main ingredient of the LCOE equation that can be expected to change significantly over the near future is the System Price (SP) composed of the cost of modules and Balance of System (BoS) costs. As argued above, the evolution of PV module prices has been remarkably consistent with an 80% learning curve over the past four decades. To determine the impact on future LCOE values, we therefore postulate continued adherence to this rate of learning for the next ten years. By definition, we therefore assume that each time the cumulative installed module capacity doubles, module prices will drop by another 20%.

For BoS prices there does not seem to be a well-established learning curve pattern as there is for module prices. Historically, the BoS share of the total system price has been relatively low. Given the dramatic decreases in module prices in the last 3 years, BoS costs now represent upward of 50% for most solar PV projects, and as a consequence cost-reduction efforts are increasingly moving towards this area. There seems to be consensus in the industry that significant cost reductions are feasible in the coming years. For example, an industry-wide event held in 2010 to specifically study potential reduction in BoS costs came up with a target reduction figure of about 50% relative to current values (Bony et al., 2010).

The forecast of future cost reductions for this cost segment is made difficult by the diversity in the required BoS inputs for different installations. For instance, Campbell (2011) reports a 2x difference between high and low BoS cost projects for SunPower in the past few years. Against this backdrop of uncertainty regarding BoS price trends, we rely on data from an industry report (Aboudi, 2011) that projects BoS costs through 2013. Accordingly, the following calculations are based on the assumption that the BoS component of the system price will be reduced by 7% per year throughout the next decade.

4.2. Installed capacity

Since the assumed 80% learning curve for module prices is not driven by calendar time but by cumulative installed capacity, we also need to forecast the latter variable. As one might expect, there is again considerable variation in the available estimates. Our analysis relies on an average of two different projections, made respectively by the EPIA (2011) and Lux Research (2011). Since EPIA's projection is through 2020 while Lux Research's is only through 2016, we extrapolate linearly for the years of 2017–2020, consistent with the EPIA pattern for those years. It should be noted that our projected path, which suggests a total of 330 GW of cumulative installed capacity by 2020, does not seem overly ambitious. With about 30 GW of new installations and a cumulative volume of 63 GW by the end of 2011, our assumption of 330 GW by 2020 would require almost no growth from here on. It would be sufficient to maintain the most recent volume of new installations throughout the remainder of the decade. To summarize, our capacity projections are represented in the following chart:

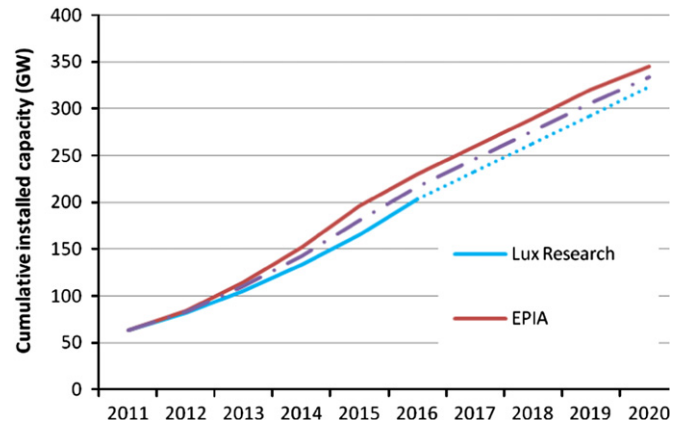

Fig. 4. Cumulative installed capacity projections by EPIA and Lux Research as an average of both projections, using a linear extrapolation of Lux Research's data for 2017 and 2020.

4.3. LCOE projections

The data and assumptions shown in the preceding subsections sections allow us to forecast the system (SP) for the coming years. As a starting point for 2011, we use the 'sustainable' module prices derived in Section 3. Thus our initial LCOE estimates are the ones in Proposition 2′ rather than the ones in Proposition 2.

The following result summarizes the conclusions of our projections.

Proposition 4. *Given our assumptions regarding the respective learning curves for PV modules and BoS components, as well as the assumed trajectory of future solar PV installations* (Fig. 4), *the projected LCOE figures evolve as shown in* Fig. 5. *In particular*:

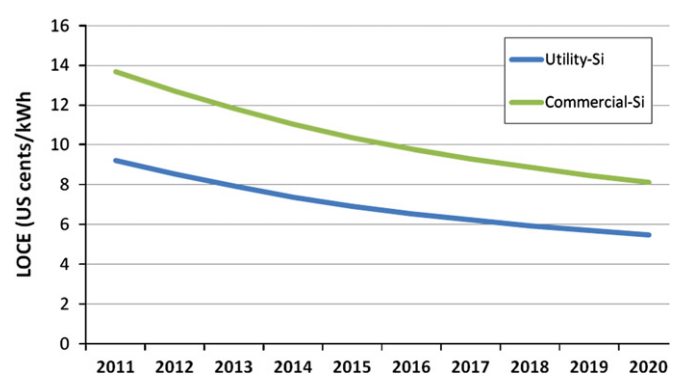

Fig. 5. LCOE projections through 2020 for crystalline silicon at both utility and commercial scale, using 'sustainable' module prices as a starting point and an 80% learning curve factor for module prices.

i) *Utility-scale crystalline silicon PV will be cost competitive with natural gas power plants by 2020.*
ii) *Commercial-scale crystalline silicon PV will attain grid parity within a decade, even in the absence of the current federal tax subsidies.*

The preceding predictions clearly have several important qualifiers attached to them. As emphasized above, any statement in support of cost competiveness or grid parity for solar PV only applies to installations in a favorable geographic location. Furthermore, the current federal tax subsidies for solar power are undoubtedly an important driver of the trajectory of future

solar installations. Thus the second statement in Proposition 4 should be interpreted as a prediction of grid parity, provided the current tax incentives were to be maintained for another decade. Overall, the predictions expressed in Proposition 4 suggest that solar PV does not require a 'technological breakthrough' in order to become economically viable within a decade.

5. Conclusion

The rapid growth in solar PV installations over the past few years has renewed the public debate as to whether solar PV has finally become competitive with other sources of electricity generation. Our analysis relies on the life-cycle cost concept of the Levelized Cost of Electricity (LCOE) in order to identify the factors that are crucial to determining the economic viability of solar PV: geographic location of the facility, technological improvements with attendant reductions in system prices as well as public subsidies in the form of tax breaks and regulatory mandates for renewable energy.

Our findings suggest that, as of 2011, utility-scale PV projects generate electricity at a cost (LCOE) that is still some 35–50% above the comparable cost of generation facilities powered by conventional fossil fuels. This assessment is based on the assumption of a most favorable location of the facility in the U.S. and the availability of the current federal tax incentives granted to solar PV installations. Removing this tax incentive would single-handedly increase the cost of electricity from solar PV by 75%. We therefore attribute the recent wave of utility-scale projects to mandates for renewable energy at the state level, for instance, California's Renewable Energy Portfolio Standard.

From the perspective of a commercial user, we find that rooftop installations of solar PV installations can already be cost competitive relative to the benchmark of retail electricity prices that the commercial user would have to pay. Again, this conclusion presumes a favorable scenario not only in terms of geographic location and tax incentives, but also in terms of relatively high retail prices for electricity. On the other hand, the conclusion does appear to be robust to the notion of 'sustainable' panel prices, that is, pricing of solar panels at levels suggested by their long-term price trend rather than the distress prices experienced by this industry as of late.

Our sensitivity analysis reveals that the capacity factor, which in turn hinges on geographic location, is the most crucial variable in driving the overall LCOE. This implies that many northern locales (for instance, Germany) will be at a permanent and seemingly insurmountable disadvantage for solar PV. As one would expect, the levelized cost is also highly sensitive to further reductions in the system price. On the other hand, income tax rates have virtually no effect on the resulting LCOE, at least for the depreciation- and investment tax credit rules that are currently applicable in the U.S.

Solar PV modules have experienced a remarkably consistent pattern of learning-by-doing over the past thirty years. Specifically, the prices of solar cells and modules have on average come down about 20% each time the total (cumulative) capacity of solar installations has doubled. To assess the prospects for cost competitive solar PV, we posit that the industry can maintain this learning for another decade. If furthermore solar facilities are installed at a rate of about 30 GW per year, which would equal the amount of capacity added in 2011, we obtain two predictions. First, utility-scale facilities are on track to achieve cost competitiveness by 2020. Secondly, commercial-scale installations will be able to achieve grid-parity at the retail price level, that is, they will be cost competitive even if even if the preferential tax treatment of solar PV were to be discontinued at that point in time. To be sure, the current tax treatment appears essential in order to sustain the investment volume that is essential for a continued trajectory down the learning curve. Yet, we also submit that the economic viability of solar PV requires neither a 'technological breakthrough', nor does it seem essential to maintain the current public subsidies indefinitely.

Appendix A1. List of Variables

See Table A1

Table A1

Variable	Units	Description
r	%	Weighted average cost of capital, WACC
γ	%	Discount factor
T	years	Useful life of power generating facility
SP	\$/kW	System price per kW of power installed
CF	%	Capacity factor
x_t	%	System degradation factor: percentage of initial capacity still functional in year t
i	%	Investment tax credit
DF	%	Derate factor
α	%	Effective corporate income tax rate (federal + state)
T^0	years	Facility's useful life for tax purposes
d_t	%	Allowable depreciation charge in year t
w_t	\$/kWh	Variable operating cost in period t per kWh
F_t	\$	Periodic fixed costs in period t per kW installed
I_t	\$	Taxable income in period t per kW installed
p	\$/kWh	Unit sales price of energy generated
Δ	%	Tax factor

Appendix A2

As argued in Section 2, many sources in the literature, e.g., IEA/NEA (2010), EPIA (2011), Branker et al. (2011), Campbell (2008, 2011) and Werner (2011), define the Levelized Cost of Electricity as:

$$\mathrm{LCOE} = \frac{Lifetime\ Cost}{Lifetime\ Electricity\ Generated}.$$

The purpose of this Appendix is to show that this definition is consistent with our characterization in Proposition 1, provided care is taken in specifying the denominator of lifetime electricity on an after-tax basis. We also demonstrate that both the numerator and the denominator can be expressed on a pre-tax basis if one multiplies the initial investment expenditure, SP, by the tax factor Δ. Starting from the definition of the LCOE as the constant sales price with the property that the present value of all cash flows is zero, the break-even requirement becomes:

$$0 = -SP \cdot (1-i) + \sum_{t=1}^{T} CFL_t \cdot \gamma^t. \tag{10}$$

where,

$$CFL_t = 8760 \cdot CF \cdot x_t \cdot (p - w_t) - F_t - \alpha \cdot I_t, \tag{11}$$

and I_t is the taxable income in year t, as defined in (6). Solving eq. (10) for p, one obtains a value of p equal to:

$$\frac{SP \cdot (1-i) + (1-\alpha) \cdot \sum_t [8760 \cdot CF \cdot x_t \cdot w_t + F_t] \cdot \gamma^t - \alpha \cdot \sum_t [SP \cdot (1-\delta i) \cdot d_t] \cdot \gamma^t}{(1-\alpha) \cdot 8760 \cdot CF \cdot \sum_t x_t \cdot \gamma^t}. \tag{12}$$

The numerator in (12) is equal to the present value of all cash outflows per kW of installed capacity, with the last term representing the depreciation tax shield. The denominator gives the

total discounted value of future electricity output, *multiplied by the factor* $(1-\alpha)$. In that sense, LCOE is equal to *Lifetime Cost* over *Lifetime Electricity Generated*.

Finally, it is instructive to note that, using the definition of the tax factor Δ in eq. (2), the expression in (12) can be simplified to:

$$p = \frac{SP \cdot \Delta + \sum_t [8760 \cdot CF \cdot x_t \cdot w_t + F_t] \cdot \gamma^t}{8760 \cdot CF \cdot \sum_t x_t \cdot \gamma^t}. \quad (13)$$

Thus LCOE can equivalently be expressed as the sum of the initial system price, marked up by the tax factor, and future discounted operating cost (on a pre-tax basis), divided by the lifetime electricity generated.[26]

Appendix A3. LCOE Calculation for a Natural Gas Power Plant.

See Table A3

Table A3

Parameters		
Scenario (Mkt. segment & technology)	5	5 = natural gas
Degradation rate, x_t	100.00%	
Fixed O&M cost ($/kWp DC—yr),	$0	
Variable O&M cost ($/kWh), w	$.048	
Discount rate, r	8.0%	
Useful life, T	30	
Investment Tax Credit, i	0%	
Depreciation type	2	20-year 150% declining
Effective corporate tax rate, α	40%	Federal & State
LCOE calculation		
AC System price ($/W), SP	$.65	
AC capacity factor, CF	85.0%	
Capacity cost, c ($/kWh)	.0078	
Tax factor, Δ	1.316	
Levelized cost of electricity (cents/kWh)	c 5.83	

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[26] We are grateful to an anonymous reviewer for this suggestion.

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