The Road Ahead for Solar PV Power

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Abstract

Over the past decade, solar photovoltaic (PV) power has experienced dramatic deployment growth coupled with substantial decreases in system prices. This article examines how solar PV power is currently positioned in the electricity marketplace and how that position is likely to evolve in the foreseeable future. We first assess the current cost competitiveness of solar PV in select U.S. locations and industry segments using the Levelized Cost of Electricity (LCOE) metric. Our framework enables us to quantify the effects that supportive public policies, time-of-use pricing, and anticipated future technological improvements have on the LCOE. We then explore the potential for combining solar PV with battery storage as a means of enhancing the value of solar power. Our analytical framework identifies conditions that make it financially attractive to add behind-the-meter batteries to an existing PV solar system in a residential setting. Taken together, our findings suggest that solar power, by itself and in conjunction with low cost storage, is positioned to account for a growing and significant share of the overall energy mix.

Keywords: Solar PV, Levelized Cost of Electricity, public policy, time-of-use pricing, battery storage.

JEL codes: Q20, Q42

1 Introduction

Solar photovolatic (PV) power has long been heralded as an energy source with enormous potential for the electricity and transportation sectors. Figure 1 shows that for new deployments, growth rates have been consistently high particularly over the past decade. For 2017, industry observers are projecting another 100 GW in new capacity installations to be added globally to the 300 GW that had been in place by the end of 2016.[1]

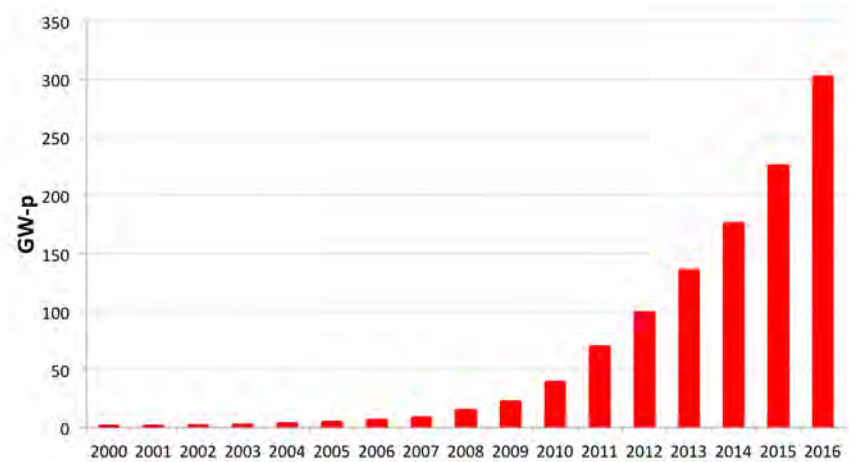

Figure 1: *Cumulative global solar capacity in 2016, (IEA, 2017).*

Coincident with the rapid growth in new solar PV deployments, the prices of solar systems have fallen precipitously in recent years. To witness, the average sales price of PV modules has declined from about \$4 per Watt in 2007 to under \$0.40 per Watt by late 2017. A large body of literature has documented reductions in module prices and their underlying manufacturing costs; see, for instance, Swanson (2011), Candelise, Winskel, and Gross (2013), Sivaram and Kann (2016). At the same time, the prices of Balance of System (BOS) components, which comprise inverters, trackers, racks, and electrical components, have also come down significantly with annual reductions in the range of 5 – 7%.

Our objective in this article is to examine how solar PV power is currently positioned in the electricity marketplace and how that position is likely to evolve in the foreseeable future. To do so, we first assess the current cost competitiveness of solar PV (as of late 2017) and then examine how further technological improvements as well as potential changes in public policy are likely to shape the industry over time. Our analysis of the impact of public policy

[1]For comparison, the entire 2015 installed generation capacity in the U.S. was 1,167GW. Of the 100 GW of new capacity to be added globally in 2017, the U.S. market share is estimated to be about 15%.

focuses on the current U.S. environment, though it will become clear that certain findings carry over to jurisdictions that have adopted different policies.

To assess the current cost competitiveness of solar PV in select U.S. locations and industry segments, we first estimate the levelized cost of electricity (LCOE) of the technology. The significance of this widely used metric is that it provides a lower bound on what an investor/developer would have to obtain as average revenue per kilowatt hour, possibly as part of a power purchasing agreement, in order to earn a normal return on investment. By the LCOE criterion, we find that in many parts of the western United States, utility-scale solar systems are currently better positioned than other electricity generation sources, in particular natural gas powered facilities or wind energy. For the commercial and residential segments we also find that the corresponding LCOE figures are generally below the rates that utilities currently charge their customers, consistent with the recent pace of deployments in these segments of the industry.

Our analysis highlights the fact that any claims about the competitiveness of solar PV power continue to rely crucially on policy support mechanisms that are currently in place. Most important among these is the U.S. federal investment tax credit available to solar investors combined with the possibility of accelerated depreciation allowances for solar facilities. The policy of net metering is another crucial support mechanism that allows commercial and residential solar customers to obtain credit at the going retail rate for surplus electricity transferred to the grid. Both of these support mechanisms are likely to diminish in the near future. For federal tax incentives, the U.S. Congress has specified a "sliding scale" leading up to the end of 2021 and many U.S. states are currently debating or implementing restrictions on net metering. These projections naturally raise the question as to what further reductions in system prices will be required to maintain the cost competitiveness of solar PV in the face of weakening public policy.

Electric power is increasingly priced not on a purely volumetric basis, but instead prices vary according to the time of day and season. Since electricity prices presently are at a premium during the hours of the day when solar PV systems generate their power, time-of-use pricing improves the economics of solar PV systems in the current environment. Our discussion here relies on earlier work that has quantified the magnitude of that synergistic effect. Yet, as the share of solar power in the overall energy mix increases, these synergies are likely to diminish. Furthermore, if some of the predicted scenarios associated with the system net load (i.e. the "duck curve") actually materialize, there may ultimately be a negative complementarity between the prevailing time-of-use-prices and the pattern of solar power generation. We examine how such developments may be counteracted by a range of measures, including energy storage and the possibility of sacrificing overall output from a solar PV facility in return for more favorable timing of the solar power.

Battery storage systems are increasingly combined with both residential and commercial solar PV installations. The financial rationale for doing so relies on the possibility of storage systems to avoid paying a premium for electricity during peak pricing hours, and, for commercial users, on the ability to reduce demand charges. Our discussion of combining battery storage with solar PV systems is focused on residential settings where restrictions on net metering effectively yield a price premium for electricity that is self-generated and subsequently self-consumed at later hours of the day. Our analysis identifies conditions that make it financially attractive to add behind-the-meter battery storage to an existing PV solar system. At the same time, our findings suggest that in addition to the price premium, the availability of federal tax credits and state-level investment rebates is critical for economically viable battery deployments in this segment.

The final part of our analysis examines the dynamics of solar PV system prices. For photovoltaic modules, recent literature has argued that the observed steep price declines are only partially attributable to intrinsic manufacturing cost reductions and partially also to excessive additions of manufacturing capacity.[2] We follow the framework in recent learning curve models to project the long-run unit cost of manufacturing modules by extrapolating from the most recent production volumes. These improvements combined with the expected reduction in BOS prices have to be weighed against the diminishing federal tax support for solar PV. The resulting dynamic leads us to the prediction that the LCOE figures will see marginal reductions over the next four years, however experience a modest increase in 2022 due to the significant incentive reductions. For instance, the LCOE of utility-scale facilities in California is projected to increase by 10% in five years time, primarily due to the investment tax credit stepping down to 10%.[3]

The remainder of this paper is organized as follows. Section 2 provides a baseline assessment of the current cost competitiveness of solar PV power. Section 3 highlights the impact of public policy, specifically federal tax support and net metering policies at the state level,

[2]See, for instance, Candelise, Winskel, and Gross (2013).

[3]From 22% one year earlier in 2021.

in the recent growth spurt of solar PV in the U.S. We examine the impact of increased time-of-use pricing on the economics of solar power in Section 4. Section 5 explores solar PV with battery storage systems and develops an analytical cost framework for such a facility in the residential setting. The past dynamics of solar system prices and corresponding forecasts for the levelized cost of solar power over the next five years are analyzed in Sections 6 and 7. We conclude in Section 8.

2 Current Cost Competitiveness of Solar PV

Our assessment of the current cost competitiveness of solar PV focuses at first on the Levelized Cost of Electricity (LCOE), a cost concept that is widely relied upon by researchers and energy analysts. This life cycle cost measure is stated in terms of dollars per kilowatt-hour of electricity, accounting for all upfront capital expenditures and subsequent operating costs. The LCOE is calculated as a per unit break-even value that a producer would need to obtain in sales revenue in order to justify an investment in a particular power generation facility.[4] A developer who signs a power purchasing agreement (PPA) for a new project will therefore be "in the money" with a new project provided the PPA exceeds the LCOE of the facility.

The LCOE can in aggregate form be expressed as the sum of three terms, the first two of which refer to unit variable - and fixed operating costs, respectively, while the third term captures the unit cost cost of capacity, scaled by a tax factor, which comprises the corporate income tax effects of the investment. Formally,

$$LCOE = w + f + c \cdot \Delta, \tag{1}$$

where w, refers to the time-averaged variable operating cost (in \$ per kWh) that includes, for example, variable operations and maintenance (O&M), fuel, and possibly carbon dioxide emission charges. The unit cost f captures the time-averaged fixed operating cost (in \$ per kWh) that is comprised of, e.g., insurance, property taxes, management costs, and fixed

[4]Our approach here follows Reichelstein and Yorston (2013), who operationalize the verbal definition in the MIT study "The Future of Coal" (MIT, 2007). Specifically, it states: "*...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.*" In addition, our LCOE calculations include corporate income taxes as an expense to be covered.

O&M costs. Finally, c, is the unit cost of capacity (in \$ per kWh). It takes the system price (i.e., overnight capital expenditure) per kW and "levelizes" this expenditure to arrive at a unit cost of capacity per kWh. The unit-less tax factor Δ scales the unit cost of capacity to reflect the impact of the corporate income tax rate, the allowable depreciation schedule for tax purposes and any available investment tax credits.

Figure 2 shows the outcome of an LCOE calculation for solar PV in California based on the LCOE Calculator (Comello, Glenk, and Reichelstein, 2017). The underlying input parameters are obtained from a variety of databases, including GTM (2017); ABB (2017); Fu et al. (2017); Bolinger, Seel, and LaCommare (2017).

The Levelized Cost of Electricity

Enter the input para

Input Parameters: Utility Scale Solar PV California		
Useful life (economic), T	30	years
Tax Depreciation Method	4	
System Price (for solar, enter DC system price), SP	1.45	(\$/W)
Investment Tax Credit, i	30%	
Capacity Factor (for solar, enter DC-to-AC capacity factor), CF	28.6%	
System Degradation Factor, x_t	99.5%	
Fixed O&M Cost	10.7	(\$/kW - yr)
Variable O&M Cost, w (excluding fuel)	0.001	(\$/kWh)
Fuel Cost	0.000	(\$/kWh)
Carbon Dioxide Emissions Cost (Allowance Cost)		(\$/tCO2e)
Emissions performance	0.0000	(kg CO2e/kWh)
Cost of Capital, r	7.50%	
Effective corporate tax rate, α	43.84%	

LCOE calculation		
Unit Capacity Cost, c	0.0516	(\$/kWh)
Tax factor, Δ	0.6653	
Average fixed O&M cost, f	0.0045	(\$/kWh)
Average variable O&M cost (including fuel), w	0.0010	(\$/kWh)
Levelized cost of electricity	**0.0398**	(\$/kWh)

Figure 2: *LCOE for Utility-scale solar PV in California*

For the particular application of utility scale PV in California, the input parameter section of the table in Figure 2 summarizes the values of all relevant input variables, including the capacity factor, the rate of system degradation, the applicable cost of capital, the applicable depreciation schedule and the combined federal and state-level corporate income tax rate.[5] The corresponding output variables, that is, w, f, and c, as well as the resulting LCOE are shown in the lower part of the table in Figure 2. As one would expect, the operating costs amount to only around 0.5 cents per kWh, with the remainder of the 3.98 cents accounting for capacity costs.[6] While the tax factor for ordinary investments in power generating facilities

[5]The cost of capital, r, is interpreted as a weighted average of the costs of equity and debt.

[6]The system price of \$1.45 per Watt includes the price of solar modules at \$0.38, with the residual

would be 1.35, its remarkably low value in the case of solar PV reflects three factors to be examined in more detail in the next section: the currently available investment tax credit, the accelerated depreciation tax schedule (MACRS) and additional first-year bonus depreciation available to solar photovoltaic installations.

In assessing the competitiveness of utility-scale solar PV in the current environment in California, the 3.98 cent LCOE figure can be calibrated against multiple relevant benchmarks.[7] First, we conclude that a merchant power producer who would sell solar power directly into the grid would not be "in-the-money" at current wholesale rates in California, which have been below 4 cents per kWh on average (EIA, 2017b). However, as argued in Section 4 below, the economics of solar PV improves somewhat (around 10%) in the current wholesale market environment because prices tend to be above average during the daytime hours when solar facilities generate their output. Prospective investors in new solar plants also continue to receive additional revenues from state level incentive programs such as renewable energy credits (RECs) that reflect the presence of Renewable Portfolio Standards.[8]

A second set of relevant benchmarks is obtained by comparing the 3.98 cent figure against the LCOE of alternative energy platforms. The LCOE calculation shows that solar PV is currently more economical in California, and by a substantial margin, than alternative facilities powered either by wind, natural gas or pulverized coal. Natural gas combined-cycle power (NGCC) plants are in second place, with an LCOE of 5.74 cents per kWh. This figure relies on a natural gas delivery price of $3.7 per thousand cubic feet and a capacity factor of 47% which is based on the recent average capacity utilization rate for natural gas facilities in the state.[9]

Going beyond utility-scale applications, Table 1 summarizes LCOE estimates for three

attributable to the Balance of System (BOS) costs, reflecting the inverter, racks, and mechanical and electrical hardware. For the BOS costs, our data inputs here are obtained from a capacity-weighted average based on installation data of facilities with 1-axis trackers in California for years 2016 – 2017 furnished by datasets (GTM, 2017), (Fu et al., 2017), (Bolinger, Seel, and LaCommare, 2017) and (ABB, 2017). The weighted average of these four sources is $1.07 per Watt.

[7]For thin-film technologies (cadmium-telluride solar cells), the data reported by Fu et al. (2017) suggest an LCOE of 3.91 cents per kWh. This estimate is consistent with the common observation that the crystalline silicon and thin-film technologies have seen price convergence in recent years.

[8]RECs have been trading at relatively low prices recently in California, but are likely to increase in value as the state has new ambitious quotas for renewable energy leading up to 2030.

[9]It can be verified that the LCOE for NGCC plants reduces to 4.68 cents if one were to assume a 75% capacity utilization factor.

segments of the solar PV industry in three different locations. In order for commercial and residential PV systems to be cost competitive, their LCOEs must be below the rates that utilities and other energy service providers charge their customers in these segments. In California, average retail rates for commercial and residential customers are around \$0.14/kWh and \$0.18/kWh, respectively (EIA, 2017a). These comparisons make the commercial segment particularly attractive for new solar PV deployments and partially explain the recent trend by energy intensive technology firms to build their own off-site solar facilities which are then connected to the central grid (Economist, 2017).

For locations in Arizona, the findings are similar to those for California. Residential- and commercial-scale solar installations would compete against average retail rates of approximately \$0.12/kWh and \$0.10/kWh, respectively. Utility-scale solar can successfully compete against pulverized coal and NGCC with LCOEs of \$0.080/kWh and \$0.072/kWh, respectively (EIA, 2017a). Finally, in Massachusetts solar PV is cost-competitive in some but not all segments. At average residential and commercial retail rates near \$0.18/kWh and \$0.12/kWh, respectively, residential- and commercial solar facilities are marginally competitive. For utility-scale projects, however, solar PV would be above the LCOE of a new NGCC facility at \$0.067/kWh. [10]

Table 1: Current LCOE Estimates for different industry segments and U.S. states

	Utility PV	Commercial PV	Residential PV
California	4.0	6.6	12.1
Arizona	3.8	4.8	8.8
Massachusetts	7.2	8.4	15.4

Our assessment of solar cost competitiveness has so far yielded point estimates. Since several of the underlying input variables are arguably subject to interpretation and discussion, it will provide further insight to consider the sensitivity of our point estimates to variations in certain key input variables. Figure 3 presents a sensitivity analysis in which the center of the "spider chart" represents the status quo and the different "legs" correspond to the impact of the percentage change in LCOE as a consequence of a particular percentage change

[10] Since the wholesale market in Massachusetts is part of the larger New England Independent System Operator (ISO-NE) market, solar installations in Massachusetts would compete with generation the entire ISO-NE area.

in one of the five input variables: capacity factor, discount rate, system price, operational life, and income tax rate.

As one might expect, the LCOE of solar PV power is most sensitive to the capacity factor which primarily reflects the quality of the solar resource at the installation site. This observation highlights a permanent, but not insurmountable, disadvantage for northern locations. The relative lack of sensitivity in the LCOE figure to changes in the assumed lifetime of the facility reflects that, at a discount rate of 7.5%, an expansion or curtailment of the number of years relative to the 30 year benchmark will have a relatively minor effect on life cycle cost. The even lower sensitivity of the LCOE estimate to changes in the tax rate shown in Figure 3 does not apply generally, but is driven largely by the presence of the investment tax credit.[11]

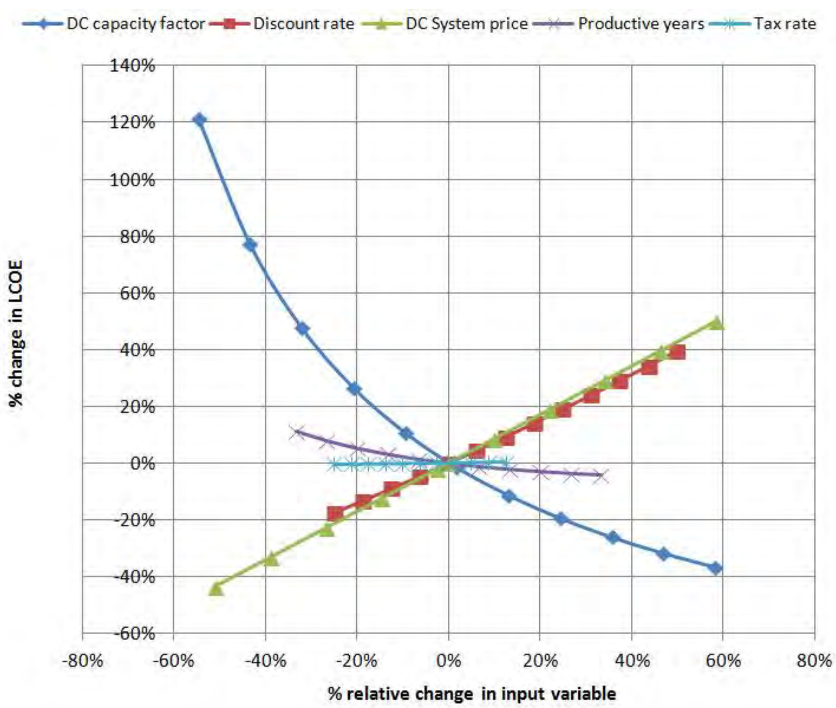

Figure 3: *LCOE sensitivity analysis for utility-scale solar PV in California*

It has been pointed out that the spectacular growth of solar PV in the U.S. and some other countries has been driven in significant part by public policy support pertaining to both tax rules and utility regulations favoring renewable energy. The following section seeks to quantify the magnitude of the effect of those policies on both the LCOE and the projected

[11]It can be shown that, given the current investment tax credit and the allowable depreciation rules, the derivative of the tax factor, Δ, with regard to the corporate income tax rate is close to zero.

growth of new installations.

3 Public Policy Support

3.1 Federal Tax Policy

The immediate impact of the current 30% federal income tax credit for solar PV facilities is that the investor will receive a 30% rebate on a solar investment, provided the investor owes a sufficient amount of income taxes in that year.[12] In evaluating the impact of the current federal tax rules on the LCOE of a new facility, it is, however, important to consider the joint impact of the investment tax credit and the Modified Accelerated Cost Recovery System (MACRS). In contrast to a standard depreciation rule, say a 20-year 150% declining balance method, MACRS provides for an accelerated five-year depreciation schedule for tax purposes. In addition, U.S. Congress added a bonus depreciation provision in December 2015 which allows for half of the investment to be written off immediately for tax purposes.

Table 2 summarizes the joint impact of the investment tax credit and the accelerated depreciation rule by considering four possible scenarios. The conclusion is that in the current environment, the LCOE of California utility scale solar would nearly double from the approximate current \$0.04/kWh if there were no investment tax credit and the solar asset would be depreciated like ordinary power plants. In the LCOE calculation, these numbers are basically driven by an increase in the tax factor, Δ, from 0.665 to 1.356.

Table 2: LCOEs under different policy assumptions.

	Standard Depreciation	Accelerated Depreciation
30% ITC	5.1	4.0
No ITC	7.5	6.2

The trajectory of system prices and balance of system costs for solar PV installations over the past decade strongly suggests that the corresponding LCOE figures will continue to fall in the coming years. For our LCOE projections shown in Section 7 below, though, it is essential to keep in mind that the federal tax incentives currently in place have partial "sunset

[12]When owners of solar projects do not have the requisite tax liability, they frequently engage tax equity investors.

provisions" attached to them. Specifically, the tax rules enacted within the Consolidated Appropriations Act, 2016 (H.R. 2029, December 2015) specify that the ITC will remain at 30% for facilities that commence construction before the end of 2019. Thereafter, it steps down to 26% in 2020 and 22% in 2021. Beginning in 2022, the credit tied to residential owners of solar facilities will drop to zero, and the tax credit given to commercial owners will drop to 10% permanently. At the same time, bonus depreciation will also experience a phaseout. It is scheduled to decrease to 40% in 2018, 30% in 2019 and zero thereafter. In contrast to these scheduled reductions, no changes are planned for the allowable depreciation schedule (5-year MACRS).

To conclude this subsection, we briefly mention the potential impact of one of the proposals currently advocated in the House of Representatives in connection with corporate income taxation. This proposal calls for a reduction of the federal corporate income tax rate from 35 to 20 percent and would allow for immediate expensing of all capital investments. Holding all other variables fixed, such a change would leave the tax factor for solar PV virtually unchanged (.665 versus .663) and, as a consequence, the corresponding LCOEs would be unchanged too. At the same time, such a change in the tax regime would *decrease* the tax factor for natural gas combined cycle plants from 1.35 to 1.03 and the corresponding LCOE for NGCC plants in California from 5.7 to 5.2 cents. The reason for the relatively muted impact on NGCC facilities is that capacity costs comprise a relatively small part of the overall LCOE for natural gas plants.

3.2 Net Metering

In many U.S. states, a common policy in support of commercial- and residential-scale PV systems has been *net metering*. This policy ensures that surplus electricity generated by the solar system at a particular point in time can be sold back to the electricity service provider (utility) at the same retail rate that the customer is charged for electricity purchases.

As the volume of residential and commercial-scale solar installations has grown, utilities and other stakeholders have become increasingly vocal that net metering amounts to a subsidy for solar power that is paid for by the entire cross-section of ratepayers. These observers point out that net metering forces utilities to buy surplus electricity (overage electricity) at the going retail rate for electricity, though they could procure the same power at the lower wholesale rate (Darghouth, Barbose, and Wiser, 2011; McHenry, 2012). Put differently, utilities are in effect required to store the energy generated at no cost to the operator of the solar facility. As of 2017, public utility commissions in multiple states have begun the process of assessing their current policies and, in some jurisdictions, have already imposed limits on the rule of full net metering (NC CETC, 2017; Shogren, 2017).[13]

The state of Nevada made headlines in late 2015 when its Public Utility Commission (PUC), acting on a legislative mandate, increased the fixed charge for all solar customers and reduced the credit for any overage electricity from solar rooftops by approximately 18%. This rule would have taken effect in 2016, with the credit continuing to decline to the wholesale rate in a step-wise manner over the subsequent 12 years. One of the more contentious elements of the new regulation was its application to all existing residential solar facilities, including those which have been previously installed (no “grandfathering” provisions). As a result many solar developers, including SolarCity and Sunrun, announced in early 2016 that they would withdraw from operations in Nevada. However in the late summer of 2017 the Nevada legislature passed AB405, which mandates utilities to purchase electricity from rooftop generators at 95% of the prevailing retail rate for the first 80 MW of capacity installed.[14] This overage tariff will decrease by 7% for every additional 80 MW in cumulative rooftop capacity installed, with a guaranteed price floor of 75% of the prevailing retail rate.

As an alternative to net-metering, public utility commissions have been considering policies under which the energy transferred back to the utility is credited at some overage tariff, OT, per kWh. If the retail electricity rate is denoted by p, then full net metering would set $OT = p$. A natural question then becomes how developers will respond to the adoption of overage tariffs that credit electricity sold back to the utility at a rate below the retail rate.[15] Comello and Reichelstein (2017a) examine this question through the lens of an investor evaluating the profitability of rooftop solar PV systems. An investor/developer will typically enter into a contract with the homeowner specifying either a power purchasing or a leasing arrangement. As part of this contractual arrangement the homeowner essentially earns a “rooftop rental fee” that must be sufficient to make the rooftop available for the solar installation. The basic tradeoff in sizing a solar PV rooftop system in the presence of

[13]Net metering is not an issue in countries like Germany that have set feed-in-tariffs *above* the going retail rate in order to promote the deployment of residential and commercial solar PV.

[14]At the end of 2015, Nevada had 129 MW of rooftop solar installed (WECC, 2016).

[15]Other studies have assessed the impact of net metering from the perspective of an incumbent utility; see, for instance, Darghouth, Barbose, and Wiser (2011), Cai et al. (2013) and Graffy (2014).

net metering restrictions is illustrated in Figure 4.[16]

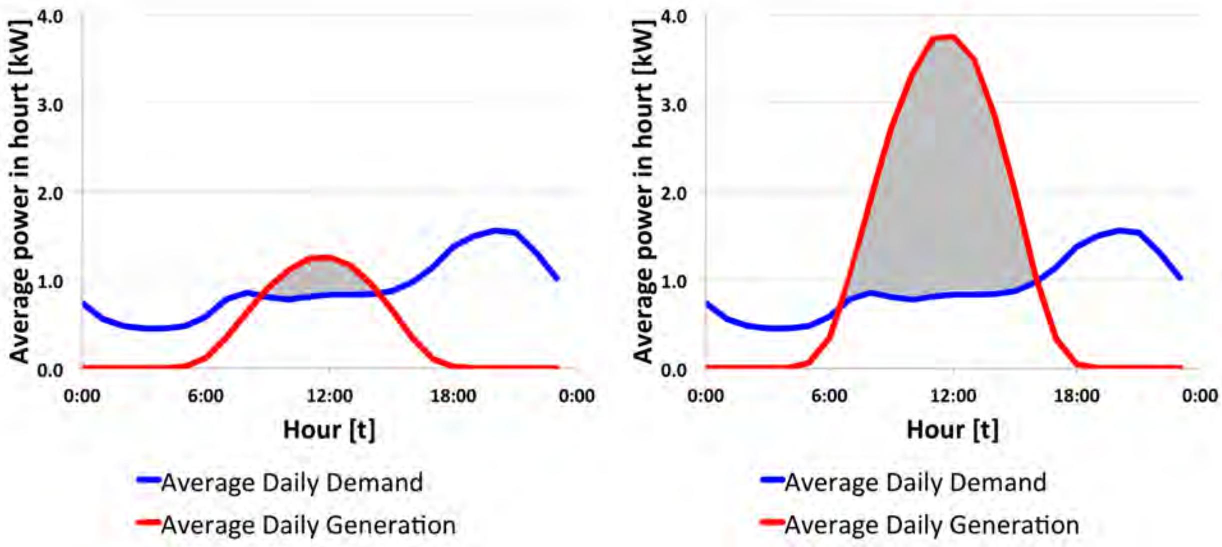

Figure 4: Load Profile and Solar Power Generation.

The blue curve in Figure 4 represents the average electricity consumption of a typical household in Los Angeles, California, for one 24-hour cycle. The red curve in the left-hand graph of Figure 4 represents the generation profile of a relatively small residential solar installation. Most of the electricity generated will be valued at the going retail rate, as household consumption exceeds production. With net metering restrictions, it is only the energy represented by the shaded area in Figure 4 (the overage electricity) that will be valued at the overage tariff, OT. By comparison, the right-hand graph in Figure 4 depicts a relatively large solar installation for which most of the electricity generated (shaded area) is valued at the overage tariff.

Even with full net metering, the size of residential and commercial solar PV systems is generally not limited by the physical constraints on rooftop size. As observed by Barbose et al. (2016), a system size of 15 kW would generally be considered such an upper physical bound for households. Instead, the effective constraint in virtually all U.S. jurisdictions is given by an aggregate surplus constraint which specifies that if the annual electricity generated by the solar PV system exceeds the total annual electricity consumption by the household, the resulting "net energy surplus" is credited at a substantially lower rate. For

[16]These figures are taken from Comello and Reichelstein (2017a), with data provided by NREL (2016), NREL (2010) and NREL (2015).

instance, despite a policy of full net metering, any net energy surplus is credited only at wholesale rates in California (AB 920 in California, and LADWP Solar Program for Los Angeles specifically). Even more extreme, such net energy surplus receives zero credit in other states, including Nevada. We refer to the size of the solar PV system that ensures that on average there is no annual net energy surplus as the *threshold* size. Comello and Reichelstein (2017a) show that with full net metering the optimal size of a solar facility will be equal to the threshold size.

For any given overage tariff, OT, it can be shown for a solar facility with peak power capacity of k kW (and k less than the threshold size), the corresponding net present value of an investment in residential rooftop facility is proportional to the following *Hourly Contribution Margin* (HCM):[17]

$$HCM(k|p, OT) \equiv z(k) \cdot p + (1 - z(k)) \cdot OT - LCOE. \tag{2}$$

The function $z(\cdot)$ in Equation 2 is decreasing in the size of the system (k) and ranges between zero and one. The exact shape of this function is determined jointly by the load curve of the investing household and the energy generation curve of the solar system. Referring back to Figure 4, the weight $1 - z(k)$ can be visualized as the proportion of the shaded area relative to the total area underneath the red curve on the interval given by the two points of intersection between the red and the blue curve.[18]

Taken together, the net present value of a PV system can thus be viewed as a fixed multiple of the hourly contribution margin which, on a per kWh basis, compares average revenue to average cost. Consistent with the characterization in Section 2 above, the average cost of solar PV power on a per kWh basis is effectively captured by LCOE. At the same time, the average revenue is a weighted average of the retail rate (avoided cost of purchases from the grid) and the overage tariff. As the size of the solar system (k) increases, the relative weight on these two revenue sources shifts towards the overage tariff because $z(\cdot)$ is decreasing in k.

The expression in Equation 2 shows that if the overage tariff is at least as large as the LCOE, the investment will continue to have a positive net present value for any k up

[17]The factor proportionality is the product of i) the number of hours in a year, that is 8760, ii) the average capacity favor of the solar photovoltaic facility, and iii) the present value of an annuity corresponding to the useful life of the facility.

[18]Accordingly, $z(k)$ is the proportion of the white area relative to the total area underneath the red curve.

to the threshold size. Furthermore, it can be shown analytically that under fairly broad conditions the optimal system size remains the threshold size provided $OT \geq LCOE$. Thus, the prediction is that a modest restriction on net metering should not result in smaller solar rooftop deployments, even though the profitability of the investment would obviously be lowered. The immediate question then becomes how investors would respond to overage tariffs set below the LCOE. The answer to this empirical question hinges on the particular shape of both the load curve and the solar generation curve. For a mid-size house in Nevada, Comello and Reichelstein (2017a) derive the following response function for the optimal size of the solar rooftop system as a function of an overage tariff gradually reduced below the LCOE.

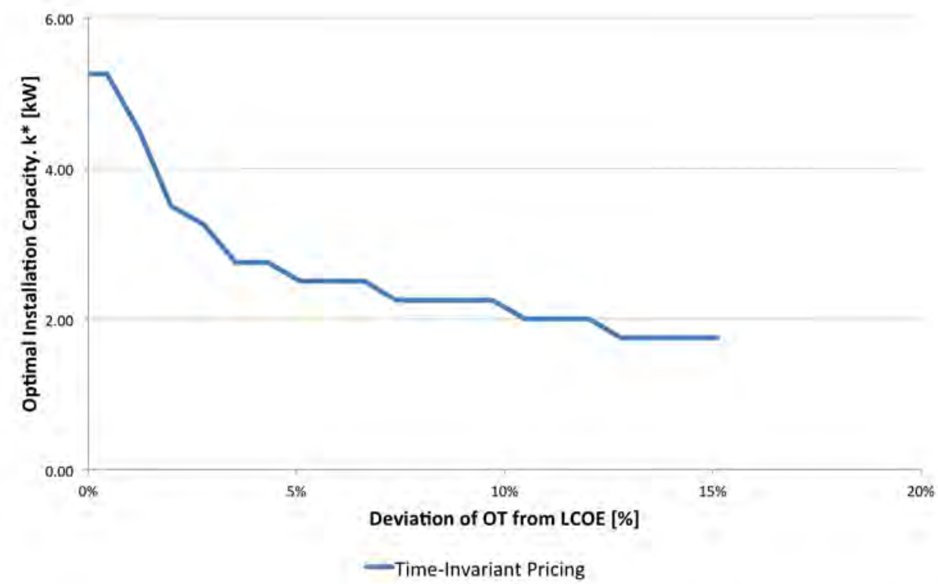

Figure 5: Optimal size of solar PV system in response to changing OT

Qualitatively similar results emerge for Los Angeles (California) and Honolulu (Hawaii). In all cases, the LCOE becomes essentially a “tipping point” such that for overage tariffs set significantly below the LCOE, say 10% or more, the optimal size of the rooftop system will start to drop quickly, to a level where it might arguably no longer make sense to install rooftop solar from a developer perspective. In particular, these simulation findings are fully consistent with the events in Nevada in 2016.

The public utilities commission in California has largely kept net metering intact, while Nevada intends to reduce the OT gradually to 75% of the prevailing retail rate, and Hawaii chose an OT that falls between these two extremes. Currently, there are approximately 36 actions (state and utility proposals, reviews and/or pilots) related to net metering across multiple U.S. states (NC CETC, 2017). It is likely that net metering rules will come under increased scrutiny as the number of solar rooftops increases in each state, and as PUC and utilities alike seek more specific compensation schemes for distributed energy resources in general.

4 Time-of-Use Pricing

As renewable energy sources in general, and solar PV power in particular, are poised to generate a share of the overall energy mix that is substantially larger than the current one, their intermittency and volatility will become more prominent concerns regarding the stability of the electrical grid. Related to the increased penetration of renewable energy is a broader trend to set the electricity price according to the time of day, and possibly the season, in order to reflect both the cost of generation and consumers' willingness to pay for electricity in real time. To illustrate, in deregulated wholesale markets, like California or Texas, average night-time prices are only approximately 50% of the overall average price per kWh (CAISO, 2017). Similarly, utilities have increasingly imposed peak price surcharges on their commercial and industrial customers to reflect the relatively high value of electricity during certain time intervals of the day. Some U.S. states have already introduced the option of time-of-use (ToU) pricing for residential customers, with California announcing that ToU pricing will become mandatory by 2019.

When electricity prices vary over time, the cost competitiveness of solar PV can no longer be captured entirely by comparing the average price to the LCOE of a facility. As pointed out in earlier studies, the intermittency of renewable energy may generate synergies or undesirable complementarities between the time pattern of power generation and that of varying prices.[19] An onshore wind park, for instance, may generate most of its electricity during the night time hours when prices tend to be low. For solar PV, in contrast, time of day prices and peak generation capacity tend to be favorably aligned in the current environment. Figure 6 provides an example generation profile for a hypothetical solar facility, based on data from NREL (2012).

Figure 7, which summarizes a summer time-of-use tariff from the utility PG&E in California for commercial customers, provides intuition for the current alignment between solar

[19] See, for instance, Joskow (2011).

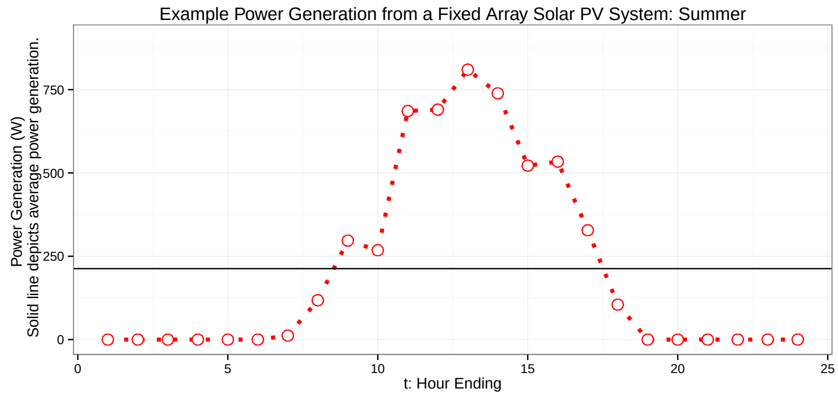

Figure 6: *Solar PV: Summer generation pattern in San Francisco*

generation, as in Figure 6, and relatively high electricity rates.

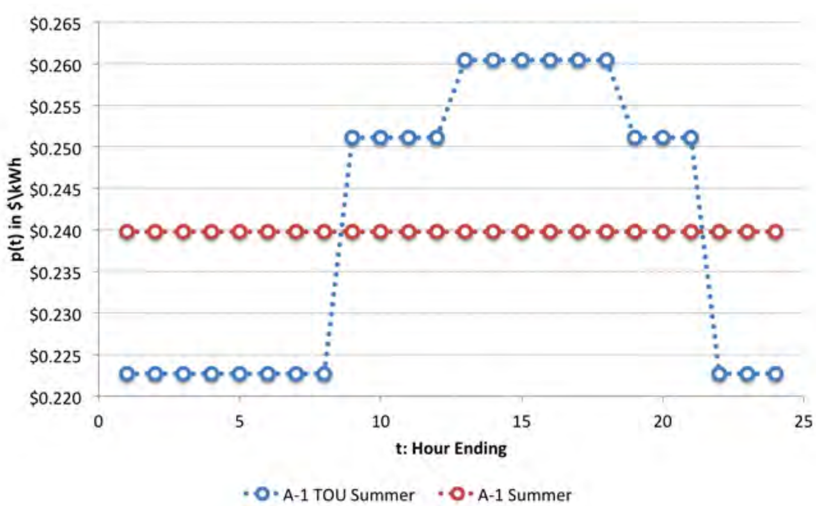

Figure 7: *PG&E A-1 retail tariff for commercial customers*

To quantify any synergistic effects between generation and pricing in the current environment, we adopt the concept of the *co-variation* coefficient, as developed in Reichelstein and Sahoo (2015). Formally, let $\epsilon(t)$ represent the *deviation* at time t from the average capacity factor, CF, in the course of a day. Thus $CF(t) = \epsilon(t) \cdot CF$ and, by definition, the average value of the $\epsilon(t)$ across the hours of the day is equal to one. Similarly, let $\mu(t)$ represent the *percentage deviation* at time t from the daily average electricity price, p, in the course of a day. Thus $p(t) = \mu(t) \cdot p$, where the average value of $p(t)$ is again equal to one. For the twenty four hours corresponding to one day, the co-variation coefficient is then defined as:

$$\Gamma = \frac{1}{24} \int_0^{24} \epsilon(t) \cdot \mu(t) \, dt.$$

The annual co-variation coefficient is obtained simply as the mean of the daily coefficients across the entire year.[20] It is readily seen that $\Gamma = 1$ if either power generation is uniform, that is, the capacity coefficient is constant (possibly because the energy source is dispatchable), or, alternatively, if electricity prices do not vary over time. With time-varying prices an investment in a new energy facility yields a positive net-present value if and only if $\Gamma \cdot p \geq LCOE$ (Reichelstein and Sahoo, 2015). Put differently, the effective levelized cost of electricity in a ToU environment is:

$$LCOE^* = \frac{LCOE}{\Gamma}.$$

In the above example for commercial-scale solar PV in San Francisco the specific value of the annual co-variation coefficient is 1.17. Thus, the effective LCOE of solar PV power generation facilities is 15% ($0.85 = \frac{1}{1.17}$) lower than the baseline LCOE.[21]

As the share of solar PV power in the total electricity mix increases, the price premia attached to electricity in the middle of the day, say prior to 4:00 p.m., are likely to decrease relative to the pattern shown in Figure 6. In contrast, a larger share of solar power in the future is likely to increase the premium for electricity delivered in the late afternoons and early evenings. Clearly, such a shift would reduce or even eliminate the synergy effect embodied in the annual co-variation effect of $\Gamma = 1.17$ calculated for San Francisco, California. In fact, for a sufficiently large shift the co-variation coefficient could easily drop below $\Gamma = 1$ once daytime electricity price would, in relative terms, effectively be priced at current nighttime rates.

Regarding the electricity grid overall, the impact of a significantly larger share of solar PV power has been forecast by the California Independent System Operator in the form of system net loads depicting timing imbalance between peak demand and (mainly) solar

[20] If one views $\epsilon(t)$ and $\delta(t)$ as random variables, then

$$\Gamma - 1 = \frac{1}{24} \int_0^{24} (\epsilon(t) - 1) \cdot (\mu(t) - 1) \, dt$$

can be interpreted as the covariance of the two random variables.

[21] The annual value of $\Gamma = 1.17$ is an average of the co-variation coefficients of $\Gamma = 1.05$ and $\Gamma = 1.29$ for the winter and summer months, respectively.

generation, known as the "duck curve" (CAISO, 2013). Figure 8 indicates that the net-loads or ramp needs in the late afternoons (after 4:00 p.m.) will increase over time, presumably as more solar power is added to the mix. The low point of the duck curve (the "belly") corresponds almost exactly to the point in time that solar generation is at its maximum, as illustrated in Figure 6. The tendency of these duck bellies to become progressively lower over time, with corresponding steeper subsequent ramp-needs, is attributed to a growing share of solar PV in the overall electricity mix.

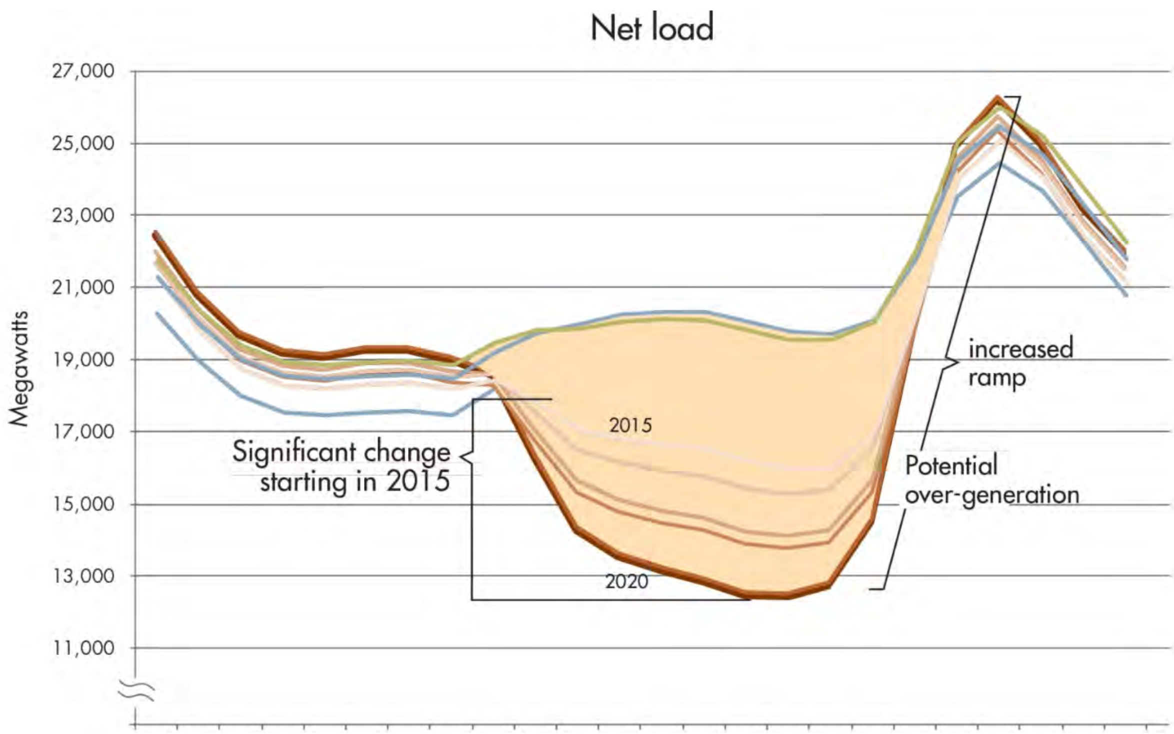

Figure 8: *Net load forecast for California, (CAISO, 2013).*

In interpreting Figure 8, it should be kept in mind that it portrays a very partial comparative static, holding factors other than increased distributed solar penetration constant. At the same time, the likely shift in peak pricing to late afternoons and early evenings is likely to provide incentives for a range of other measures that may counteract the steep ramp needs. The simplest one might be to deliberately angle solar PV installations in a suboptimal fashion from an overall power generation perspective and do so in return for more power generated at later hours of the day. Similarly, Goodall (2016) argues that by investing in a PV system with lower inverter capacity, one obtains a lower system price and lower overall AC output, yet the generation curve in Figure 6 becomes more angular at the top. Other potential shifts include demand response mechanisms that "pull" load from the early evening hours forward into the middle of the day. Finally, energy storage in the form of batteries, chemical storage or possibly pumped hydropower, would allow energy generated during the main hours of the day to be released back into the grid system at later hours of the same day. Such measures might allow for a significant "flattening" of the duck curve (Denholm et al., 2015).[22]

5 Combining Solar PV with Battery Storage

In recent years, stationary energy storage facilities have seen a dramatic rise in installations. In the U.S., the annual deployment of battery storage across utility-scale, commercial and residential installations between 2012 – 2017 has increased by 37% for power capacity (per MW) and 58% for energy capacity (per MWh) (GTM Research, 2017). While utility scale storage accounts for the majority of the annual demand (64% – 95%), "behind-the-meter" distributed storage, located at the point of demand, has experienced the highest growth rate in deployments at 190% and 240% for power and energy capacity, respectively. The consensus view for battery storage, both in the U.S. and globally, is continued double digit growth across all segments over the coming decade (GTM Research, 2017; Lux Research, 2017).

The observed growth in storage deployments is due in part to declining costs of the energy storage modules, which is a partial result of expanded manufacturing capacity to meet the demand for electric vehicles (Kittner, Lill, and Kammen, 2017; Schmidt et al., 2017). Energy storage modules on average constitute 40% – 50% of the total system price, with power components (BOS) comprising the remainder (State of California, 2017; Fisher and Apt, 2017).[23] Regarding energy storage modules, the most prevalent option - lithium-ion batteries (li-ion) - have seen costs fall by 80% from $1,000 per kWh to approximately $250 per kWh. Forecasts for the li-ion energy storage modules project prices in the $150 per kWh range within the next few years (Schmidt et al., 2017; Lux Research, 2017; Kittner, Lill, and Kammen, 2017). On the other hand, much like the history for solar PV system prices, BOS

[22]Denholm et al. (2015) distinguish shifts that would flatten the duck curve from those that would "fatten" it. such, actions to increase the flexibility of the electricity grid for example. These actions might include changes in the operations of conventional generation facilities to allow more cycling starts and stops of units, and improved forecasts of variable generation output.

[23]BOS includes inverter, thermal control, power electronics, hardware, software subcomponents.

costs (power components) are projected to decline at a considerably slower pace.

Battery storage systems are increasingly combined with solar PV installations. We refer to the combination of the two as a PVS system. From the perspective of utilities and energy service providers, a PVS system moves solar power in the direction of a "dispatchable" generation source. PVS can ensure a constant level of output irrespective of short-term disruptions in solar power generation (e.g. cloud cover). In terms of long-term average patterns, PVS enables flexibility as to when electricity is actually provided (dispatched). The latter effect results in the provision of power when it is most valuable, for example in late afternoons/early evenings in order to address the steep system ramp rates, as shown above by the duck curve.

Some recent projects and their PPA structures are providing an indication of the economics of PVS systems. For example, the island of Kauai in Hawaii has experienced a high degree of saturation of electricity on the grid during high insolation periods. In that environment, a recent PVS project combined a 17MW solar farm with a 13MW/52MWh storage system. The contract entailed a 20-year PPA at $0.139/kWh based on offtake during evening hours. Similarly, another project in Hawaii combines a 28MW solar facility with 20MW/100MWh storage under a 20-year PPA with an offtake price of $0.11/kWh. These systems combine relatively little solar generation dispatch during the day with the majority of dispatch occurring in evenings, typically for 4 – 5 hours. Notably, the PPA price of these systems is substantially below the wholesale price of electricity in Hawaii which is approximately $0.15 per kWh .

Another recent PVS implementation combines a relatively high share of solar capacity relative to the size of the storage system, Such is the case for the 100 MW solar, 30MW/120MWh storage facility developed for Tucson Electric Power (TEP) in Arizona, where the 20-year PPA price came in set at $0.045 per kWh. By construction, the majority of generation is dispatched to the grid during hours of solar PV production, while a fraction of the electricity is retained to offset evening peak demand. The remarkably low PPA price can be viewed as a result of favorable solar insolation, resulting in a high capacity factor, and the averaging of the low generation cost with the cost of the relatively small storage capacity. For a utility like TEP in the southwestern U.S., where peak demand typically occurs in the late afternoon and early evening, the PVS system effectively "flattens" the Duck curve shown in the previous section.

PVS is also being deployed increasingly behind-the-meter in commercial and residential applications. The financial rationale for investing in storage systems relies on avoided premium electricity prices during peak pricing hours. In addition, battery storage systems enable commercial users to reduce demand charges they face for peak power consumption. For that segment, 60% of proposed storage installations in California are paired with solar PV installations. For the residential segment, 92% of the expected battery installations are combined with a solar PV system (State of California, 2017). As detailed below, the current structure of tax credits and governmental rebates makes such parings particularly attractive for prospective investors.

The following application illustrates the emergence of battery storage in the context of a residential setting. Building on the framework and analysis in Section 3.2, we ask under what conditions a household that has already installed a solar PV system will add battery storage if it anticipates restrictions on net metering. These restrictions would force surplus energy sold back to the utility during the day to be credited at an overage tariff, OT, below the retail rate, p. Restrictions on net metering effectively yield a price premium for electricity that is self-generated and subsequently self-consumed at later hours of the day. The storage facility would be charged from a portion of the solar energy that would have been valued at the overage tariff. This is illustrated by the black region within the red region in Figure 9. The battery would discharge during times when household demand (blue curve) exceeds generation by the rooftop solar facility. Accordingly, the grey region in Figure 9 has the same area (energy capacity) as the black region. Clearly, the energy storage capacity is bounded above by the amount of solar generation that is subject to OT valuation, i.e. the red area showing the amount of electricity that would otherwise be fed into the grid.

The storage device will be optimally sized in two dimensions, namely power and energy capacity. The power component, measured in kW, governs the maximum rated charge/discharge rate. The energy component, measured in kWh, provides the total capacity of electrical charge that can be stored. Moreover, the ratio of energy capacity to rated power provides the duration for which the storage facility can provide the rated (maximum) power. This is also the length of time needed to charge the facility assuming maximum power charging.[24]

To characterize conditions under which it would be financially advantageous to install a battery supplementing an existing solar rooftop system, we adopt the framework of Comello

[24]If the charge/discharge were to occur at half the rated power, the storage facility would generally be able to provide double the duration at 50% of the power output.

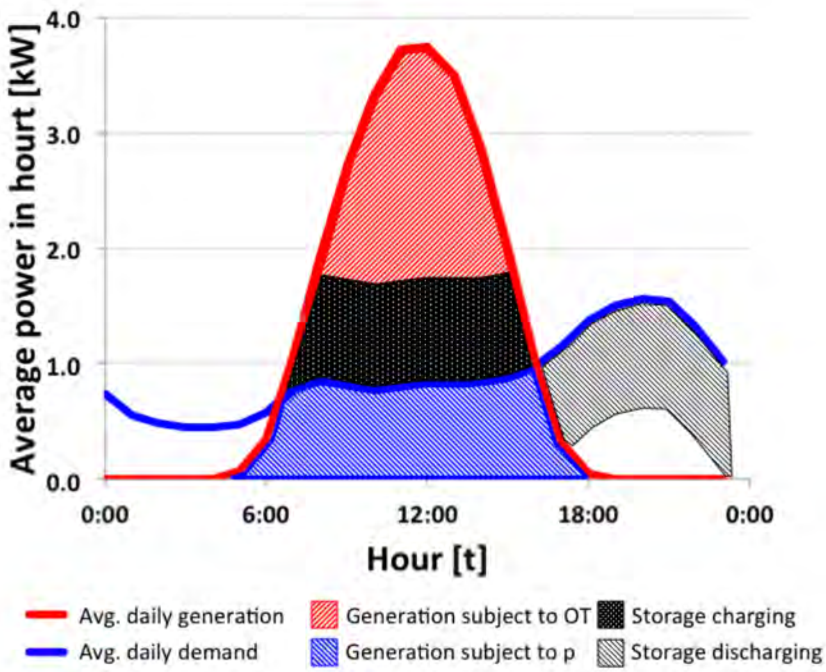

Figure 9: *Charging and discharging a battery combined with a residential PV system.*

and Reichelstein (2017b). Given a retail price, p, and an overage tariff, OT, the value of a battery storage system will, on a per kWh basis, be given by the difference between the price premium $p - OT$ and the unit cost of an energy component, multiplied by the number of energy storage units in the battery system. Furthermore, the profit margin must be large enough to cover the unit cost associated with the power components of the battery storage system. To cover that fixed cost, an efficient storage system will assign as many energy components as feasible behind each kW of power to be discharged. Referring again to Figure 9, the largest amount of energy storage (in kWh) that can be accommodated with a system that can dispatch k_p kW at any given point in time is the area shaded in black. Formally, this area is given by:

$$\hat{k}_e(k_p) = \int_0^{24} \Big[\min\{L(t) + k_p, CF(t) \cdot k_s\} - \min\{L(t), CF(t) \cdot k_s\}\Big]\, dt.$$

As before, $L(t)$ represents the household's power consumption (load) at time t, CF(t) denotes the capacity factor and k_s represents the size of the solar PV system. It is readily verified that the function $\hat{k}_e(\cdot)$ is increasing and concave in k_p, such that $\hat{k}_e(0) = 0$. To capture the relevant unit cost figures, Comello and Reichelstein (2017b) derive the levelized cost of energy components (LCOEC) and the levelized cost of power components (LCOPC). These are conceptually similar to the LCOE given by Equation 1. Specifically:

$$LCOPC = c_p \cdot \Delta_B, \qquad LCOEC = c_e \cdot \Delta_B,$$

where c_p denotes the levelized cost of power capacity (in \$ per kW), c_e denotes the cost of energy capacity (in \$ per kWh) and Δ_B is the tax factor that applies to battery acquisitions. The levelized costs c_p and c_e, in turn, are defined as:

$$c_p = \frac{v_p}{\frac{N}{\eta} \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}, \qquad c_e = \frac{v_e}{\frac{N}{\eta} \cdot \sum_{i=1}^{T} x_i \cdot \gamma^i}.$$

The input variables for these levelized cost calculations are:

- v_p is the system price of power components (in \$ per kW) and v_e is the system price energy component (in \$ per kWh),
- $\gamma = \frac{1}{1+r}$ is the discount factor based on the discount rate (cost of capital) r,
- T is the useful life of the battery system,
- x_i is the storage degradation factor,
- η represents the roundtrip efficiency factor of the battery storage system,
- N denotes the number of full cycle (charge and discharge) occurrences per year.

As shown in Comello and Reichelstein (2017b), the overall net present value of a battery storage system is proportional to the daily profit margin (DPM) given by:

$$DPM(k_p) = [(p - OT) - LCOEC] \cdot \hat{k}_e(k_p) - LCOPC \cdot k_p \qquad (3)$$

An immediate implication of Equation 3 is that adding a battery storage system will be a worthwhile investment only if the price premium $p - OT$ exceeds the levelized cost of an energy storage component, $LCOEC$. In fact, since there are diminishing marginal returns to a system with a higher power rating (the function $\hat{k}_e(\cdot)$ is concave in p_k), a necessary and sufficient condition for any storage system to have a positive net present value is that the daily profit margin be positive for a small value of k_p. For small values of k_p, $\hat{k}_e(k_p)$

approaches $k_p \cdot (t^+ - t^-)$, where t^- and t^+ denote the left and right point of intersection, respectively, between the blue and red curves in Figure 9. Thus a necessary and sufficient condition for a storage investment to have value is that:

$$[(p - OT) - LCOEC] \cdot (t^+ - t^-) > LCOPC.$$

Finally, an investor who seeks to optimize the size of the battery system will choose the power rating, k_p^*, which maximizes the daily profit margin in Equation 3. If $k_p^* > 0$, the unique first-order condition is given by:

$$DPM'(k_p^*) = [(p - OT) - LCOEC] \cdot \hat{k}_e'(k_p^*) - LCOPC = 0.$$

This model framework can be applied to the case of a medium-sized home located in Los Angeles, facing a flat retail rate of \$0.16/kWh, and a rooftop solar installation k_s of size 4.85 kW.[25] Given the parameter estimates, including v_e and v_p, we determine numerically the optimal combination of the power rating, k_p^* and the corresponding optimal energy capacity, $\hat{k}_e(k_p^*)$.[26]

For the storage system component prices, we use the estimates of v_e = \$225/kWh and v_p = \$1,000/kW respectively. Figure 10 shows the optimal combination of power and energy storage capacities as a function of alternative price premium values, $p - OT$. The graphs in Figure 10 furthermore highlight the impact of different policy support mechanisms for battery storage. As explained in more detail in the Appendix, storage systems that are combined with solar PV systems (possibly as retrofits) are generally also eligible for the 30% investment tax credit (ITC) and the accelerated depreciation schedule (5-year MACRS) that is available to solar PV. Furthermore, states like California have added additional investor support through a capital subsidy (rebate program) that applies to storage facilities at a rate of \$350/kWh – \$400/kWh.[27] More detail on the stipulations of the California program, known as Self Generation Incentive Program (SGIP), are provided in the Appendix.

Figure 10 shows that with full federal and state level incentives, a residential solar facility

[25]As shown in Comello and Reichelstein (2017a), the 4.85 kW figure corresponds to the threshold size for a so-defined medium sized house in Los Angeles.

[26]It is readily verified that $\hat{k}_e'(k_p)$ is given by $||\mathcal{I}(k_p)||$, where $|| \cdot ||$ denotes the length of the interval $\mathcal{I}(k_p) \equiv \{t | L(t) + k_p < CF(t) \cdot k_s\}$.

[27]Notably, SGIP incentives are reduced as the duration of energy storage (Wh) increases in relation to rated capacity (CPUC, 2017).

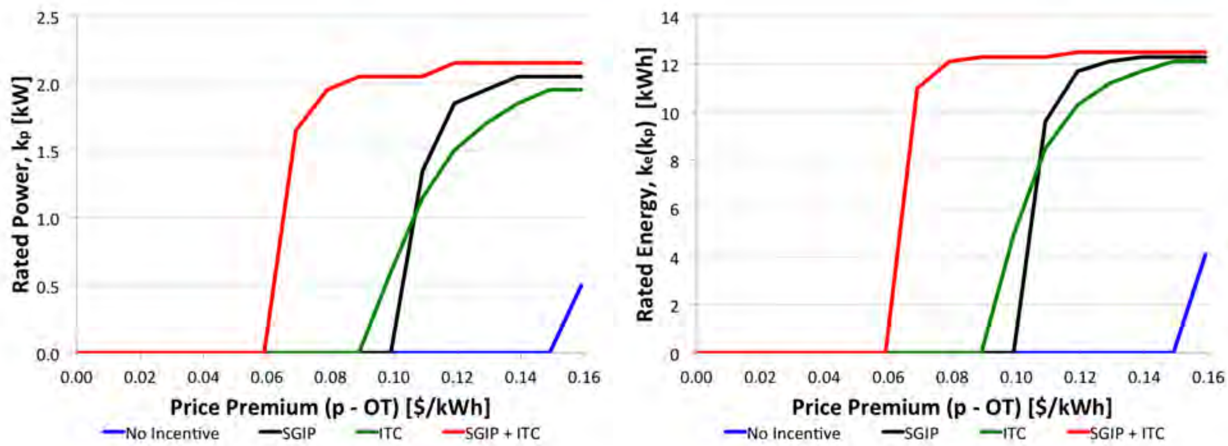

Figure 10: Optimal power and energy storage capacities related to price premium.

in Los Angeles would add battery storage provided the price premium is at least 6¢. In contrast, there is essentially no incentive to invest in battery storage absent both the federal ITC and the SGIP. In all scenarios, we find that once a threshold price premium has been crossed, the optimal size of the battery increases quickly to a power rating of about 2 kW and a corresponding average energy storage capacity of around 6 kWh for each kW of power.

The system price figures shown above for power and energy components are arguably ambitious in the current market environment. If instead one uses more conservative estimates of $v_e = \$300$/kWh and $v_p = \$1{,}100$/kW, the threshold price premium with full policy support would move from around 6¢ – 8¢. Overall, we conclude that sufficiently steep restrictions on net metering for residential PV systems will motivate investments in distributed storage, though at current battery system prices both the federal tax support in the form of the ITC and state-level incentives, like California's SGIP program remain essential.

We conclude this section with a discussion about the cost measurement for battery storage systems. There is a Levelized Cost Of Storage (LCOS) metric used in industry and the academic literature; see for example, Pawel (2014), Julch (2016), Lai and McCulloch (2017) and Lazard (2017) among others. Like LCOE, the general purpose of LCOS is to provide a life cycle cost measure of a storage facility, given storage technology and presumed operational conditions.[28] To illustrate, Lazard (2017) considers a residential 5 kW power system that is capable of discharging 10 kWh of electricity. For the baseline unit power and energy

[28]For example, the LCOS is useful in determining the relative cost of storing and discharging one unit of energy (kWh) in a typical pattern over a defined operational life for lithium ion chemistry compared to vanadium redox flow technology.

component prices, v_p = \$1,000/kW and v_e =\$ 225/kWh quoted above, Lazard (2017) would calculate an LCOS of \$725/kWh, provided there are no federal or state level incentives (the blue line in Figure 10).[29]

An alternative, and arguably more instructive, metric for the levelized cost of storage is to ask how much it costs on a life cycle basis to store one kWh of electricity and dispatch it at later hours of the day. A lower bound for this levelized cost is given by our LCOEC concept introduced above. That lower bound does not include the cost of the power component, which, in turn, is shared by all the energy modules that can sequentially be dispatched through the same power component. Thus, the LCOS measure will necessarily have to be contingent on the duration ratio, that is, the ratio of kWh of energy stored to the kW of maximum power dispatched. In the Lazard (2017) calculations, this ratio is 2, while it is 4 in the Arizona TEP installation mentioned above. For a storage system with a duration ratio of y, Comello and Reichelstein (2017b) introduce the following cost measure:

$$LCOS(y) = LCOEC + \frac{LCOPC}{y}.$$

$LCOS(y)$ is expressed in \$/kWh since the duration ratio, y, in the denominator is stated in hours. To illustrate this measure, for the representative Los Angeles home considered above, we recall an optimal duration ratio of approximately 6 hours in Figure 10. Including the federal ITC, but not the California SGIP rebate, the levelized cost figures were $LCOEC$ =\$0.019/ kWh and $LCOPC$ =\$0.196/kW, yielding an aggregate levelized cost of storage of $LCOS(6) = .019 + \frac{0.196}{6} = 5.2$ ¢ per kWh. Thus for an optimized battery storage system, the household will pay *on average* 5.2 ¢ per kWh in order to transport a total of approximately 12 kWh to those hours of the day where the household load exceeds the self-generation by the solar PV system. To make such an investment worthwhile, the price premium must exceed 9 cents per kWh (green curve in Figure 10).[30]

6 Dynamics of Solar PV System Prices

Our review has so far established that while solar PV-based electricity generation is, in selected locations, already cost-competitive, solar technology faces four potential hindrances.

[29]This figure is calculated as follows: $\frac{(5kW \cdot \$1000/kW)+(10kWh \cdot \$225/kWh)}{10kWh} = \$725/kWh$

[30]Owing to the parabolic shaped solar generation curve, the marginal (levelized) cost of a larger storage system will be exactly equal to the price premium.

First, public utility commissions have begun to revise net energy metering provisions, suggesting lower incentives for solar facilities. Second, as more solar capacity is added, its value to the energy system will tend to decline without additional mitigating strategies. Third, actions to bolster the economic value of solar facilities by adding storage challenge the technology's cost competitiveness. Fourth, the scheduled reduction in the federal tax incentives threaten to diminish the cost competitiveness of the technology. Countering all four trends, however, is a persistent dynamic of cost reductions for the components of solar PV facilities. In this section, we describe potential cost reductions for the main components of future PV facilities, namely modules and BOS.

6.1 Module Prices

The dramatic decline in the sales price of solar PV modules has been widely documented. A well known chart is Figure 11, based on a graph by Swanson (2011), shown originally as the history of (the logarithm of) average module sales prices (ASPs) against (the logarithm of) cumulative module output for the years 1979 to 2010. The price trajectory depicted by the plot is characterized well by an 80% constant elasticity learning curve.[31] In line with this trend, prices would be expected to drop by 20% with every doubling of cumulative output, measured in MW.

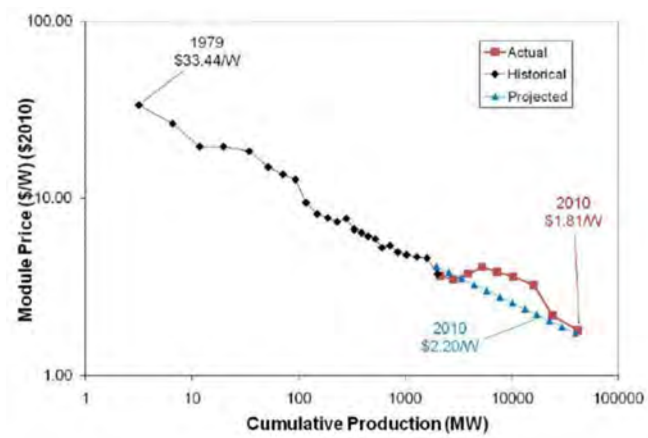

Figure 11: *Plot from Swanson (2011)*

However, since 2010, module prices have dropped much faster than the historical trend

[31]Figure 11 shows that in 2008 and 2009, ASPs markedly exceeded the trend line suggested by the 80% learning curve. Many industry observers attribute this departure from the learning curve to a polysilicon shortage which increased the raw input cost of silicon wafers in the short-term.

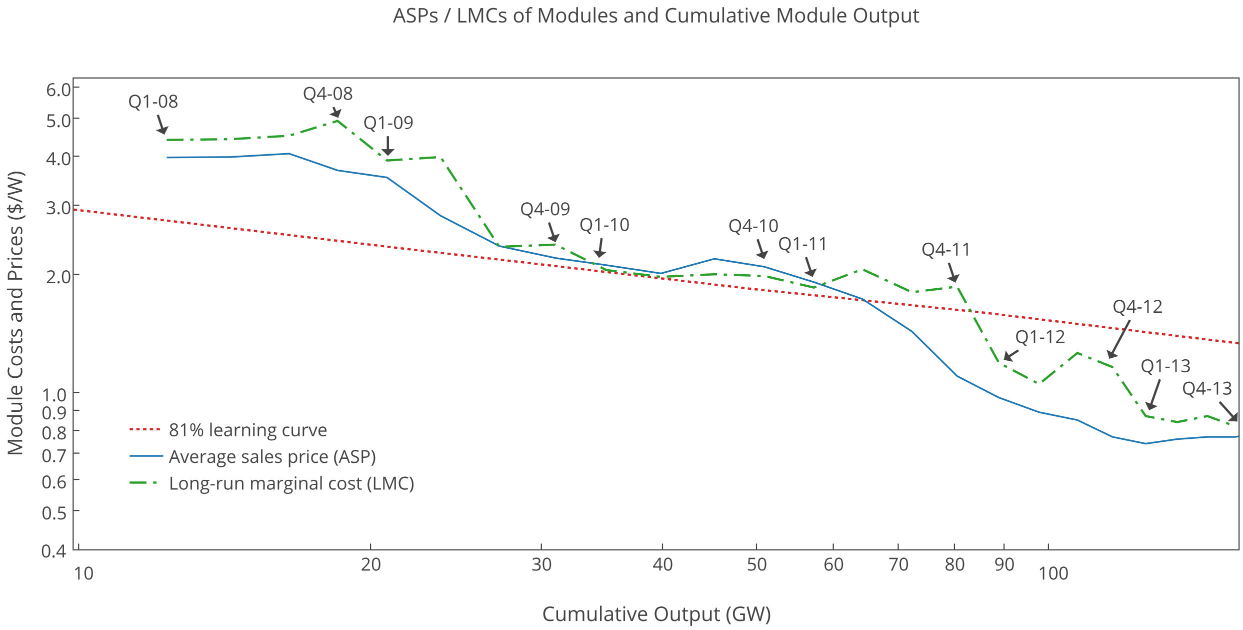

Figure 12: *LMCs and ASPs between Q1-08 and Q4-13. All prices are in 2013 U.S. dollars.*

line would suggest. The blue curve in Figure 12 extends the Swanson plot from 2010 to 2013 and shows a decline in PV module ASPs between 2011 and 2013 that was much steeper than that predicted by the 80% learning curve. The 40% price drop in 2011 alone and rebound in prices in late 2013 are particularly striking. Most observers link this price drop to both large increases in solar panel manufacturing capacity and continued reductions in manufacturing costs. Given ambiguity in the drivers of past price decreases and therefore price-based trajectories of future module prices, Reichelstein and Sahoo (2017) estimate long-run marginal cost (LMC) of solar modules for the same time period. Since, in equilibrium, the ASP should equal the LMC, these estimates allow an approximation of cost reductions that is independent of manufacturing capacity considerations.

Figure 12 suggests a close match between average sales prices and the estimated long-run marginal costs for the years 2008 – 2010. Second, beginning in late 2011, the dramatic decline in the observed ASPs for most of the quarters in 2012 – 2013 result in average sales prices significantly below the estimates of the contemporary long-run marginal cost.[32] In other words, these cost estimates provide evidence that the sharp drop in ASPs for those

[32]This conclusion is corroborated by the sharply negative earnings and declining share prices that firms in the industry experienced during those two years.

time periods was partly due to factors beyond cost reductions, such as excessive additions in manufacturing capacity. Since in a competitive environment, such as that characterizing the module industry, the equilibrium price of a product will be driven to its long-run marginal cost, estimates of marginal costs and decline rates also allow a projection of future module prices.[33] In light of this evidence, we use in Section 7 the estimates of cost declines from Reichelstein and Sahoo (2017), instead of a price-based forecast, to build a forward-looking trajectory of both module prices and the levelized cost of electricity from solar PV systems.

Econometric analyses of the LMC estimates show evidence that the sharp drop in ASPs between 2011 and 2013 was partly due to manufacturing cost reductions in excess of the 80% learning curve. Using quarterly financial statements from a subset of module manufacturers, as well as quarterly data from an industry observer (Lux Research, 2014) about manufacturing capacity and product shipments, two rates of cost declines are inferred. These correspond to two components of the long-run marginal cost in manufacturing industries, namely, capacity-related costs for machinery and equipment and core manufacturing costs for materials, labor and overhead. In particular, the authors estimate a 62% constant elasticity learning curve for core manufacturing costs and that capacity-related costs for machinery and equipment have fallen by 24% each year. Given recent industry output, these capacity-related cost declines also outperform the 80% learning rate benchmark.

6.2 Balance of System Prices

Balance of system costs now account for the majority of the price of new solar installations. These costs have fallen recently in part to innovations by solar developers. These firms have reduced BOS costs by focusing on vertical integration, decreasing installation time, simplifying the permitting and interconnection process, and streamlining the process of sales, marketing, and financing.

In addition, we estimate BOS prices decreasing at a rate of 6.1% annually until 2022, based on forecasts from a composite of data from Fu et al. (2017), GTM (2017), GlobalData (2017). This expected cost reduction rate is determined by taking an average of historical annual BOS cost estimates (2010 – 2017) and fitting an exponential regression curve. The R^2 for this regression is 0.90 with t-statistic of -7.33 (df = 7). In similar fashion to Comello

[33] The module industry can be characterized as competitive since a large number of firms supply a relatively homogeneous product. As corroborating evidence, the median market share of firms in this industry was less than 1% in 2012.

and Reichelstein (2016), the time-dependent relationship for BOS price decreases can be expressed as:

$$BOS(t) = BOS(0) \cdot e^{-\lambda \cdot t} \tag{4}$$

where, $BOS(0)$: denotes the BOS at $t = 0$ (i.e. 2017); $BOS(t)$: denotes the cost BOS in period t; and, λ represents the rate of cost reduction in each period. Given a value of 0.061 for λ from the composite estimate above, yields $e^{-\lambda} = 0.935$, which is effectively the expected annual cost deflator on the BOS of a solar PV system from 2017 – 2022.

7 Levelized Cost of Electricity Projections

In this final section, we project the LCOE of utility-scale solar PV installations in California considering both the dynamics of component system prices and public policy support mechanisms. We begin by providing an update to Figure 12, based on an assumed capacity addition of 100 GW in 2017 and a 10% annual growth to 2022.[34]

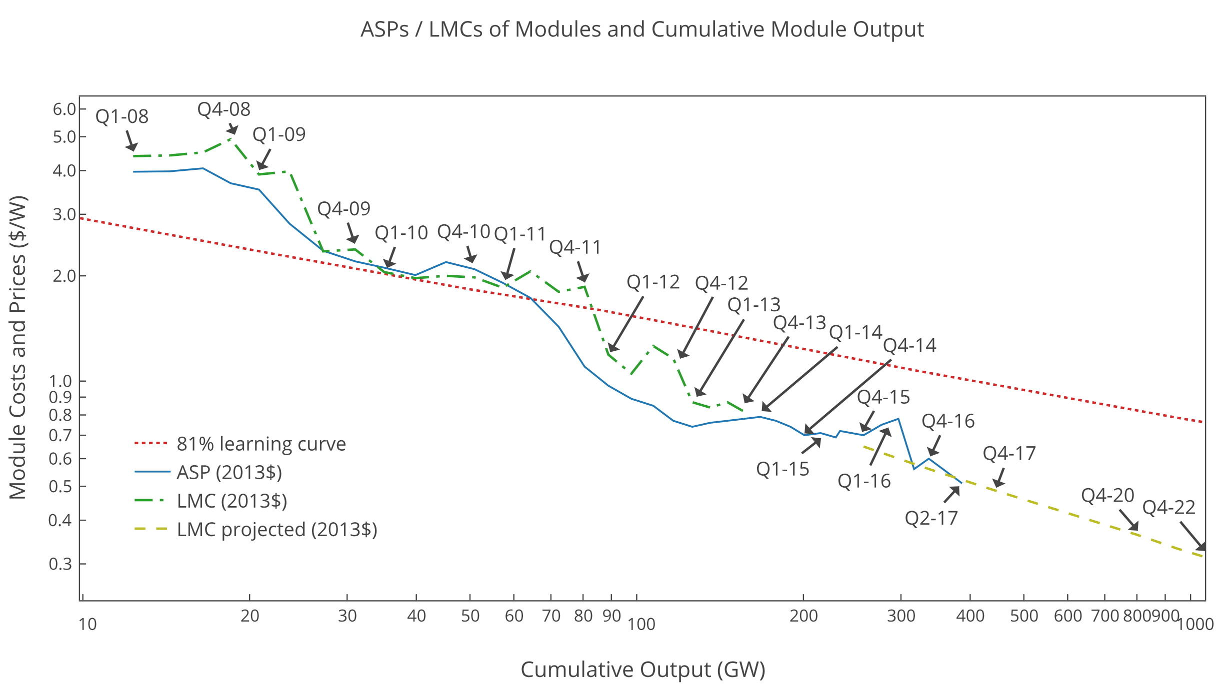

Figure 13: *LMCs projected to the end of 2022. All prices are in 2013 U.S. dollars.*

[34]Assumed capacity additions for 2014, 2015 and 2016 are 45 GW, 56 GW and 80 GW, respectively.

The yellow curve in Figure 13 is the estimated volume-driven LMC for PV modules, based on the assumed capacity additions in 2017 and growth rate thereafter. To project the LCOE, we use the minimum of the module ASP and LMC. For example, given that the per unit LMC for 2017 is \$0.49, yet the ASP is \$0.38, we use the latter for our 2017 LCOE calculation. Once the long-run marginal cost is lower, we then presume the ASP will equal the economical sustainable price and follow the projected trajectory. Given constant decline in BOS (Section 6) and expected reductions in policy support (Section 3), we plot he expected LCOE for utility-scale solar in California in Figure 14.

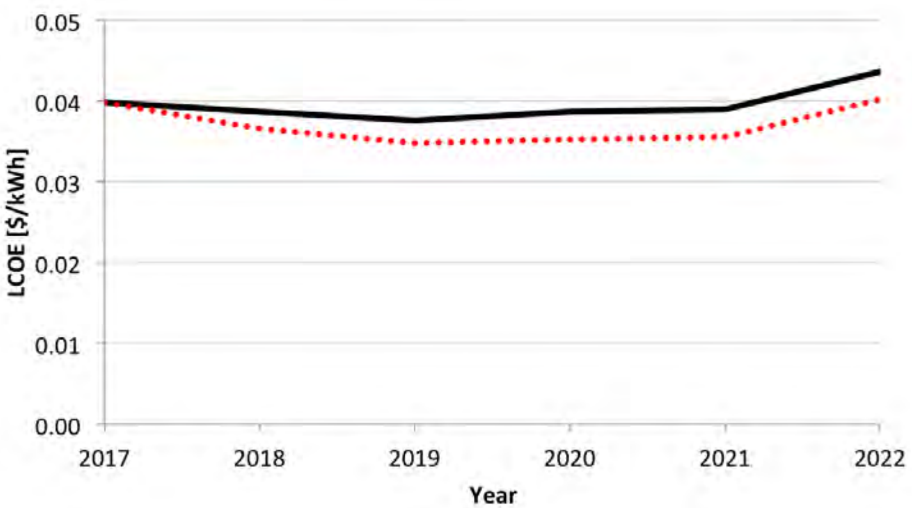

Figure 14: *LCOE of utility-scale solar in California projected to the end of 2022. All prices are in 2017 U.S. dollars.*

The resulting dynamic implies that the LCOE will drop slightly over the next four years and then modestly increase starting in 2022 due to significant tax incentive reductions. In the example provided, the LCOE is projected to increase by approximately 10% from the 2017 estimate, from 3.98¢ per kWh to approximately 4.3¢ per kWh. This final result bears witness to the extent policy support mechanisms shape the cost-competitiveness of solar PV.

At the same time, current tax proposals being circulated in the U.S. Congress related to solar installations may have a modest positive impact on the LCOE in the near-term. Specifically, one such proposal calls for 100% bonus depreciation on solar systems in exchange for the investment tax credit for commercially owned installations to be permanently set to zero in 2027 (as opposed to remaining at 10% from 2022 onward). The immediate effect of such a proposal would be a reduction of the tax factor from 0.665 to 0.629 in the case of California. *Ceteris paribus*, this proposed change would decrease the projected LCOE in 2022 for utility-scale solar PV in California to 4.02¢. The red dotted line in Figure 14 depicts this result.

8 Conclusion

Over the past decade, solar PV installations have seen a dramatic rise in global deployment. At the same time the price of such systems across all segments has fallen precipitously, with the reductions in the cost of modules providing the majority share of this phenomenon. This paper examines how solar PV power is currently positioned in the electricity marketplace and how that position is likely to evolve in the foreseeable future. Specifically, we begin with an evaluation of the current cost-competitiveness of solar PV in the U.S. setting, and then investigate how further technological improvements as well as both scheduled and potential changes in public policy are likely to shape that assessment in the near future.

We find that for many parts of the western U.S., utility-scale systems are currently better positioned than other sources of generation, based on the calculated LCOE. Further, commercial and residential segments also fare well, given that the LCOE of those systems is below the going retail rate utilities charge their customers. However, we also show that such cost-competitiveness relies crucially on policy support mechanisms, such as net metering, federal investment tax credits and accelerated depreciation rules. Further, as the share of solar power increases within the overall energy mix, the likelihood of over-generation during times of high insolation will result in an increasingly unfavorable complementarity between the prevailing time-of-use prices and the pattern of solar power generation.

We identify the parallel emergence of storage facilities, in particular those combined with solar facilities and their ability to make solar "dispatchable" by supplying stored electricity at later times of the day, when it would be more economical to do so. Moreover, we explore the application of storage combined with solar PV in a residential setting where restrictions on net metering yield a price premium for electricity that is self-generated and later self-consumed. We develop an analytical approach that identifies conditions that make it financially attractive to add behind the meter storage to existing solar systems. Through investigation of a case of a medium-sized home in Los Angeles, we find that – similar to solar PV – federal tax credits and state-level investment rebates are necessary to enable the economical deployment of batteries in this segment and application.

Our final analysis combines the dynamics of module and BOS cost reductions with scheduled diminishing federal support mechanisms for solar PV to project the near-term effects on the LCOE. In applying this dynamic to utility-scale facilities in California, we find that over the next 5 years, expected cost improvements will be more than offset by the reductions in public policy support, leading to a modest 10% increase in LCOE at the end of this timeframe.

There are several promising avenues for extending the analysis in this paper. In particular, it would be useful to explore the co-optimization of storage and solar facility capacities for applications within the utility, commercial and residential segments. For the utility setting, this would include an examination of the required component cost reductions required for cost-competitiveness with incumbent generation. It would also include the required wholesale price dynamics required to make the economical case for the installation of a storage device in order to flatten the "duck curve." The residential and commercial segments offer particularly complex settings, as these customers face rate structures that include time of use rates coupled with the prospect of diminishing/changing net metering support and reduced solar investment tax credits. Moreover, commercial customers often face demand charges, which have a significant effect on the total electricity bill. For different tariff structures and load profiles, it would be useful to determine the extent policy support would be required for PVS installations to gain traction in these segments.

A Appendix

A.1 U.S. Public Policy Support for Battery Storage

Federal Tax Policy

Various types of storage facilities (thermal, mechanical, etc.), when combined with a solar installation, are eligible for the ITC as the entire system is then considered renewable energy property.[35] Eligibility is extended to both new PVS installations and to storage devices that are retrofitted to existing solar facilities. To be able to claim the full ITC incentive, 100% of the energy used to charge the storage device must come directly from the solar system for each of the first 5 years the storage facility is placed into service. For storage devices charged by other means there will be a proportional reduction on the remaining amount of the ITC claimed.[36] At the same time the IRS requires that in order to be eligible for any ITC related to a storage facility at least 75% of the electricity that is used to charge the storage facility must come directly from the solar system in any of the first 5 years. Failing to meet this minimum threshold would result in "recapture" of the entire ITC, effectively removing the incentive altogether.

Another federal incentive that is offered for storage equipment is accelerated depreciation. The appropriate schedule is based on the proportion of charge received by the storage device from the solar system. If the storage facility receives less than 50% of its annual charge from the PV system, the storage facility is eligible for 7-year MACRS. For a storage facility receive more than 50% of its annual electricity charge from the corresponding PV system the 5-year MACRS schedule can be applied. (Denholm, Eichman, and Margolis, 2017).

State Policy

Public support at the state level takes two forms, namely deployment mandates for storage capacity and economic incentives. The number of states offering any support mechanism is currently limited, with California leading in terms of the magnitude of its programs.[37] California's deployment mandate has a 2020 target of 1,825 MW of storage capacity to be placed

[35] As defined within Section 48 of the Internal Revenue Code: 26 CFR §1.48-9.

[36] For example, if in the second through fifth years 90% of the storage device was charged by solar following 100% solar charging in the first year, the eligible ITC for storage would be $(100\% \cdot 30\%)/5 + 4 \cdot (90\% \cdot 30\%)/5 = 27.6\%$.

[37] California accounts for 40% of all storage capacity deployed in the U.S., as measured by power capacity (approximately 230 MW). With respect to utility, commercial and residential segments, the share of capacity deployed by California is: 32%, 92% and 32% respectively (GTM Research, 2017).

into operation by no later than 2024.[38] This target is limited to the three investor owned utilities in the state, and specifies sub-targets based on ownership and placement on the electricity grid. Notably, 200MW customer sited storage, with an additional 425MW within the distribution grid, is to be owned by entities other than utilities. However, there is no requirement to pair any of the storage with solar as part of the mandate.

California also offers a capital subsidy through its Self Generation Incentive Program (SGIP). In its current form, SGIP compensates storage developers on a $ per Wh basis for the capital costs of storage projects (up to 100%) that are located at the customer site ("behind-the-meter" or BTM installations). BTM installations are classified as either "large-scale storage" ($>$ 10 kW) or small "small residential storage" ($<$ 10 kW and installed at a place of residence). Currently, the SGIP incentive is \$0.35/Wh – \$0.40/Wh (\$350/kWh – \$400/kWh), depending on the installation type and current deployment threshold.[39] Notably, SGIP incentives are reduced as the duration of energy storage (Wh) increases in relation to rated capacity (CPUC, 2017).[40] Importantly, while SGIP cannot be applied to solar facilities, the ITC can be used in combination with SGIP to reduce the cost of storage given that PVS constitutes one system. In other words, in California, PVS systems installed at customer sites can take advantage of the ITC and MACRS for the solar component and the ITC, MACRS and SGIP for the storage component.

[38] AB 2514 is the California legislative directive that required the state Public Utility Commission (CPUC) to determine storage appropriate targets. CPUC decision set the target of 1,325 MW in 2015, and effectively raised it by 500 MW in 2017.

[39] The incentive decreases in a step-wise function as thresholds of deployment capacity are achieved for both large-scale and small residential classes.

[40] A system with $\leq$ 2 hours of output at the given power rating can claim 100% of the incentive. For a system between 2–4 hours, the additional capacity would be eligible for 50% of the SGIP incentive. For a system 4–6, hours, the fraction falls to 25%, with anything greater than 6 hours receiving no SGIP.

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