Grid Parity for Residential Photovoltaics in the United States: Key Drivers and Sensitivities

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ABSTRACT

Grid parity for photovoltaic (PV) technology is defined as the point where the cost of PV-generated electricity equals the cost of electricity purchased from the grid. Achieving grid parity is a function of many variables, including the solar resource, local electricity prices, and various incentives. In this report, we evaluate some of the key drivers of grid parity both regionally and over time. We begin by considering a base-case scenario, which includes a single set of assumptions for financing, technical performance, and several other factors. We also consider how grid parity may change over time considering the evolution of PV technical performance, financing parameters, electricity prices and rates, and policies.

1. INTRODUCTION

The break-even cost for photovoltaic (PV) technology is defined as the point where the cost of PV-generated electricity equals the cost of electricity purchased from the grid. This target has also been referred to as "grid parity" and may be expressed in \$/W[1] of an installed system. Achieving PV breakeven is a function of many variables, including the solar resource, local electricity prices, and various incentives. As a result, for a country like the United States, where these factors vary regionally, there can be considerable variation in break-even cost.

In this report, we provide an updated analysis of PV break-even costs for residential customers in the United States, and we evaluate some of the key drivers of PV breakeven cost. We begin by considering a base-case scenario evaluating the break-even cost for residential PV in the largest 1000 utilities in the United States for the year 2015. This base case includes a single set of assumptions for financing, technical performance, and several other factors. We also examine the impact of moving from flat to time-of-use (TOU) rates. We also consider the sensitivity of the break-even cost to four major drivers: technical performance, financing parameters, electricity prices and rates, and policies.

Currently, the break-even cost of PV in the United States varies by more than a factor of 10 despite a much smaller variation in solar resource (Denholm et al. 2009). Overall, the key drivers of the break-even cost of PV are non-technical factors, including the cost of electricity, the rate structure, and the availability of system financing, as opposed to technical parameters such as solar resource or orientation. This analysis of the break-even cost of PV represents neither a market depth analysis nor an estimate of likely consumer adoption, but it does provide insight about the potential viability of PV markets.

2. RESIDENTIAL PV BREAK-EVEN COSTS

In this section, we examine the projected break-even cost of residential PV systems in 2015, and we consider the sensitivity of break-even costs to a number of factors. We define the break-even cost of PV as the point at which the net present cost (NPC) of the PV system equals the net present benefit (NPB) realized to its owner. This can be used to find the installed system cost (\$/W) required for a given electricity price.

[1] This price refers to \$/DC Watt, which is the system's rating before conversion to AC. This nomenclature differs from that generally applied to traditional power plants, which are typically stated in terms of their price per AC kW of capacity.

We begin by establishing a base scenario for 2015 with a uniform set of assumptions, including system performance, electricity price escalation, financing, and incentives. We include an annual real electricity price escalation of 0.5%. This analysis considers the 30% federal investment tax credit (ITC), but we assume no state or local incentives.[2] We assume a carbon policy resulting in an effective cost of carbon equal to $25/ton of CO_2. This results in an effective increase in retail electricity prices that is calculated by multiplying the average carbon content of a kWh of electricity in each state[3] by the assumed carbon cost. The adders range from 0.3 cents/kWh in Oregon to 2.5 cents/kWh in North Dakota with a national (load weighted) average of 1.5 cents/kWh.

The break-even cost for PV is calculated for the top 1000 utilities in the United States, which represent about 95% of the total residential load (based on annual energy consumption). The break-even system cost is calculated by iteratively varying the price of PV until the NPC equals the NPB. The NPC of the system includes all financing and incentives, while the NPB is the cumulative discounted benefits of reduced electric bills. The net present cost in our base scenario assumes a system financed with a home-equity type loan (with tax-deductible interest and a 28% marginal federal tax rate), a 20% down payment, a real interest rate and discount rate of 6%, and a loan term of 30 years.[4] The evaluation period for the analysis is 30 years.[5] The NPB at each location is based on the discounted cumulative benefits of reduced electricity bills over the evaluated period, driven by the local PV system performance and electricity rate.

To determine the annual PV generation at each location, we use hourly insolation data for 2003-2005 from the National Solar Radiation Database (NSRDB) (NREL 2007). For each utility, a solar resource location is selected by choosing the location closest to the population-weighted center of service territory.

Solar insolation values are converted to solar energy production for each of the sites using the PVWATTS/PVFORM model (Marion et al. 2005), assuming a 1 kW STC module[6] and an average system derate factor of 82% (i.e., including both inverter and other system related efficiency loses).[7] The base-case assumptions include having a south-facing system with panels tilted at 25 degrees,[8] and an annual degradation of 0.5% per year.

Overall, this combination of factors represents a customer with excellent home orientation and access to attractive financing, but who places no additional value on locally produced renewable energy.

The NPB is highly sensitive to the price of electricity and the electricity rate structure. We evaluate two rate scenarios: one based on the most common (typically flat or seasonally adjusted flat) rate structures and one based on time-of-use (TOU) rate structures. For the most common rate structure scenario, a combination of tariff sheet data and Energy Information Administration (EIA) utility data are used. Form EIA-861 data provide the total revenue and total energy sales for all utilities in the United States.[9] These data are used to form the basis for an "average" cost of electricity to residential customers (equal to the annual residential revenue divided by the annual residential sales). The values provide no insight into the actual rate structure because they average over an entire year and include fixed billing charges and other components that would not be offset by customer-sited PV generation. To establish the relative difference in value between the annual average cost of electricity for each utility

[2] We assume the federal ITC of 30% since it does not expire until the end of 2016. (See http://www.dsireusa.org/). However we consider elimination of the federal tax credit as sensitivity.

[3] These values are based on the average emissions factors from Energy Information Administration (2002). For a discussion of average versus marginal avoided emissions rates, see Rothschild & Diem (2009)

[4] Here and elsewhere, we use real interest rates as opposed to nominal interest rates. The relationship is real interest rate = nominal interest rate – inflation rate.

[5] This implies an expected 30-year life of system.

[6] The module efficiency is defined under Standard Test Conditions (STC) of 1,000 W/m^2 solar irradiance and 25^{o}C.

[7] The derate factor converts the system's DC rating to actual AC output. For additional discussion, see the "DC to AC Derate Factor" discussion of the PVWATTS model at http://rredc.nrel.gov/solar/codes_algs/PVWATTS/version1/system.html#derate

[8] Twenty-five degrees corresponds to a roof pitch angle of about 6/12 or roughly midway between the most common roof ranges of 4/12 to 8/12.

[9] Because 2007 was the most recent year available at the time of this report, we scaled each utility to 2008 values using the state average value for 2008 derived from the EIA (2009a).

and the actual value of PV, we use information from the tariff sheet for the largest utility in each state.

Using the simulation data from PVWATTS, we multiply the output of the PV system in each hour by the value of electricity in that hour based on the actual utility tariff (in the flat rate scenario, this value is constant or varies only by season). In this base case, we assume full retail net metering so any electricity exported is worth an amount equivalent to electricity normally consumed (in reality access to full retail net metering is limited, so sensitivities to this assumption are considered in the next section). We develop a simple spreadsheet/Visual Basic for Applications (VBA) tool to calculate the hourly and annual value of PV using different rates; however, publicly and commercially available models can be used for this purpose.[10]

Once we obtain the annual PV value for the largest utility in each state, we compare it to the PV value calculated from the EIA average electricity price data for that utility. The relative difference establish a scale factor, accounting for the relative change in value associated with the actual tariff structure as well as removing fixed billing components.[11] This scale factor is then applied to the remaining utilities in each state. This assumes that the rate structure for the remaining utilities is essentially the same as the largest utility, which is an oversimplification, but it roughly captures the difference in price among utilities in the states.[12]

Future price escalation is also considered to perform the cash-flow calculation. In the base case, we assume that electricity has a real price escalation of 0.5%/year.[13]

As discussed previously, the break-even point is found by iteratively increasing the cost of the PV system or the cost of electricity until the NPC equals the NPB over the evaluation period. Figure 1 provides the break-even cost of PV ($/W) needed in the "base" rate scenario for the largest 1000 utilities. This scenario uses the most common rate structure, which is generally a flat or seasonal flat rate for most utilities (or an increasing block rate structure for large investor owned utilities in California).[14] The remaining area in each state (representing the remaining 2173 of 3173 utilities in the EIA data set and providing about 5% of total U.S. residential electricity sales) uses the PV performance from the largest utility in that state combined with the average electricity price from the smallest utilities in that state. All other assumptions are identical to those of the base case.

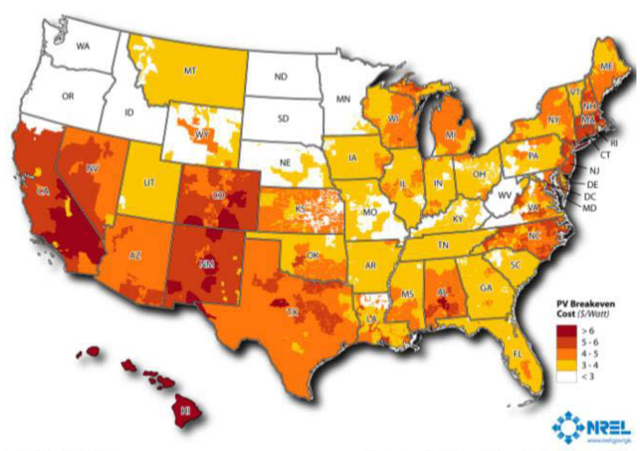

Fig. 1: Residential solar PV break-even cost ($/W) in 2015 using the base-case assumptions in Table 1 and the most common rate structure

[10] Examples include the Clean Power Estimator at http://www.cleanpower.com/, HOMER at https://analysis.nrel.gov/homer/, and the Solar Advisor Model (SAM) at https://www.nrel.gov/analysis/sam/.

[11] Because EIA revenue data include items such as fixed billing charges, which are not reduced with the installation of PV, most utilities exhibited a lower PV value when using the tariff rates as opposed to using the average rates from EIA's sales and revenue data.

[12] Because of this assumption—and many other assumptions associated with financing, system performance, and other variables—this analysis cannot be used to evaluate any individual system; it represents a general trend in the economics of residential PV.

[13] This is a real price escalation (before the effects of inflation). Estimates of future electricity prices are highly uncertain, and sensitivities to this assumption are provided in the next section. For reference, the EIA's Annual Energy Outlook 2009 (EIA 2009b) projects an annual real increase from 2008 to 2030 of 0.4%.

[14] For California, the base rate structures for investor owned utilities include a tiered-rate schedule with the highest tier exceeding 40 cents/kWh. Most customers do not consume electricity at the highest tier, and we assumed that PV displaces the second tier.

Figure 1 indicates that the only areas where PV is close to or at breakeven is where there are a combination of high electricity prices and good solar resources (such as California), or a combination of high electricity prices and incentives (such as New York state and Massachusetts). In this case, 43% of residential electricity sales are in utilities where break-even conditions occur for some customers when PV system costs \$4/W. At \$3/W, 85% of residential electricity sales are in utilities where some customers are at break-even cost.[15] It is important to note that, in practice, only a fraction of customers in these utility service territories are likely to meet all the criteria to be at breakeven (full retail net metering, good solar exposure, and financing), and the presence of break-even conditions does not necessarily equate to large consumer adoption.

This basic methodology used to generate Figure 1 was repeated for a time-of-use (TOU) scenario, using the tariff sheets for the largest utility in each state (or region of the state for CA and NY) to estimate the change in PV value associated with TOU rates. Importantly, many utilities, especially smaller utilities, do not offer TOU rates to residential customers. Moreover, even the largest utilities in many states did not offer TOU rates to residential customers at the time of this analysis; overall, we found TOU rates in the largest utility in 25 states and the District of Columbia. We assume that all utilities offer TOU rates in 2015; in states that do not currently offer TOU rates, we use the TOU multiplier from a nearby state. In each state where the largest utility offers TOU rates, we assume that a similar TOU rate structure is applied to other utilities within that state and that the value of PV would be scaled proportionally across the state. The results of this analysis are shown in Figure 2.

Also noteworthy is that TOU rates do not always result in a net benefit to a customer even when PV has higher value on TOU rates. We found that about 20% of the TOU rates evaluated showed a decrease in PV value when shifting the customer from a flat rate to a TOU rate. In addition, even with a TOU rate that increases PV value, some customers may opt not to choose TOU rates because their "base" usage would result in increased bills relative to a flat rate. For example, a customer with an above average daytime consumption pattern would likely be negatively affected by switching from a flat rate to a TOU rate. In this analysis, we consider TOU rates in all cases to be optional and we apply only those TOU rates that increase PV value.

The results of this scenario are similar to those in Figure 1 with an increase in break-even price in several states in the Southwest and Northeast plus a few other states such as Wisconsin and Florida. The result is a significant shift in the break-even cost in many states. Here, the \$4/W and \$3/W percentages are 75% and 91% respectively.

We examine the sensitivity of the break-even cost for each state to a set of four classes of impacts: technical performance, electricity cost, financing, and policies. Table 1 lists the base case and the parameters included in the four sensitivity cases evaluated.

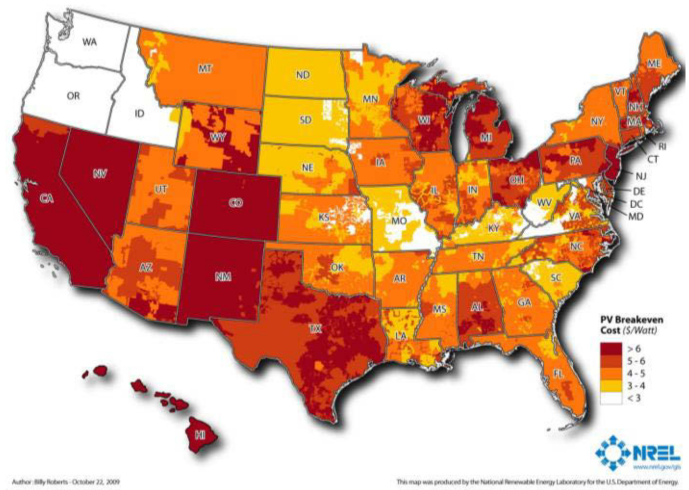

Fig. 2: Residential solar PV break-even cost (\$/W) in 2015 using the base-case assumptions in Table 1 and an optional time-of-use rate in all states

[15] Since these figures are percentages, they would not change with absolute population growth. However, they assume neither demographic shifts (equal population growth in all states) nor changes in electricity usage patterns.

TABLE 1: PV SENSITIVITY CASES IN 2015[a]

<table>
<tr><th rowspan="2" colspan="2">Base Case</th><th colspan="2">Finance</th><th colspan="2">Technical</th><th colspan="2">Electricity</th><th colspan="2">Policy</th></tr>
<tr><th>Low</th><th>High</th><th>Low</th><th>High</th><th>Low</th><th>High</th><th>Low</th><th>High</th></tr>
<tr><td>Down Payment</td><td>20%</td><td>base</td><td>0%</td><td rowspan="6" colspan="2">base</td><td rowspan="10" colspan="2">base</td><td rowspan="13" colspan="2">base</td></tr>
<tr><td>Federal Tax Bracket</td><td>28%</td><td>20%</td><td>35%</td></tr>
<tr><td>Discount rate</td><td>6%</td><td>7%</td><td>4%</td></tr>
<tr><td>Interest Rate</td><td>6%</td><td>7%</td><td>4%</td></tr>
<tr><td>Loan Type</td><td>30yr home equity</td><td>15-yr home</td><td rowspan="2">base</td></tr>
<tr><td>Evaluation Period</td><td>30 yrs</td><td>25yr</td></tr>
<tr><td>Solar Resource Location</td><td>Largest Utility</td><td rowspan="10" colspan="2">base</td><td>lowest</td><td>highest</td></tr>
<tr><td>Orientation</td><td>S - 25deg – fixed</td><td>flat</td><td>base</td></tr>
<tr><td>Derate</td><td>82%</td><td>82%</td><td>86%</td></tr>
<tr><td>O&M[b]</td><td>Solar Program Goals</td><td>EIA</td><td>base</td></tr>
<tr><td>Rate Type</td><td>Basic</td><td rowspan="6" colspan="2">base</td><td>base</td><td>TOU</td></tr>
<tr><td>Real Electricity Price Escalation</td><td>0.5% per year</td><td>0%</td><td>1.5%</td></tr>
<tr><td>Electric Cost Location</td><td>Largest Utility</td><td>lowest</td><td>highest</td></tr>
<tr><td>Net Metering[c]</td><td>Full Retail Net Metering</td><td>avoided cost</td><td>base</td></tr>
<tr><td>CO2 cost</td><td>$25/ton</td><td rowspan="2" colspan="2">base</td><td>$0</td><td>$50/ton</td></tr>
<tr><td>Incentives</td><td>Federal ITC (30%)</td><td>None</td><td>base</td></tr>
</table>

a The values used in Table 1 are not intended to represent all possible scenarios but were chosen to provide a reasonable range of values for each parameter.

b O&M values were based on inverter replacements at 10 and 20 years (2025 and 2035). Solar program goals (base case) assumed $297/kw in 2025 and $280/kW in 2030. EIA values used were $974/kW and $960/kw for 2025 and 2030 respectively.

c Avoided cost assumes that PV (1) offsets only the fuel cost of a mix of combined-cycle and single cycle gas turbines with a composite heat rate of 8000 BTU/kWh and (2) receives no credit for capacity or T&D losses. For further discussion of avoided fuels, see Denholm et al. (2009).We used the projected natural gas price in 2015 from the 2009 Annual Energy Outlook (EIA 2009), which results in a national average avoided cost of 5.4 cents/kWh.

Figures 3a and 3b present the results. In each state, a base-case break-even cost based on the largest utility in the region is provided; four error bars show the range of break-even costs for the sensitivity cases. Each of the four drivers has a low case and a high case. The low case, which decreases the economic performance of PV and moves the error bar left, represents a lower break-even cost. Examples include lower PV output from non-optimal orientation or a premature elimination of the federal ITC. The low cases could also represent the impact of reducing the benefits of TOU rates or retail net metering. The high case represents improved economy performance, increasing the break-even price. Examples include a higher derate factor (perhaps resulting from improved inverter efficiency) or a larger effective cost of carbon.

The scenarios and error bars in the figures are partially additive. For example, both a more aggressive carbon policy and improved derate factors could occur, decreasing the break-even cost more than these factors individually. However, these factors are not completely additive; for example, the highest solar resource location in each state may not correspond to the highest price region.

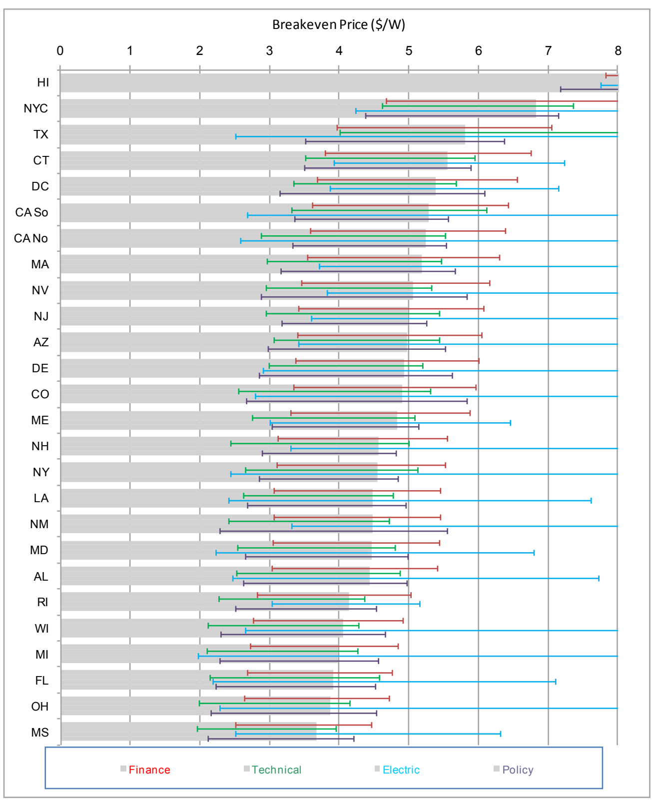

Fig. 3a. Range of PV break-even costs in the 2015 scenarios: Top 26 regions

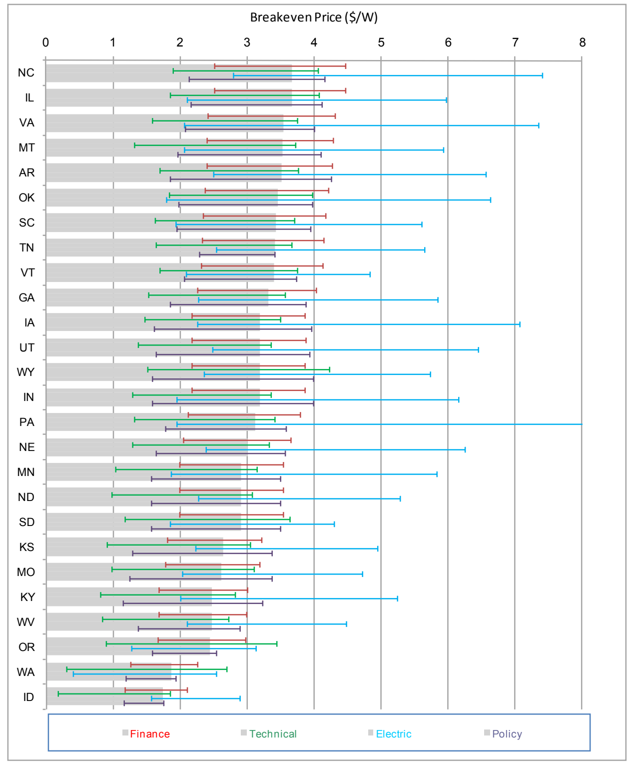

Fig. 3b. Range of PV break-even costs in the 2015 scenarios: Bottom 26 region

As shown in Figure 3, the base-case break-even price in 2015 is between $1.6/W and $6.2/W (excluding Hawaii). Figure 3 shows that the electricity price is the biggest driver of break-even price variation and is followed generally by finance factors, policy issues, and technical performance. The variation in the electricity prices is due more to the spread between utilities within a state than the variation in the price escalation assumed. The finance assumptions result in a roughly symmetrical impact on breakeven of +/- 35% across all states. The ITC is the single largest policy driver evaluated. Technical sensitivities are the least important variable and generally decrease the breakeven price because of the analysis of the flat orientation case, which reduces the annual average PV output by about 13%.

3. CONCLUSIONS

We evaluate the break-even price for residential PV customers in the United States and find that the current break-even price varies more than a factor of 10 even though the solar resource varies by less than a factor of two. This difference is largely driven by electricity prices, which can vary by a factor of eight (or more when considering the range of tiered rates in California). Large variations in break-even cost also result from the range of financing options and other non-technical factors.

The general trend observed in this analysis is that break-even conditions appear first in the Southwest where they are driven by resource and in the Northeast where they are driven by high electricity prices. As PV system prices continue to decline, break-even conditions begin to occur in the Southeast and Midwest. Very low electricity prices will preclude break-even conditions in certain areas in the Northwest and Midwest even with PV prices at \$3.5/W and continuation of the federal investment tax credit.

Overall, the scenarios evaluated represent a market entry point for solar PV. However, the scenarios do not consider the potential for a deep, sustained market. PV breakeven does not imply that customers will necessarily adopt PV, and only a fraction of customers in each utility will have the necessary combination of good solar access and attractive financing options to consider a PV system. A true depth of market analysis is required to determine a "demand curve" for PV at various price points.

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