




Breakeven Prices for Photovoltaics on Supermarkets in the United States

Sean Ong, Nathan Clark, Paul Denholm,
and Robert Margolis

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Executive Summary

The photovoltaic (PV) breakeven price is the PV system price at which the cost of PV-generated electricity equals the cost of electricity purchased from the grid. This point is also called "grid parity" and can be expressed as dollars per watt ($/W) of installed PV system capacity. Achieving the PV breakeven price depends on many factors, including the solar resource, local electricity prices and rate structure, customer load profile, PV incentives, and financing. In the United States, where these factors vary substantially across regions, breakeven prices vary substantially across regions as well.

In this study, we estimate current and future breakeven prices and drivers for PV systems installed on U.S. supermarkets. As of 2012, 85,988 supermarkets exist in the United States that use about 36,000 gigawatt-hours (GWh) of electricity per year. This analysis suggests that more than 17% of these supermarkets are in utility territories where PV breakeven conditions exist under today's market and policy conditions. PV systems are installed on less than 0.3%[1] of supermarkets in the United States, as of the end of 2012.

This analysis is a first step in examining the breakeven price for PV systems across the larger category of commercial "big-box" retail stores. Current and future (2020) breakeven prices are calculated. We compare breakeven prices under default electricity-rate assumptions versus optional rate assumptions (typically time-of-use rates) that increase PV's value, and we compare these breakeven prices with current and potential future commercial PV prices. We also analyze the impacts of incentives on breakeven prices in each state. Finally, we analyze the sensitivity of breakeven price to electricity prices and financial, technical, and policy factors.

The results suggest that breakeven prices for PV systems installed on supermarkets vary by more than a factor of 30 across the United States, even though the solar resource varies by less than a factor of 2. Non-technical factors—including electricity rates, rate structures, and incentives—drive breakeven prices more than technical factors such as solar resource or system orientation. Additional key results of this analysis include:

- Under base-case assumptions, about 17% of supermarkets nationwide were in utility territories where breakeven conditions existed at a PV system price of $5/W in 2011 (the U.S. average installed price of commercial PV systems in 2011). Using the estimated 2012 installed price of commercial PV systems ($3.43/W), 40% of supermarkets were in utility territories where breakeven conditions existed. These percentages increase to 33% and 53%, respectively, when rate structures favorable to PV (time-of-use, tiered rates) are used.
- In 2020 (where we assume higher electricity prices and lower PV incentives), under base-case assumptions, we estimate that about 17% of supermarkets will be in utility territories where breakeven conditions exist at a PV system price of

[1] The percentage of supermarkets with PV systems is calculated by dividing the estimated number of supermarkets with PV systems by the total number of supermarkets in the United States (85,988). The number of supermarkets with PV systems (183) is estimated from SEIA 2012.

$3/W; this increases to 79% at $1.25/W (the DOE SunShot Initiative's commercial PV price target for 2020) (DOE 2012a). These percentages increase to 26% and 91%, respectively, when rate structures favorable to PV are used.

- In general, the areas with the highest PV breakeven prices (i.e., those most favorable for PV) are located in areas with high electricity prices and favorable incentives.
- Breakeven price is most sensitive to variations in electricity rate and then, generally, to variations in policy, technical performance, and financing factors.

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1 Introduction

The photovoltaic (PV) breakeven price is the PV system price at which the cost of PV-generated electricity equals the cost of electricity purchased from the grid. This point is also called "grid parity" and can be expressed as dollars per watt ($/W) of installed PV system capacity.[2] Achieving the PV breakeven price depends on many factors, including the solar resource, local electricity prices, PV incentives, and financing. In the United States, where these factors vary substantially across regions, breakeven prices vary substantially across regions as well.

The National Renewable Energy Laboratory (NREL) previously estimated breakeven prices for residential rooftop PV systems in the United States (Denholm et al. 2009).[3] This work expands on the previous study by using similar methods to estimate current and future breakeven prices for PV systems installed on U.S. supermarkets, a subset of commercial buildings within the larger category of "big-box" retail stores. We also evaluate key drivers of current and future PV breakeven prices by region.

Our analysis begins by defining the characteristics of a hypothetical supermarket PV system and then models the financial performance of this system nationwide using the System Advisor Model (SAM) with meteorological, utility-rate, and building-load data inputs. We calculate breakeven price as the point at which the net present cost (NPC) of a PV system equals the net present benefit (NPB) realized to its owner in the form of reduced electricity bills, which is also the point at which the PV system's net present value (NPV) equals zero. Current and future (2020) breakeven prices are calculated. For each timeframe, we compare breakeven prices under default electricity-rate assumptions versus optional rate assumptions (typically time-of-use rates) that increase PV's value, and we compare these breakeven prices with current and potential future commercial PV prices. We also analyze the contribution of various cost components (e.g., electricity rates and incentives) to breakeven prices in each state. Finally, we analyze the sensitivity of breakeven price to electricity prices and financial, technical, and policy factors.

Note that the presence of breakeven conditions in an area does not imply that all potential supermarkets in that area could achieve PV breakeven. It is likely that only a fraction of customers could meet the location-specific criteria necessary for breakeven. Caps on PV incentive and net-metering programs could also limit the prevalence of breakeven conditions in practice. Further, the presence of breakeven conditions does not necessarily equate to widespread adoption of PV systems. Finally, large-scale adoption of PV would change electricity demand and price patterns and could decrease the value of PV under optional rate structures. Thus, this study of PV breakeven prices is not a market-depth analysis or an estimate of PV adoption, but it does provide new insights about the potential viability of one important segment of the rooftop commercial PV market.

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[2] 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-Watt of capacity.

[3] Additional studies have estimated the breakeven cost of PV, including Herig et al. (2002) and Herig et al. (2003).

The remainder of this report details the study's data and methodology (Section 2), current PV breakeven price results (Section 3), and future PV breakeven price results and sensitivity analysis (Section 4). Section 5 presents conclusions and directions for future research.

2 Data and Methodology

Understanding rooftop solar economic performance requires an analysis of the interaction between the building load, PV generation, rate structure, and a variety of financial and policy assumptions. The complex interaction between building load, solar production, and electricity rate structure requires a model that can simultaneously address all elements involved. SAM (Section 2.1) is used to generate solar production and economic performance results from a variety of inputs, including solar resource data (Section 2.2), utility rate data (Section 2.3), and hourly building load data (Section 2.4). The following sections provide details on the data and methodology used in this analysis.

2.1 System Advisor Model and Calculations

Analysis in this report was performed using SAM, which was developed by NREL in collaboration with Sandia National Laboratories and the U.S. Department of Energy (DOE). SAM is a performance and economic model designed to facilitate decision making and analysis for renewable energy projects (Gilman and Dobos 2012). SAM uses meteorological data, a PV performance model, and user-defined assumptions to simulate hourly PV generation data. In this analysis, a reference system was modeled using the following assumptions[4] to generate PV performance data:

- 250 kW (DC)[5]
- 15-degree tilt
- South facing (180-degree azimuth)
- A derate factor of 80%
- Annual degradation of 0.5%.

PV breakeven prices were evaluated for both near-term and future (2020) scenarios. We define the breakeven price of PV as the point at which the NPC of the PV system equals the NPB realized to its owner. This may also be expressed as the point at which the NPV is equal to zero. The breakeven system price ($/W) was calculated by iteratively varying the price of PV until the NPC equaled the NPB.[6] A review of the methods used to calculate NPC and NPB is provided in Appendix A.

The NPC of the system includes all financing and incentives, while the NPB is the cumulative discounted benefits of reduced electric bills. All financing assumptions used in this study are from DOE's *SunShot Vision Study* (DOE 2012a). The NPC in our base

[4] Note that SAM contains many input fields. SAM default inputs were used for any assumption not specifically called out in this report.

[5] For context, a commercial building with a rooftop area of 45,000 ft^2 could support a 300 DC-kW PV system, assuming a module efficiency of 15% and 50% rooftop availability due to shading and obstructions. The DOE supermarket building model used in this analysis has a single-story floor area of 45,000 ft^2, from which we assume a rooftop area of approximately 45,000 ft^2.

[6] Often, a linear relationship between the breakeven price and NPV was observed. Whenever a linear relationship was observed, the calculation was performed by solving for the breakeven price at NPV = 0 to reduce simulation time.

scenario assumes a system financed with a loan (with tax-deductible interest and a 35% marginal federal tax rate), a 40% down payment, a real interest rate and discount rate of 4.5%, and a loan term of 20 years.[7] The evaluation period for the analysis is 30 years.[8]

Near-term analysis considered several incentive programs, including the 30% federal investment tax credit (ITC), as well as known state, local, and utility incentives derived from the DSIRE database.[9] Tax credits were applied at the end of year one in the NPC calculation.[10] The taxability of rebates and their effect on the federal ITC must be considered. In our base assumption, we assume that the rebate is paid to the installer rather than the building owner. This effectively reduces the installation price to the building owner by the amount of the rebate and also reduces the basis for the federal ITC. A list of the state and local incentives used in this analysis is provided in Appendix B.

Near-term analysis also assumed the federal 5-year Modified Accelerated Cost Recovery System (MACRS) depreciation schedule, an annual operation and maintenance (O&M) cost of $23.50/kW, and inverter replacement at 15 years.

Sensitivities to these assumptions are evaluated in Section 4.

2.2 Solar Resource Data

The PV production data used in this analysis were simulated using the Typical Meteorological Year 3 (TMY3) dataset of the National Solar Radiation Database (Wilcox and Marion 2008). The TMY3 dataset is intended to represent a typical year's weather and solar resource patterns, although the dataset does not consist of an actual representative year. Rather, TMY3 was created by combining data from multiple years.[11] The meteorological dataset was used as an input for SAM, which simulated hourly PV production for use in the financial calculations.

2.3 Utility Rate Data

The breakeven price for PV was calculated for 3,143 utilities in the United States, which represents about 98% of the total commercial load (based on annual energy consumption). We evaluated breakeven prices under two electricity rate categories: one based on the default rate (typically demand rates and/or tiered rate structures) and one

[7] 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.
[8] This implies an expected 30-year life of system.
[9] Database of State Incentives for Renewables and Efficiency (DSIRE), http://www.dsireusa.org/. All incentives are as of May 2012.
[10] This analysis makes two assumptions regarding sales taxes and property taxes. First, it assumes that PV systems are exempt from sales tax, which is true in some but not all states. In states where PV systems are taxed, the breakeven price would be reduced by a percentage roughly equal to the sales tax rate. Second, the analysis assumes that PV systems are exempt from property tax, which is also true for many but not all regions and states. For a list of states and localities that exempt PV systems from sales and property tax, see DSIRE (http://www.dsireusa.org/).
[11] For example, the month of January may be from one year (e.g., 1989), while February may be from another year (e.g., 1994). Each TMY3 file may contain data from up to 12 different years. Data were intentionally selected to represent typical meteorological conditions.

based on an optional rate (typically time-of-use rate structures or rates with lower demand charges and higher energy charges than the default rate). A default rate refers to a rate that a building would be subject to by default, based on applicability requirements such as peak demand, voltage requirements, or energy consumption. An optional rate refers to a rate that customers may choose in lieu of the standard rate option. Utilities offer various commercial rate structures for different load sizes and types. We considered applicability requirements when collecting rates for the load data used in this analysis.[12] Net metering is characterized as follows: PV energy production is compensated at the retail electricity rate for all energy produced, up to 100% of the building's annual electricity use.[13]

A combination of tariff sheet data and Energy Information Administration (EIA) utility data is used in this study. Form EIA-861 data provide the total revenue and total energy sales for all utilities in the United States.[14] This dataset formed the basis for an "average" cost of electricity to commercial customers. However, these data do not provide insight into the actual rate structure because they represent an annual average 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 and the actual value of PV, we used rate data obtained from the current tariff sheet for the largest utility in each state, here referred to as "high-fidelity" rate data. The value of PV in a specific utility territory was calculated twice: once using the high-fidelity rate data and again using the annual average cost of electricity. The relative difference in value between these two calculations established a scale factor. This scale factor was then applied to the remaining utilities in each state in order to approximate the value of PV under actual electricity tariffs as well as removing fixed billing components. A total of 104 rates from 52 utility companies were evaluated. Figure 1 shows the utilities with high-fidelity rate data available. These rates were obtained from the online Utility Rate Database (URDB) on the OpenEI platform[15] and were current as of late 2011 and early 2012.

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[12] Rates ineligible to be used with supermarkets (or any building with similar demand requirements as the supermarket load data used) are not evaluated in this analysis.
[13] Net metering may not be available in all states or utilities. For a complete list of utilities participating in net-metering arrangements, see DSIRE at http://www.dsireusa.org/. In this analysis, PV production never exceeds 100% of the building's annual electricity use.
[14] Because 2010 was the most recent year available at the time of this report, we scaled each utility to 2011 values using the state average value for 2011 derived from the EIA (EIA 2012).
[15] http://en.openei.org/wiki/Gateway:Utilities

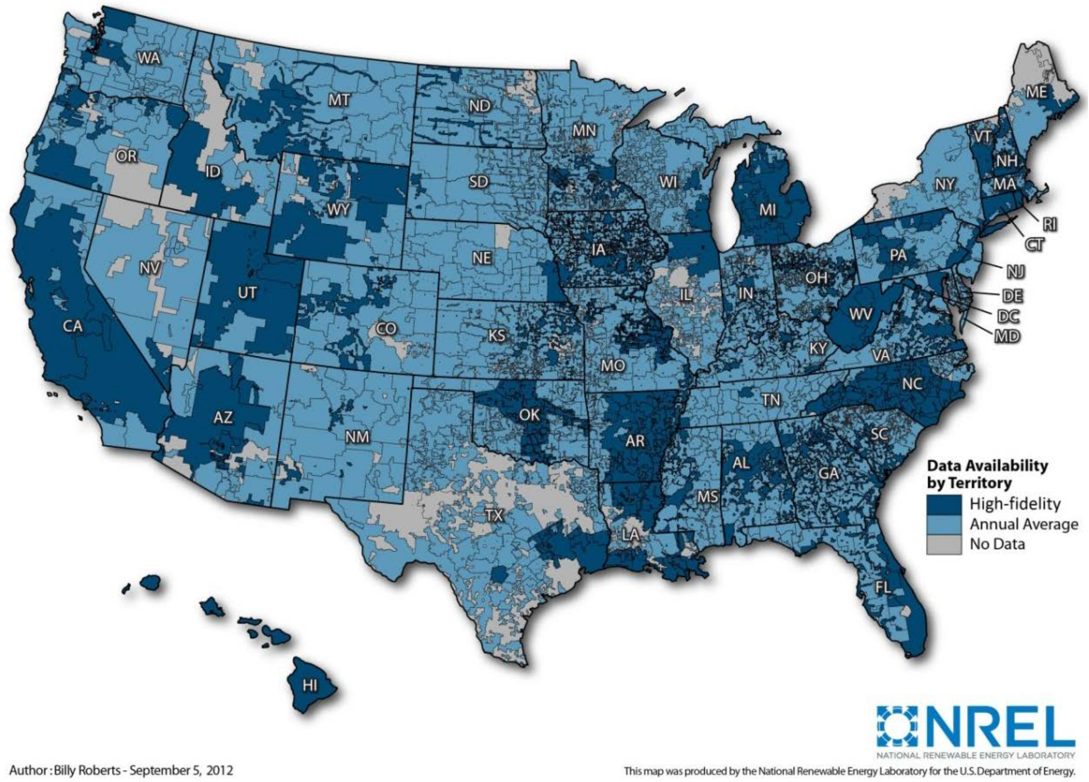

Figure 1. U.S. map depicting locations with high-fidelity utility rate data (dark blue) and annual average utility rate data from EIA-861 (light blue)

2.4 Hourly Building Load Data

Obtaining or simulating building load data is an important component of any analysis that includes demand charges and tiered rates. Demand charges are usually based on the peak monthly power demand of a building; consequently, quantifying the demand reduction value of a PV system requires a detailed load profile for a building. Load profiles are also required when evaluating tiered rates and demand charges, where rates vary depending on monthly energy use. For the analysis presented here, we generated a set of region-specific simulated hourly load profiles for supermarkets. These load profiles are based on the DOE commercial reference building models for supermarkets (Deru et al. 2011) and were simulated using DOE's EnergyPlus software.[16] In order to ensure that the simulated supermarket load and PV production profiles were properly aligned, we used the same TMY3 datasets to simulate both sets of data.

Building construction and model assumptions were varied throughout the United States with 16 unique supermarket models used [i.e., one for each of the official climate zones recognized by the American Society of Heating, Refrigeration, and Air-Conditioning Engineers (ASHRAE)]. These region-specific building models account for factors such as region-specific building codes, characteristics, major loads and plug loads. The 16

[16] For more information on the EnergyPlus model, see http://apps1.eere.energy.gov/buildings/energyplus/.

region-specific building models were then simulated at 79 TMY3 locations throughout the United States (there are a total of 1,020 TMY3 locations) in order to generate a more geographically diverse set of load profiles that could be matched to TMY-specific solar-generation profiles. Appendix C contains a complete listing of all building locations and associated ASHRAE zones and TMY sites. The total hourly electrical load of each building location was then entered into SAM.

As of 2012, DOE estimates there are 85,988 supermarkets[17] in the United States, representing 4.8% of commercial buildings and 6.3% of all commercial building electricity consumption (DOE 2012b). The average simulated building has a floor area of 45,000 ft^2, an annual electricity consumption of 1,687 MWh, and a peak demand of 367 kW. While supermarkets represent an important segment of the commercial building sector, a more comprehensive analysis of PV economic performance in the commercial building sector would require simulating load profiles across multiple building types.

[17] Building statistics are obtained from the Energy Index (http://buildingsdatabook.eren.doe.gov/CBECS.aspx). The 85,988 buildings are representative of the modeled supermarket and not smaller (e.g., convenience stores) or larger (e.g., mixed-use stores) buildings.

3 Near-Term PV Breakeven Prices

We begin by evaluating the breakeven price of PV ($/W) in the base scenario. This scenario uses the default rate structure, which generally consists of demand and/or tiered rates and includes all federal and local incentives. Figure 2 shows the base-case breakeven price of PV for each utility service territory evaluated. For the areas in each state where utility data is unavailable (consisting of about 2% of total U.S. commercial electricity sales), we assume 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.

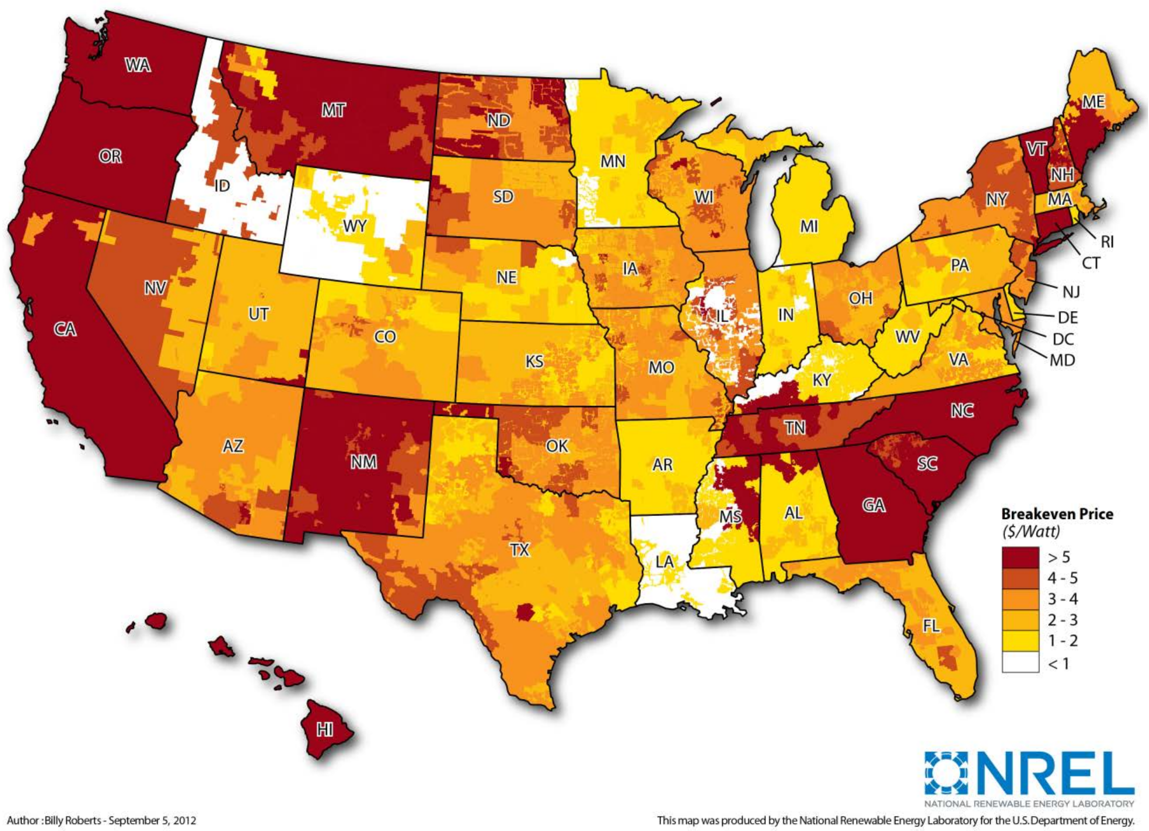

Figure 2. PV breakeven price ($/W) for supermarkets in 2012 using the default rate structure and all incentives

The average installed cost of commercial PV systems (250–500 kW) in the United States was $4.90/W in 2011 (Barbose et al. 2012) and $3.43/W in 2012[18] (Feldman et al. 2012). At $5/W, 17% of supermarkets are in utilities where breakeven conditions exist. At $3.43/W, 40% of supermarkets are in utility territories where breakeven conditions exist. In practice, only a fraction of customers in these utility service territories are likely to

[18] Benchmarked based on fourth quarter 2011 data.

meet all the criteria (full retail net metering, good solar exposure, and access to financing) to be at breakeven, and the presence of breakeven conditions does not necessarily equate to large consumer adoption. Furthermore, there are budget caps for most current incentive programs and typically limits or caps on the number of net-metered systems that can be connected to the grid in a specific utility service territory. Also, in Figure 2 and elsewhere, this analysis represents a single point in time. Because incentives and electricity prices are constantly changing, results for any single area may be substantially different when evaluated later.

The methodology used to generate Figure 2 was repeated for the optional rate scenario, using the tariff sheets for the largest utility in each state to estimate the change in PV value associated with optional rates. Optional rates typically consist of time-of-use rate structures or rates that have lower demand charges and higher energy charges than the default rate option. In states without an optional rate, the default rate was evaluated, and the breakeven price did not change from the default rate scenario (Figure 2). In each state where the largest utility offers optional rates, we assumed that a similar optional rate structure would be 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 3.

Optional rates do not always result in a net benefit to a customer. About 26% of the optional rates evaluated showed a *decrease* in PV value when shifting the customer from the default to the optional rate. In addition, even with an optional rate that increases PV value, some customers may opt not to choose optional rates because their “base” use would result in increased bills relative to a default rate. In this analysis, we assumed that customers chose optional rates only when those rates increased PV value. For a complete discussion of commercial rate impacts on PV value and bill savings, see Ong et al. (2012).

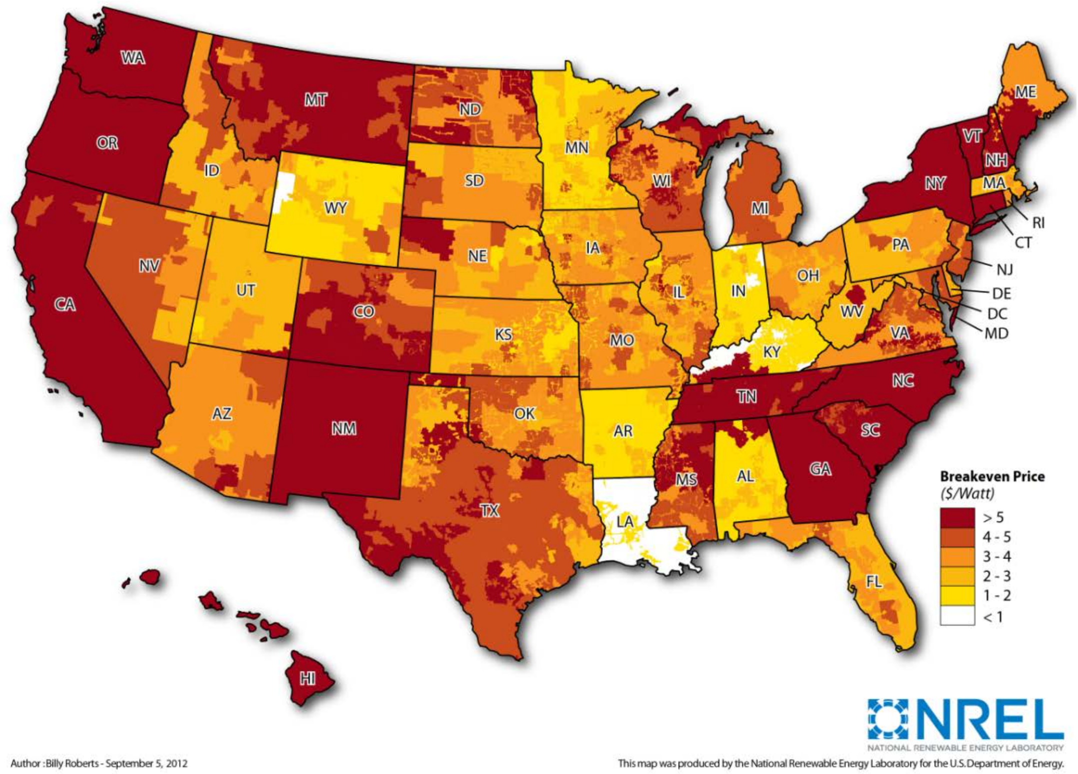

Figure 3. PV breakeven price ($/W) for supermarkets in 2012 using an optional rate structure (where offered) and all incentives

The results of this scenario are similar to those in the default scenario (Figure 2) but with higher breakeven prices in several northeastern and central states. In the optional rate scenario, the fraction of supermarkets in utility areas where breakeven conditions exist increases to 33% and 53% for installed prices of $5/W and $3.43/W, respectively. The lowest breakeven prices occur in Louisiana, where electricity prices are low and primarily driven by demand charges.[19] Actual adoption will be restricted by consumer adoption behavior and limits on incentives, and large-scale adoption of PV will change demand and price patterns, decreasing the value of PV on optional rates (Darghouth et al. 2013).[20]

Figure 4 illustrates the breakeven price for the largest utility in each state along with a distribution of the breakeven price components, including the default electricity rate, optional rate "adder" (where available[21]), the effect of tax-deductible interest on loans,

[19] Rates that are driven by demand charges have been shown to reduce the value of PV generation (Ong et al. 2010).

[20] At large-scale deployment, PV would suppress the mid-day demand for electricity and thus the electricity price. This would decrease the value of PV and reduce the likelihood of receiving full retail net metering. Also see Denholm and Margolis (2007a and 2007b) for a discussion of the grid impacts of large-scale PV deployment.

[21] In this analysis, we assumed that customers chose optional rates in all cases in which those rates increased PV value.

and federal and local incentives. Also included is the range in breakeven values for all utilities evaluated.

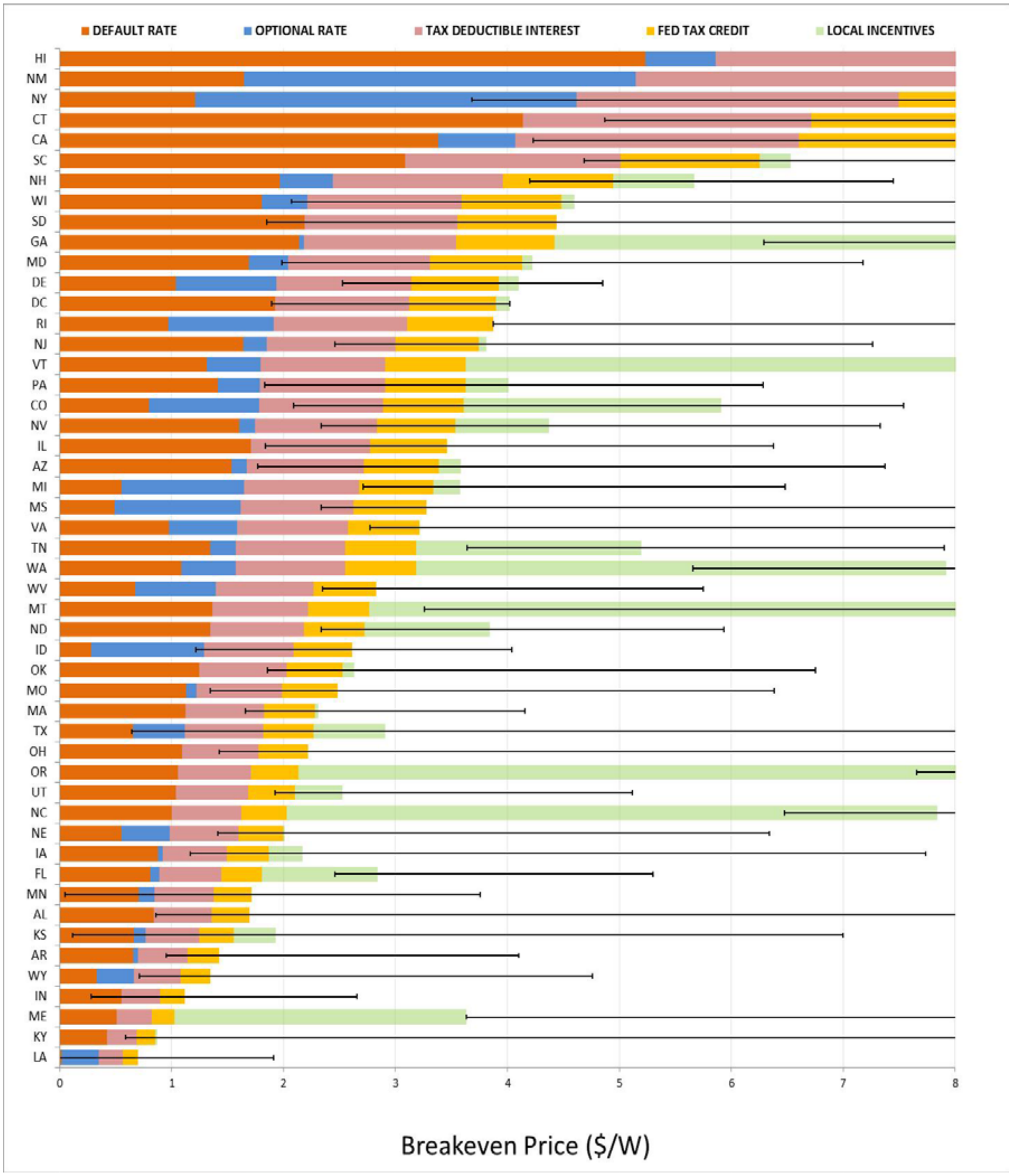

Figure 4. Components of the breakeven value for the largest utility in each state and Washington, D.C. (colored bars) and range in breakeven value for all utilities in each state (whiskers)

Note: For clarity, breakeven prices above $8/W are not displayed.

As shown in Figure 4, each state shows considerable variability. In some cases, the breakeven value for the most attractive utility is several dollars per watt more than the largest utility. However, these more attractive utilities tend to be significantly smaller than the largest utility, often providing less than a few percent of the state's sales.[22] We also see breakeven prices above $4/W in only a few places without local incentives. Without local incentives or the federal ITC, half of the largest utilities in each state have a breakeven price below $2.50/W.

Figure 5 repeats the analysis in Figure 3 but illustrates the breakeven price relative to the 2012 average installed price ($3.43/W, based on Q4 2011 data) data for commercial PV systems from Feldman et al. (2012). We identify locations at or below grid parity, within 25% of parity (the current average installed price is within 25% of being at grid parity), and beyond 25% of parity. At an installed price of $3.43/W, the fraction of supermarkets that are at or below grid parity is 53%, while an additional 20% are within 25% of grid parity. Note again that only a fraction of customers in these utility service territories are likely to meet all our assumptions to be at breakeven, and the presence of breakeven conditions does not necessarily lead to large consumer adoption.

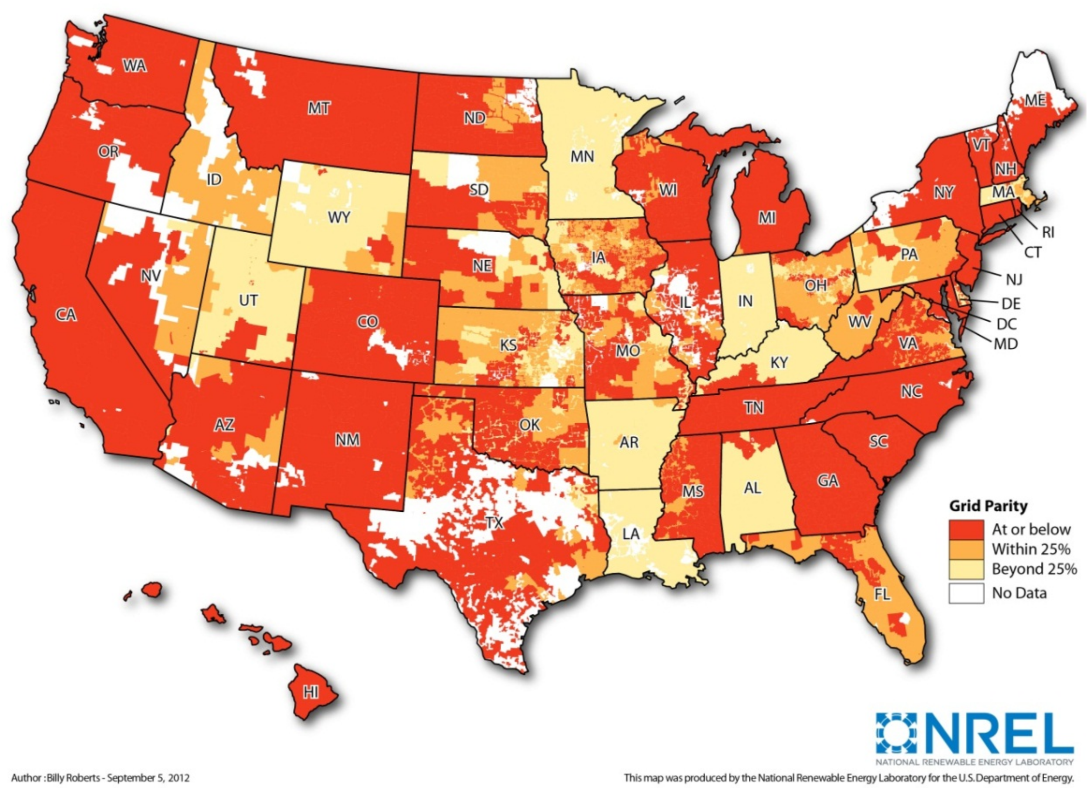

Figure 5. Grid parity for supermarkets at the 2012 PV price ($3.43/W) using an optional rate structure with incentives (where applicable)

[22] As an example, at the time of this analysis, the base-case breakeven price in the largest utility in Arizona (serving 32% of the state's commercial load) is about $3.60/W, while the maximum breakeven price in the state is nearly $7.40/W. However, this higher price applies only to a small utility serving about 5% of the state's commercial load.

4 Future Market Sensitivities of Breakeven Prices

The high breakeven prices in many states that were noted in the previous section are driven primarily by state, utility, and federal incentive programs. These programs are designed primarily to encourage the development of PV markets; however, over time they are expected to be phased down as the price of PV systems decreases and PV markets become self-sustaining. In this section, we examine the projected breakeven prices of PV systems installed on supermarkets in 2020, and we consider the sensitivity of breakeven prices to a number of factors.

We begin by establishing a base scenario for 2020 with a uniform set of assumptions, including system performance, electricity price escalation, financing, and incentives. This is similar to the previous scenario but includes an annual real electricity price escalation of 0.5% that results in an overall increase in electricity prices of 4% by 2020. State and local incentives are eliminated, and the federal ITC is reduced to 10%.[23]

Figure 6 (default electricity rate structure) and Figure 7 (optional rate structure) provide the results for the 2020 base case. Note that the color scales in these figures are different from those in Figures 2 and 3. In Figures 6 and 7, the presence of any color other than white indicates a breakeven price above DOE's SunShot commercial PV price target of $1.25/W (DOE 2012a).

[23] Under the current Internal Revenue Service (IRS) tax code, the 30% federal ITC will revert to a 10% ITC for commercial and utility systems after 2016 (see http://www.dsireusa.org/).

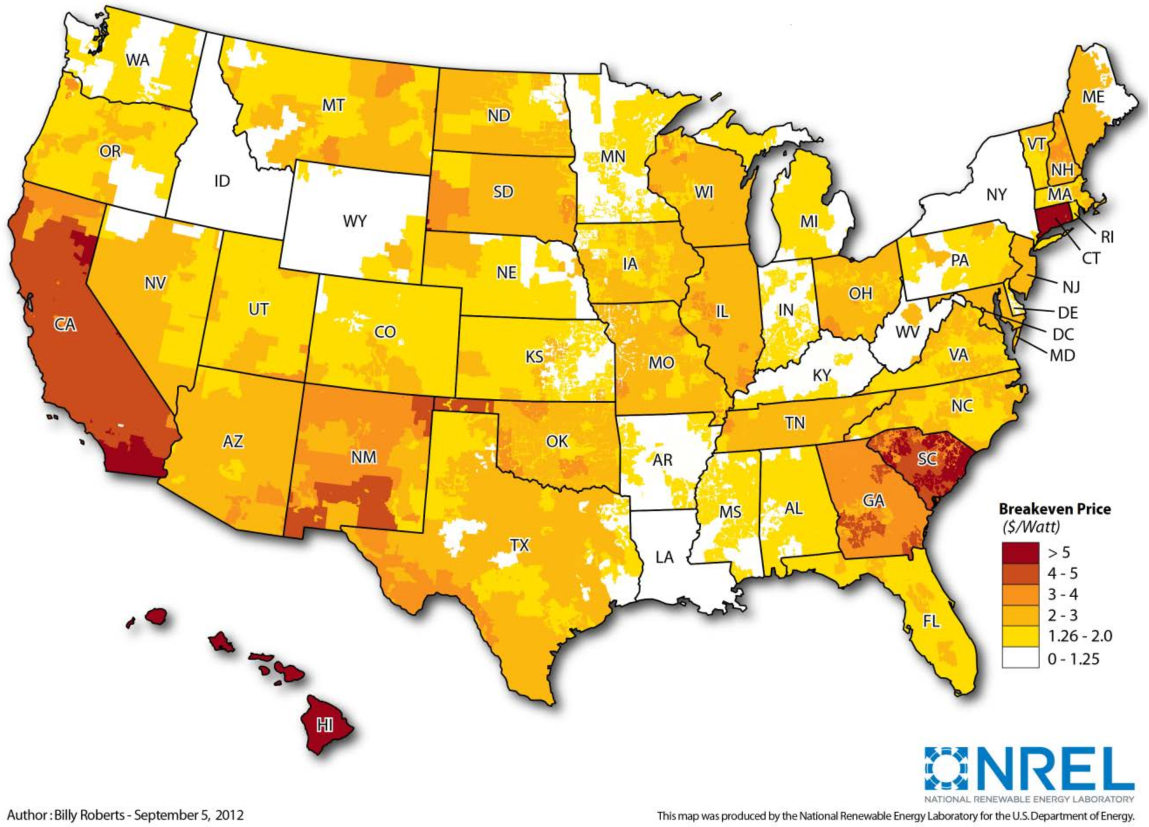

Figure 6. PV breakeven prices ($/W) for supermarkets in 2020 using the base-case assumptions in Table 1 and the default rate structure

Note: The color scale is different from the scale used in Figures 2 and 3.

The 2020 case shows a dramatic reduction in the breakeven price of PV where local incentives existed in early 2012. Breakeven prices are also reduced in locations where no incentives existed in early 2012 owing to the reduction of the ITC from 30% to 10%. In this case, 17% of supermarkets are in utility areas where breakeven conditions exist at a PV system price of $3/W. At a price of $1.25/W, 79% of supermarkets are in utility areas where breakeven conditions exist.

Figure 7 repeats the analysis for an optional rate structure. Again, the dramatic reduction in breakeven prices from 2012 is due to the elimination of state and local incentives and a reduction in the ITC. Here, 26% of supermarkets are in utility areas where breakeven conditions exist at a PV system price of $3/W. At $1.25/W, 91% of supermarkets are in utility areas where breakeven conditions exist.

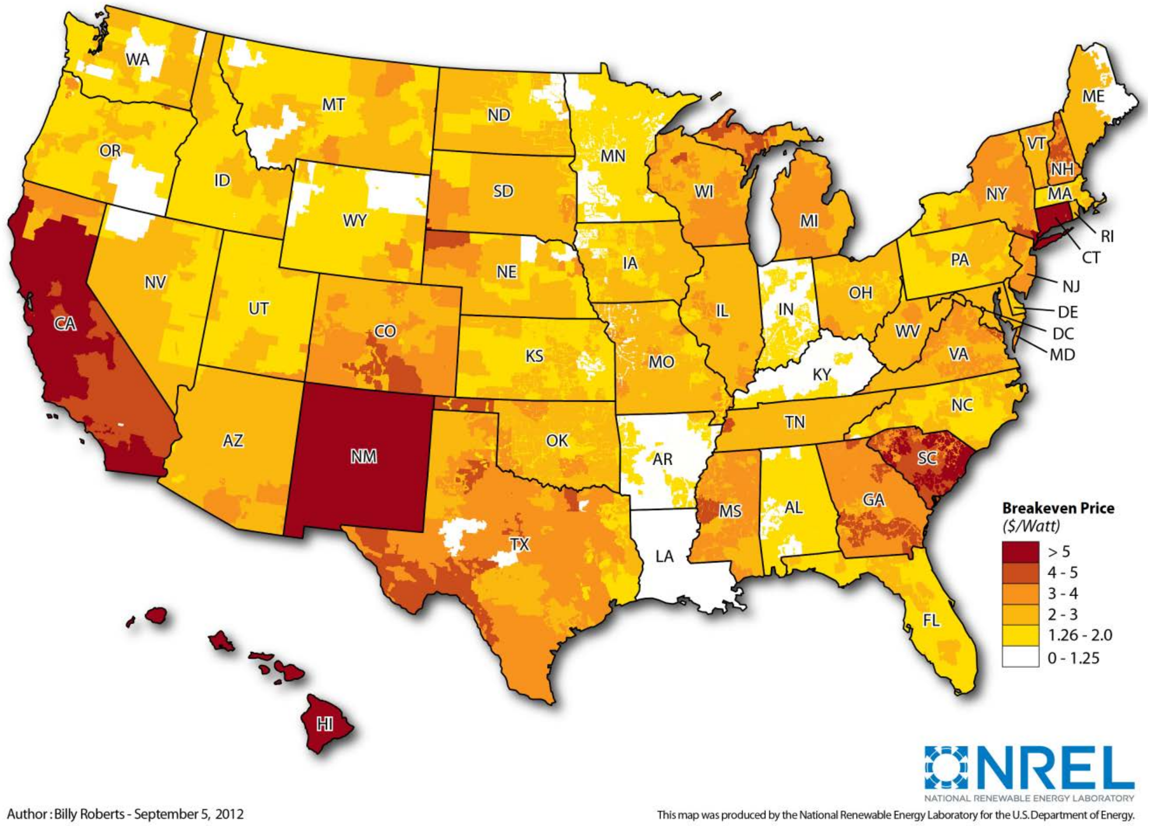

Figure 7. PV breakeven prices ($/W) for supermarkets in 2020 using the base-case assumptions in Table 1 and an optional rate structure

Note: The color scale is different from the scale used in Figures 2 and 3.

The base 2020 scenario represents only a single scenario among many possible scenarios for future breakeven prices. The PV market of the future will have a variety of customers with different financing options, buildings with non-optimal orientations, and changes in electricity prices and rate structures. Many of these drivers, such as escalation of electricity prices and future net-metering policies, are highly uncertain. As a result, it is important to consider the sensitivity of the breakeven price to a variety of drivers.

We examined the sensitivity of the breakeven price 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 four sensitivity cases evaluated.

Table 1. PV Base and Sensitivity Cases in 2020[a]

<table>
<tr><th colspan="2" rowspan="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>40%</td><td>60%</td><td>20%</td><td colspan="2" rowspan="6">Base</td><td colspan="2" rowspan="10">Base</td><td colspan="2" rowspan="13">Base</td></tr>
<tr><td>Federal Tax Bracket</td><td>35%</td><td>33%</td><td>Base</td></tr>
<tr><td>Discount Rate</td><td>5%</td><td>7%</td><td>4%</td></tr>
<tr><td>Interest Rate</td><td>5%</td><td>7%</td><td>4%</td></tr>
<tr><td>Financing Type</td><td>20-yr Loan</td><td>15 yr</td><td rowspan="2">Base</td></tr>
<tr><td>Evaluation Period</td><td>30 yr</td><td>25 yr</td></tr>
<tr><td>Solar Resource Location</td><td>Largest Utility</td><td colspan="2" rowspan="8">Base</td><td>low</td><td>high</td></tr>
<tr><td>Orientation</td><td>South Facing - 15 Deg - Fixed</td><td>Flat</td><td>25 Deg</td></tr>
<tr><td>Derate</td><td>80%</td><td>77%</td><td>82%</td></tr>
<tr><td>O&M[b]</td><td>$7.50/kW-yr</td><td>$10/kW-yr</td><td>$5/kW-yr</td></tr>
<tr><td>Rate Type</td><td>Default (Demand Based)</td><td colspan="2" rowspan="4">Base</td><td>Base</td><td>Time of Use/ Tier</td></tr>
<tr><td>Electricity Price Escalation</td><td>0.5% per year</td><td>0%</td><td>2%</td></tr>
<tr><td>Electric Cost Location</td><td>Largest Utility</td><td>low</td><td>high</td></tr>
<tr><td>Incentives</td><td>Federal ITC (10%)</td><td colspan="2">Base</td><td>0%</td><td>30% ITC</td></tr>
</table>

[a] The values used in Table 1 are not intended to represent all possible scenarios but provide a reasonable range of values for each parameter.
[b] O&M values are based on DOE SunShot targets. Inverter replacements occur at year 15 (2035), with a cost of $0.11/W.

Figures 8 and 9 show the results. For each state, the gray bar indicates the base-case breakeven price based on the largest utility in the state, and four error bars show the range of breakeven prices 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 to the left, represents a lower breakeven price. Examples include lower PV output from non-optimal orientation or a total elimination of the federal ITC. The high case represents improved economic performance, which increases the breakeven price and moves the error bar to the right. Examples include an improved derate factor (perhaps resulting from improved inverter efficiency) or a more effective system orientation.

The scenarios and error bars in the figures are partially additive. For example, both an extension of the 30% ITC and improved derate factors could occur, increasing the breakeven price 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 electricity price region.

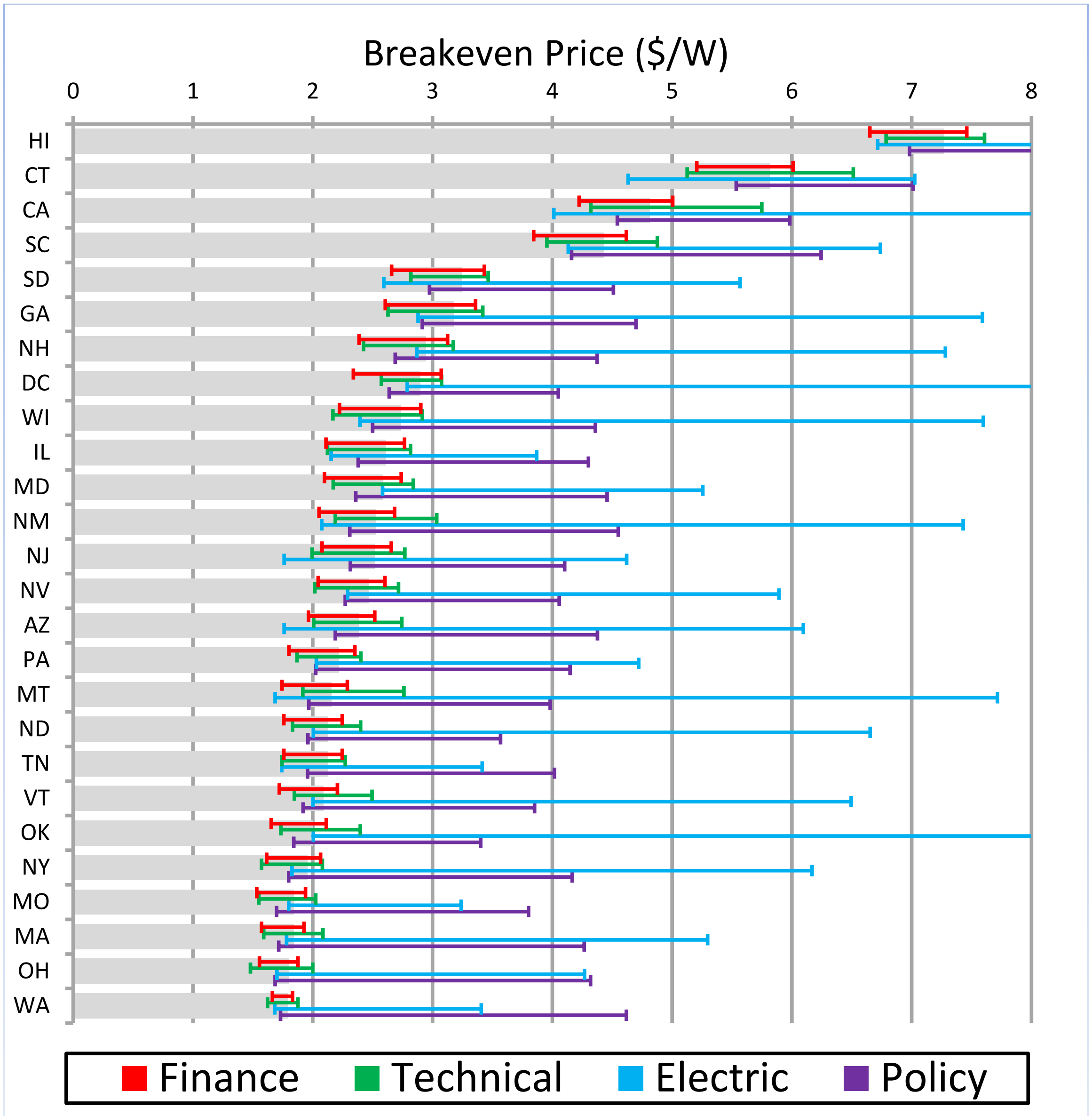

Figure 8. Range of PV breakeven prices in the 2020 scenarios: Top 26 states and Washington, D.C. The gray bars indicate the base case from the largest utility in the state, and the four error bars show the range of breakeven prices for the sensitivity cases.

Note: For clarity, breakeven prices above $8/W are not displayed.

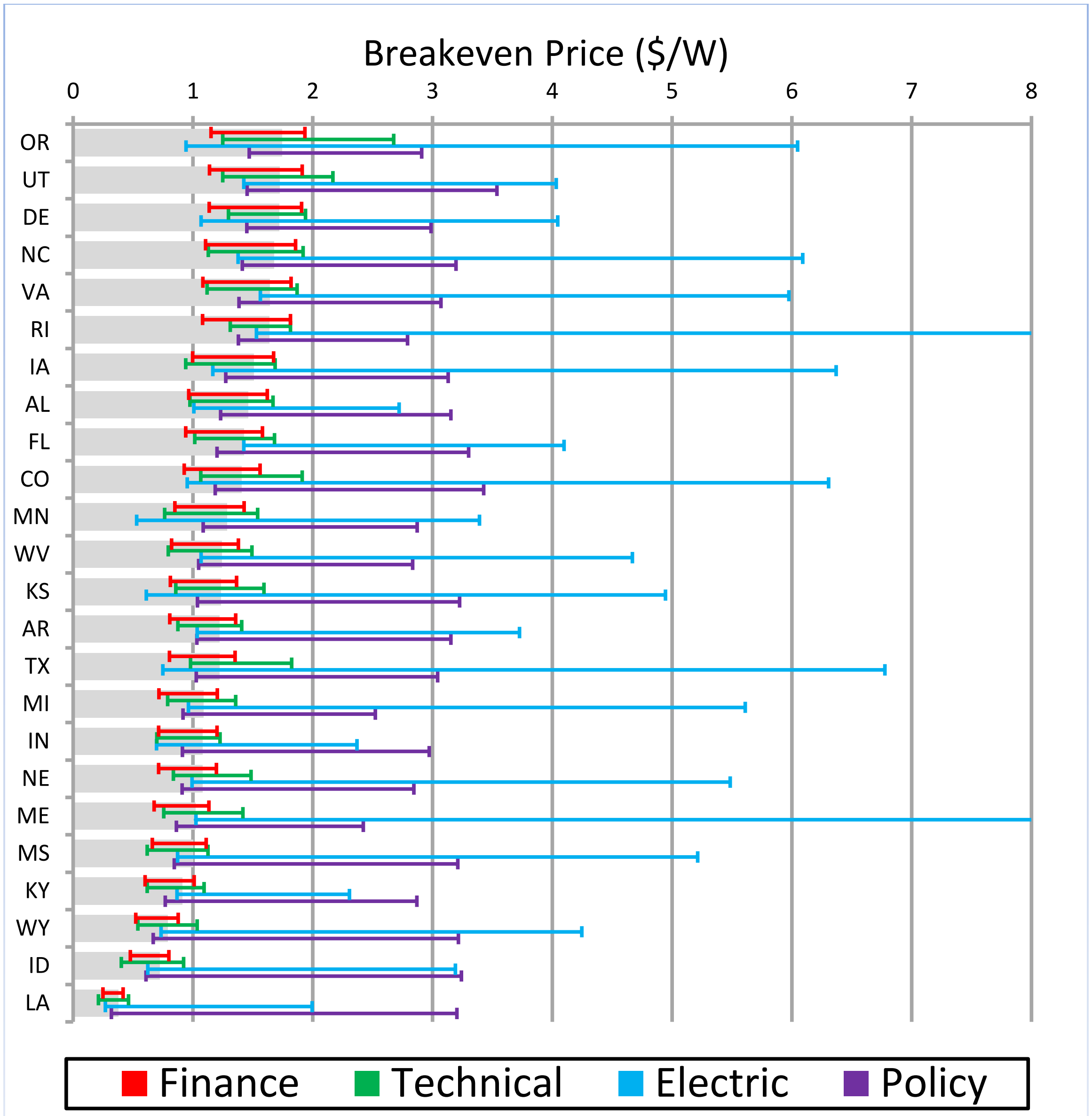

Figure 9. Range of PV breakeven prices in the 2020 scenarios: Bottom 25 states. The gray bars indicate the base case from the largest utility in the state, and the four error bars show the range of breakeven prices for the sensitivity cases.

Note: For clarity, breakeven prices above $8/W are not displayed.

As shown in Figures 8 and 9, the base-case breakeven price in 2020 is between $0.38/W and $7.27/W. Electricity price is the biggest driver of breakeven price variation and is followed generally by policy (availability of the ITC), technical performance, and finance factors. 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.

5 Conclusions

We evaluated breakeven prices for rooftop PV installed on U.S. supermarkets. Our results suggest that breakeven prices vary by more than a factor of 30 nationwide, even though the solar resource varies by less than a factor of 2. Non-technical factors—including electricity rates, rate structures, and incentives—drive breakeven prices more than technical factors like solar resource or system orientation.

Under base-case assumptions, about 17% of supermarkets nationwide were in utility territories where breakeven conditions existed at a PV system price of $5/W in 2011. Using the estimated 2012 installed price of commercial PV systems ($3.43/W), 40% of supermarkets were in utility territories where breakeven conditions existed. These percentages increase to 33% and 53%, respectively, when rate structures favorable to PV (time-of-use, tiered rates) are used. In 2020 (where we assume higher electricity prices and lower PV incentives), up to 26% of supermarkets are in utility territories where breakeven conditions exist at a PV system price of $3/W; this increases to 91% at $1.25/W (the DOE SunShot Initiative's commercial PV price target).

The general trend observed in this analysis is that breakeven conditions appear first in parts of the East Coast, California, and Hawaii, where they are driven by high electricity prices. As PV system prices continue to decline, breakeven conditions begin to occur in parts of the central United States. Very low electricity prices could preclude breakeven conditions in certain areas even with PV prices approaching $1.25/W.

Overall, the scenarios evaluated represent a market entry point for PV. However, the scenarios do not examine the potential for a deep, sustained market. Therefore, caution must be used when considering this analysis. PV breakeven does not imply that customers will necessarily adopt PV. In reality, only a fraction of supermarkets in each utility are currently likely to have access to the range of factors that make PV an attractive and viable option. A more detailed depth-of-market analysis is required to determine a "demand curve" for PV at various price points. This type of depth-of-market analysis could be combined with analysis of various commercial building types to provide a more robust estimate of the market potential of commercial rooftop PV. In future work we will examine breakeven in a broader set of commercial building types and explore how breakeven relates to market depth and market evolution.

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Appendix A: Calculation of Breakeven Price

The breakeven price of a PV system is defined as the point where the net present cost (NPC) of the system equals the net present benefit (NPB) to its owner.

The NPC is the cumulative discounted cost of the system, including initial cost, financing, tax impacts, incentives, and O&M, equal to the sum of the cost in each year multiplied by the discount factor in that year.

The discount factor in year $y = \frac{1}{(1+d)^y}$

Where d is the discount rate.

The cost in each year is based on the system financing. At the beginning of the financing period, a down payment and then a loan amount are established by:

Loan Amount = PV System Cost - Down Payment - Initial Rebates

The annual loan payment is then calculated by multiplying the load amount by the capital recovery factor:

$$\text{Loan Payment} = \text{Loan Amount} * \frac{i(1+i)^n}{(1+i)^n - 1}$$

Where i is the interest rate and n is the loan term in years. The tax savings on the loan interest in each year is given by:

$$\text{Interest Deduction}_y = \text{Marginal Federal Tax Rate} * i * \text{Current System Balance}_y$$

Some incentives (such as tax incentives) may not occur until a year or so after installation. These incentives are discounted by one year.

Tax savings from 5-year federal MACRS depreciation is also considered in this analysis.

The NPB is the discounted cumulative benefits of reduced electricity bills over the evaluated period or the sum of the benefits in each year multiplied by the discount factor.

Appendix B: Incentives Used in this Study

Table B-1. Statewide Incentives (as of May 2012)

State	Incentive ($/W)
AZ	$0.10
CA	$0.42
CO	$0.10
DC	$0.07
DE	$0.10
FL	$0.40
GA	$1.76
HI	$2.00
IA	$0.18
KS	$0.11
KY	$0.01
MA	$0.02
MD	$0.05
ME	$1.99
MT	$0.80
NC	$1.03
ND	$0.25
NE	$0.01
NH	$0.40
NJ	$0.04
NM	$0.67
NV	$0.46
NY	$1.75
OK	$0.07
PA	$0.21
SC	$0.14
TN	$1.44
UT	$0.17
VT	$0.29
WA	$4.92
WI	$0.06

Note: All incentives from http://www.dsireusa.org/. All incentives expressed in dollars per watt.

Table B-2. Utility Incentives in the Form of Tax Credits or Rebates as of May 2012

State	Utility Name	Incentive ($/W)
AZ	Mohave Electric Coop Inc	$0.20
AZ	Tucson Electric Power Co	$2.20
CA	Azusa, CA (City of)	$0.50
CA	Corona, CA (City of)	$0.19
CA	Glendale Water & Power	$2.00
CA	Gridley, CA (City of)	$0.02
CA	Healdsburg, CA (City of)	$0.09
CA	Imperial Irrigation District	$1.91
CA	Lodi, CA (City of)	$1.50
CA	Lompoc, CA (City of)	$3.00
CA	Los Angeles Dept of Water & Power	$2.56
CA	Merced Irrigation District	$0.28
CA	Moreno Valley Public Utilities	$2.80
CA	PacifiCorp	$2.00
CA	Redding Electric Utility	$4.78
CA	Riverside Public Utilities	$2.50
CA	Shasta Lake, CA (City of)	$0.77
CA	Truckee Donner Public Utility District	$3.65
CA	Ukiah, CA (City of)	$0.06
CO	Highline Electric Association	$0.02
CO	Holy Cross Electric Association Inc	$1.50
CO	Public Service Co of Colorado	$1.60
DE	Delaware Electric Coop Inc	$0.08
DE	Dover, DE (City of)	$0.06
FL	Florida Power & Light Co	$0.17
FL	Orlando Utilities Commission	$0.31
MA	Concord, MA (Town of)	$0.01
MI	Detroit Edison Co	$0.18
MT	NorthWestern Corp	$0.02
NM	El Paso Electric Co	$0.09
NM	Public Service Co of New Mexico	$0.08
NM	Southwestern Public Service Co	$0.10
NY	Long Island Power Authority	$1.75
OR	Ashland, OR (City of)	$0.03
TX	Austin Energy	$0.14
TX	El Paso Electric Co	$0.17
TX	Entergy Texas Inc	$0.35
TX	Southwestern Electric Power Co	$0.07
UT	PacifiCorp	$0.09
VT	Green Mountain Power Corp	$1.28

State	Utility Name	Incentive ($/W)
WA	PUD No 1 of Chelan County	$0.74
WA	PUD No 1 of Klickitat County	$0.01
WA	PUD No 1 of Okanogan County	$1.34

Note: All incentives from http://www.dsireusa.org/.

Table B-3. Statewide Feed-In Tariffs as of May 2012

State	Incentive
HI	$0.189/kWh
OR	$0.432/kWh
VT	$0.240/kWh

Note: All incentives from http://www.dsireusa.org/.

Table B-4. Utility Feed-In Tariffs as of May 2012

State	Utility Name	Incentive
(Multiple)	Tennessee Valley Authority[24]	$0.22/kWh
TX	San Antonio, TX (City of)	$0.27/kWh
VA	Bristol Virginia Utilities	$0.22/kWh
WI	River Falls, WI (City of)	$0.30/kWh
WI	Madison Gas & Electric Co	$0.25/kWh

Note: All incentives from http://www.dsireusa.org/.

[24] http://www.tva.gov/ee/in_home_eval_dist.htm

Appendix C: Complete Listing of All Building Locations and Associated ASHRAE Zone

Table C-1. Complete Listing of All Building Locations, Associated ASHRAE Zone, and Electric Load Summary

TMY3 Station Name	State	ASHRAE Zone	Peak Demand (kW)	Peak Demand Month	Annual Load (kWh)
MONTGOMERY DANNELLY FIELD	AL	3A	395	Jun	1,822,494
LITTLE ROCK ADAMS FIELD	AR	3A	396	Jul	1,795,596
FLAGSTAFF PULLIAM ARPT	AZ	5B	319	Jul	1,556,093
PHOENIX SKY HARBOR INTL ARPT	AZ	2B	403	Jul	1,830,044
TUCSON INTL ARPT	AZ	2B	378	Jul	1,747,086
ARCATA ARPT	CA	4B	303	Oct	1,588,265
LOS ANGELES INTL ARPT	CA	3B	315	Sep	1,706,465
SAN FRANCISCO INTL ARPT	CA	3C	309	Jun	1,618,194
BROOMFIELD/JEFFCO [BOULDER - SURFRAD]	CO	5B	337	Jun	1,587,414
EAGLE COUNTY AP	CO	6B	332	Jul	1,642,215
PUEBLO MEMORIAL AP	CO	5B	343	Aug	1,629,719
BRIDGEPORT SIKORSKY MEMORIAL	CT	5A	355	Aug	1,653,340
ANDREWS AFB	MD	4A	379	Jul	1,692,667
WILMINGTON NEW CASTLE CNTY AP	DE	4A	371	Jul	1,683,104
MIAMI INTL AP	FL	1A	373	Jul	2,008,354
TAMPA INTERNATIONAL AP	FL	2A	386	Jul	1,982,531
ATLANTA HARTSFIELD INTL AP	GA	3A	375	Jul	1,771,016
SAVANNAH INTL AP	GA	2A	392	Jul	1,868,763
NASA SHUTTLE FCLTY	HI	2A	358	Aug	2,011,748
DES MOINES INTL AP	IA	5A	385	Jul	1,671,076

TMY3 Station Name	State	ASHRAE Zone	Peak Demand (kW)	Peak Demand Month	Annual Load (kWh)
MASON CITY MUNICIPAL ARPT	IA	6A	391	Jul	1,659,628
BOISE AIR TERMINAL [UO]	ID	5B	340	Jul	1,573,929
CHICAGO O’HARE INTL AP	IL	5A	377	Jul	1,661,322
SPRINGFIELD CAPITAL AP	IL	5A	388	Jul	1,698,913
INDIANAPOLIS INTL AP	IN	5A	394	Jul	1,687,539
GOODLAND RENNER FIELD	KS	5A	371	Jul	1,653,292
WICHITA MID-CONTINENT AP	KS	4A	381	Jul	1,723,956
LEXINGTON BLUEGRASS AP	KY	4A	372	Jul	1,712,492
NEW IBERIA NAAS	LA	2A	392	Jul	1,919,480
SHREVEPORT REGIONAL ARPT	LA	3A	384	Aug	1,836,323
BOSTON LOGAN INTL ARPT	MA	5A	369	Jul	1,636,845
BALTIMORE BLT-WASHINGTON INTL	MD	4A	381	Jul	1,695,038
CARIBOU MUNICIPAL ARPT	ME	7A	346	Aug	1,597,984
PORTLAND INTL JETPORT	ME	6A	383	Jul	1,607,226
DETROIT METROPOLITAN ARPT	MI	5A	383	Aug	1,644,386
HOUGHTON LAKE ROSCOMMON CNTY AR	MI	6A	351	Aug	1,616,760
TRAVERSE CITY CHERRY CAPITAL	MI	6A	369	Jul	1,629,565
INTERNATIONAL FALLS INTL AP	MN	7A	359	Jun	1,617,660
MINNEAPOLIS-ST PAUL INTL ARP	MN	6A	380	Jul	1,638,514
KANSAS CITY INTL ARPT	MO	4A	382	Jul	1,707,772
JACKSON INTERNATIONAL AP	MS	3A	392	Aug	1,824,543
BILLINGS LOGAN INTL ARPT	MT	6B	345	Jul	1,592,177
GREENSBORO PIEDMONT TRIAD INT	NC	4A	381	Jul	1,738,573
WILMINGTON INTERNATIONAL ARPT	NC	3A	388	Jul	1,804,250
BISMARCK MUNICIPAL ARPT [ISIS]	ND	6A	375	Jul	1,616,434

TMY3 Station Name	State	ASHRAE Zone	Peak Demand (kW)	Peak Demand Month	Annual Load (kWh)
MINOT AFB	ND	7A	371	Jul	1,618,827
NORTH PLATTE REGIONAL AP	NE	5A	395	Jul	1,684,894
CONCORD MUNICIPAL ARPT	NH	6A	364	Aug	1,628,888
ATLANTIC CITY INTL AP	NJ	4A	384	Aug	1,681,071
ALBUQUERQUE INTL ARPT [ISIS]	NM	4B	337	Jun	1,609,145
LAS VEGAS MCCARRAN INTL AP	NV	3B	379	Jul	1,675,363
RENO TAHOE INTERNATIONAL AP	NV	5B	327	Aug	1,573,274
NEW YORK CENTRAL PARK OBS BELV	NY	4A	380	Aug	1,676,682
ROCHESTER GREATER ROCHESTER I	NY	5A	371	Jul	1,648,672
SYRACUSE HANCOCK INTL ARPT	NY	5A	349	Jun	1,648,827
CLEVELAND HOPKINS INTL AP	OH	5A	373	Jul	1,659,179
OKLAHOMA CITY WILL ROGERS WOR	OK	3A	384	Aug	1,766,035
BURNS MUNICIPAL ARPT [UO]	OR	5B	324	Jun	1,543,472
PENDLETON E OR REGIONAL AP	OR	5B	357	Jul	1,613,894
LANCASTER	PA	5A	382	Jul	1,687,642
PHILADELPHIA INTERNATIONAL AP	PA	4A	366	Jul	1,652,704
PROVIDENCE T F GREEN STATE AR	RI	5A	378	Aug	1,644,430
CHARLESTON INTL ARPT	SC	3A	400	Jul	1,842,480
PIERRE MUNICIPAL AP	SD	6A	393	Jul	1,648,259
MEMPHIS INTERNATIONAL AP	TN	3A	391	Aug	1,789,899
NASHVILLE INTERNATIONAL AP	TN	4A	386	Jun	1,762,733
AMARILLO INTERNATIONAL AP [CANYON - UT]	TX	4B	351	Jun	1,665,680
EL PASO INTERNATIONAL AP [UT]	TX	3B	347	Jul	1,685,767
HOUSTON BUSH INTERCONTINENTAL	TX	2A	400	Aug	1,915,653
CEDAR CITY MUNICIPAL AP	UT	5B	344	Jul	1,638,632

TMY3 Station Name	State	ASHRAE Zone	Peak Demand (kW)	Peak Demand Month	Annual Load (kWh)
SALT LAKE CITY INTL ARPT [ISIS]	UT	5B	337	Jul	1,603,261
RICHMOND INTERNATIONAL AP	VA	4A	390	Jul	1,739,577
BURLINGTON INTERNATIONAL AP	VT	6A	377	Jul	1,615,115
SEATTLE SEATTLE-TACOMA INTL A	WA	4C	315	Aug	1,582,913
YAKIMA AIR TERMINAL	WA	5B	360	Jul	1,579,183
GREEN BAY AUSTIN STRAUBEL INT	WI	6A	378	Jun	1,636,747
CHARLESTON YEAGER ARPT	WV	4A	370	Jul	1,704,164
ELKINS ELKINS-RANDOLPH CO ARP	WV	5A	353	Jun	1,655,137
CHEYENNE MUNICIPAL ARPT	WY	6B	326	Jul	1,576,865

Appendix D: Grid Parity and Installed PV Prices by State as of August 8, 2012

The analysis in the main report assumes a uniform price for PV installations. Preliminary data indicate a wide range in installed prices for commercial systems, especially in locations with limited PV markets. This is indicated in Table D-1, which provides installed prices for 50-kW to 500-kW PV systems installed between January 1 and August 8, 2012. These prices were derived from the OpenPV database (https://openpv.nrel.gov/). This dataset has not been validated, and the results in this section are useful primarily to indicate the general relationship between installed prices and breakeven conditions. Figure D-1 applies these prices in addition to the other factors described previously and identifies locations at or below grid parity, within 25% of parity (where current installed prices are within 25% of being at grid parity), and beyond 25% of parity.

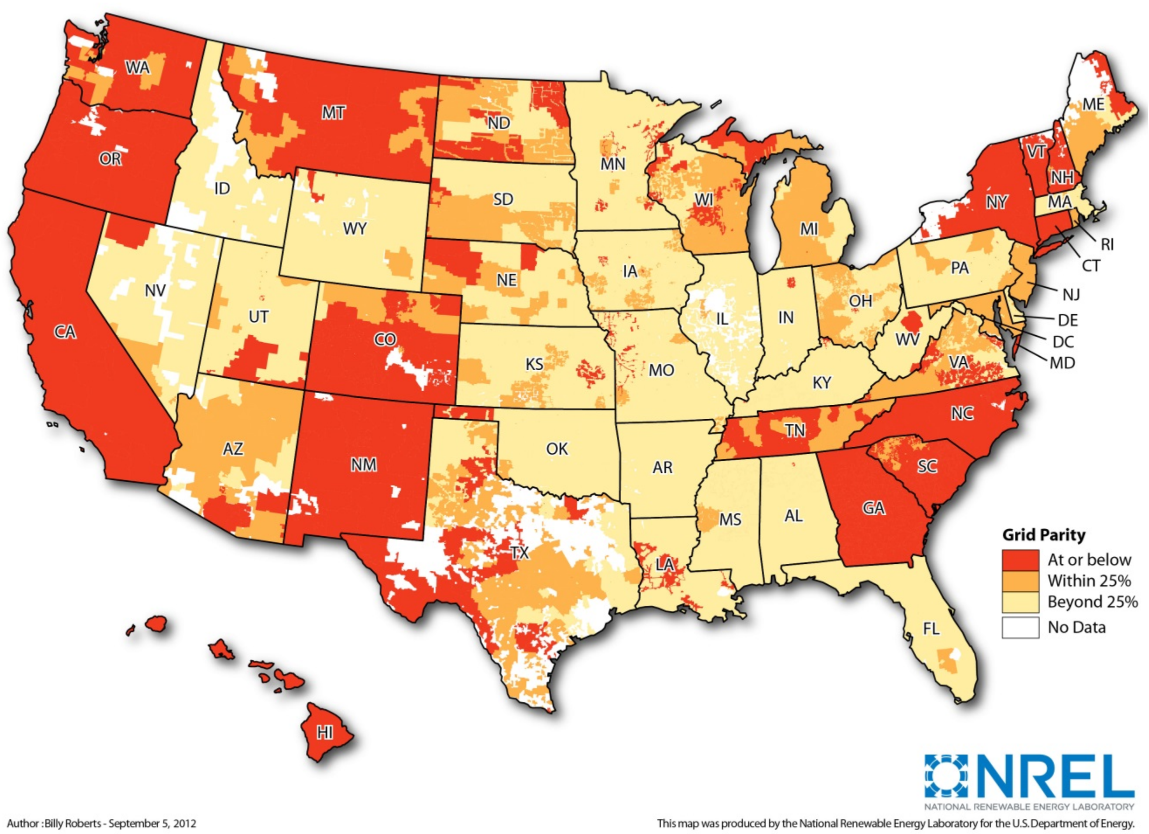

Figure D-1. Grid parity for supermarkets at current state average PV prices using an optional rate structure with incentives (where applicable)

Table D-1. Installed Prices for 50-kW to 500-kW PV Systems Installed Between January 1 and August 8, 2012

State	Installed Price ($/W)
AL	8.00
AR	5.42
AZ	4.50
CA	4.40
CO	4.41
CT	5.12
DC	5.29
DE	4.90
FL	5.77
GA	6.00
HI	4.84
IA	4.79
ID	5.00
IL	7.32
IN	5.93
KS	4.84
KY	7.80
LA	5.40
MA	4.92
MD	4.92
ME	6.59
MI	5.63
MN	3.40
MO	6.13
MS	7.10
MT	4.84
NC	4.59
ND	4.84
NE	9.70
NH	4.53
NJ	4.88
NM	4.84
NV	5.98
NY	5.13
OH	4.38
OK	6.27

State	Installed Price ($/W)
OR	5.85
PA	4.70
RI	4.48
SC	4.84
SD	4.84
TN	5.45
TX	5.99
UT	3.45
VA	4.84
VT	6.44
WA	6.78
WI	7.10
WV	4.84
WY	4.84