U.S. Residential Photovoltaic (PV) System Prices, Q4 2013 Benchmarks: Cash Purchase, Fair Market Value, and Prepaid Lease Transaction Prices

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Technical Report
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October 2014

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NATIONAL RENEWABLE ENERGY LABORATORY

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Prepared under Task No. SS13.6510

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Executive Summary

Benchmarking and tracking installed photovoltaic (PV) prices informs research and investment decisions, as well as supporting the creation of policies aimed at further reducing costs. Previous work by Goodrich, James, and Woodhouse (2012) relied on industry-validated cost models to benchmark fourth quarter (Q4) 2010 residential PV system prices in the United States. It also examined several cost-reduction opportunities for achieving the U.S. Department of Energy's SunShot Initiative targets of $1.50 per watt-direct current (W) for residential systems. This report provides a Q4 2013 update for residential PV systems, incorporating declines in equipment costs since the previous report. Several cases are benchmarked to represent common variation in business models, labor rates, and module choice. Our results should not be viewed as endorsing any particular business model. Rather, we aim to illustrate key sources of cost variation across scenarios (module efficiency, system location and business model). We estimate the following for U.S. residential PV systems installed in Q4 2013:

- The weighted-average cash purchase price for modeled standard-efficiency, polycrystalline-silicon residential PV systems installed in the United States is estimated at $3.29/W. This is a 46% decline from the 2013-dollar-adjusted price reported in the Q4 2010 benchmark report.
    - The cash purchase price for a system installed by a typical U.S. installer (using national-average labor rates) is estimated at $3.16/W.
    - The cash purchase price for a system installed by a large integrated company (using national-average labor rates) is estimated at $3.38/W.
    - The cash purchase price for a system installed by an installer in a higher-wage region (California) is estimated at $3.26/W; installed by a vertically integrated company, it is $3.51/W.
- The cash purchase price for a system installed by a large installer (using national-average labor rates) and employing high-efficiency monocrystalline modules is estimated at $3.98/W.

In addition, this report frames the cash purchase price in the context of key price metrics relevant to the continually evolving landscape of third-party-owned PV systems by benchmarking the minimum sustainable lease price and the fair market value of residential PV systems. We estimate the following for third-party-relevant metrics—assuming standard-efficiency modules:

- The minimum sustainable lease price (net of incentives), for a modeled California system is estimated at $1.93/W for an installer and $1.72/W for an integrator in Q4 2013. A sample of historical lease data indicates that mean leases over the 2010–2012 period transacted from $1.94/W–$2.45/W in California, with an overall mean across the period of $2.22/W.
- The typical fair market value for a California system is estimated at $4.59/W in Q4 2013.

Although these figures are distinct, they are linked, and each is relevant to different stakeholders involved in a solar installation. The cash purchase price represents the all-in cost to install a system and is the key economic driver that can be influenced by installers, manufacturers, and research and development investment. The minimum sustainable lease price provides the minimum upfront payment required, from the customer, for an installer to cover all costs (including margins) associated with providing the solar leasing service. The historical data of lease transactions indicate the prices that customers have been willing to bear to power their homes with solar electricity. Finally, the fair market value can be considered representative of investor/owner value, incorporating all sources of economic value accruing to the system.

Contents

Acronyms and Abbreviations

AC	Alternating current
BoM	Bill of materials
BoS	Balance of systems
CA	California
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
c-Si	Crystalline silicon
DC	Direct current
FMV	Fair market value
IRS	U.S. Internal Revenue Service
ITC	Investment tax credit
kW	Kilowatt
kWh	Kilowatt-hour
MACRS	Modified Accelerated Cost Recovery System
NPC	Net present cost
NPV	Net present value
NREL	National Renewable Energy Laboratory
O&M	Operations and maintenance
PPA	Power-purchase agreement
PV	Photovoltaic(s)
Q4	Fourth quarter
T.E.	Tax equity
TPO	Third-party ownership
W or $W_{P\ DC}$	Peak watts direct current
w-Si	Wafer silicon

1 Introduction

The residential photovoltaic (PV) sector continues to grow at the fastest rate of any sector in the U.S. solar market. In the fourth quarter of 2013 (Q4 2013), more U.S. residential PV systems were installed than in any other quarter in history (186 MW) (GTM and SEIA 2013a). Sustained growth can be attributed to a precipitous decline in installed system prices spurred by declining equipment costs and increasing productivity—all signs of a maturing solar industry.

Previous work by Goodrich, James, and Woodhouse (2012) benchmarked U.S. PV system prices for a “typical” cash-purchased system installed in Q4 2010. However, since this earlier report was published, the residential solar landscape has evolved rapidly, largely driven by the shift towards third-party ownership (TPO). Figure 1 shows this trend in California. In the past, a single installer largely spearheaded the entire process from customer acquisition to installation. Now, key functions have been partitioned, and several different business entities may be responsible for carrying out specific functions or a set of functions. This shift in market structure complicates the task of comparing prices across companies and business models.

This report first updates installed residential PV system cash purchase prices as of Q4 2013 to gauge progress in cost reductions, relying on a range of dynamic input costs (wage rates, hardware costs, margins).[1] Second, the report illustrates market diversity by benchmarking several variations of a “typical system,” evaluating the cost implications of installer business practices, module efficiency, and system location.[2] We present five Q4 2013 price estimates under different combinations of these assumptions. Our Q4 2013 benchmark relies on a weighted average of available market data for these common residential system configurations, incorporating estimated market share.

In addition, we frame the installed prices within the context of TPO, which continues to be the predominant ownership choice in many U.S. markets (Figure 1).[3] In a TPO scenario, key stakeholders rely on different metrics to assess the value of PV systems: PV customers rely on lease transaction prices, whereas financers rely on the fair market value (FMV) of the system. In this report, we model these metrics using the same bottom-up methodology employed to model the cash purchase price. We also provide a summary of lease transaction prices based on California data to illustrate historical lease prices. We then compare the various third-party metrics to the 2013 cash purchase price, summarizing implications for evaluating residential PV economics.

[1] This benchmark represents the price expected for a project quote placed in Q4 2013, not necessarily a project installed in Q4 2013. There is often a time lag of a few weeks to several months between when a project is first quoted and when it is installed.

[2] This figure may not always be consistent with transaction prices reported to state incentive programs for several possible reasons. Primarily, the bottom-up figure represents the full economic cost to install a system - and does not reflect market dynamics that influence transaction prices. Further, market data does not always represent consistent transactions; data can represent transactions at different points in project development – for example, in many cases, it is the price at which a system is sold to a project financer or a fair market valuation. While market data can provide a proxy for transaction price trends, it does not provide insight into component costs or business processes required to install a system, nor can it distinguish between supply (cost) and demand (value) drivers.

[3] Third-party ownership is still not available in all states, yet a thriving TPO segment exists in the most active residential solar markets—California, Arizona, New Jersey, Massachusetts, and Colorado—in which TPO constituted an estimated 70%– 90% of new installations in 2013 (Kann 2013).

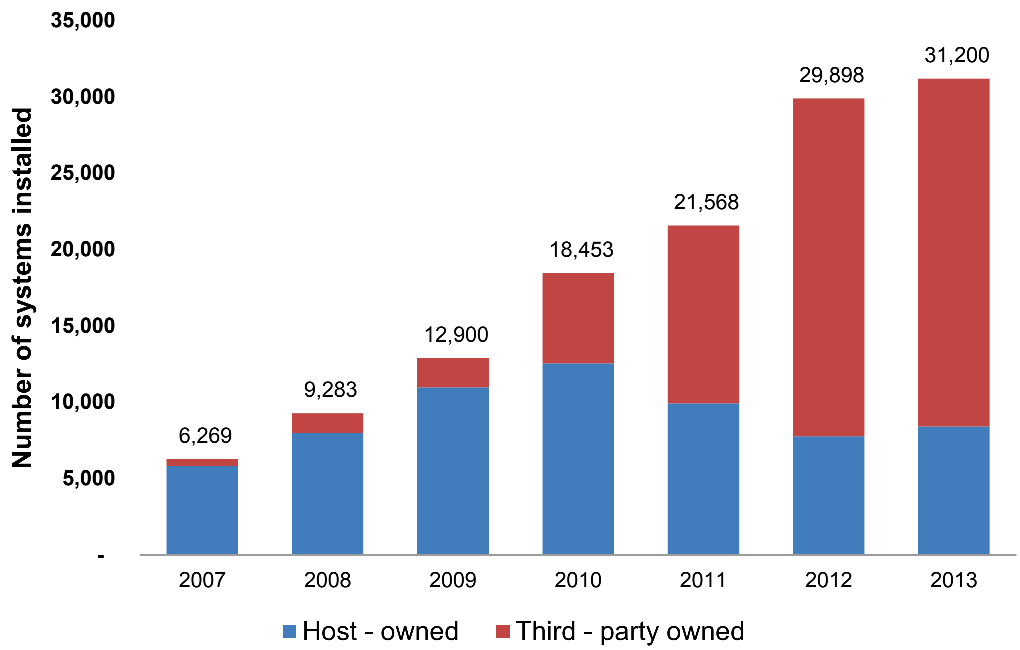

Figure 1. Annual residential PV system installations in California by ownership type (CSI 2013)

2 Residential Cash Purchase Price Benchmark – Q4 2013

2.1 Methodology

We estimate the cash purchase prices of host-owned PV systems using a bottom-up methodology. This metric reflects current prices for hardware as well as the cost of labor associated with typical installation methods, system size constraints, regulatory costs, and all relevant direct and indirect costs associated with operationalizing a system in a sustainable business (including a profit margin). In benchmarking the cash purchase price, we rely on a combination of public and private sources to inform inputs and validate our model results.

We generate a bill of materials (BoM) that considers typical U.S. rooftop sizes, materials (e.g., asphalt shingles), site specifics (e.g., number of stories, rooftop pitch), and PV installation methods in order to estimate material costs and installation labor requirements. In addition, we include indirect costs such as business overhead, profits, supply-chain costs, and regulatory costs. Figure 2 illustrates the high-level process and key inputs relied upon to calculate the cash purchase price.

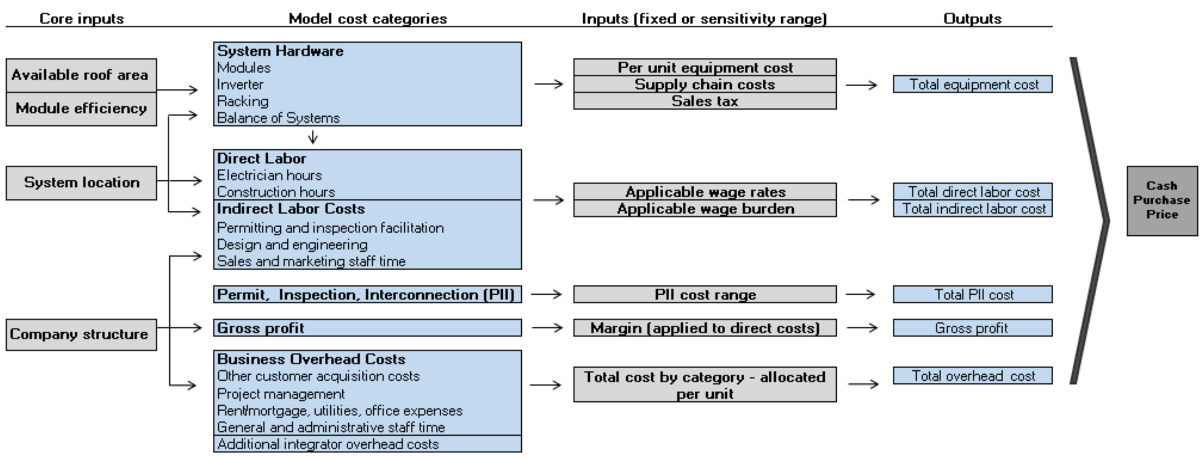

Figure 2. National Renewable Energy Laboratory (NREL) residential system cash purchase price model schematic

Expanding on Goodrich, James, and Woodhouse (2012), who modeled one typical system, we model five common scenarios to reflect common variation in incurred costs: four scenarios model standard-efficiency modules, and one models high-efficiency modules (see Section 2.3 for complete scenario specifications). Our reported benchmark price represents a weighted average of the four standard-efficiency module scenarios based on estimated market shares of each scenario. We conduct a sensitivity analysis for all five scenarios, providing a distribution of inputs as specified in Appendix A. Whenever possible, distributions pull from market data; when no market data are available, we rely on literature and installer's feedback to produce high and low estimates. As such, this approach provides a summary benchmark price that incorporates extant price variation in the market, without trying to represent PV system price variations across the United States comprehensively.

The following subsection describes the cost categories and key inputs entered into a BoM; these categories are typically common to all systems. For each system type, we calculate the median cash purchase price by running a Monte Carlo simulation.

2.2 System and Model Description

The costs of installed PV systems are driven by major hardware components such as modules and inverters and a collection of other components, which we define as balance of systems (BoS) materials. System configuration and the bill of materials drives the installation labor requirement. We assess both electrical and general installation labor requirements, including burdens. Soft costs cover a range of regulatory costs and overhead, which we outline as a combination of general and administrative labor. Regulatory factors can influence the prices of grid-tied residential PV systems, for example by limiting the maximum size of a system or by affecting the value of solar energy generated at a customer site. These constraints may vary significantly from one jurisdiction to another. The ranges of these requirements are difficult to capture in a model.

Modules

Crystalline silicon (c-Si) modules (both polycrystalline and monocrystalline) constitute the majority of U.S. PV deployments across all grid-tied rooftop market segments. Owing to a combination of market dynamics (e.g., oversupply conditions), growth of the supply base in low-cost regions, and innovations throughout the supply chain, c-Si module selling prices have fallen sharply in recent years (Goodrich et al. 2013). Between Q4 2010, when our last system price report was published (Goodrich, James, and Woodhouse 2012), and Q4 2013, the typical ex-factory gate price for standard-efficiency (polycrystalline) c-Si modules fell by more than 60%, from $1.95/W to $0.68/W (BNEF 2014, GTM and SEIA 2013a). In Q4 2013, the ex-factory gate price for standard (13.5%–15.5% efficiency) c-Si modules varied between $0.64/W and $0.75/W; for high-efficiency (19.6%–21.0% efficiency) c-Si modules, it varied between $1.20/W and $1.60/W (CSI 2013). Average efficiency of installed modules has steadily increased over time. Appendix D provides data on the average installed efficiency based on installed systems in California.

Inverters

The vast majority of newly installed grid-tied residential systems in the United States still use one or more centrally located DC-to-AC (direct current to alternating current) inverters (CSI 2013), despite the rising share of microinverters among host-owned residential systems.[4] Owing to the entrance of low-cost suppliers to the market, technology-cost reductions, and market dynamics (e.g. margin compression), the prices for these components have decreased. Since the time of our last report (Q4 2010), the ex-factory gate price for a residential inverter has fallen from $0.42/W to $0.25/W (BNEF 2013, GTM and SEIA 2013a). We model inverter prices per watt as decreasing with increased system wattage (from $0.34/W for a 2-kW system to $0.25/W for a 10-kW system).

Racking and Balance of Systems Materials

In addition to the module and inverter components, a residential PV system typically includes racking and mounting hardware as well as BoS material (electrical pathway materials—wiring, connectors, conduit, and disconnects—and monitoring components). We rely on racking providers' material estimates, generated based on the assumed system size (power, area), most common module dimensions

[4] For system sizes between 2.5 and 10 kW, microinverters constituted about 25% of market share in the California Solar Initiative (CSI) database; in this dataset, the share of systems using microinverters in 2012 was considerably higher for host-owned systems (45%) than for systems owned by third parties (12%). While this analysis does not model microinverters, future efforts will evaluate microinverters from an installed-cost and levelized-cost-of-energy perspective.

and module count, for each targeted system. Racking cost estimates assume bulk purchase. However, large installers can often negotiate substantial discounts on these costs, and this will not be incorporated into the model. Module sizes are based on the typical area of framed c-Si modules used in rooftop applications: 1.28 m × 1.64 m (4.19 ft × 5.38 ft). In some regions, additional materials such as "squirrel guard" are often used to protect the undersides of modules and electrical components from animals. These types of additional materials are not detailed in our analysis of a typical system.

Roofing material and racking selection decisions may significantly impact installation labor requirements; for example, some racking systems may eliminate the need for flashing around roof connection points or significantly reduce the amount of additional grounding pathways. While we assume a basic through-roof mounting for our typical system price benchmark, we also include a wide range of labor productivities (see the *Installation Labor* section below), which may be driven by racking hardware choices.

Balance of systems also comprises string- and system-level wiring, conduit, grounding wires, monitoring equipment, meter(s), and disconnection points. Specific equipment varies based on system size, jurisdiction requirements, installer and customer preferences, and other factors. For the purposes of this analysis, we assume that the system includes the installation of a meter, a monitoring system, one AC disconnect, and additional breakers added to an existing breaker box. Wiring and conduit requirements are based on a basic system layout (no complicating roof features such as dormers), a typical roof pitch (4–12 degrees), and a typical height (two stories or less).

Supply Chain and Sales Tax

Depending on an installer's supply strategies and purchasing power, markups of 5%–15% may apply above ex-factory gate module prices. In the lowest-cost scenario, modules are purchased directly (no markup on ex-factory gate prices). Sales tax is applied as a distribution that reflects variation in tax treatment on a state-by-state basis, based on a weighted average of installations by state.

Installation Labor

Direct labor for the installation of residential PV systems generally consists of both electrical and general construction labor types to install the electrical and mounting hardware, respectively. We assume a national average wage rate for each labor type and include standard burden rates to estimate total labor costs for 2012, adjusted upwards for inflation to reflect 2013 prices (U.S. BLS 2012). We model two sets of labor rates: California rates, which are representative of a higher-cost labor market, and U.S. average labor rates. However, the maximum in the sensitivity analysis for the U.S case incorporates labor rates that are higher than California wages – to reflect the highest nationwide wages.

We assume that trained solar installers are required to install all electrical hardware; however, this requirement may also vary depending on state, county, or other jurisdiction requirements. Using the BoM, we estimate electrical direct labor content. Through our uncertainty analysis, we model significant variation that may occur due to the impact of site-specific factors on the installation of wire/conduit, interconnection, and monitoring equipment. In all cases, general construction (helper, construction trades) labor is assumed for the installation of the remaining system components, including racking and mounting structures.

Owing to differences in roof features and layout—such as access to and condition of attic space and rafters, number of stories, roof pitch or slope, location of job site (drive time), weather and other project delays, and inspection requirements—installers report that total direct installation labor (electrical and general construction) time may vary between 50% and 200% of the average time, depending on the particular installation. The following factors may affect installation productivity: new versus old construction, access to and condition of attic space and rafters, roof pitch, roof height, weather and other project delays, and proximity to population centers (urban or suburban locations can minimize installer drive times compared to rural job sites). Local inspection requirements may also slow installer productivity. In some jurisdictions, installers may not proceed with system installation until inspectors have conducted onsite reviews of work in progress. Delays associated with these inspection appointments may increase construction times considerably by extending the job period, thus forcing the installation crew to incur additional drive times.

Gross Profit

The model applies a percentage markup on all direct project costs. This markup represents a gross margin, and is assumed to be large enough to cover the cost of goods sold as well as all other business costs including overhead, taxes, interest expenses, and the cost to grow the business. While profit margin varies substantially by project and by company based on job specifics and local market conditions, we model a gross profit margin applied to the direct costs of installing a system ranging from 15%–25% across all scenarios based on industry discussions. Note that actual profit margins can be much higher for a company if the market will bear them.

Overhead, Customer Acquisition, Permitting, Inspection, and Interconnection

Installers must also account for business or operating overhead costs, including customer acquisition, design, engineering, regulatory, and other business-operation expenses. These costs are challenging to benchmark because they vary uniquely based on company structure, operations, and business strategy. Typically, customer-acquisition costs include lead generation, basic system design, sales commissions, travel expenses, and mileage. Installers use a range of approaches to generate customer leads– often relying on one or more third-party vendors in addition to an internal sales and marketing department — directly purchasing exclusive or non-exclusive leads and paying commission to retail partners that provide customers (i.e. national hardware stores). Expenditure of customer acquisition varies drastically by company - a company in an aggressive growth phase would be expected to incur high customer acquisition costs in an attempt to secure market share. Design and engineering activities include structural assessments, layout and drafting of plans (and approval of designs by appropriate regulators), and electrical system design (and approval). General operating expenses associated with maintaining an office and equipment, as well as staff for the purposes of general and administrative functions, are also included. We adapt the overhead estimates provided in Feldman, Friedman, and Margolis (2013) by applying all direct and indirect overhead costs relevant to the installer. For the integrator case, we remove direct project overhead costs associated with providing third-party ownership but retain associated indirect overhead costs, because these reflect company business costs that direct project revenue is assumed to cover. Regulatory expenses may include permitting fees, onsite inspections for which installer representatives or crews must be present, and the time required for installers to facilitate customer rebates.

2.3 System and Installer Scenarios

This analysis evaluates several system scenarios, assumed to represent variation that characterizes the most likely differentiators of system prices in the current market.[5] Specifically, we model the following five scenarios: (1) a standard-efficiency system installed by a large installer in an average-labor-cost area,[6] (2) a standard-efficiency system installed by a large installer in a high-labor-cost area (California), (3) a standard-efficiency system installed by a large integrator in an average-labor-cost area, (4) a standard-efficiency system installed by a large integrator in a high-labor-cost area (California), and (5) a high-efficiency system installed by a large installer in an average-labor-cost area (Table 1). When computing our weighted-average Q4 2013 benchmark price, we use only the first four, standard-efficiency-module, scenarios. California market share was based on GTM and SEIA (2013b) estimates. The proportion of systems installed by an integrator versus installer was estimated based on California Solar Initiative data. Due to a lack of nationwide data on systems by installer, we assumed these same proportions applied nation-wide.

We model a high-labor-cost area because labor is one of the largest cost categories. We chose the high-labor-cost California market because this market accounts for nearly half of U.S. installations (GTM and SEIA 2013b). However, California is not the only high-cost labor market—Hawaii and several states in the Northeast report equally high or higher labor costs (U.S. BLS 2012).[7]

The scenarios assume a large installer or integrator in order for findings to be most representative of the current market; in 2013 an estimated 50% of the new residential installed capacity was installed by the top 10 installers in terms of installed capacity, based on data from the California Solar Initiative (CSI 2013). Focusing our analysis on large installers represents a substantial simplification of the diversity of solar installers and contractors currently operating within the U.S. market. For example, nearly 800 solar contractors are estimated to be operating within California, ranging from small solar-focused installers to roofing, construction/handyman, or electrical contractors. Smaller contractors may install as few as two and as many as several hundred systems per year (CSI 2013). Some customers might prefer these smaller companies for several reasons, including strong local reputation, a proven record in non-solar contracting work (lending confidence in firm longevity), more personalized service, attention to detail, and more customizable options. These companies continue to play a significant role in the U.S. solar market and can compete with large companies in providing value to homeowners, both in terms of service provided and cost in selected markets.

[5] This analysis does not aim to reflect every variation present in the market. The focus is on business models that can reflect a majority of current market share.
[6] For the purposes of this analysis, we characterize a large installer as one with estimated annual revenue of $15 million or more. Each of these firms typically holds an estimated 5% or more of market share in a given state (this threshold would be 2% or more in California). Together, these large installers typically constitute 50%–70% of the market share in a given state.
[7] These labor rates are reflected in the "high" labor estimates for the sensitivity analysis of the "U.S." scenarios. See Appendix A.

Table 1. Modeled Residential Installation Scenarios

Scenario	Core Business Functions	Module Efficiency	Labor Costs	Est. U.S. Market Share	Benchmark Weight (est. share among large U.S installers/integrators)
1. Large installer – U.S.	Installation	Standard	National average	17%	36%*
2. Large installer – CA	Installation	Standard	California rates	15%	32%
3. Large integrator – U.S.	Installation, third-party financing, system monitoring	Standard	National average	8%	17%*
4. Large integrator – CA	Installation, third-party financing, system monitoring	Standard	California rates	7%	15%
5. Large installer – high-efficiency modules	Installation	High	National average	17%	--
Total				47% (excluding high efficiency)	100%

*Excludes systems installed in California.

Scenarios 1 and 2: Large Installer, Standard Modules, U.S. Average and California Labor Rates

PV market growth has propagated varying business models in which firms specialize in one or more functions. Most often, firms focus on sales, design, and installation, and they outsource financing and system monitoring to firms or distinct business units. In these two scenarios, we assume that systems are installed by a large installer with the following key functions: customer acquisition, lead generation, sales, and installation. In practice, however, installers exhibit a range of business functions in addition to the core function of installation (GTM Research 2014).

Scenarios 3 and 4: Large Integrator, Standard Modules, U.S. Average and California Labor Rates

As an alternative to installation-focused firms, integrators maintain all functions in-house: in addition to providing the functions of the installer, the integrator provides financing and system monitoring for TPO systems. By incorporating the ability to arrange tax-equity financing and track system performance over a long time horizon, the integrator incurs additional overhead that increase costs compared with a host-owned system. This model of vertical integration provides benefits when transacting a TPO system, namely, increasing supply-chain coordination/control and capturing the installer margin. Integration may carry the risk of being less responsive to changing market conditions and having a limited ability to adapt operational and managerial infrastructure to significant growth. Perhaps to leverage the benefits and mitigate the risks of this model, the PV market space is increasingly characterized by a hybrid model in which, for example, a financer may acquire an installer or a lead-generating vendor. As a result, the classification of installer versus integrator often represents a simplification of the actual business practices employed.

Scenario 5: Large Installer, High-efficiency Modules, U.S. Average Labor Rates

The average residential system uses modules that are approximately 15% efficient (CSI 2013). However, roughly one fifth of 2013 installations employed modules with efficiencies above 18%; in many cases, modules surpassed 20% efficiency.

All else being equal, systems with high-efficiency modules have higher per-watt module costs but lower area-related costs. High-efficiency modules might be particularly attractive for customers with small rooftops, where standard-efficiency modules could produce less electricity. We benchmark high-efficiency systems separately from the standard-efficiency scenarios because of their different value proposition.

3 Residential Cash Purchase Price Benchmarks

The estimated cash purchase price for a typical residential PV system employing standard-efficiency modules was $3.29/W in Q4 2013. This is a 46% decline from the 2013-dollar-adjusted price reported in NREL's Q4 2010 benchmark report (Goodrich, James, and Woodhouse 2012) (Figure 3).[8] This rapid decline in residential system prices is due to falling hardware costs, particularly for modules and inverters as well as improved business productivity resulting from experience.

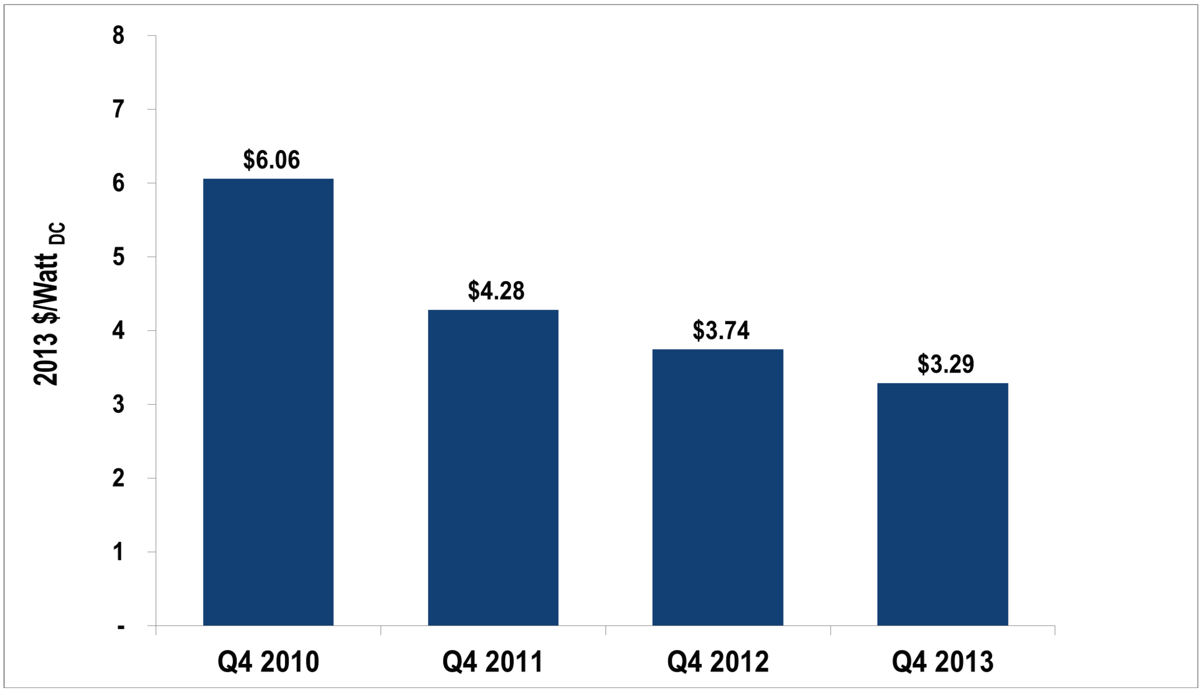

Figure 3. Residential PV benchmark (Q4 2010–Q4 2013) for standard-efficiency c-Si modules

Figure 4 presents the Q4 2013 benchmarks for the five modeled scenarios as well as the weighted average for standard-efficiency modules ($3.29/W), with the 2010 benchmark included for comparison. The weighting scheme is an approximation based on best-available information on market segmentation. The error bars for each scenario represent the 20th and the 80th percentile of results from the Monte Carlo sensitivity analysis. Each Monte Carlo simulation iterates through the model, pulling from an assumed distribution for parameters from which we have provided a range of values. Additional detail on scenario inputs can be found in Appendix A. Benchmarks for the five scenarios range from $3.17/W (large installer – U.S. – standard efficiency modules) to $3.98/W (large installer – high-efficiency modules).

[8] The solar market is constantly evolving in terms of prevalent business models and strategies, and a benchmark provides a point-in-time estimate that will not be an exact comparison with previous and future estimates. The values for 2011and 2012 are based on Feldman et al. (2013). In contrast to the Q4 2013 benchmark, the 2010-2012 benchmarks included a range of installer sizes. This results in cost savings resulting from supply-chain efficiencies accrued by large installers/integrators, but also relatively higher operating overhead.

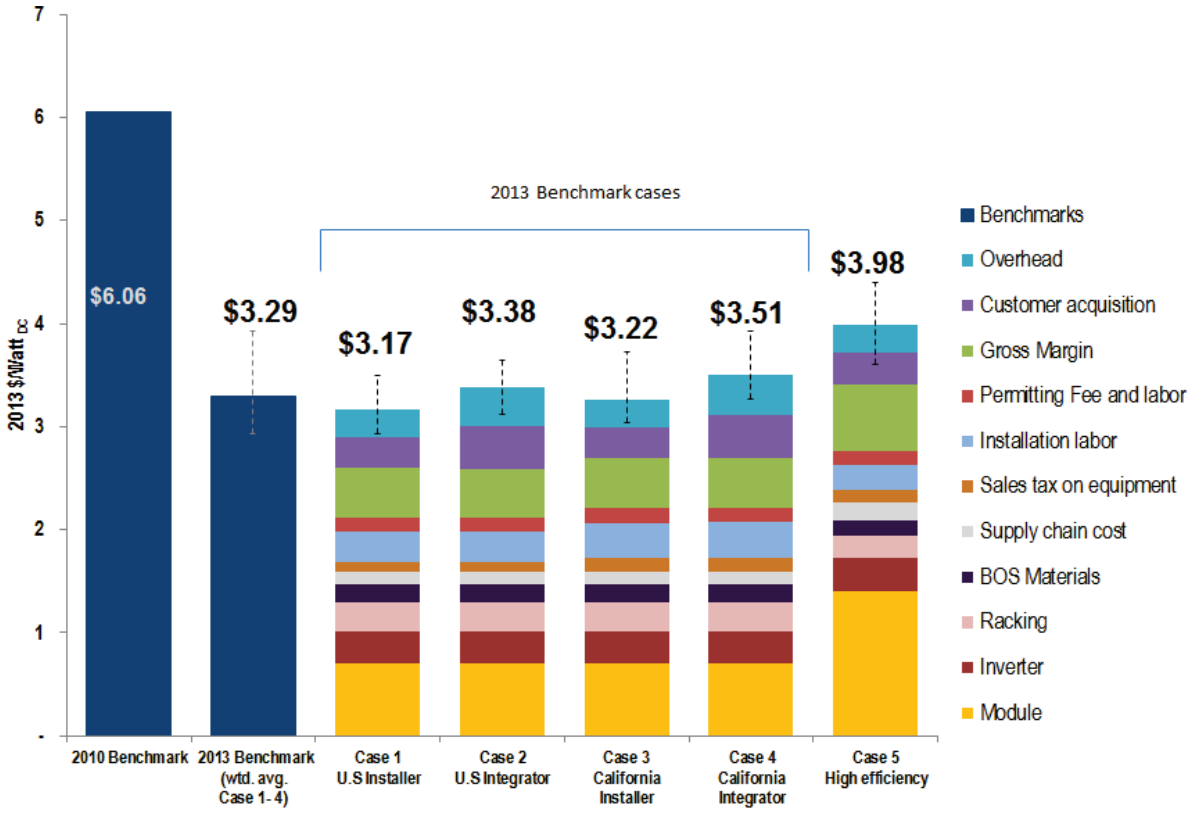

Figure 4. Q4 2013 residential cash purchase price benchmarks, with Q4 2010 benchmark for comparison

The modeling results suggest that large installers in lower-wage areas might be able to provide a host-owned system at a lower price relative to integrators by avoiding higher overhead rates that integrators incur to provide TPO services (e.g., securing tax equity and monitoring systems).[9] While we have estimated these costs in our model, they are more difficult to allocate on a per unit ($/W) basis due to limited market data. Finally our estimates may not capture additional supply chain discounts that an integrator operating at a large scale may receive.

Although systems employing high-efficiency modules result in higher per-watt capital costs compared with standard-efficiency systems, high-efficiency systems offer the following value proposition:

1. For area-constrained roofs, they produce more electricity than could be produced by standard-efficiency systems, which can increase the financial viability of the system.
2. They reduce BoS and installation costs by requiring fewer modules to achieve a desired power. While higher module costs currently surpass these savings, this could be particularly beneficial when installation costs are very high.

[9] Results for installed costs can be corroborated with installed costs indicated (either directly reported or calculated based on reported figures) in SEC filings by publically-traded companies active in the residential solar industry. Certain cost categories such as overhead and sales figures are difficult to compare because they are driven by a number of factors, including corporate choices and strategy.

As illustrated by the uncertainty analysis, our results should not be viewed as endorsing any particular business model. Rather, we aim to illustrate key sources of cost variation across scenarios (module efficiency, system location and business model). Further, our results reflect variation among larger installers and integrators and may not be representative of costs incurred by smaller installers, which may vary in ways that our modeling of large installers and integrators does not explore.

4 Residential Lease Prices: Modeled and Historical

The analysis of cash purchase prices presented above provides a consistent method for understanding the underlying cost trends for U.S. residential PV. However, the TPO model has driven much of the recent growth in the residential PV sector. Third-party ownership—leases and power-purchase agreements (PPAs)—have provided a clear value proposition: supplying customers with affordable solar electricity while minimizing and, in some cases, eliminating upfront costs.[10] Unlike residential cash purchase arrangements, TPO enables all tax incentives to be monetized fully, which maximizes the system's value under the current U.S. incentive landscape. The price of a solar lease (or PPA) is net of all incentives, so it reflects the all-in price at which a TPO system transacts.[11] This figure, rather than the system cash purchase price, is the primary figure a TPO customer evaluates when deciding whether to adopt solar. We evaluate the lease price from both the installer and the customer standpoint by (1) modeling the minimum sustainable price for a "typical" leased system, and (2) evaluating the data of lease contract prices transacted in the California market over the past several years, which reflect a consumer's willingness to pay. To facilitate comparison to a cash purchase price, we focus on leases with a prepaid price rather than on leases requiring payments over a 20-year period.

4.1 Minimum Sustainable Lease Price

First, we model the minimum sustainable prepaid lease price, which represents the minimum upfront payment required from a solar customer for an installer to cover all costs (including margins) associated with providing the solar lease service, including operational overhead, financing and ongoing operations and maintenance (and netting incentives). We assume a large installer in California.[12] As shown in Figure 5, to estimate the prepaid lease price, we begin with our estimate for system cash purchase price ($3.26/W) for a large installer in California) and then include an estimate of the cost of a production meter[13] as well as the cost (sum over system lifetime) of the system's operations and maintenance (O&M) ($0.30/W).[14] Next we consider the additional project-development overhead costs associated with bundling leases, including the costs associated with contracts, legal, and fund management ($0.20/W). For the installer case, we include a developer gross profit margin of 15% ($0.49/W). We include a state rebate, which, at the end of Q4 2013, was $0.20/W in nearly all of the California investor-owned utility areas. Federal incentives, namely the investment tax credit (ITC) and the value of accelerated depreciation (5-year Modified Accelerated Cost Recovery System [MACRS], excluding bonus depreciation), rely on the estimated FMV of a system (we discuss this derivation Section 5). Given a modeled system FMV of $4.59/W, a typical system qualifies for a gross ITC benefit of $1.38/W; a 15% assumed margin reduces this to $1.16/W. The value of accelerated depreciation over

[10] The transaction price for a homeowner installing a TPO system can take several forms. First, the contract can be a PPA (where customers pay for system generation) or a lease (where customers lease the equipment). Second, customers choose the timeframe over which they will pay for the lease/PPA. Most often, customers either fully prepay the lease/PPA prior to installation or make monthly payments that may or may not escalate annually, as opposed to paying a fraction of the lease and paying the remaining amount in monthly payments.

[11] We elect to evaluate a lease, rather than a PPA, in order to compare a pre-purchased lease contract with a host owned cash purchase price.

[12] We chose California to facilitate a comparison with actual TPO contract data, which we only have for California. We model an installer because this is the most likely scenario based on California data.

[13] Host owned systems in markets with solar carveouts within the state's Renewable Portfolio Standard are also often required to install production meters in order to accurately calculate solar production.

[14] The O&M cost includes one inverter replacement in year 10, at a cost of $0.68/W (parts and labor).

the project timeframe is equal to a cumulative present value of the reduction in taxable income each year, based on the percentage of the project cost that can be depreciated in each year. This value amounts to \$1.08/W.[15] Given our estimates for California cash purchase price for this system type, and all associated costs to provide a lease, we estimate a typical minimum sustainable lease price of \$1.93 /W for an installer and \$1.72/W for an integrator (Figure 5). This corresponds to a non-escalating PPA price of \$0.10/kWh and \$0.09/kWh for an installer and an integrator, respectively, assuming system production of 1,446 kWh_{AC}/kW_{DC} and a 0.75% annual degradation rate for 20 years. Integrators, by eliminating the developer margin, may incur overall lower costs to provide a lease/PPA, despite incurring higher overhead.[16] In practice, contract duration and structure varies; this contract price could be monetized through a combination of a prepayment sum and monthly payments, based on installer and customer preferences.

[15] The 5-year MACRS schedule is applied to the depreciable basis, which is equal to the project cost minus 50% of the ITC value. In this case, the depreciable basis is \$3.87 (\$4.50- [\$4.50 × 30% × 50%]). In each year, this is discounted at 8%.
[16] Relative to an installer, an integrator will maintain a larger staff, including a corporate staff of executives and human resources, legal team, finance team, supply-chain team, and software/information technology department (Feldman, Friedman, and Margolis 2013). In the case of a TPO system placed by an installer, these costs will be borne by a separate party, the financer. Overhead costs for different business structures are very difficult to parse out, and this analysis can not characterize well the differences in overhead costs between an integrator and an installer.

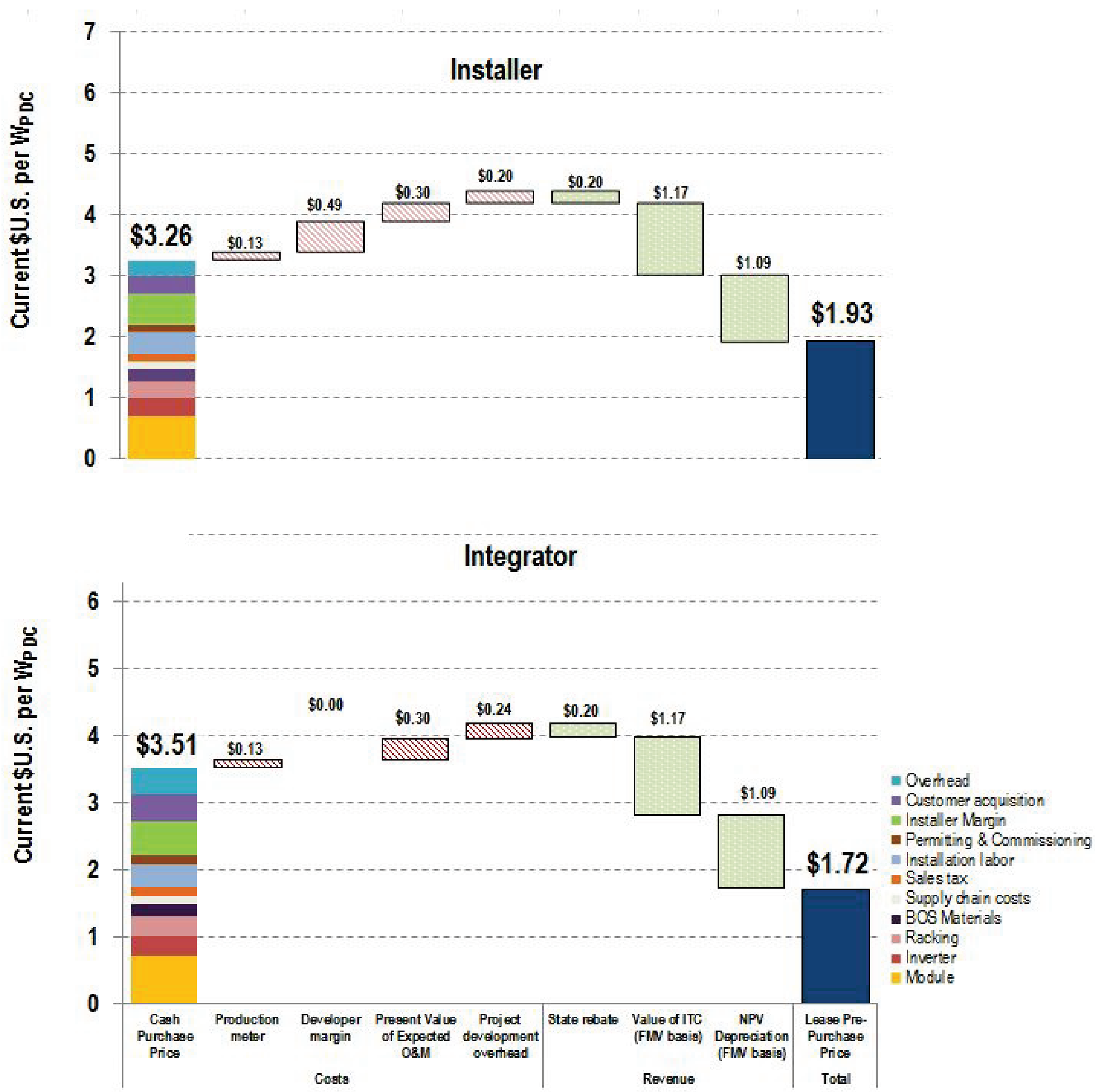

Figure 5. Minimum sustainable lease price (prepaid lease) for a standard-efficiency California system installed by a large installer or integrator in Q4 2013

The actual price a customer pays depends on market fundamentals, what the market will bear. This will vary by state, customer and utility.

4.2 Historical Lease Data

To compare our modeled lease results with market transaction data, we evaluated a sample of 1,333 California lease contracts executed over 2010-2012. [17] To facilitate comparison to a cash purchase price, we focus on prepaid leases (1/4 of the data) rather than on leases requiring monthly payments over

[17] We did not have access to contracts executed in 2013. The 2010–2012 data suggest that contract prices did not decline significantly during this period. Here we assume that this pricing dynamic continued into 2013, and thus Q4 2013 contract prices were consistent with this earlier sample.

a 20-year period. Figure 6 shows a box-and-whisker plot (median, quartiles and outliers) of prepaid lease prices. Median lease contract prices increased over the 2-year period, with the mean lease price by year ranging from \$1.94/W–\$2.45/W. The overall median was \$2.22/W. This range is higher than our modeled minimum sustainable lease price. Over this period, California incentives dropped from \$2.00/W to \$0.20/W. If installers were not able to reduce costs to keep pace with incentive declines, we would expect a corresponding increase in lease payments.

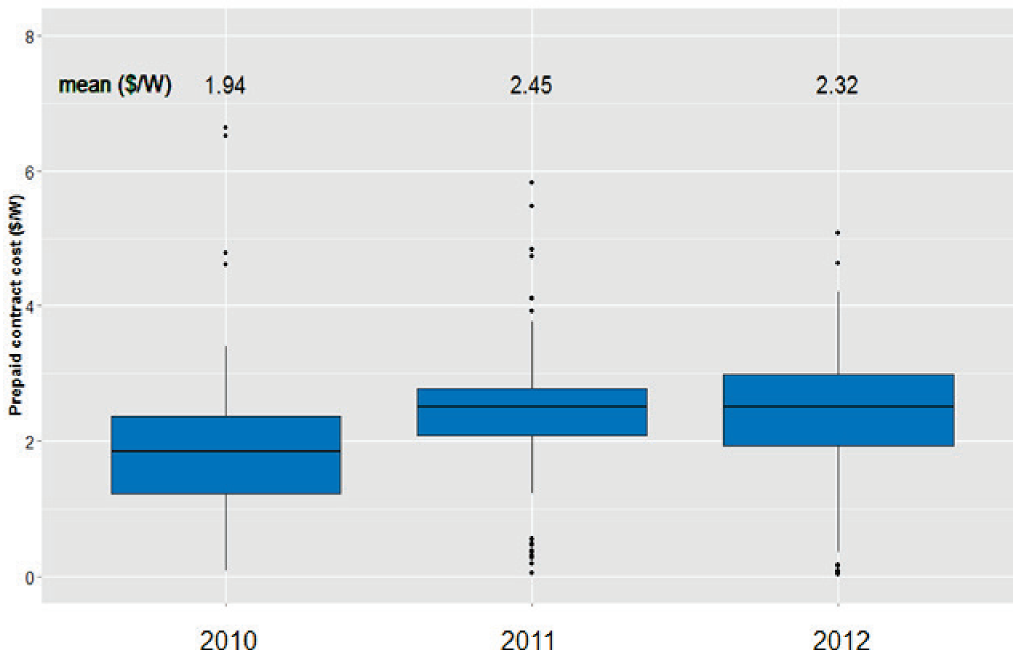

Figure 6. California prepaid lease contract prices, by year (2010–2012), sample of 348contracts

However, lease contracts vary substantially in structure and term length: 80% of leases within this California sample included monthly payments over the 20-year contract term. To compare diverse contracts, we calculated a single 'out-of-pocket' cost (i.e. contract cost) for all leases by summing any down payment and all lease payments over the contract term, for the full sample of 1,113 contracts. Because this cost critically depends on the selected discount rate, we present the mean contract price for each year at discount rates of 0%–20% (Figure 7). Over a realistic range of discount rates (approximately 4%–12%), the contract price ranges from \$2.75/W to \$4.00/W in 2012. This figure suggests that there was no clear price decline in lease contracts from 2010–2012, despite steep reductions in hardware costs over the same period.[18]

[18] In 2010, roughly one quarter of the lease contracts included an upfront payment of 25%–75% of the full cost of the lease, with fewer "no-money-down" contracts relative to other years. In subsequent years, contract payment horizons transitioned to be largely binary, in which customers either fully prepaid or prepaid less than 5% of the contract cost. Since more contracts in 2010 paid a large portion of the contract upfront, the median net present cost is less sensitive to the selected discount rate, relative to other years.

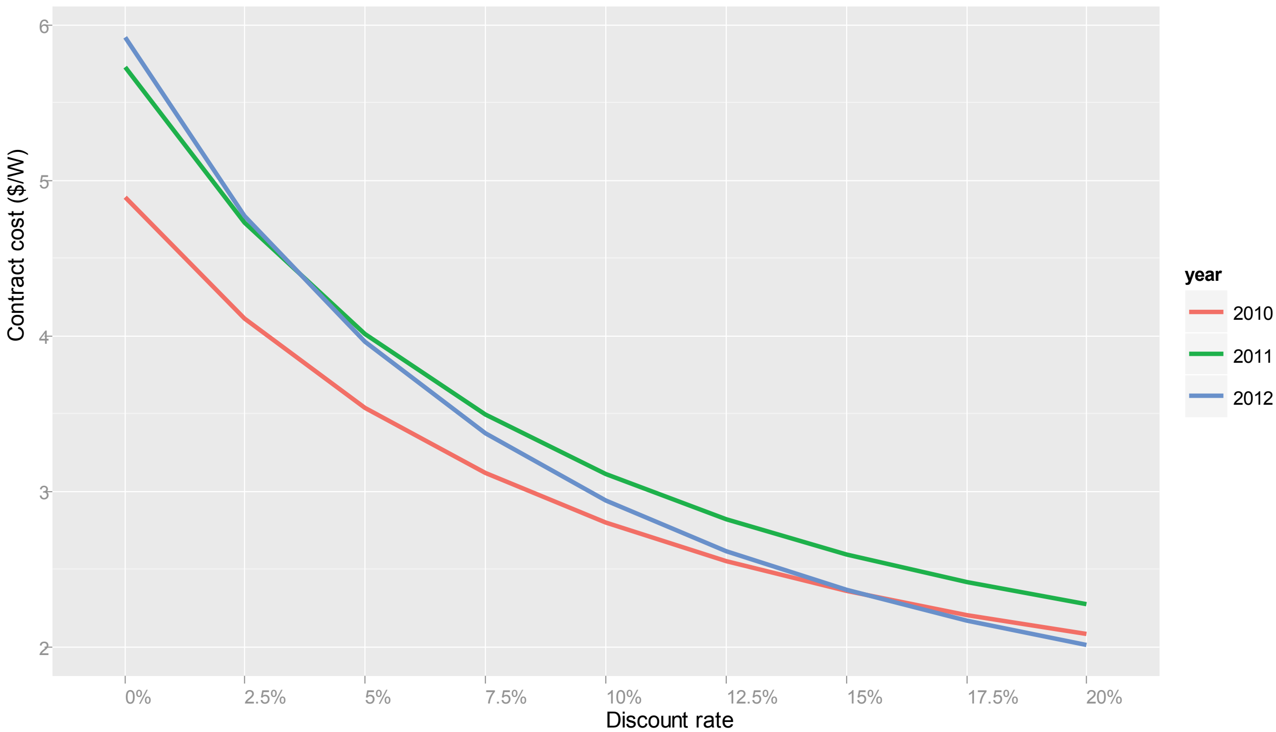

Figure 7. Mean real contract price (present cost of all payments) for 1,113 TPO systems (2010–2012) in California, varying discount rates

5 Fair Market Value

Any TPO installer/integrator that applies for an ITC for installing a PV system is required to report an FMV, which is an estimate of the arm's-length transaction price for that particular system. In addition, if a customer chooses to purchase the system at any point during the lease, the system value is represented by the FMV. This figure provides an important metric for understanding system value to solar owners and investors, but it should not be interpreted as either the cash purchase price or a customer's cost to lease a system.

The U.S. Internal Revenue Service (IRS) defines FMV as "the price at which the property would change hands between a willing buyer and a willing seller, neither being under any compulsion to buy or to sell and both having reasonable knowledge of relevant facts" (IRS 2012). As an alternative to submitting manufacturers' invoices and costs, the owner of a PV system may submit a detailed and credible third-party appraisal that reflects a figure consistent with a fair market transaction. An appraisal can be used to determine the FMV based on three approved valuation methods—the cost method, the market method, and the income method (Table 2)—applied appropriately based on the circumstances of the solar property (U.S. Treasury Department 2011).

Table 2. Approved Appraisal Methods

Method	Description
Income	The income approach establishes property value based on the net cash flows accruing to the property. This method relies on the discounted cash flow model, which aggregates future cash flows and discounts them at an appropriate level of risk. This method is typically used for assets that produce a quantifiable stream of income.
Cost	The cost approach relies on the assumption that an informed purchaser would pay no more for the property than the cost of replacing the property. This method can be supported by a recent bill of sale for a comparable property.
Market	The market approach relies on established value based on recent transactional data, or recent sale of comparables, to help determine value.

Since a typical TPO PV property generates known and quantifiable income to the owner (monthly PPA or lease payments, renewable energy credit payments, and state and federal incentives), the income method has been a commonly used approach for valuing PV systems. We provide an estimate of FMV based on the income method. Future cash flows are discounted based on the after-tax discount rate that reflects perceived risks associated with anticipated revenue, and can also be considered the rate of return required to compensate an investor for undertaking an investment in the system. Appendix C provides the median and range of values for all relevant parameters. We estimate a FMV (median) of $4.59/W for a TPO residential PV system installed in California in 2013. The income method is sensitive to a number of assumptions; Figure 8 provides a sensitivity analysis of the modeled FMV to a range of key parameters, organized by the direction of the impact that an increase in a specific parameter has on FMV. Given the long time horizon of income from lease payments, the FMV critically depends on the selected discount rate. Other key drivers include the selected PPA/lease rate, which varies by market. The FMV provides a useful indicator of system value to the investor, thus the parameters that drive variation in FMV differ from those that determine system cost.

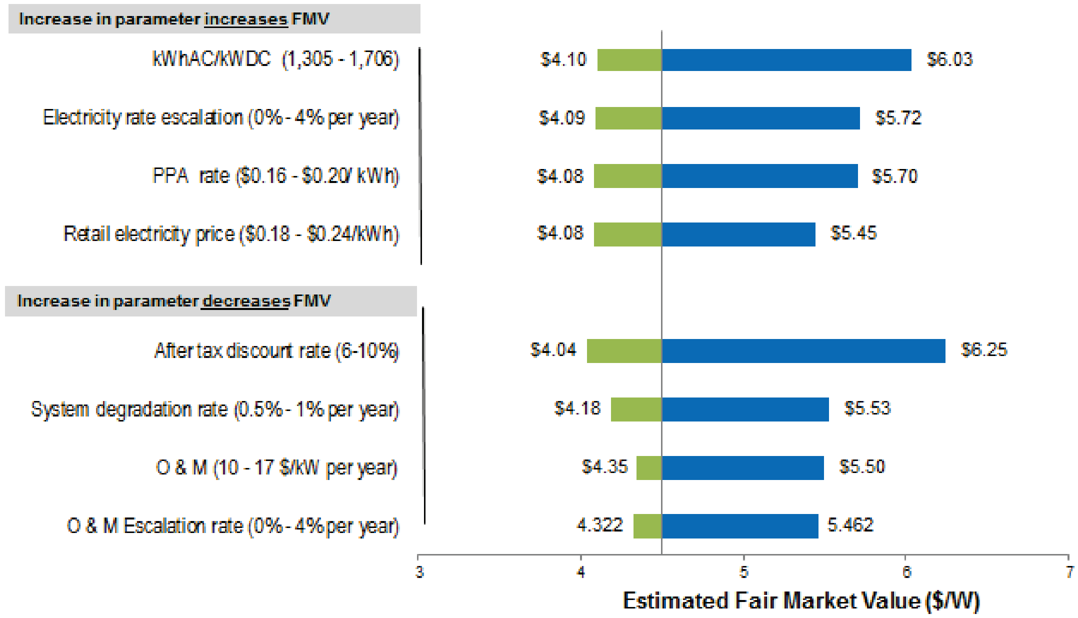

Figure 8. Drivers of FMV for a typical TPO residential PV system in California

6 Conclusion

This report updates our Q4 2010 benchmark of residential PV prices (Goodrich, James, and Woodhouse 2012) using Q4 2013 data and assumptions. To capture the variation inherent in the residential PV market, we model five key scenarios by illustrating example benchmarks based on level of business integration, location, and module efficiency. System benchmarks for our four standard-efficiency systems range from \$3.17/W to 3.51/W, with an estimated weighted-average cash purchase benchmark of \$3.29/W. This represents a 46% price decline from Q4 2010. We estimate a \$3.98/W cash purchase price for a system using high-efficiency c-Si modules. Declining installed prices largely reflect sustained declines in module and inverter costs. As hardware costs continue to decline, the importance of non-hardware BoS costs (installation labor, permitting, inspection, interconnection, and customer acquisition) will become larger drivers of residential system prices.

Although the cash purchase price provides a key metric to inform policy and research and development investment strategies, several other system-price metrics are relevant to understand the dynamics of the residential PV market in the United States. This is particularly true given the rise of third-party financing. We compare the cash purchase benchmark with additional metrics: the transaction price paid by the customer who leases a PV system, which provides the amount the user actually pays for solar electricity, and the FMV, which indicates the market value of the system when installed. We also examine transaction data on lease prices for a sample of California systems installed during 2010–2012.

To summarize, Figure 9 (following page) presents the cash purchase price, the FMV, the minimum sustainable lease price, and transactional data on lease prices—specific to a large California system.[19] The maximum and minimum heights of the bars represent the minimum and the maximum.[20] The diamond marker and numerical value represent the mean, the box limits represent the quartiles, and the dotted line dividing the box represents the median. Although all four figures represent a way of reporting the price for the same asset, they also represent very distinct, yet linked metrics.

[19] We selected the California case as a summary because this is the only location that provides actual lease transaction prices. Where costs differ between an installer and an integrator (cash purchase price and minimum sustainable lease) we present a market-weighted average.

[20] For visual clarity, the box and whiskers for the prepaid lease transaction price excludes 32 outliers exhibited in Figure 6. Outliers are defined as more than 1.5 times the interquartile (25% -75%) range. The highest value is \$6.5/W and the lowest is \$0.2/W.

Figure 9. Summary of modeled residential prices—California system (2013)

The FMV represents the value of a PV system to a buyer (who may be an institutional investor), which is established by an independent appraiser based on IRS guidelines. An income-based method derivation of the FMV is based on the capitalization of the expected cash flows from that asset. This figure can be considered representative of investor/owner value, incorporating all sources of economic value accruing to the system. In some cases, the FMV has been historically reported as the "system cost" or "system price" to incentive programs (specifically for TPO systems), which has confounded historical cost data comparisons since progress in cost-reduction efforts does not necessarily impact the FMV of PV systems.

The cash purchase price models the unsubsidized cash purchase price of PV systems, an objective measure that most closely approximates the book value of an asset. This figure includes all materials, labor, overhead, profit, and permitting costs for a PV system up to the point of grid tie-in. Our detailed results can be used to guide research and development efforts (by installers, manufacturers, and policymakers) aimed at reducing PV system costs as well as to understand the potential benefits of proposed technological improvements.

The modeled minimum sustainable lease price represents the minimum upfront payment required from a solar customer for an installer to cover all costs (including margins) associated with providing the solar lease service, including operational overhead, financing and ongoing operations and maintenance. This figure nets the value of all incentive payments, namely, the ITC and accelerated depreciation accruing to that project, so would be expected to be lower than the FMV and the cash purchase price. Note that the actual lease price offered to the customer will be driven by local market conditions.

The historical lease transaction price, on the other hand, draws on actual market data of the lease prices customers are willing to pay for PV electricity (in California, which is not necessarily representative of prices seen in all markets). This metric, when evaluated as an upfront payment, provides an estimate of the value of solar electricity to solar customers, particularly in a market with high electricity prices. In a post-incentive market, the contract price will be the primary revenue stream for owners and developers of TPO systems, and would need to cover all costs of maintaining and growing the business. Installed cost reductions alone will not drive this figure down. Rather market competition -- characterized by an informed customer base and a more transparent market will be key to lowering lease transaction prices.

This analysis benchmarks and clarifies multiple solar price metrics relevant to distinct stakeholders. We rely on simplifying assumptions—particularly focusing on large installers and integrators—to model installed prices. Our analysis does not reflect the full diversity of installers, practices, and input costs in the U.S. market, nor does it promote any particular business model. Further, the PV market is rapidly evolving, incorporating ever-changing technology and installation processes as well as business practices and functions employed by various parties (contractors, financers, and integrators). Future efforts will aim to characterize this evolution and model new technologies as they gain market share.

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Appendix A. Model Assumptions

The table below includes key assumptions for distributions that were selected from data, literature and/or conversations with installers. Also included are assumptions that differ between scenarios. Blank cells indicate that inputs did not vary from the U.S. Installer case.

		US Installer			California			Integrator			High Efficiency		
Model Input:	**units**	**Min**	**Median**	**Max**	**Min**	**Median**	**Max**	**Min**	**Median**	**Max**	**Min**	**Median**	**Max**
System													
System size	*$W_{P\ DC}$*	2,000	4,906	18,000									
Available roof space	*m^2*	27.9	38.8	54.3									
Module packing efficiency	*%*	75%	88%	95%									
Installation Materials													
Module price	*per $W_{P\ DC}$*	$0.64	$0.71	$0.75							$1.20	$1.40	$1.60
Module efficiency		13.5%	15.0%	17.5%							18%	21%	22%
Supply chain costs (Module, inverter, hardware, materials)	*%-materials price*	5%	10%	15%									
Installation Labor													
Electrician	*$ per hour*	$15.7	$25.0	$40.9	$17.8	$30.0	$45.7						
Construction Laborers	*$ per hour*	$9.2	$14.4	$20.0	$11.1	$19.4	$33.3						
Office Staff: Procurement Clerks	*$ per hour*	$15.5	$18.7	$22.2	$11.9	$20.8	$28.2						
Electrical and Electronics Drafters	*$ per hour*	$16.8	$26.8	$42.5	$18.8	$28.0	$43.5						
Workers Comp insurance			13.8%		28%	28%	28%						
Labor content	*hours*	0.42	1.00	2.00									
Installer margin	*%-markup*	15%	20%	25%									
Other Costs													
Permitting fee	*$ per system*	$0	$430	$600									
Sales tax	*percent*	0%	5.0%	9%		8%							
Overhead	*$ per watt*		$0.35						$0.59				
Customer acquisition	*$ per watt*		$0.22						$0.32				

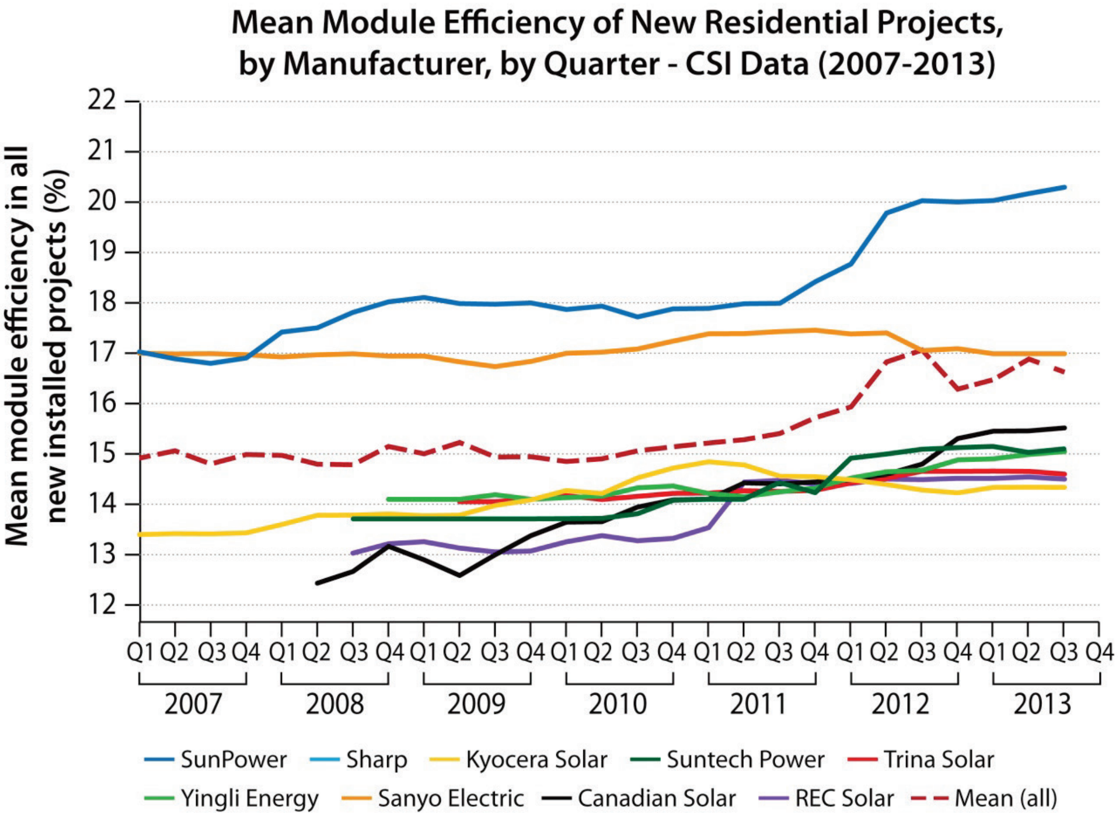
Appendix B. Cost by Category for Modeled System Types

Cost Category	$/W$_{p\ DC}$					
	US Installer	U.S Integrator	CA Installer	CA Integrator	High Efficiency	2013 Benchmark (wtd avg)
Module	$0.70	$0.70	$0.70	$0.70	$1.40	$0.70
Inverter	$0.31	$0.31	$0.31	$0.31	$0.32	$0.31
Hardware (Racking) and Mounting	$0.28	$0.28	$0.28	$0.28	$0.22	$0.28
BOS Materials	$0.18	$0.18	$0.18	$0.18	$0.15	$0.18
Supply chain costs (Module, inverter, hardware, materials)	$0.12	$0.12	$0.12	$0.12	$0.17	$0.12
Sales Tax (Module, inverter, hardware, materials)	$0.08	$0.08	$0.13	$0.13	$0.12	$0.11
Subtotal: Equipment costs	$1.68	$1.68	$1.73	$1.73	$2.38	$1.70
Installation labor (fully burdened)	$0.30	$0.30	$0.34	$0.35	$0.25	$0.32
Permitting Fee and labor	$0.13	$0.13	$0.14	$0.14	$0.13	$0.14
Subtotal: Engineering, Procurement, & Construction (EPC) costs	**$2.11**	**$2.11**	**$2.21**	**$2.22**	**$2.76**	**$2.16**
Gross Margin	$0.48	$0.48	$0.48	$0.48	$0.64	$0.48
Customer acquisition	$0.31	$0.41	$0.31	$0.42	$0.31	$0.34
Overhead	$0.27	$0.38	$0.27	$0.39	$0.27	$0.30
Cash purchase price	**$3.17**	**$3.38**	**$3.26**	**$3.51**	**$3.98**	**$3.29**

Appendix C. Model Assumptions: Fair Market Value

Sensitivity Parameters						
Yield	kWh_{AC}/kW_{DC}	1,305	1,446	1,776	Data-defined	CSI 2013; CPUC module database
System degradation rate	percent	0.50%	0.75%	1.00%	PERT	NREL estimate (w-Si)
Revenue						
Retail electricity price	$/kWh	$0.16	$0.20	$0.24	PERT	Darghouth et al 2010
Retail electricity price escalation rate	percent	0%	2%	4%	PERT	NREL estimate: no escalation, up to 2x inflation
Investment Tax Credit (ITC)	percent		30%		Fixed	Internal Revenue Service (2013)
Portion of ITC applied to reduction of depreciation basis	percent		50%		Fixed	Internal Revenue Service (2013)
PPA/lease rate	$/kWh	$0.16	$0.18	$0.20	Data-defined	NREL data on TPO contracts; range at 2.9% escalator
PPA escalation rate	percent		2.90%		Fixed	NREL data on TPO contracts; mode escalator
Year 1 rebate	$\$/W_{DC}$		$0.20		Fixed	CSI 2013
Operating Expenses						
Years (1-20) O&M	$/kW*year	$10	$12	$17	PERT	NREL estimate
Escalation rate (Years 1-20 O&M)	percent	1.00%	2.00%	4.00%	PERT	NREL estimate: minimum, up to 2x inflation
Years (20-30) O&M	$/kWh		$0.03		Fixed	NREL estimate
Escalation rate (Years 20-30 O&M)	percent	1.00%	2.00%	4.00%	PERT	NREL estimate: minimum, up to 2x inflation
Other						
Discount Rate (after tax)	percent	6%	8%	10%	PERT	Damodaran 2013, Value Line Investment Survey
Federal income tax rate	percent		35%		Fixed	NREL estimate: effective, statutory U.S. rates
State income tax rate	percent		8.84%		Fixed	State of California Franchise Tax Board 2013

Appendix D. Average Module Efficiency of New Residential Projects



The average efficiency of c-Si modules deployed in the CSI program rose to approximately 16.5% in 2013, led by high-efficiency manufacturers SunPower and Sanyo. However, for the same period, the average efficiency of Yingli modules (the world's largest manufacturer of PV modules at the time of this report) deployed only rose from 14.1% to 15% (CSI 2013).