NATIONAL RENEWABLE ENERGY LABORATORY

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List of Acronyms

AC	alternating current
B/C ratio	benefit-to-cost ratio
CO_2	carbon dioxide
CPI	consumer price index
DC	direct current
GDP	gross domestic product
ITC	investment tax credit
IRR	internal rate of return
kW	kilowatt
kWh	kilowatt-hour
LCOE	levelized cost of energy
MACRS	modified accelerated cost recovery system
MBS	monthly bill savings
MIRR	modified internal rate of return
NPV	net present value
O&M	operations and maintenance
PI	profitability index
PPA	power purchase agreement
PV	photovoltaics
REC	renewable energy certificate
SREC	solar renewable energy certificate
TNP	time-to-net-positive-cash-flow
W	watt

Executive Summary

Photovoltaic (PV) systems are installed by several types of market participants, ranging from residential customers to large-scale project developers and utilities. Each type of market participant frequently uses a different economic performance metric to characterize PV value because they are looking for different types of returns from a PV investment. We find that different economic performance metrics frequently show different price thresholds for when a PV investment becomes profitable or attractive. Additionally, several project parameters, such as financing terms, can have a significant impact on some metrics [e.g., internal rate of return (IRR), net present value (NPV), and benefit-to-cost (B/C) ratio] while having a minimal impact on other metrics (e.g., simple payback time). As such, we find that the choice of economic performance metric by different customer types can significantly shape each customer's perception of PV investment value and ultimately their adoption decision.

In this analysis, we characterize PV economic performance for three ownership types: residential customers who purchase their own PV systems, commercial customers (for-profit companies) who purchase their own PV systems, and residential and commercial customers who lease PV equipment or buy PV electricity from a third-party company. We characterize the differences in PV economics for each customer based on the different tax implications of ownership. We do not characterize PV economics for large-scale PV developers or utilities because they frequently use complex project financing structures (Harper et al. 2007) that are beyond the scope of this analysis.

We compare PV economic returns for different PV customers using the following economic performance metrics:

- Net present value (NPV)
- Profitability index (PI)
- Benefit-to-cost (B/C) ratio
- Internal rate of return (IRR)
- Modified internal rate of return (MIRR)
- Simple payback and time-to-net-positive-cash-flow (TNP) payback
- Annualized monthly bill savings (MBS)
- Levelized cost of energy (LCOE).

We characterize relative PV economics for each metric over a range of system characteristics, including PV system price and several non-price parameters including financing terms, tax rates, electricity rates and assumed rate escalations, and PV system performance. Key findings include:

- Different economic performance metrics can show unique price thresholds for when a PV investment becomes profitable or attractive.

- In some cases, the choice of an economic performance metric could have as much impact on the representation of value as decreasing (or increasing) PV prices by up to a factor of four.
- Varying non-price system characteristics, such as financing terms or assumed electricity rate increases, can impact PV economic performance as much as decreasing (or increasing) PV prices by several dollars per watt.
- At higher PV prices, commercial projects may generate higher returns than residential projects because commercial customers can depreciate the capital invested in a PV project. At lower PV prices, commercial projects may generate lower returns because the gain from capital depreciation is offset by the loss from valuing PV based on tax-deductible energy costs.
- IRR is a poor metric for characterizing the value of U.S. PV systems because the upfront nature of financed PV costs and incentives can lead to an inflated perception of value.
- MIRR and simple payback times show very little sensitivity varying several project parameters, and customers using these metrics may be less likely to be incentivized by policy measures targeting non-price system parameters.
- The MBS metric may generate attractive returns at higher PV prices than other metrics and may be effective at stimulating PV markets. However, the third-party PV companies that frequently market systems based on MBS have different tax structures and costs of capital, and it is unclear whether this will lead to higher or lower relative returns.
- The upfront nature of U.S. PV incentives (e.g., federal investment tax credit and accelerated capital depreciation for commercial customers) can lead to very different PV returns for U.S. systems relative to identical systems located in different countries that are described in the international PV literature.

The different price thresholds for when a PV investment becomes profitable or attractive and the different sensitivities to varying system parameters have significant implications for policy design. For example, if policy is introduced to improve PV financing terms, it could preferentially stimulate market segments where customers use metrics that are sensitive to financing terms (IRR, NPV, and B/C ratios) while having little or no impact on market segments where customers use metrics that are insensitive to financing terms (simple payback). There is also a strong potential for stimulating U.S. PV demand using new mechanisms in addition to traditional incentives focused on reducing PV prices or increasing revenues. These range from simply educating potential customers about the value of a PV investment as seen through different economic performance metrics, to providing access to long-term low-cost financing, to allowing third-party companies to develop simple PV products that can generate MBS.

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1 Introduction

Photovoltaic (PV) systems are installed by several different types of customers. The economic returns generated by a PV investment can be very different for each market segment. This is partly caused by fundamental differences in PV prices and revenues for each market segment but can also be caused by the use of different economic performance metrics to characterize PV value. For example, a PV system may generate an internal rate of return (IRR) greater than 50%, giving a potential commercial customer the perception of a high return on investment, while an identical system could generate simple payback time that is longer than 10 years, giving a potential residential customer the perception of a low return on investment.

In this analysis, we explore how the use of different economic performance metrics can shape the perception of PV value for different market participants. We calculate PV economics using several economic performance metrics for a range of PV prices to gain insight into how different metrics can exhibit unique price thresholds for when a PV investment may begin to look profitable or attractive. We also calculate the sensitivity of PV economics to non-price project parameters to gain insight into how evolving market and policy conditions could preferentially stimulate some market segments relative to others. Lastly, we highlight policy implications for the metric-dependent nature of PV economics, including unique price thresholds that may entice different PV customers to adopt PV and unique sensitivities to evolving market conditions.

The report is organized as follows: Sections 2–4 describe the types of potential PV customers, the key variables that influence PV economic performance, and the economic performance metrics that are commonly used to characterize PV value; Section 5 describes the reference assumptions used to calculate PV economic performance; Sections 6–7 present results showing how PV price and non-price parameters uniquely impact each economic performance metric; Section 8 presents a method for comparing the relative sensitivity of PV economic performance across several economic metrics; Section 9 discusses policy implications; and Section 10 presents conclusions and recommendations for future research. Additional discussions of the monthly bill savings (MBS) and IRR metrics are included in Appendix A and B, respectively.

2 Types of PV Adopters and Markets

PV systems are purchased by several types of customers, and projects are frequently categorized by the type of installation:

- **Residential**—Typically roof-mounted systems that range in size from a few kilowatts up to about 10 kW. Residential PV electricity is frequently valued at retail rates and is dependent on the type of rate structure (e.g., flat rate, time-of-use rate, or tiered rate) and local net-metering policy.
- **Commercial, public sector, and non-profits—**Roof- or ground-mounted systems that range in size from a few kilowatts up to a few megawatts. Commercial PV electricity is typically valued at retail rates and is dependent on rate structure (e.g., flat rate, time-of-use rate, or demand-based rate) and local net-metering policy.
- **Large system installers**—Typically ground-mounted arrays installed by electric-service providers or large system developers ranging in generation capacity from hundreds of kilowatts to tens of megawatts. PV electricity is frequently valued at rates set by power purchase agreements (PPAs) or by wholesale electricity market prices.

Each PV market segment has unique characteristics—including market-specific PV prices, revenues, incentives, and financing options—that affect the relative value of a PV investment. For example, residential PV prices can be twice as high on a capacity basis (installed $/W) as large-scale systems (Barbose et al. 2011; SEIA-GTM 2011). However, residential retail electricity rates ($/kWh) can be twice as high as wholesale electricity rates (EIA 2011a).

In this analysis, we characterize the different tax implications for three types of PV ownership structures: (1) residential customers who own their systems, which we refer to as "residential"; (2) for-profit commercial customers, which we refer to as "commercial," who own their PV system and are not in the business of selling electricity; and (3) PV systems owned and operated by third-party companies that either lease PV equipment or sell PV electricity to residential or commercial customers. There are many other types of PV customers that we do not characterize in this analysis. These include public sector or non-profit customers that own and maintain their own systems and electric service providers (e.g., investor-owned utilities, municipal utilities, or independent electricity generators) that frequently use complex ownership structures to develop PV projects (Harper et al. 2007). While we do not characterize the full range of PV economics to each type of market participant, several system characteristics will be similar across different ownership classes. However, care must be taken in applying the general market trends evaluated here to different customer classes.

3 Parameters that Influence PV Economic Performance

Several project parameters influence PV economic performance. In this analysis, we evaluate how PV prices, revenues, non-price project parameters, and business models can affect PV economics and how these impacts vary depending on the use of different economic performance metrics.

3.1 PV Prices

PV system prices per unit of capacity ($/kW) are primarily driven by project type and size. Large PV projects can be significantly less expensive per unit of installed capacity than small PV projects, primarily because large system installers can achieve significant economies of scale. For example, average PV prices ranged from $3.85/W for utility-scale PV systems to $5.35/W for commercial systems and $6.41/W for residential systems in the first quarter of 2011 (SEIA-GTM 2011). The PV prices seen by customers are also impacted by state and local incentives, which frequently target specific market segments.

In this analysis, we make two simplifying cost assumptions. First, we define an "effective PV price" as the retail price minus state and local incentives[1] to generalize results. The 30% federal investment tax credit (ITC) is then applied to the remaining system cost. Second, in the base case, we assume that the reference effective PV prices and electricity rates are identical in all markets to highlight the impact of metric choice on perceived PV value. We explore the impact of varying effective PV prices and electricity rates on economic performance in Sections 6–8. All PV prices are given in units of 2010 U.S. dollars per kilowatt of direct current (DC) nameplate capacity.

3.2 Non-Price System Parameters

Various project parameters affect PV economics in addition to system price. We consider how the following non-price parameters impact project economics and how these impacts vary depending on the use of different economic performance metrics.

- **Down payment**—The initial payment made by a potential PV customer on the debt-financed PV asset.
- **Loan term**—The duration of the PV loan, measured in years.
- **Loan rate**—The interest rate for the PV loan, given in terms of real, not nominal, rates.[2]
- **Discount rate**—The rate used to depreciate future PV revenues and costs into an equivalent present value, given in real dollars. Discount rates are frequently chosen to

[1] State and local rebates frequently increase a customer's federal tax basis, although there are some exceptions based on ownership or project structure (SEIA 2009). We assume that the effective PV price includes all tax payments (e.g., sales tax and federal tax on state and local rebates) and is not subject to further taxation.

[2] Nominal interest rates or dollars account for the effects of inflation, and the value of one nominal dollar changes from year to year. Real interest rates or dollars are adjusted to exclude inflation, and the value of one real dollar does not change over time. Nominal dollars are frequently converted to real dollars using the consumer price index (CPI) or gross domestic product (GDP), depending on application.

equal the loan rate to avoid introducing a time value of money to debt-financed capital.[3]

- **Effective tax rate**—The tax rate paid by a potential PV customer, simplified here to include federal, state, and local taxes.
- **Effective electricity rate**—The mean value of electricity generated by a PV project, measured in units of cents per kilowatt-hour. This represents a simplifying assumption intended to capture the annualized value of hourly PV generation, accounting for the daily and seasonal variations in electricity value based on electricity prices in wholesale markets or different retail electricity rate structures (e.g., time-of-use rates based on time of day and season, demand-based rates based on peak customer power use, or tiered rates based on total energy use). Effective electricity prices could also represent rates defined in PPAs offered by a local utility.
- **Annual electricity rate increase**—The projected annual increase in electricity rates, given in units of real escalation rates.
- **Carbon price**—The projected price for emitting carbon, given in units of dollars per metric ton of carbon dioxide (CO_2) emitted.
- **Capacity factor**—The ratio of electricity generated by a PV system relative to the maximum electricity that would have been produced if the system had operated at peak capacity during an entire representative time period. PV capacity factors vary based on the local solar resource and module orientation and are given here in units of alternating current (AC) electricity generated by a given unit of nameplate DC PV capacity over one year.

There are several additional parameters that impact PV economic performance. These include: property tax, sales tax [PV is exempt from state sales tax in several, but not all, states (DSIRE 2011)], and additional solar incentives including renewable energy certificates (RECs) and solar RECs (SRECs). These, and other, parameters are not explicitly evaluated in this study; however, their impacts on PV economics are also metric dependent.

3.3 Business Models

Historically, most PV adopters have purchased and maintained their own PV system and recouped project costs using the revenues generated by their system. However, several new business models have entered the PV market in recent years, and the different ownership structures can impact economic performance. For example, PV systems can be owned and operated by a third-party company, which can then lease PV equipment or sell PV electricity to the building occupant (NREL 2009; Kollins et al. 2010).

PV project costs and revenues are typically taxed differently for third-party owned PV systems than customer-owned systems, which could potentially lead to higher PV returns for third-party owned systems (see Appendix A). However, third-party companies are likely to have a higher

[3] PV economics are characterized in this analysis assuming dedicated PV financing and a discount rate that is equal to the loan rate. Large-system developers and third-party PV companies typically use more complex project financing, which include a range of tax equity, equity, and debt investors (e.g., Harper et al. 2007). The impacts of more complex project financing, and potentially higher capital costs, are not characterized in this analysis but will be the focus of subsequent work.

cost of capital than customers installing their own systems. Third-party companies typically finance PV projects using several sources of capital including tax-equity investors, equity investors, and debt investors. Most investors will require a higher rate of return than the cost of dedicated debt financing available to several residential and commercial customers.[4] Also, the cost of capital will vary based on the third-party company, deal structure, and the PV market. For example, the cost of financing third-party residential systems may be higher than commercial systems based on increased investment risk.

[4] For example, the interest rate for a residential home equity loan may be much lower than the interest rate for commercial debt financing because the capital accrued in the house can be used to offset investment risk.

4 Metrics Commonly Used to Represent PV Economic Performance

Several economic performance metrics are commonly used to characterize PV value (Short et al. 1995; Duffie and Beckman 2006). Table 1 summarizes several of these metrics. Some metric definitions, such as net present value (NPV) and IRR, are standard across different industries. Others, such as MBS and several definitions of payback time, are specific to PV investments. Each economic performance metric characterizes PV economics in different units, including dollars, annualized percent return on investment, years, and cents per kilowatt-hour, as indicated in Table 1. Although potential PV customers might use more than one performance metric, Table 1 highlights the different PV market segments that are likely to use each metric.

Table 1. Metrics Used to Characterize PV Economic Performance

Metric	Equation	Units	Likely User
Net Present Value (NPV)	$NPV = \sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t}$	\$	Some residential Commercial[a] Large-scale
Profitability Index (PI)	$PI = \frac{\sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t}}{Investment\ Cost}$	%	Some residential Commercial Large-scale
Benefit-to-Cost (B/C) Ratio	$B/C\ Ratio = \frac{\sum_{t=0}^{N} \frac{Revenue_t}{(1+d)^t}}{\sum_{t=0}^{N} \frac{Cost_t}{(1+d)^t}}$	%	Commercial Large-scale Public sector
Internal Rate of Return (IRR)[b]	$IRR:\ NPV = \sum_{t=0}^{N} \frac{Revenue_t - Cost_t}{(1+IRR)^t} = 0$	%	Some residential Commercial Large-scale
Modified Internal Rate of Return (MIRR)	$MIRR = \left(\frac{\sum_{t=1}^{N} PositiveCashFlow_t * (1+r)^{N-t}}{\sum_{t=1}^{N} \frac{NegativeCashFlow_t}{(1+d)^t}} \right)^{\frac{1}{N}} - 1$ $PositiveCashFlow_t = \begin{cases} Revenue_t - Cost_t & if \quad Revenue_t > Cost_t \\ 0 & if \quad Revenue_t \le Cost_t \end{cases}$ $NegativeCashFlow_t = \begin{cases} 0 & if \quad Revenue_t \ge Cost_t \\ Revenue_t - Cost_t & if \quad Revenue_t < Cost_t \end{cases}$	%	Some residential Commercial Large-scale
Payback Time[c]	$Simple\ Payback = \frac{PV\ Price - Federal\ ITC}{Annual\ PV\ Revenue - O\ \&\ M}$ $TNP\ Payback: \sum_{t=0}^{TNP\ Payback} \frac{Revenue_t - Cost_t}{(1+d)^t} > 0$ & $\sum_{t=TNP\ Payback}^{N} \frac{Revenue_t - Cost_t}{(1+d)^t} > 0$ *Several others (e.g., Duffie and Beckman 2006)*	years	Residential Some commercial
Annualized Monthly Bill Savings (MBS)[d]	$MBS = \frac{1}{LeaseTerm * 12} \sum_{t=1}^{LeaseTerm} \frac{PV\ Generation_t * (Electricity\ Rate_t - LCOE)}{(1+d)^t}$	\$/ month	Residential Some commercial

Levelized Cost of Energy (LCOE)[e]	$$LCOE_{Residential} = \frac{\sum_{t=0}^{N} \frac{Cost_t}{(1+d)^t}}{\sum_{t=0}^{N} \frac{Electrical\ Energy_t}{(1+d)^t}}$$ $$LCOE_{Commercial} = \frac{\sum_{t=0}^{N} \frac{Cost_t}{(1+d)^t}}{\sum_{t=0}^{N} \frac{Electrical\ Energy_t}{(1+d)^t}} * \frac{1}{(1 - Commercial\ Tax\ Rate)}$$	cents/ kWh	Primarily large-scale

Note: *N* represents the number of years for the economic analysis; *t* represents the year variable in each summation; *d* represents the discount rate, which we have also used interchangeably with the loan rate; $Revenue_t$ represents the revenue generated by the PV system in year *t*; $Cost_t$ represents the cost of the system in year *t*; and *r* in the MIRR formulation represents the reinvestment rate, which is a company's opportunity cost of capital. All other variables have descriptive labels.

[a] In this analysis, we use the term "commercial" to represent for-profit commercial entities that pay taxes.

[b] See Appendix B for further discussion.

[c] TNP payback is defined as the time required to satisfy two conditions: (1) the discounted PV revenues exceed the discounted system costs accrued to that date and (2) the discounted revenues remain higher than discounted costs for the duration of the investment

[d] See Appendix A for further discussion.

[e] Represents LCOE in real, not nominal, dollars. Commercial LCOEs are adjusted to represent the before-tax cost of electricity that can be compared to retail or wholesale electricity rates.

4.1 Net Present Value

NPV represents the net profit generated by an investment, calculated from the discounted sum of future costs and revenues. When the NPV of a PV system equals zero, the cost of PV-generated electricity is equal to the cost or value of electricity that could have been purchased from the grid. This is frequently referred to as reaching "grid-parity" (Denholm et al. 2009). Projects with NPVs that are greater than zero potentially represent profitable investments. NPVs generally increase with increasing revenues or decreasing costs; however, these relationships are not always intuitive because the relative timing of project costs and revenues is important since they are discounted. NPVs cannot, by themselves, be used to rank the relative returns of investments with different costs. To compare between different investments, NPVs can be scaled by the investment cost, which results in the profitability index (PI) metric, or variations of NPV can be calculated like the benefit-to-cost (B/C) ratio. The NPV metric is likely to be used to evaluate commercial and large-scale PV systems and possibly some residential PV systems.

4.2 Profitability Index and Benefit-to-Cost Ratio

The PI represents the project NPV divided by the initial investment cost. PIs represent the discounted percent return on an investment, and PIs greater than zero represent profitable investments. Since PIs are normalized by the investment price, they can be used to rank the relative returns from several investments with different costs.[5] The B/C ratio represents the discounted system revenues divided by the discounted system costs. A B/C ratio greater than one represents a profitable investment. The main difference between the PI and B/C ratio is that all costs in the B/C ratio are discounted, whereas PI is calculated by normalizing the difference between discounted revenues minus costs (NPV) by the undiscounted initial investment cost. These differences are generally small, and PI frequently shows similar returns as the B/C ratio.

[5] Several other metrics are similar to PI but scale NPV by different costs, including the maximum capital exposure (maximum capital outflow before positive system revenues reduce cost outlays) (Stermole and Stermole 2009) or life-cycle cost (Nofuentes et al. 2002).

Both metrics are likely to be used by potential commercial and large-scale PV market segments and may additionally be used by some residential customers. The B/C ratio is frequently used in the public sector.

4.3 Internal Rate of Return and Modified Internal Rate of Return

The IRR represents the discount rate at which the project NPV equals zero and is frequently interpreted as the annualized return on investment. The upfront nature of PV costs and tax incentives can lead to several challenges in calculating and interpreting PV IRRs, which are discussed in detail in Section 7 and Appendix B. Modified IRRs (MIRRs) are similar to IRRs, but positive net revenues are explicitly reinvested at the company's, or an individual's, opportunity cost of capital[6] rather than implicitly reinvested at a rate equal to the system IRR. This tends to shift low IRRs up to the reinvestment rate and high IRRs down to the reinvestment rate (McKinsey & Co. 2004). The IRR and MIRR metrics are likely to be used to evaluate commercial and large-scale PV investments.

4.4 Simple and Time-to-Net-Positive-Cash-Flow Payback

Investment payback times have several definitions (Duffie and Beckman 2006). We include two in this analysis:

- **Simple payback time**—The time required for undiscounted PV net revenues to equal the initial investment cost (Perez et al. 2004; Paidipati et al. 2008; Black 2009).
- **Time-to-net-positive-cash-flow (TNP) payback time**—The time required for: (1) the discounted PV revenues to exceed the discounted system costs accrued to that date and (2) the discounted revenues to remain higher than discounted costs for the duration of the investment (Nofuentes et al. 2002; Sidiras and Koukios 2005; Audenaert et al. 2010).

Simple and TNP payback times are the most frequently used payback metrics for PV investments, but there are several other payback definitions. Although we do not evaluate the relative economics of each payback definition, the difference between simple payback times and TNP payback times illustrate the wide range in payback times that are generated by different payback definitions. These differences are primarily driven by the fact that simple payback times are not sensitive to financing parameters or the relative timing of system costs and revenues, whereas other payback metrics can be very sensitive to these and other parameters. The simple and TNP payback metrics are likely to be used to evaluate residential and some commercial PV investments.

4.5 Annualized Monthly Bill Savings

Annualized MBS are used to characterize the potential average decrease in a PV customer's electricity bill resulting from a PV investment. We estimate this based on the difference between PV levelized costs of energy (LCOEs) and effective electricity rates, multiplied by the discounted electricity generated by a PV system in a given year. Based on differences in PV electricity generation profiles and retail electricity rates in different months, the MBS in any given month will likely be higher or lower than the annualized MBS.

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[6] The opportunity cost of capital is the rate of return that could be realized on alternative investments of equivalent risk (Stermole and Stermole 2009).

The MBS metric is frequently used by third-party PV companies to characterize PV value to potential customers (NREL 2009; SolarCity 2011; SunRun 2011). Third-party PV companies can repackage PV costs and revenues into a simple product that shows monthly bill savings, and their customers are likely to characterize PV value in these terms. This potentially reduces the complexity of valuing a PV investment by framing PV returns in an intuitive measure that may be more likely to entice customer adoption (Wilson and Dowlatabadi 2007). While a mean annualized MBS can be calculated for customer-owned systems, the annualized MBS will not reflect the actual PV costs and revenues generated by a PV investment, and it is less likely that customer-owned PV adopters will use MBS to represent investment value.

The MBS earned by a PV project can vary for different ownership structures. For example, a third-party owned residential PV system represents a depreciable asset, which could potentially allow a third-party owned PV system to produce higher bill savings than a residential customer. The difference for commercial systems is not as pronounced because commercial customers already depreciate PV assets, but third-party owned MBSs could potentially be slightly higher, as described in Appendix A. However, the higher cost of capital for third-party PV companies will reduce potential PV returns, and it is unclear whether the combination of different tax structures and costs of capital will lead to higher or lower returns. We explore the impact ownership-dependent tax structures, but not costs of capital, in this analysis.

4.6 Levelized Cost of Energy

The LCOE represents the discounted price that PV electricity must be sold at to recoup discounted project costs over the life of the system. PV LCOEs are calculated in units of real dollars in this analysis, whereas PV project developers and utilities often use nominal LCOEs. Unlike all other economic performance metrics in this analysis, PV LCOEs are relative metrics that must be compared to the value of the electricity generated, which can range from the electricity price seen by the customer or LCOEs from different technologies. These valuations frequently do not capture the general correspondence of PV generation with times of peak electricity demand and electricity prices (Borenstein 2008), and the use of different comparison values can lead to a wide range in the perceived economics of identical PV systems. Other metrics may be less prone to multiple interpretations of value.

4.7 Use of Different Economic Metrics in the PV Literature

PV users frequently use different economic performance metrics because they prioritize PV investment risk and returns differently. For example, home owners might be interested in PV systems with short payback times because they are uncertain about how long they will live in their current home and how a PV investment will affect their home’s value. Research has suggested that residential customers, and some commercial customers, are more likely to use payback times to characterize the value of a PV investment or other energy-saving investments (Kastovich et al. 1982; Perez et al. 2004; Sidiras and Koukios 2005; Black 2009). Residential and commercial customers may also think of PV value in terms of how much their monthly electricity bills will decrease if they invest in PV, and third-party owned PV companies frequently market PV products using bill savings metrics (NREL 2009; SolarCity 2011; SunRun 2011).

Potential commercial PV customers may think of PV as a longer-term investment than residential customers and may be more likely to characterize PV value as an annualized return on investment (Chabot 1998; Talavera et al. 2007; Talavera et al. 2010). Commercial customers may use B/C ratios, PIs, IRRs, or MIRRs to compare potential PV returns relative to other investment opportunities.

Utilities and large-scale developers frequently characterize PV costs in terms of LCOE (CEC 2007; SunPower Corp. 2008), which can be compared to wholesale electricity prices, local PPA offerings, or the LCOEs of different generation technologies. Large developers may also use additional metrics such as the B/C ratio, NPV, IRR, MIRR, or others to rank PV investment performance relative to other investment opportunities.

Several recent European studies have recommended using IRRs to characterize PV value (Nofuentes et al. 2002; Talavera et al. 2007; Talavera et al. 2010; Audenaert et al. 2010). Wind investors frequently use IRR-based hurdle rates[7] to characterize project economics (Harper et al. 2007) and may apply similar investment criteria to evaluate solar projects. Others have recommended the use of metrics based on NPV, such as PI (Chabot 1998; Nofuentes et al. 2002; Audenaert et al. 2010).

[7] A hurdle rate represents the minimum rate of return that a company or project manager is willing to accept before developing a project.

5 Reference PV System Assumptions

To calculate the sensitivity of PV economic performance to a range of system parameters, we first define reference PV price, performance, and financing assumptions and apply these to all PV market participants (Table 2). We assume identical system characteristics for each market participant, which does not capture the differences seen for each customer type.[8] However, this assumption is made to highlight how the use of different economic performance metrics can shape the perceived value of a PV investment.

The reference assumptions in Table 2 are used to evaluate the relative economics for residential and commercial systems for each economic performance metric over a range of price, performance, and financing parameters. Some states have a combination of PV incentives and retail electricity rates where PV economic performance may meet or exceed the reference conditions (e.g., Florida, Hawaii, New York, New Jersey, and parts of California) (DSIRE 2011; EIA 2011b). PV systems installed in other states may generate lower economic returns than the reference conditions. One challenge in characterizing the value of PV electricity is that several rate structures vary by time or season (time-of-use rates), peak electricity use (demand-based rates), or total electricity use (tiered rates). Regardless, the reference values in Table 2 are not meant to characterize representative U.S. PV economic performance; they are meant only as a starting point for the sensitivity analysis, which is used to compare the relative value of PV, as shown by different economic performance metrics.

[8] For example, in the first quarter of 2011 PV prices varied from $3.85/W for utility-scale systems, to $5.35/W for commercial systems, to $6.41/W for residential systems (SEIA-GTM 2011). However, electricity prices are frequently twice as high for residential retail markets as they are for wholesale electricity markets (EIA 2011a).

Table 2. Reference PV System Parameters

	Reference Characteristics
Effective PV Price[a]	$4,000/kW
Capacity Factor[b]	17%
Annualized Electricity Rate[c]	$0.15/kWh
Annual Electricity Rate Increase (real dollars)	None
PV Performance Degradation	0.5%/year
Down Payment	20%
Loan Rate (real)	5%
Loan Term	20 years
Duration of Economic Analysis	30 years
Capital Reinvestment Rate[d] **(real)**	8%
Discount Rate[e] **(real)**	5%
Incentives	30% federal ITC; capital depreciation for commercial customers[f]
Net Metering	Full
Carbon Policy	None[g]
Annualized Operations and Maintenance Payment[h]	$35/year for years 1-10 $25/yr for years 11-20 $20/yr for years 21-30
Analysis Term	30 years
Tax Rates	State and federal tax rates are combined into an aggregate tax rate of 35% for residential customers and 40% for commercial customers
Tax Implications	After-tax energy costs for residential; before-tax energy costs for commercial

[a] Effective PV price (in 2010 U.S. dollars) represents the system price after taking state and local PV incentives but not the 30% federal ITC.

[b] A 17% PV capacity factor roughly represents PV output from a fixed-tilt (tilt = latitude) residential PV system in Kansas City, Missouri (SAM 2011). Similar PV systems are likely to perform better (21.5% capacity factor in Phoenix, Arizona) or worse (15.5% capacity factor in Chicago, Illinois) (SAM 2011).

[c] The reference annualized rate is higher than the average U.S. retail electricity rate from June 2010 for residential ($0.12/kWh) and commercial ($0.11/kWh) customers (EIA 2011b). However, the annualized rate is at or below the June mean electricity rates for states in New England, the Middle Atlantic, and California (EIA 2011b).

[d] The capital reinvestment rate is used to calculate the MIRR and represents the rate of return a company could receive on investments of similar risk outside the project. This is frequently referred to as the opportunity cost of capital (Stermole and Stermole 2009).

[e] The discount rate is assumed to be the same as the loan rate in the reference scenario to avoid introducing a time value of money for debt financed capital.

[f] Commercial depreciation follows a five year Modified Accelerated Cost Recovery System schedule (DSIRE 2011).

[g] We do not include carbon policy in the reference scenario; however, we do include carbon prices in the sensitivity analysis. We assume a 0.58 kg CO_2/kWh carbon intensity, based on mean emissions rates from the U.S. electricity sector (EIA 2011a), to represent the increase in electricity rates for a range of carbon policies.

[h] Operation and maintenance costs are assumed to decrease over time to reflect technical improvements, primarily longer inverter lifetimes, and lower costs.

Figure 1 shows annual after-tax PV cash flows for customer-owned residential and commercial PV systems that are calculated using the reference parameters in Table 2. PV costs are primarily composed of an initial down payment, followed by annual loan payments and operation and maintenance (O&M) costs. These costs are partially offset by system tax benefits, including the federal ITC, Modified Accelerated Cost Recover System (MACRS) capital depreciation for commercial customers, and tax-deductible payments on loan interest.[9] Annual PV revenues are primarily based on the PV output multiplied by the annualized value of PV electricity. PV revenues are also affected by state and local net-metering policy (NNEC 2010).[10] PV generation decreases over time based on an assumed 0.5%/year system degradation, with a corresponding decrease in annual PV revenue.

[9] The interest paid on a residential home mortgage, or a home equity loan up to $100,000, is tax deductible (IRS 2010).

[10] Net metering is a market mechanism that sets the value of PV generation that exceeds electricity use over a given amount of time. In areas with full net metering, excess PV electricity is purchased by local utilities at retail electricity rates. Other areas have partial net-metering policies in which excess PV generation is valued at prices that are similar to wholesale electricity rates and are roughly based on the value of offsetting fossil fuel use. Other areas have no net-metering policy and excess PV generation is not valued.

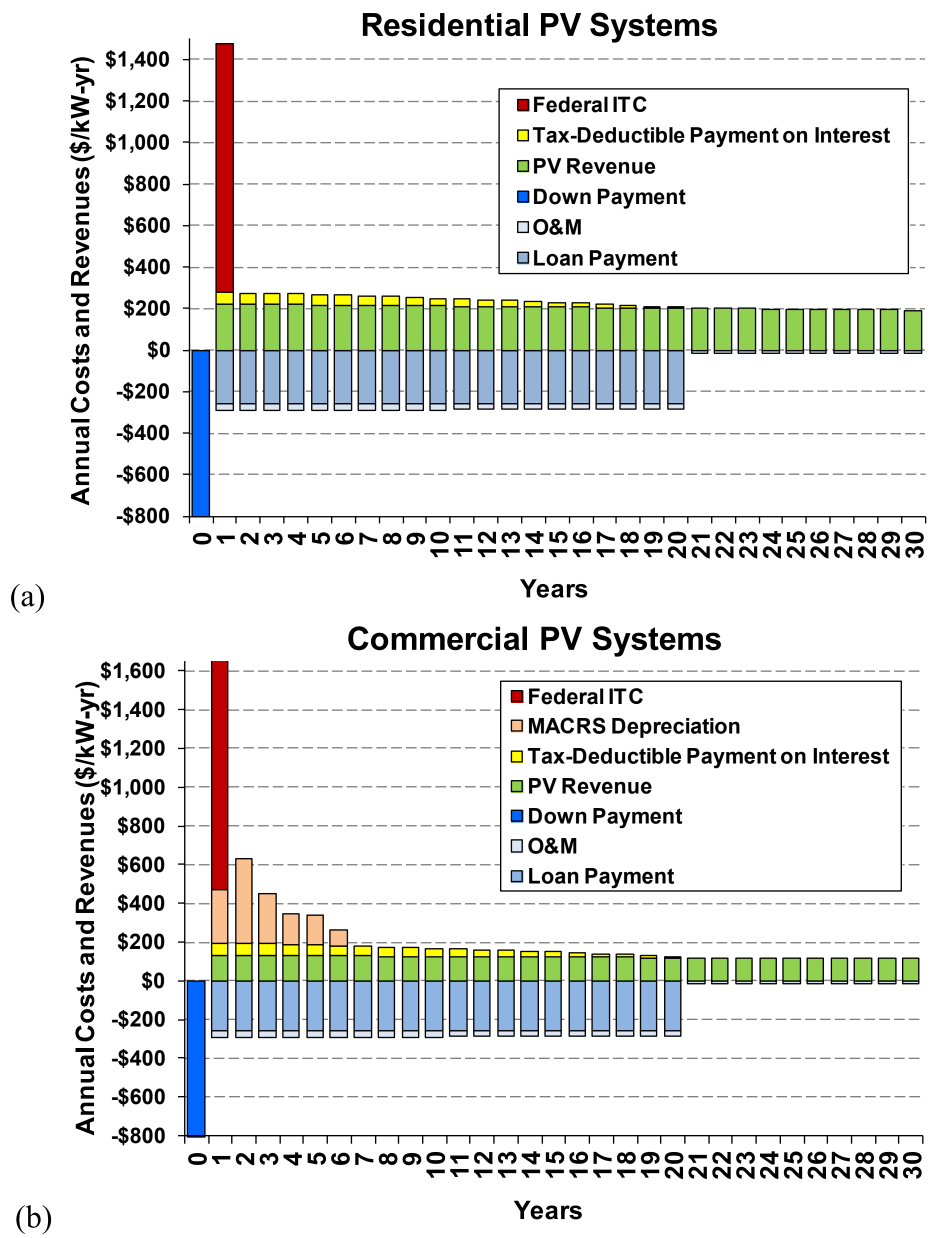

Figure 1. Reference residential (a) and commercial (b) undiscounted annual PV system costs, revenues, and tax benefits given in real dollars

Figure 1 shows that the largest annual PV costs (down payment) and tax incentives (federal ITC and MACRS) occur in the first few years of system ownership. After this, the reference PV costs and revenues are nearly identical, leading to small net revenues or net costs each year. The upfront nature of PV costs and incentives has a significant impact on some economic performance metrics (e.g., IRR and TNP payback) but not others (e.g., simple payback).

In addition to the customer-owned PV systems shown in Figure 1, we also characterize the MBS that could be offered by third-party owned PV companies (see Section 4.5 and Appendix A) using the project assumptions listed in Table 2. Third-party owned PV systems are a rapidly growing market segment (Drury et al. 2011; SEIA-GTM 2011) because of their potential to reduce several adoption barriers like upfront adoption costs and technology risk and complexity. We focus the analysis only on the potential MBS that could be offered to a building occupant, and we do not characterize PV returns to third-party companies or various tax, equity, and debt investors. We also assume the same PV prices, and other system parameters listed in Table 2, as those used for other ownership structures.

The following sections evaluate the sensitivity of PV economic performance to varying system price (Section 6) and non-price (Section 7) system characteristics. The sensitivity of PV economic performance to varying prices provides insight into how different economic metrics can exhibit unique price thresholds for when a PV investment may begin to look attractive. The sensitivity of PV economic performance to each non-price parameter (PV generation, financing, and electricity market assumptions) provides insight into how future market and policy projections could differentially impact PV market participants.

6 Sensitivity Analysis—Effects of PV Price

In this section, we evaluate the relative sensitivity of PV economic performance to a range of system prices and evaluate the different thresholds for when PV becomes a profitable investment for different performance metrics. Figure 2 shows PV economic performance for a range of effective PV prices from $1,000–$7,000/kW,[11] calculated for each economic performance metric. Effective PV prices represent the total installed system price after taking state and local incentives but before taking the 30% federal ITC. [12] This range in effective PV prices covers the range of current PV prices seen by U.S. customers, which are subject to widely varying state and local PV incentives (DSIRE 2011). All non-price assumptions are based on the reference parameters in Table 2, and the economic returns represent after-tax valuation for both residential and commercial systems.[13] As such, the returns from a PV investment must be compared to the after-tax returns from other investment opportunities. Because energy costs are tax deductible for commercial customers, commercial LCOEs are adjusted to represent the before-tax cost of electricity to compare with retail or wholesale electricity rates. Both the NPV and MBS represent the value generated by 1 kW of PV capacity; the actual net savings or costs will be larger based on system size. Lastly, we add one to the PI metric (1 + PI) so that PI results can be compared to B/C ratios. This scaling does not affect PI sensitivities—it just shifts the results so that returns are positive if (1 + PI) is greater than one, and returns are negative if the results are less than one.

[11] Here and elsewhere, all PV costs, revenues, and market price projections are given in units of 2010 U.S. dollars.
[12] Although the application of PV incentives varies by state, the general trend is that state and local incentives are taken first, and then the 30% federal ITC is taken from the remaining system price. In this way, state and local incentives reduce the federal incentive.
[13] PV generation offsets after-tax energy costs for residential systems. However, commercial PV generation offsets tax-deductible energy costs, and commercial electricity rates are scaled by (1 – effective commercial tax rate) to generate after-tax returns (Figure 1).

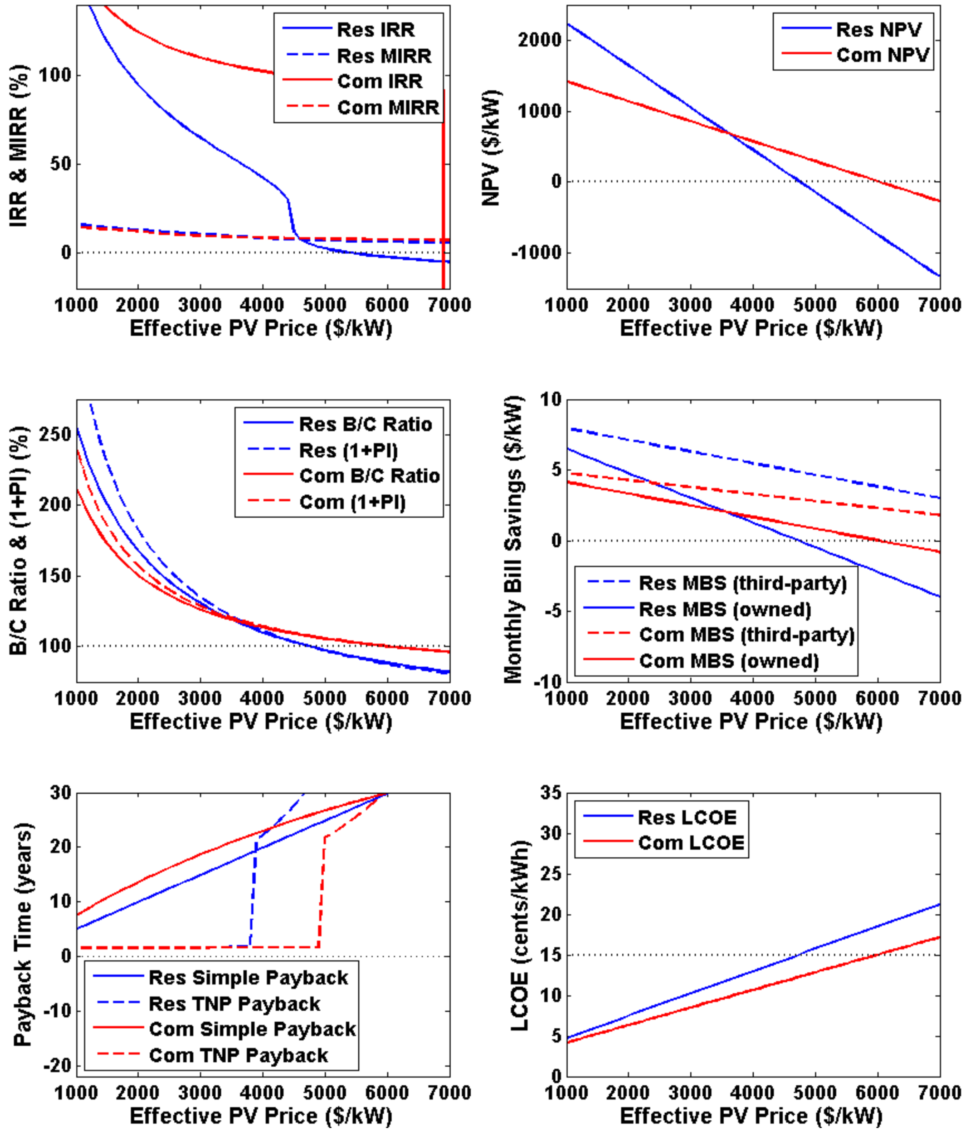

Figure 2. PV economic performance, characterized using several metrics, for a range of effective PV prices for residential ("Res") and commercial ("Com") systems

Note: Here and elsewhere, PI is shifted by adding one (1 + PI) to better compare PI performance to B/C ratios. MBSs are shown for both customer-owned and third-party owned systems to characterize the different tax implications of ownership. The dotted black line shows the transition from an unprofitable to a profitable investment, with the exception of payback time, where it shows an instantaneous payback that defines the lower limit. All returns are after-tax and given in units of real dollars.

Figure 2 shows the different sensitivities of PV economic performance to price. The behavior of different metrics can be roughly categorized as those showing: (1) a nearly linear response to changing PV prices, including NPV, MBS, MIRR, simple payback times, and LCOE; (2) a non-linear, smoothly varying response to changing prices, including B/C ratio and PI; and (3) strong threshold behavior, including IRR and TNP payback times. Potential customers can typically expect a higher sensitivity to changing PV prices when using metrics that show non-linear or threshold behavior. For example, IRR shows a 4.5% annualized return on a $4,800/kW residential PV system and a 30.3% return on a $4,400/kW system. The decrease in effective PV price from $4,800/kW to $4,400/kW could potentially make a PV investment look attractive to a residential customer if they use IRR to characterize PV value. However, this same decrease in residential system prices leads to a $0.01/kWh decrease in residential PV LCOE (from $0.15/kWh to $0.14/kWh), a two-year reduction in simple payback time (from 23.9 to 21.9 years), a $0.70/kW-month increase in MBS for customer-owned systems (from –$0.15/kW-month to $0.55/kW-month), and about a 5% increase for the B/C ratio (from 0.99 to 1.04) and PI metric (from –0.01 to 0.04). The improvement in IRR returns for a reduction in system price from $4,800/kW to $4,400/kW is much larger than the associated improvements for other metrics and customers using IRR may be more likely to adopt PV given this price reduction. Commercial PV systems show similar non-linear and threshold behavior to changing prices.

Both commercial and residential IRRs show very high returns relative to other metrics and strong threshold behavior. This is primarily caused by the upfront nature of system costs (down payment) and incentives (federal ITC and MACRS for commercial customers). The timing of system costs and revenues leads to several challenges for calculating and interpreting PV IRRs, and we generally find that IRR is a poor metric for characterizing the value of U.S. PV systems, as discussed in Appendix B.

One consequence of the metric-dependent nature of PV returns is that each metric can show a different price threshold for when a PV investment becomes profitable or attractive enough to entice adoption. For example, residential NPV, PI, and MBS (customer owned) all pass from negative to positive returns when PV prices reach $4,700/kW. At this same price, residential PV LCOEs become less expensive than effective electricity rates, and the B/C ratio passes through unity, representing a profitable investment. However, residential IRRs become positive at $5,400/kW, and MIRRs are positive for all system prices but do not exceed the assumed 8% (real) reinvestment rate[14] until PV prices are below $4,200/kW. Third-party owned MBS are also positive for all system prices evaluated in Figure 2 (Appendix A). Simple payback times are about 23 years for $4,700/kW residential PV systems and are not reduced to less than 10 years until effective PV prices reach $2,000/kW. Residential TNP payback times transition from more than 20 years to less than 2 years at $3,800/kW.

We find similar relationships for commercial PV systems, where a $6,000/kW system price will produce positive NPVs, PIs, and MBSs (customer owned), while different metrics can show higher or lower price thresholds for when an investment becomes profitable. Commercial systems typically show higher returns than residential systems at higher PV prices and lower relative returns at lower prices, as shown by the lower slope between commercial PV returns and price relative to residential systems. This is because, at higher PV costs, MACRS depreciation typically has a greater impact on net returns than the decrease in commercial PV revenues (commercial energy costs are tax deductible). The converse is true at lower PV prices, where the reduction in commercial PV revenues has a greater impact on project economics than MACRS depreciation. Not all metrics follow this general trend. For example, payback times are typically lower for residential systems than commercial systems.

[14] The reinvestment rate represents a company's opportunity cost of capital, or the returns they could expect on invested capital. For a PV system to be a profitable investment, relative to other investment opportunities, the PV MIRR must exceed the assumed reinvestment rate.

The difference in PV price thresholds between metrics could significantly shape the perceived value of a PV investment for different customers. For example, a commercial customer may be interested in investing in a $6,000/kW PV system if they use positive system NPVs, PI, and B/C ratios as their investment criteria. However, a similar commercial customer may base their investment decision on achieving a simple payback time of 10 years or less and wait for effective PV prices to reach $1,300/kW before investing. In this case, the choice of an economic performance metric could have as much impact on the investment decision as changing PV prices by a factor of four. In addition, even if residential and commercial customers used the same investment criteria (e.g., a positive NPV or PI), the commercial customer may be enticed to adopt a $6,000/kW system while a residential customer may wait for effective PV prices to reach $4,700/kW.

Another challenge is to understand not only what price thresholds represent a *profitable* investment (net revenues exceed costs) but what prices represent an *attractive* investment (returns are high enough to entice customer adoption). For example, a PV system that generates a PI greater than zero represents a profitable investment, but a potential customer may look for additional returns such as a PI greater than 0.2 before investing (Chabot 1998). However, the system that produced a PI greater than zero would generate a positive MBS, which may be sufficient to entice customer adoption. In this case, the system characteristics are identical and the returns are similar, but a customer may perceive the value of PV to be higher if returns are described in terms of bill savings rather than PI, which could lead to higher effective price thresholds for adoption. This is not specific to PV; general customer behavior has been shown to be influenced by the way information is presented (e.g., Wilson and Dowlatabadi 2007), and customers typically value near-term savings or costs much more than savings or costs that occur in the distant future (see Section 9).

Lastly, Figure 2 shows that third-party owned PV systems could potentially generate higher MBSs than identical customer-owned systems based on the different tax structures for third-party ownership (see Appendix A). The higher returns are based on the assumption that third-party PV companies can depreciate PV assets based on MACRS and that they are likely to have a higher tax rate, which typically increases PV value (see Section 7). Because of this, a third-party owned residential and commercial system could potentially generate positive bill savings for a $7,000/kW system, while an identical customer-owned residential or commercial system would have to reach $4,700/kW or $6,000/kW, respectively, to generate positive bill savings. The MBS for third-party owned PV systems show profitable returns at higher costs than any other metric. However, we assume the same cost of capital for third-party owned systems and customer-owned systems, which likely overestimates the potential MBS that could be offered by third-party PV companies.

7 Sensitivity Analysis—Effects of Non-Price Parameters

In this section, we evaluate the relative sensitivity of PV economic performance to a range of non-price system parameters for several performance metrics: PI[15] and B/C ratio, payback times, MBS, IRR and MIRR, and LCOE. We calculate and compare the relative sensitivities for: (1) several non-price parameters within one metric and (2) one non-price parameter between several metrics. The relative sensitivity of one metric to several non-price parameters gives insight on how a market participant, using a specific metric, may react to varying system parameters, either through a natural evolution of market conditions or through directed policy. The relative sensitivity of varying one non-price parameter across several metrics gives us insight into how a market or policy change could differentially impact several different types of market participants.

7.1 Profitability Index and Benefit-to-Cost Ratio

Figure 3 shows the sensitivity of the B/C ratio and PI to a range of non-price system characteristics for a PV system at the reference $4,000/kW[16] price. We shift PI by one (1 + PI) in Figure 3 to better compare PI and B/C ratio sensitivities. In general, the B/C ratio and PI show similar returns and sensitivities, are smoothly varying, and do not exhibit threshold behavior.

[15] We do not include NPV because all of the important trends and sensitivities are shown by the PI metric since it is equal to NPV normalized by the undiscounted initial investment price. NPV was shown in Figure 2 because the investment price was a variable, and the trends for NPV and PI are not identical.

[16] Here and elsewhere, the reference PV price includes all state and local incentives but not the federal ITC. PV price represents 2010 U.S. dollars.

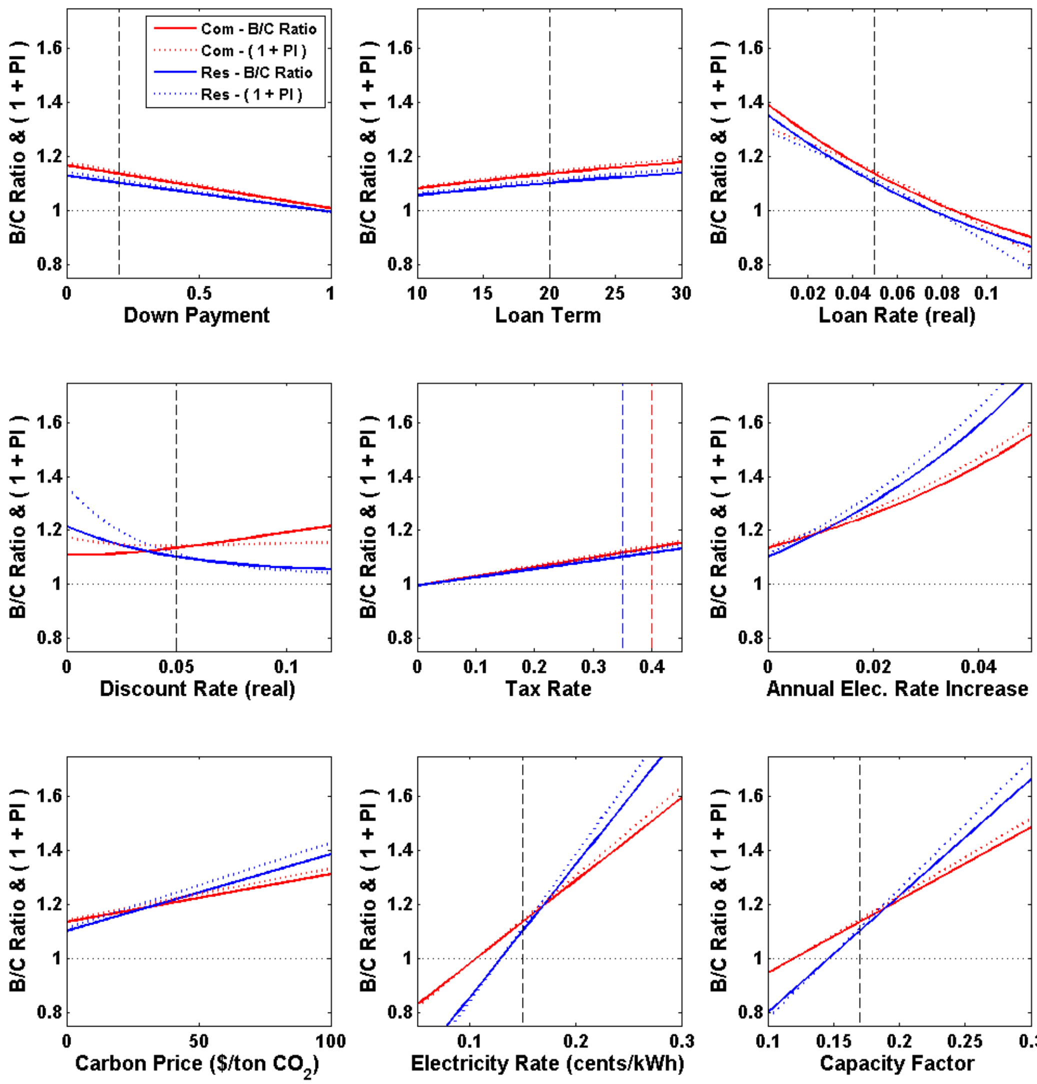

Figure 3. B/C ratios and the shifted PI (1 + PI) are shown for $4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters

Note: Vertical dashed lines show the reference PV assumptions, and horizontal dotted grey lines show the demarcation between a profitable and unprofitable investment.

The B/C ratio and PI sensitivities illustrate several general trends. PV returns typically increase if: (1) the system costs are spread out over more years (lower down payment fraction or longer loan term), (2) the system costs are reduced (lower loan rates[17] or higher tax rates), or (3) the system revenues are increased (increased electricity rates, positive rate escalations, carbon emission pricing,[18] or increased capacity factors). We find that B/C ratios and PIs show similar

[17] Decreasing the loan rate has two effects: (1) it reduces the cost of borrowing money, and by extension, the cost of the PV system, and (2) it can introduce a time value for money because the discount rate is held fixed at the reference loan rate. If the loan rate is lower than the discount rate, the discounted sum of loan payments is less than the initial price of the PV system, and the converse is true for loan rates that are higher than the discount rate.

[18] Carbon policy would increase the cost of electricity generated by burning fossil fuels. For example, coal-generated electricity produces about 1 kg CO_2/kWh, and natural gas generators produce about 0.45 kg CO_2/kWh (mean emissions from the combination of combustion turbine and combined cycle gas generation) (EIA 2011a). A

returns, and the use of either metric is roughly interchangeable with the exception of varying discount rates.[19]

Several metrics show higher commercial returns and lower residential returns for increasing discount rates. For commercial customers, this trend is based on the increased impact of near-term incentives (30% federal ITC and MACRS) and the decreased impact of later-term cash flows where loan payments and O&M costs often exceed PV revenues, as shown in Figure 1. The converse is true for residential systems, where the increased influence of near-term incentives (30% federal ITC) has less impact than the reduced influence of later cash flows where PV revenues often exceed loan payments and O&M costs.

The B/C ratio, PI, and several other metrics frequently show higher returns for increasing tax rates since higher tax rates effectively lower the price of a financed PV system. This is because payments on loan interest are typically tax deductible, which effectively reduces the cost of a PV system. Commercial customers can also depreciate a PV asset following MACRS, which increases in direct proportion to the company's tax rate. However, commercial PV revenues also decrease in direct proportion to their tax rate, and we find the benefits from MACRS depreciation are roughly canceled by the decrease in revenues for a $4,000/kW PV system. While we do not calculate PV economics for public sector and non-profit entities, the economics of these systems are shown for reference parameters by a tax rate of zero. PV returns are significantly lower for these systems, and states frequently compensate for this by developing larger incentives for this market segment (DSIRE 2011). Another option for the public sector or non-profits could be to adopt third-party owned PV systems (Bolinger 2009), where the third-party company could benefit from non-zero tax rates and potentially pass these benefits on to the end user.

PV returns also predictably increase with increasing system revenues. PV returns can be particularly sensitive to the assumed increase in electricity rates over time, and PV retailers often assume a non-zero increase in real electricity rates over time when characterizing PV economic returns (e.g., SolarCity 2011; Sun Light & Power 2011). For example, a 3% annual electricity rate increase (real dollars) has as much of an impact on residential system economics as decreasing the loan rate to about 0% or introducing a $100 per metric ton of CO_2 price. Rate increases are also frequently written into PPA contracts offered by third-party PV owners, with a similar increase in the returns third-party PV providers generate from their PV assets. Potential PV customers should be careful to understand how this and other market assumptions affect PV economics, and this represents a strong opportunity for the public sector to help inform potential PV adopters.

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carbon price of $20 per metric ton of CO_2 (spot price of carbon in the EU Emissions Trading System for January 2011) would add about $0.02/kWh to coal-generated electricity and about $0.01/kWh to electricity generated by natural gas.

[19] The B/C ratio differs from the (1 + PI) metric in that PI is calculated by dividing the NPV by the initial system price (Table 1), whereas the B/C ratio is calculated by dividing the discounted revenues by the discounted system cost. The B/C ratio frequently equals (1 + PI) when the discount rate is close to the loan rate, at a value where the discounted loan payments and O&M costs equal the initial system price. However, the discounted loan payments are higher than the initial system price if the discount rate is lower than the loan rate, and the converse is true if the discount rate is higher than the loan rate. This results in higher (1 + PI) returns for discount rates that are lower than the loan rate and higher B/C ratios for discount rates that are higher than the loan rate.

7.2 Internal Rate of Return and Modified Internal Rate of Return

Figure 4 shows IRR and MIRR for residential and commercial PV customers for a range of non-price system characteristics. IRR is very high for the reference system parameters (42% for residential and 102% for commercial) and exhibits strong threshold behavior. These trends are driven by the upfront nature of PV costs (loan down payment) and revenues (federal ITC and MACRS for commercial customers). IRRs are also sensitive to cash flows that change sign, and net PV cash flows frequently oscillate from negative to positive multiple times, as discussed in Appendix B.

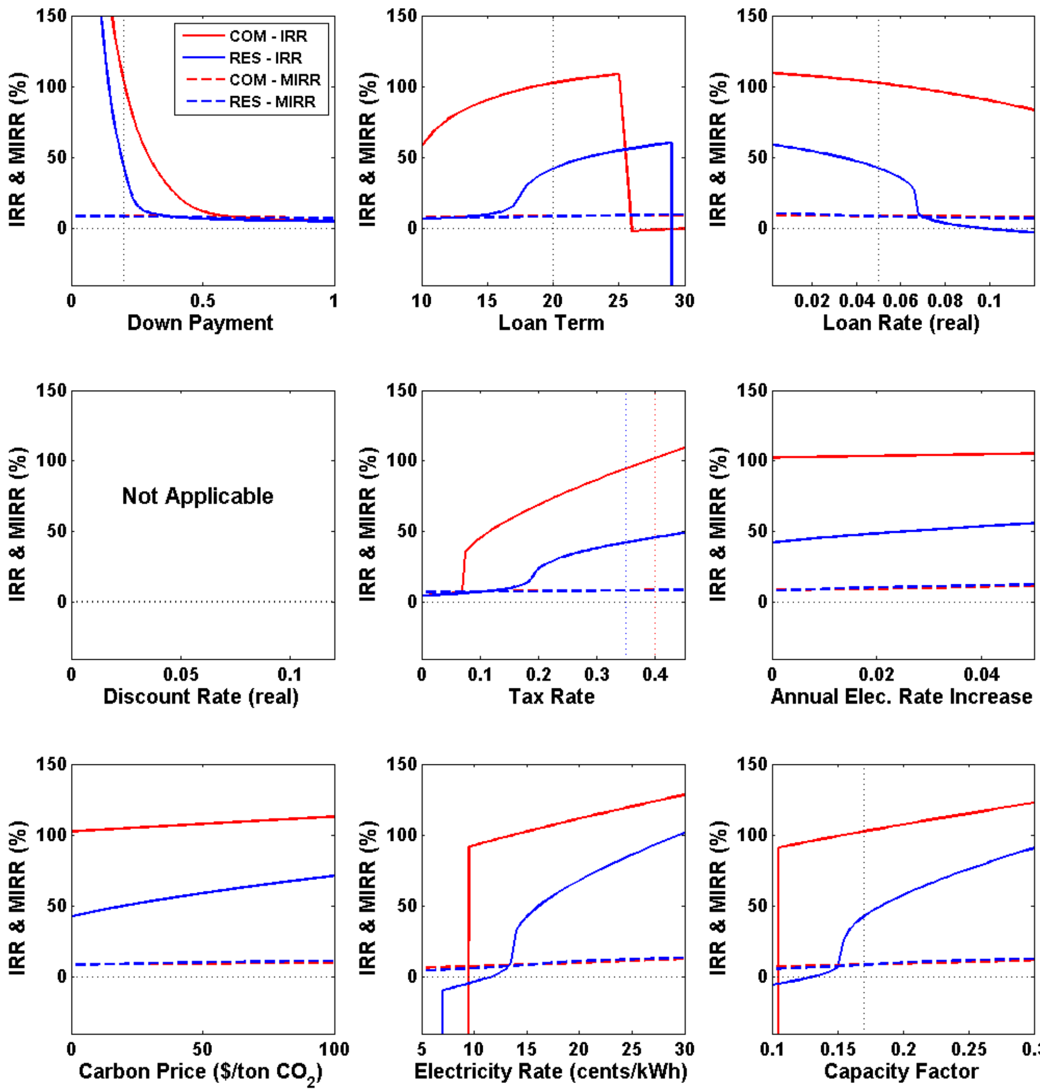

Figure 4. IRR and MIRR for $4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters

Note: Vertical dashed lines show reference PV assumptions.

PV IRRs are very sensitive to variables that affect the timing of system costs (down payment fraction and loan term) and upfront incentives (tax rate that scales MACRS depreciation and tax-deductible payments on loan interest). Commercial IRRs are typically much higher than residential IRRs because the upfront nature of MACRS depreciation has more of an impact on system IRRs than the reduced PV revenues (energy costs are tax deductible for the commercial customers considered here). The IRR is less sensitive to parameters that affect mean system costs (loan rate) or revenues (electricity rate escalations and carbon prices) unless the variations are sufficient to move IRR beyond a threshold (electricity rates and capacity factors).

When PV cash flows are sufficient to achieve system IRRs of about 50% or higher, IRRs become relatively insensitive to further improvements in system characteristics. This is because high IRR solutions represent very high discount rates, which magnify the importance of PV costs and revenues in the first few years of ownership and reduce the impacts of costs and revenues in later years. For example, pricing carbon emissions would lead to higher PV returns over the life of the investment, but for a commercial system with an IRR (and discount rate) greater than 100%, the benefits are so highly discounted that IRR becomes virtually insensitive to carbon price.

The IRR is very sensitive to the loan down payment fraction. This is primarily because it impacts the balance of upfront costs (loan down payment) and incentives (federal ITC and MACRS depreciation). The sensitivity to down payment fraction is important for residential customers who may pay for the system out of pocket (corresponding to a 100% down payment), finance the system through a home-equity loan (zero or small down payment), or roll the system cost into the home mortgage for new homes, with a corresponding wide range in potential down payment fractions. The sensitivity to down payment fraction is also important for commercial customers. Small commercial companies may get dedicated financing for a PV investment, while larger commercial customers may use existing capital and debt reserves to develop the system. If the latter method is used, the down payment fraction is roughly based on a company's debt-to-equity ratio, which can vary significantly both within and across industries. Since PV IRRs are so dependent on this uncertain parameter, it is challenging to specify a reference IRR for each type of market participant. Rather, PV economic analysis should be calculated on a project-specific basis.

We generally find higher IRRs for U.S. PV systems than the IRRs calculated for similar European PV systems (Audenaert et al. 2010; Talavera et al. 2010). This difference is driven by the upfront incentives available to U.S. systems (federal ITC and MACRS depreciation for commercial systems), as compared to the production-based incentives frequently available in European PV markets. We also find that the IRRs calculated for U.S. PV systems are much more sensitive to the customer's tax rate than the IRRs calculated for European systems (Talavera et al. 2010) because tax rates directly scale both MACRS depreciation and the tax-deductible payments on loan interest for U.S. systems. Generally, IRRs for U.S. systems also exhibit stronger threshold behavior because of the upfront nature of PV costs and incentives. Unlike recent European studies, we find that IRR is a poor measure of PV value because of the differences between U.S. versus European incentives. We evaluate the challenge of calculating and interpreting PV IRRs for U.S. systems in further detail in Appendix B.

The MIRR has been proposed as a better metric for characterizing investment returns than the IRR (McKinsey & Co. 2004). However, the upfront nature of PV costs and incentives makes the MIRR highly sensitive to the assumed reinvestment rate (8% in the reference case) and relatively insensitive to other system characteristics. For example, the reference commercial MIRR is

8.7%. This MIRR increases to 9.9% if the annualized electricity rate is increased from \$0.15/kWh to \$0.20/kWh and increases to 12.6% if the electricity rate is increased to \$0.30/kWh. MIRR also shows a similarly small increase for decreasing PV prices (Figure 2). These and other changes in PV price and performance characteristics have a far greater impact on the other economic performance metrics. The upfront nature of PV costs and incentives makes the MIRR unresponsive to varying input parameters and strongly dependent on the assumed reinvestment rate, and we generally find that the MIRR is a poor measure of PV value for U.S. systems.

7.3 Simple and Time-to-Net-Positive-Cash-Flow Payback

Potential residential and smaller commercial customers may use payback times to characterize the value of PV or other energy efficiency investments (Kastovich et al. 1982; Perez et al. 2004; Sidiras and Koukios 2005). One challenge is that there are several definitions of PV payback time (Duffie and Beckman 2006), each of which can give a different perception of value. Here, we characterize the sensitivity of PV payback time to several system parameters using both the simple payback time definition (Kastovich et al. 1982; Perez et al. 2004; Black 2009) and the TNP payback definition (Nofuentes et al. 2002; Sidiras and Koukios 2005; Audenaert et al. 2010). Although there are several other payback definitions, the relative performance of these two metrics illustrates how different definitions of payback can lead to a large range in payback times and sensitivities.

Figure 5 shows simple and TNP payback times for a range of non-price system characteristics. Based on the common definition of simple payback time (Table 1), the simple payback metric is insensitive to financing terms, discount rates, and electricity-rate increases since only the first year of revenue is considered in the formulation used. Simple payback times are mainly affected by increasing system revenue (electricity rates and capacity factors) or lowering system cost (Figure 2) and remain longer than 10 years for nearly all variations in non-price project parameters.

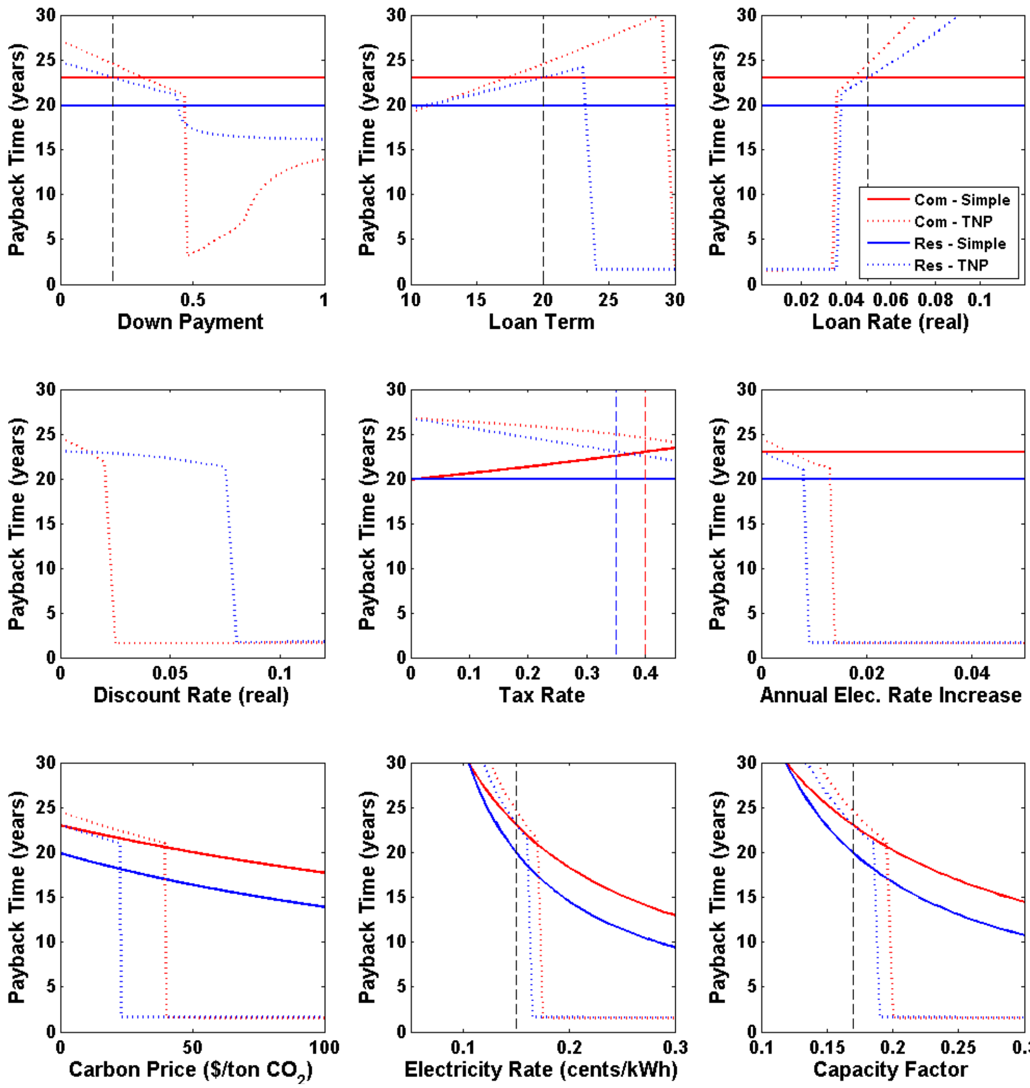

Figure 5. Simple and TNP payback times for $4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters

Note: Vertical dashed lines show reference PV assumptions.

TNP payback frequently shows significantly lower payback times than simple payback and exhibits strong threshold behavior. For residential systems, these include small improvements in loan term, loan rate, capacity factor, and higher electricity rates. For commercial systems, these include shorter loan terms, higher loan rates, lower capacity factors, lower electricity rates, and lower tax rates. The threshold behavior for payback times is not unique to the TNP payback metric; several other payback definitions (Duffie and Beckman 2006) are likely to show similar threshold behavior for varying system price and non-price parameters.

Customers using payback metrics may be less likely to adopt PV than if they used other metrics to characterize PV value. Simple payback times are frequently on the order of decades, which may not entice customers to adopt, particularly residential customers who frequently internalize high discount rates when valuing energy saving investments (Wilson and Dowlatabadi 2007). Although the TNP payback metric frequently shows very short payback times, the large sensitivity to system assumptions, seen by the strong threshold behavior, may confuse potential customers as to the actual value of a PV system, which may reduce adoption because of customer aversion to uncertainty (Wilson and Dowlatabadi 2007). Also, PV customers using simple payback times to characterize PV value are insensitive to improving several non-price system parameters, and they may only be enticed to adopt PV if the variables they are sensitive to, system price and revenues, are significantly improved. This again represents a strong opportunity for the public sector to educate potential PV customers about the value of a PV investment as shown through other economic performance metrics.

7.4 Annualized Monthly Bill Savings

Figure 6 shows annualized MBS for residential and commercial PV customers for a range of non-price system characteristics. MBS are shown for both customer-owned and third-party owned systems. MBS from third-party PV systems are typically higher, based on the different tax implications of system ownership, as discussed in Section 4.5 and Appendix A. Although all PV economic metrics would show different returns based on the ownership structure, we only highlight the differences for MBS because third-party PV companies frequently market products to customers based on MBS (NREL 2009; SolarCity 2011; SunRun 2011). However, several of the trends shown for MBS are similar across other metrics.

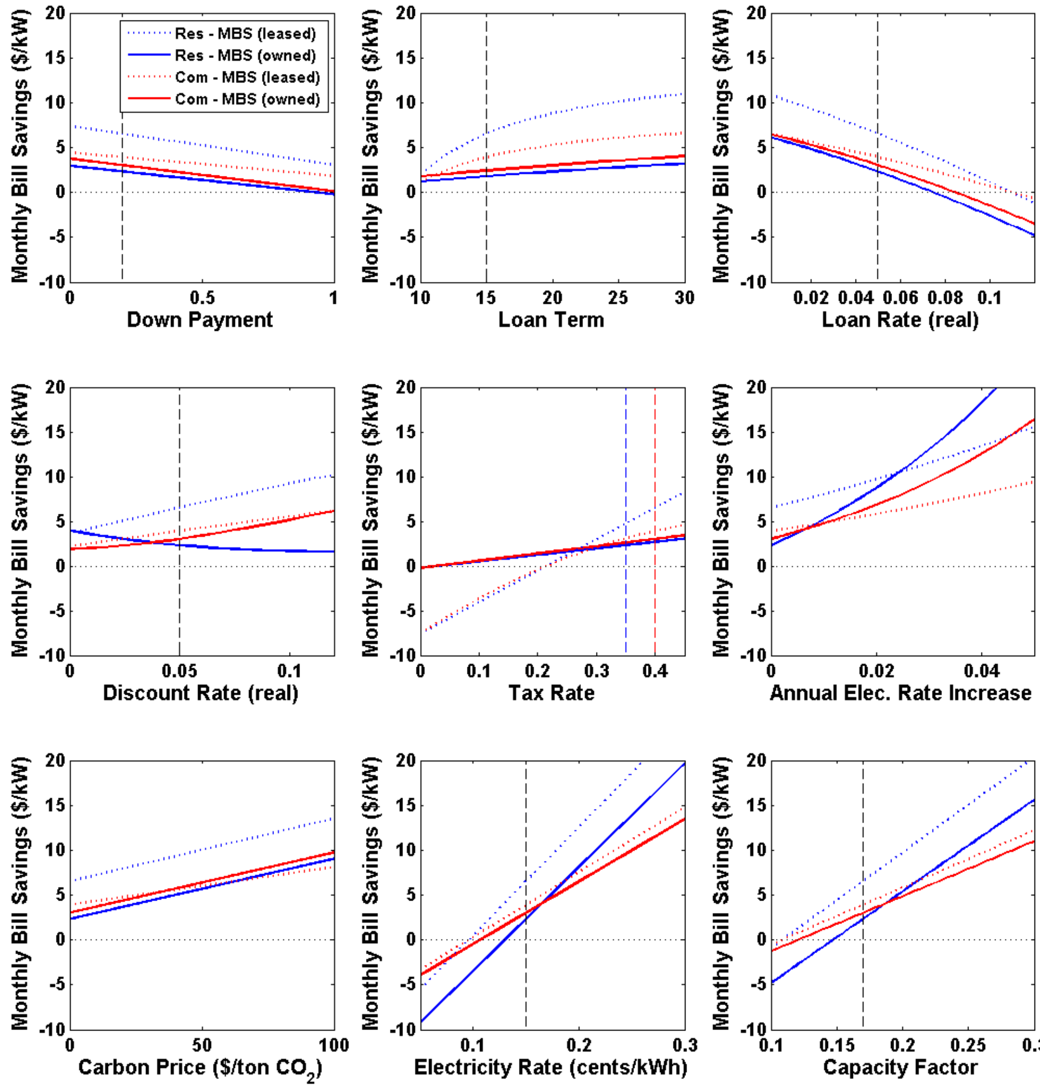

Figure 6. Annualized MBS for $4,000/kW residential and commercial PV systems

Note: Vertical dashed lines show reference PV assumptions, and horizontal dotted grey lines show the demarcation between a profitable and unprofitable investment.

MBS shows positive savings for the reference parameters, and they generally increase by spreading system costs over more years, decreasing system costs, and increasing revenues. For the reference conditions, MBS ranges from $1.27–$5.46/kW-month for residential systems and $1.66–$3.28/kW-month for commercial systems. The savings shown in Figure 6 are generally higher for third-party owned systems than for customer-owned systems because of the different tax structures (see Appendix A). These savings are based on the reference PV cost of capital and financing assumptions, but actual third-party owned MBS offerings may be lower based on higher capital costs and overhead. The actual MBS (or monthly costs) seen by customers is based on the size of their PV system. For example, residential PV systems are typically about 5 kW, and commercial systems are around 100 kW, leading to annual bill savings that are on the order of $76–$330/yr for residential customers and $2,000–$3,900/yr for commercial customers.

The reference PV cost and performance parameters represent positive MBS, which may be more attractive to potential PV customers than framing the system in terms of a simple payback time on the order of tens of years, particularly for residential customers who typically internalize high discount rates when evaluating investment choices (Wilson and Dowlatabadi 2007). This suggests that third-party PV companies have a strong opportunity to attract customers by repackaging costs and revenues into a simple product that generates MBS (NREL 2009; Drury et al. 2011).

7.5 Levelized Cost of Energy

Figure 7 shows residential and commercial LCOEs for a range of non-price system characteristics. Since LCOE is a relative metric that must be compared to the value of electricity generated, we also show the assumed effective electricity rate ($0.15/kWh) on each figure. PV LCOEs that are lower than the effective electricity price may represent a profitable investment, and PV LCOEs that are higher may represent an unprofitable investment. LCOEs are unaffected by varying electricity rates, rate increases, and carbon prices, and these sensitivities are not shown in Figure 7. However, varying these parameters will modify electricity rates, and an increase for each parameter will increase the value of a PV investment.

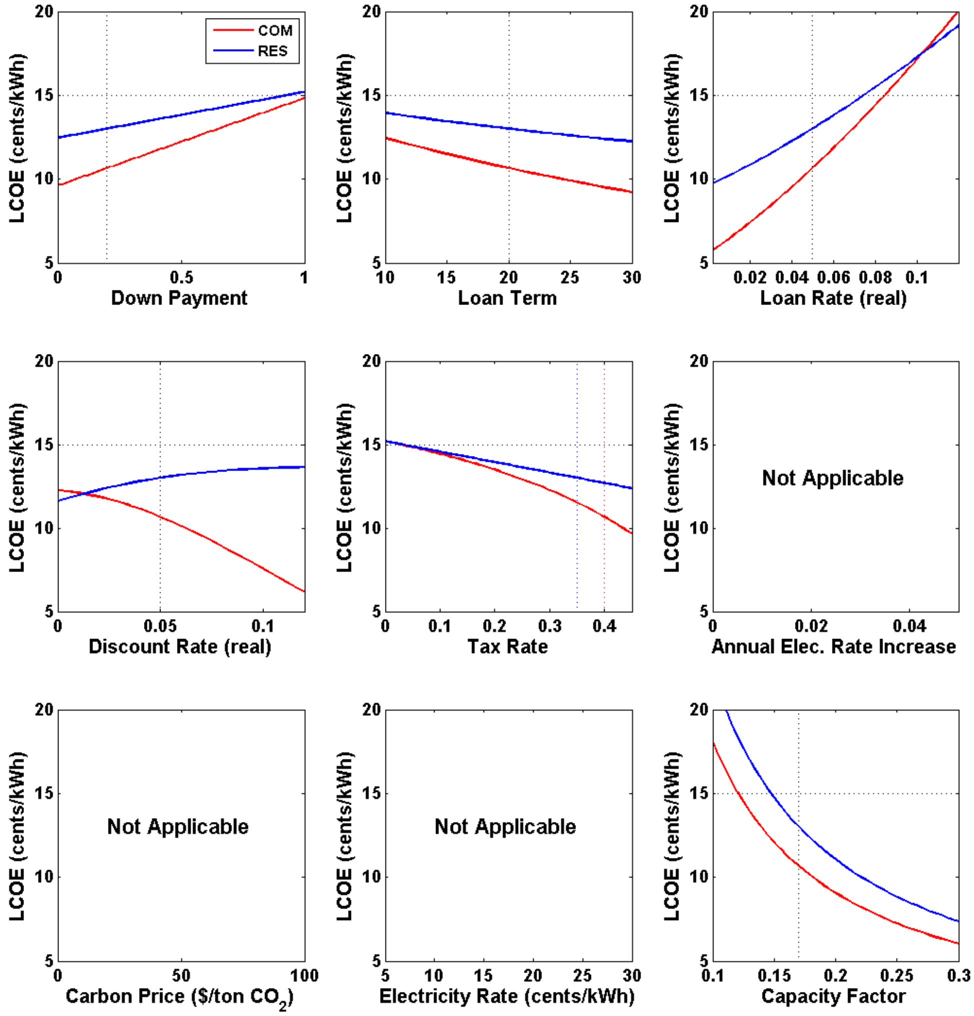

Figure 7. LCOEs for $4,000/kW residential and commercial PV systems over a range of financing, performance, and market parameters

Note: The LCOEs shown here are in units of real dollars, not nominal, dollars.

PV LCOEs are lower than the assumed effective electricity rate for the reference assumptions and for several variations in system parameters, and these may represent profitable PV investment opportunities. Like other metrics, PV LCOEs improve by decreasing system costs, spreading costs over more years, and increasing revenues. However, the value of a PV investment is directly tied to the relationship between LCOEs and the value of PV electricity, which is based on the characteristics of the local electricity generation fleet, load profiles, fuel prices, transmission constraints, net-metering policy, and several other variables. PV LCOEs are also frequently compared to the LCOEs of other electricity-generating technologies with different generation profiles, which can lead to an incorrect estimation of value (Borenstein 2008). These, and other, factors need to be taken into account for LCOE to produce an accurate measure of PV value.

8 Results Across Performance Metrics

One challenge in comparing PV economic performance across several metrics is that each metric typically uses different units to characterize PV value (Table 1). These include years for payback times, annualized returns for IRR, total discounted returns for B/C ratio and PI, dollars for NPV and dollars per month for MBS, and the cost of generating electricity for LCOE. Although we can evaluate the relative sensitivity of each metric to a range of system parameters, it is challenging to compare these sensitivities between metrics. We address this here by defining a common unit of performance that allows us to compare relative sensitivities between metrics. We define this metric as the "Equivalent Change in PV Price," which characterizes the impact of varying non-price system parameters in units of an equivalent change in PV price that produces identical returns. We calculate the Equivalent Change in PV Price using four steps:

1. Calculate reference PV performance for each economic metric. This represents a $4,000/kW PV system and the reference financing, market, and performance parameters listed in Table 2.
2. Vary one of the non-price system parameters and recalculate PV performance for a $4,000/kW system. This generates a second return for each metric.
3. Using reference non-price system parameters solve for a new PV price that generates the second return (found in step 2).
4. Define the Equivalent Change in PV Price as the new PV system price (found in step 3), minus the reference system price.

For example, to calculate the Equivalent Change in PV Price when varying the loan rate from 5% to 3% (real) for a residential system using the PI metric, we: (1) calculate PI for a reference residential PV system and find PI = 11.2%; (2) vary the loan rate from 5% to 3% (real) and find that PI increases to 19.2%; (3) return to the reference non-price parameters, including a 5% (real) loan rate, and vary PV price until we solve for the PV price that gives us a PI of 19.2%; we find that a PV system price of $3,595/kW will generate a 19.2% PI for a system with a 5% (real) loan rate; and (4) define the Equivalent Change in PV Price as the new system price minus the reference system price ($4,000/kW) and find an Equivalent Change in PV Price of –$405/kW. Conceptually, this means that system PIs could be increased from 11.2% to 19.2% by decreasing the loan rate from 5% to 3% (real) or by decreasing the system price from $4,000/kW to $3,595/kW. In this way, the value of decreasing loan rates from 5% to 3% (real) is equal to reducing capital costs by $405/kW for the PI metric.

We then use the same method for several economic performance metrics and find different Equivalent Changes in PV Price for each variation in non-price parameter. For example, using the LCOE metric, we find that reducing residential loan rates from 5% to 3% (real) leads to a higher Equivalent Change in PV Price of –$533/kW. This suggests that the LCOE metric is more sensitive to the loan rate parameter than the PI metric for the reference residential system.

Figure 8 shows the Equivalent Change in PV Price for residential and commercial systems for several economic performance metrics and a range of non-price project parameters. Most metrics show similar trends (all positive or all negative slopes), although the strength of these trends varies. Metrics with steeper slopes are more sensitive to the non-price variable than metrics with flatter slopes. For example, commercial LCOEs show an Equivalent Change in PV Price of about $2,000/kW if the down payment is increased from 20% to 100%, whereas residential LCOEs show about a $1,000/kW Equivalent Change in PV Price for the same increase in down payment fraction. Different metrics can also show different trends, illustrated by a positive slope for one metric and a negative slope for another metric. For example, the commercial LCOE shows a positive Equivalent Change in PV Price for a discount rate equal to zero, while all other metrics show a negative or zero Equivalent Change in PV Price.

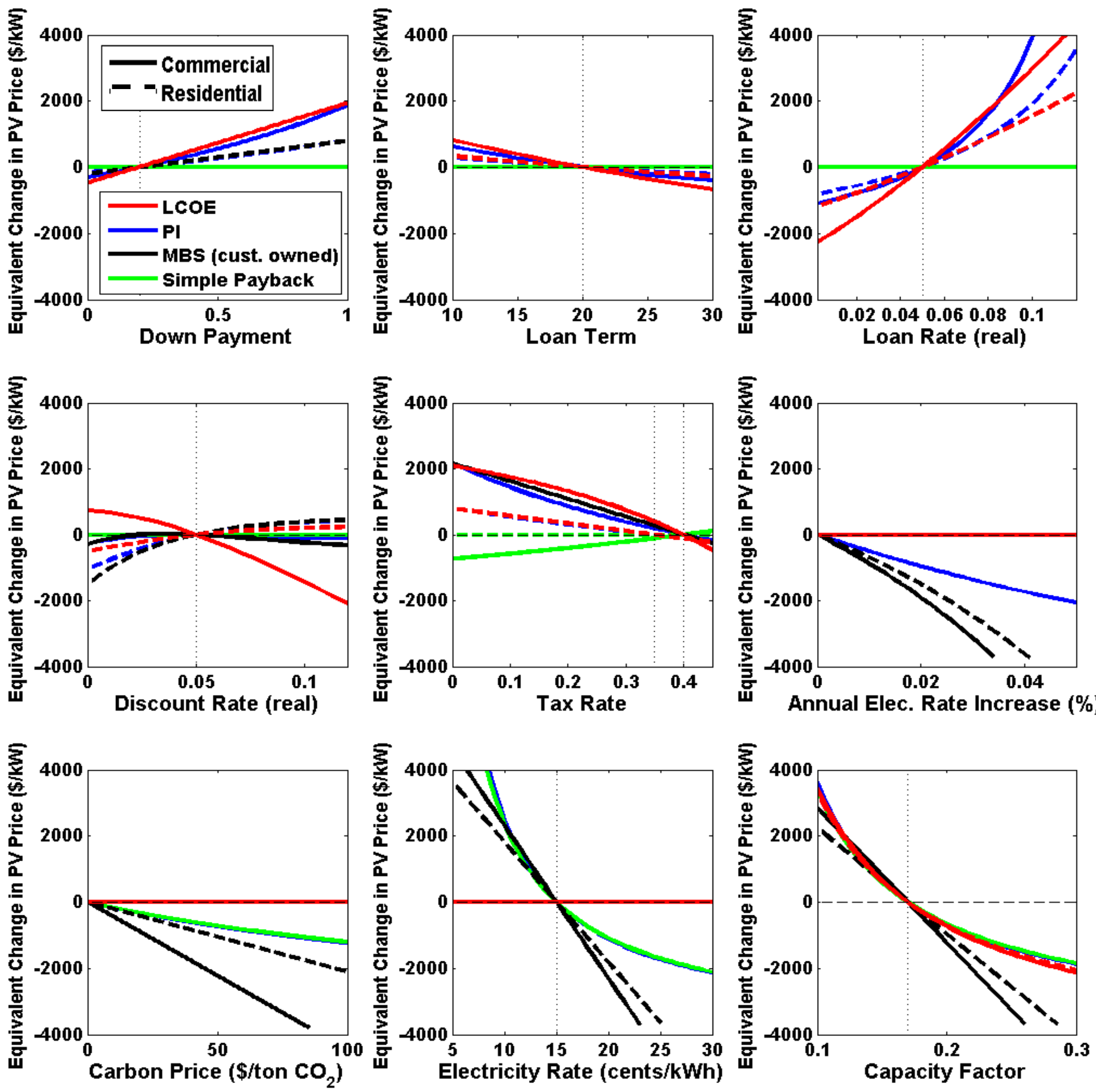

Figure 8. Equivalent Change in PV Price for the PI, LCOE, simple payback time (payback), and customer-owned MBS metrics

Note: Vertical dashed lines show the reference PV assumptions, which are assumed to be identical for residential and commercial systems except for the effective tax rate (35% for residential, 40% for commercial).

Most metrics show different Equivalent Changes in PV Price to varying system parameters. These differences show how evolving market conditions, financing terms, or carbon policy could impact some market participants more strongly than others. For example, if loan rates (real) were to decrease broadly across all customer classes, PV MBS and LCOEs would improve more significantly than system PIs. This suggests that access to low-cost capital could preferentially stimulate market segments using MBS (likely residential) and LCOE (likely large-scale) relative to other market segments using PI (likely commercial rooftop). Also, since MBS improves significantly while simple payback times remain static, access to low-cost capital could preferentially stimulate third-party owned PV adoption, which is typically marketed in terms of MBS, relative to customer-owned PV adoption where residents frequently think in terms of investment payback times. Similar trends are shown for several other system parameters.

The Equivalent Change in PV Price results shown in Figure 8 also quantify, in terms of dollars per kilowatt, the impact of varying several non-price system characteristics. These impacts can be compared to capacity-based or investment-based incentives, such the federal ITC or PV rebates offered by several states (DSIRE 2011), as additional methods for stimulating PV markets. However, since the impacts of varying non-price project parameters are often inconsistent between different economic metrics, it is important to understand these sensitivities for designing effective policy.

9 Policy Implications

Several types of incentives have been developed to spur renewable energy deployment worldwide. The majority of U.S. solar incentives are either capacity-based (reducing project costs by a fixed amount per unit of installed capacity) or investment-based (reducing project costs by a fixed fraction) (DSIRE 2011). These incentives are typically paid during the first year of ownership. In contrast, U.S. wind projects and European solar projects frequently receive production-based incentives, which are paid over several years based on the amount of electricity generated by a project. We find that the timing of project costs and revenues, including incentives, is a key driver for the economic returns generated by a PV investment (Sections 7–8). In general, an upfront incentive has more impact per dollar spent than an incentive spread over several years. However, the sensitivity to the timing of incentives is metric-dependent, and switching from one incentive type to another could preferentially stimulate individual market segments relative to others.

In addition to traditional incentives, we find that PV returns can be improved significantly by modifying several non-price project parameters. In particular, attractive financing terms can improve PV economics by spreading costs over more years (e.g., lower down payment fraction and longer loan term) and by decreasing investment costs (e.g., lower capital costs). We find that varying PV financing parameters can impact project economics by an amount that is equivalent to increasing or decreasing PV project costs by several dollars per watt (Figure 8). Providing renewable energy projects with access to long-term, low-cost financing may be a cost-effective method for increasing demand at lower costs than providing capacity-based, investment-based, or production-based incentives.

Since the perceived value of a PV investment can be shaped by the economic metric used to characterize performance, there is a strong potential for increasing PV demand by educating potential customers about the value of a PV investment as represented by several metrics. Behavioral economics suggests that customers respond strongly to how information is presented, which is called the "framing effect" (Wilson and Dowlatabadi 2007). For example, a residential customer who uses simple payback time to characterize the value of a PV investment may be far less likely to invest in PV than a similar residential customer characterizing the same investment in terms of MBS. The customer using simple payback time may require lower PV prices, either through direct incentives or PV price and performance improvements, before they are willing to adopt PV, whereas the customer using MBS may be enticed to adopt the given system. Improving the information available to customers could potentially reduce disparities in adoption trends both within and between market segments.

Lastly, new business models like third-party PV ownership can repackage PV costs and revenues into simple products like MBS, and allowing these businesses to enter the market could stimulate PV demand. For example, mean annualized MBS can be calculated for a customer-owned system; however, the actual costs and revenues generated by the PV system will vary significantly from the annualized MBS on a monthly basis. For customers to see a PV investment in terms of MBS may require a third-party company to repackage PV returns into a simple product. In this way, third-party business models can fundamentally reshape the perception of PV value. Several states have policies that limit third-party PV ownership (Kollins et al. 2010), and this represents a strong opportunity for the public sector to engage state and local officials to reduce the barriers to entry.

10 Conclusions and Future Work

PV is adopted by several types of market participants, ranging from residential customers to utilities and large-scale developers. We find that the use of different economic performance metrics by each market participant can significantly shape the perceived value of a PV investment. This can lead to different prices for when a PV investment looks profitable or attractive and different sensitivities to non-price system parameters.

The upfront nature of U.S. PV incentives can lead to challenges in calculating and interpreting PV value using some economic performance metrics. For example, we find that the upfront nature of U.S. incentives make IRRs and MIRRs poor metrics for characterizing PV economics. U.S. incentives can make IRRs very sensitive to changing system price and non-price parameters and generally lead to an inflated perception of potential returns. The same incentives make MIRRs relatively insensitive to varying system price and non-price parameters. Also, the upfront nature of U.S. incentives can lead to large differences in the economic returns calculated for U.S. systems relative to similar systems located in other countries and discussed in the international PV literature (e.g., Nofuentes et al. 2002; Talavera et al. 2007; Talavera et al. 2010; Audenaert et al. 2010).

That the perceived value of a PV investment can be significantly shaped by the choice of economic performance metric has important implications for policy design. For example, enabling access to long-term, low-cost capital could preferentially stimulate markets that use economic performance metrics that are sensitive to financing parameters (commercial and some residential), while having little or no impact on customers using metrics that are insensitive to financing terms (some residential). It is critical that policymakers understand these metric-dependent sensitivities to design effective policy.

This analysis suggests several areas for improving our understanding of how customers make adoption decisions and how policy affects these decisions. This represents an opportunity to learn from PV customers and to better understand their concerns and priorities when evaluating a potential PV investment. This also represents an opportunity to educate potential customers about the value of a PV investment as seen through several economic performance metrics and help them make more informed adoption decisions.

Improving our understanding of customer behavior can also be used to improve the representation of adoption behavior in PV market penetration models (EIA 2008a; EIA 2008b; Paidipati et al. 2008; Denholm et al. 2009; R.W. Beck 2009; Drury et al. 2010). These models frequently use one economic metric for each customer type, typically a payback time, to characterize adoption behavior. Modeled depictions of market evolution and the impacts of new policy are shaped by the sensitivities of one economic performance metric and do not capture the impacts of market participants using several metrics or evolving customer behavior. This represents a strong opportunity for improving the representation of PV value and adoption behavior in models, which can be used to better inform policy design.

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Appendix A. Tax Implications for Third-Party PV Ownership

Monthly bill savings (MBS) are frequently used by third-party owned PV companies and other PV retailers to characterize the value of a PV system to potential customers (NREL 2009; SolarCity 2011; SunRun 2011). In this analysis, we define the annualized MBS of a PV system based on the difference between the PV LCOE and the effective electricity rate, multiplied by the amount of electricity generated by the PV system, as shown in Equation A.1:

$$MBS = \frac{1}{LeaseTerm * 12} \sum_{t=1}^{Lease\,Term} \frac{PV\ Generation_t * (Electricity\ Rate_t\ \text{-}\ LCOE)}{(1+d)^t} \qquad [A.1]$$

Here, *PV Generation*$_t$ is the annual amount of electricity generated by a PV system in a given year, *Electricity Rate*$_t$ is the effective electricity rate that represents the annualized value of hourly PV generation for a given year, and *PV LCOE* is calculated for a standard financed system (Table 1).

PV MBS can vary significantly for different ownership models. If the PV system is owned by a residential customer, the *Electricity Rate*$_t$ is based on full retail electricity prices. If the PV system is owned by a commercial customer, the *Electricity Rate*$_t$ is based on tax-deductible electricity prices, and the PV *LCOE* accounts for MACRS depreciation. If the PV system is owned by a third-party PV company, we assume that the PV *LCOE* accounts for MACRS depreciation, for both residential and commercial site hosts, and a higher tax rate than residential customers.

Different ownership structures could potentially lead to higher MBS offerings from third-party owned systems, based on different tax burdens for each ownership structure. For residential systems, access to MACRS and higher commercial tax rates could produce higher MBS offerings for systems with identical prices, electricity rates, and financing terms.[20] The difference for commercial systems is not likely to be as great because they already depreciate PV assets based on MACRS. However, third-party MBS offerings could potentially be higher because of differences in taxing energy costs. For a customer-owned system, the effective electricity price is the tax-deductible retail electricity rate representing the value of avoided electricity use, and PV LCOEs have to be lower than this to produce a bill savings. For third-party systems, the PV LCOE only has to be lower than the retail electricity rate to produce bill savings, as shown in Equations A.2–A.4:

$$MBS_{Customer\ Owned} = \frac{1}{LeaseTerm * 12} \sum_{t=1}^{Lease\,Term} \frac{PV\ Generation_t * (Electricity\ Rate_t * (1\ \text{-}\ Tax\ Rate)\ \text{-}\ LCOE)}{(1+d)^t} \qquad [A.2]$$

$$MBS_{Third-party} = \frac{1}{LeaseTerm * 12} \sum_{t=1}^{Lease\,Term} \frac{PV\ Generation_t * Electricity\ Rate_t * (1\ \text{-}\ Tax\ Rate)\ \text{-}\ Lease\ /\ PPA\ Cost_t * (1\ \text{-}\ Tax\ Rate)}{(1+d)^t} \qquad [A.3]$$

$$MBS_{Third-party} = \frac{1}{LeaseTerm * 12} \sum_{t=1}^{Lease\,Term} \frac{PV\ Generation_t * (Electricity\ Rate_t\ \text{-}\ LCOE) * (1\ \text{-}\ Tax\ Rate)}{(1+d)^t} \qquad [A.4]$$

Here, all variables have the same definitions as those in Equation A.1, and *Lease/PPA Cost*$_t$ represents either the annual cost for leasing PV equipment or the annual cost for purchasing PV

[20] This does not include the additional costs (financing costs, operating costs, additional overhead and margins) and benefits (economies of scale reached though high-volume installation) of third-party ownership, which will partially cancel.

electricity through a PPA. Equation A.2 represents the annualized MBS for a customer-owned commercial system, and Equation A.3 represents the MBS for a third-party owned PV system that is either leased to a commercial customer or the electricity sold to a commercial customer through a PPA.

If the system *Lease/PPA Cost*$_t$ can be approximated as the LCOE of the system times the amount of energy generated by the system, Equation A.3 simplifies to Equation A.4. Equations A.2 and A.4 show the difference in customer-owned and third-party owned commercial systems, where the LCOE of a customer-owned system needs to be less than the tax-deductible electricity rate to generate bill savings while the LCOE of the third-party owned system may only need to be lower than the effective electricity rate to generate savings. Equations A.3 and A.4 do not factor in how the tax burden of the third-party company impacts potential MBS offerings. If all third-party PV revenues were taxed, and the third-party company had the same marginal tax rate as the commercial client, Equation A.4 would trend toward equation A.2, and there would be no tax benefit for third-party ownership. However, third-party PV companies pay taxes on net revenues (where MBS would trend toward equation A.4), not total revenues (where MBS would trend toward A.2). This suggests that third-party PV companies may have a competitive advantage relative to residential and commercial customers buying their own systems, based on tax structure.

Appendix B. The Challenge of Interpreting Internal Rates of Return for U.S. PV Systems

Several types of investors use the IRR to characterize and rank investment returns for a range of investment opportunities. This is particularly true for wind developers and tax investors, where IRR-based hurdle rates[21] are often used to rank potential wind projects (Harper et al. 2007). IRR is also frequently used to evaluate PV economic performance, particularly in European markets (Nofuentes et al. 2002; Talavera et al. 2007; Talavera et al. 2010; Audenaert et al. 2010). Although IRR can be useful for characterizing the value of projects that receive no incentives, or production-based incentives, it frequently shows threshold effects (Talavera et al. 2010) can have multiple positive real solutions (Stermole and Stermole 2009) and can inflate the perceived value of an investment if the IRR is significantly higher than the opportunity cost of capital (McKinsey & Co. 2004). The challenges with IRR are even greater for U.S. PV systems because the combination of the 30% federal ITC, along with MACRS for commercial systems, exacerbates threshold behavior and inflates the perception of value. Because of these issues, we find that IRR is a poor metric for characterizing the value of U.S. PV systems.

There are three main challenges for interpreting PV IRR: (1) IRR frequently has multiple positive, real solutions, (2) IRR is subject to strong threshold behavior, and (3) IRR frequently inflates the perceived value of a PV investment. PV IRR frequently has multiple solutions because solving for the IRR of a PV system with a 20-year lifetime entails finding the solution to a 20^{th}-order polynomial, which can have up to 20 solutions. Often, there is only one IRR solution that is both positive and real.[22] However, it is not uncommon for PV cash flows to generate several solutions that are both positive and real, particularly for financed PV systems. This is primarily based on the upfront nature of PV costs (down payment) and U.S. incentives (federal ITC plus MACRS depreciation for commercial customers), where PV cash flows can transition from negative (down payment), to positive (incentives), to negative (if PV revenues are insufficient to fully offset loan payments and O&M costs), to positive (PV revenues after the loan term) (see Figure 1).

Figure B.1 shows the relationship between the system NPV and discount rate, where IRR solutions represent the discount rates in which NPV equals zero (Table 1). Also shown are system IRRs for a range of PV prices, which illustrate some of the challenges in interpreting IRR as a measure of PV investment value.

[21] A hurdle rate represents the minimum rate of return that a company or project manager is willing to accept before developing a project.
[22] Several polynomial solutions will have non-zero imaginary components.

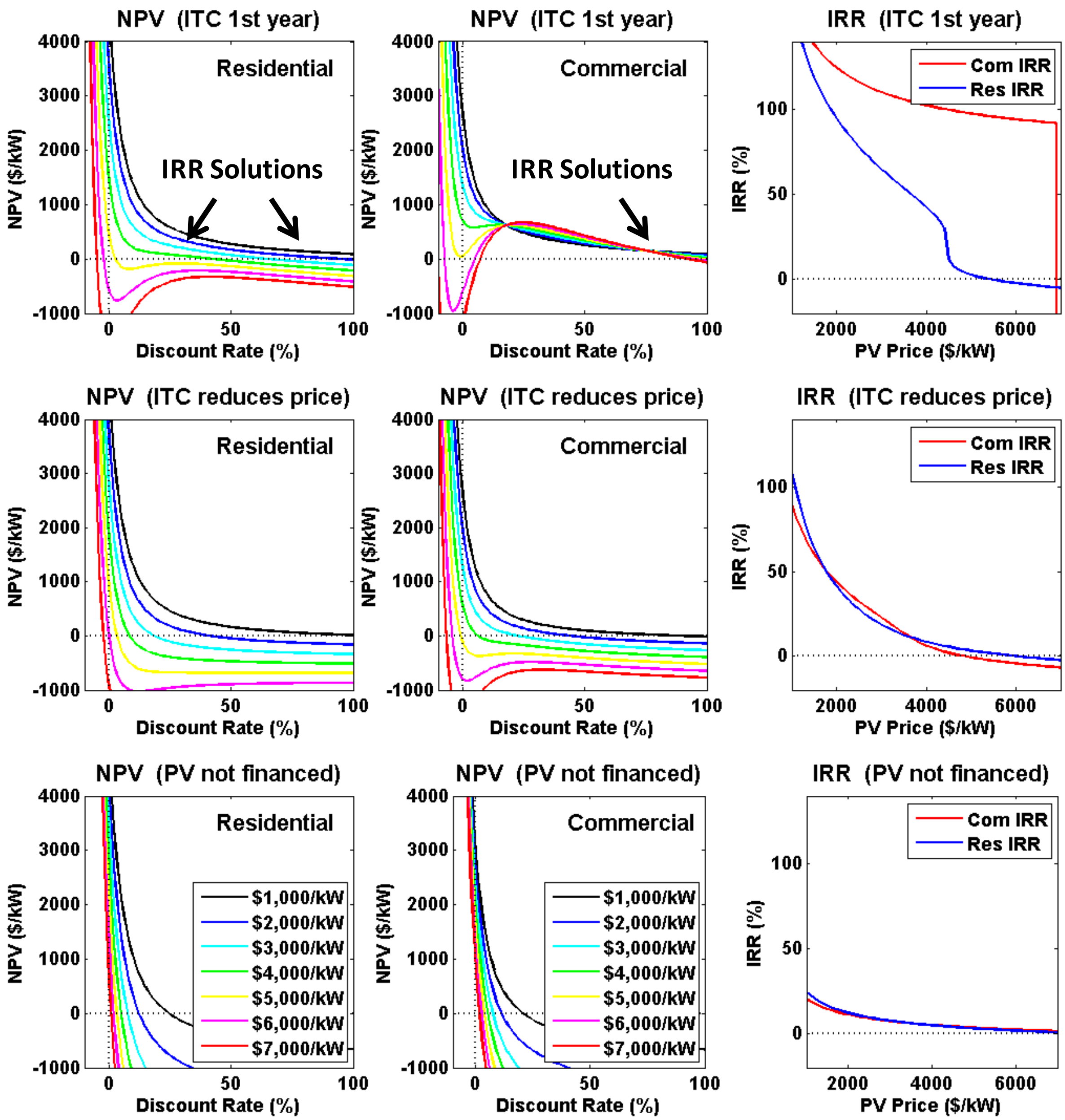

Figure B.1. The relationship between residential and commercial NPV to discount rates for several PV prices and the corresponding relationship between residential and commercial IRRs and PV prices for three financing and incentive structures

Note: IRR solutions represent the discount rates where the NPV(s) of a PV system equals zero.

Figure B.1 shows that several systems have only one real IRR solution and an NPV-to-discount-rate relationship that suggests the IRR solution is meaningful and representative of investment returns. For example, unfinanced residential and commercial PV systems show positive NPVs for discount rates equal to zero, a steep decline in NPVs with increasing discount rates, and a single IRR solution that gives a meaningful indication of investment returns.

However, the combination of system financing and incentives frequently complicates the interpretation of a project IRR. For example, a $6,000/kW financed commercial PV system that takes the federal ITC in the first year of ownership has a negative NPV for a discount rate of 0%, which transitions to positive NPVs for discount rates higher than 5% and then transitions to negative NPVs for discount rates above about 100% (Figure B.1). The negative NPV for a discount rate of 0% shows that the undiscounted PV revenues are less than the undiscounted system costs. However, NPVs become positive for discount rates above 5% because the discounting is sufficient to decrease the relative importance of the years with negative cash flows after MACRS expires (years 7–20 for the $6,000/kW system) and increase the relative importance of years with positive cash flows from the federal ITC and MACRS (years 1–7). NPVs become negative again for discount rates greater than 100%, which increases the relative importance of the loan down payment in the first year and decreases the importance of the positive cash flows from the federal ITC and MACRS payments over the next six years. The issue of multiple IRR solutions is resolved for: (1) commercial systems that account for the federal ITC by reducing the system price rather than as a positive revenue source after the first year of ownership; (2) residential systems that do not receive MACRS depreciation; and (3) residential and commercial systems that are not financed.

Another challenge in interpreting investment returns for systems with high IRR solutions is that the timing of PV cash flows frequently leads to very high IRR solutions that show small but positive NPVs. For example, a $4,000/kW residential PV system that takes the federal ITC in the first year of ownership shows an IRR of 42%, but system NPVs are less than $100/kW (equivalent to PI < 2.5%) for discount rates above 21%. The very slow decrease in NPV with increasing discount rates is primarily caused by the upfront nature of PV costs (down payment) and incentives (ITC and MACRS depreciation for commercial systems), where very high discount rates are required to affect the relative balance between the loan down payment and the federal ITC.

Several previous studies have focused on the utility of IRR to characterize PV value (e.g., Talavera et al. 2010; Talavera et al. 2007). However, these studies did not analyze the economics of PV systems receiving large upfront capacity-based or investment-based incentives, such as those in the United States. We find that IRR values are frequently misleading for U.S. systems and are poor measures of PV value.