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A Survey of State and Local PV Program Response to Financial Innovation and Disparate Federal Tax Treatment in the Residential PV Sector

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Executive Summary

High up-front costs and a lack of financing options have historically been the primary barriers to the adoption of photovoltaics (PV) in the residential sector. State clean energy funds, which emerged in a number of states from the restructuring of the electricity industry in the mid-to-late 1990s, have for many years attempted to overcome these barriers through PV rebate and, in some cases, loan programs. While these programs (rebate programs in particular) have been popular, the residential PV market in the United States only started to achieve significant scale in the last five years – driven in large part by an initial wave of financial innovation that led to the rise of third-party ownership.

Under third-party ownership (“TPO”), a PV system host does not own the system, but instead leases it or else buys the electricity it generates through a power purchase agreement (“PPA”). The rise and success of TPO has been driven primarily by four factors:

- *Built-in financing* converts an otherwise high up-front cost into a more-affordable cents/kWh or monthly payment that can be easily compared to utility bills;
- *Investment tax credit (“ITC”) monetization* enables hosts with insufficient tax liability to still benefit from the ITC, assuming at least some degree of incentive pass-through;
- *Reduced performance risk* stems from the TPO provider handling all system maintenance expenses; and
- *Larger federal tax benefits* accrue to TPO providers than to host-owners, due to a combination of statutory differences in the residential and commercial ITCs, TPO financing practices that “step up” the commercial ITC basis, and accelerated depreciation deductions available to commercial but not residential taxpayers.

In combination, these four drivers of TPO have enabled many homeowners to install PV for little or no money down, and with monthly lease or PPA payments that are, at least initially, at or below what they would otherwise pay their local utility. As a result, TPO has made significant inroads into the residential PV market, capturing more than 60%, and as much as 90%, of market share among residential systems installed in six key states in 2014 (GTM Research and SEIA 2015).

The success of TPO – which is, at its core, a form of financing – has drawn the attention of both conventional and unconventional lenders intent on capturing a portion of TPO’s market share. At the same time, three of the four drivers of TPO listed above have begun to fade as a result of changing market conditions. Specifically, with the cost of PV having declined substantially in recent years, it is now possible for lenders to offer competitive solar loan products that provide financial benefits similar to TPO (e.g., little or no money down and at least cash-flow-neutral) while preserving other benefits of ownership (e.g., free electricity once the loan is paid off). Declining installed prices also make it easier for host-owners to fully absorb the ITC, thereby reducing the need for third-party monetization. Some have also argued that performance risk has declined along with falling prices (e.g., for inverters – the component most likely to fail over time), stronger manufacturers’ warranties, and the ongoing accumulation of operating experience. With TPO no longer holding as much of a unique competitive advantage in the

marketplace, the past two years have witnessed a proliferation of tailored solar loan products that marks the start of a second wave of financial innovation in the residential PV sector.

The ensuing competition between TPO and solar loans has sparked much debate over the pros and cons of each. This debate has played out in both the trade and national press, on the conference circuit, and among industry researchers, and has generally led to increasing recognition in the market that PPAs/leases may leave money on the table. In fact, some of the larger residential TPO providers have recently launched their own solar loan products, in some cases noting that in most cases the loan will provide savings relative to lease or PPA offerings. On the other hand, TPO continues to offer performance assurance, risk minimization, and tax credit monetization benefits that extend beyond purely financial returns, and so continues to remain popular.

Whether one favors TPO through a lease/PPA or host-ownership through a solar loan, the proliferation of both types of financial offerings has had a profound impact on the growth of the residential PV market – with corresponding implications for the role of state and local PV programs within that market. For example, the combination of declining costs and increasing access to a variety of financing products – whether leases, PPAs, or loans – has gone a long way towards overcoming the age-old barrier to PV deployment posed by high first costs. At the same time, state-level PV incentives have become less-critical to deployment, as in many cases they have declined in tandem with installed costs.¹

Within this market environment – again, characterized by declining installed costs, dwindling state PV incentives, booming demand, high TPO market share in many states, growing consensus that host-ownership provides greater savings than TPO to most PV adopters (but that TPO offers benefits besides financial returns), and a recent proliferation of solar loan products designed to encourage host-ownership – a number of state and local PV program managers have responded by re-orienting their programs, generally in one of two ways (or in some cases both), in order to maximize the impact of their remaining funds. Both responses potentially help to preserve scarce public funding for PV by using remaining incentives more as a tool to fine-tune the market rather than to stimulate it outright, and/or by shifting away from incentive disbursements in favor of financial support that can better sustain fund balances and potentially even provide a return on capital.

The first response involves the state or local PV program taking a proactive role as a “market monitor” of sorts, to promote and maintain a competitive market between TPO and host-owned systems by using state or local incentives to correct for the higher federal tax benefits enjoyed by TPO providers. Analysis presented in the Appendix estimates that this disparity in federal tax benefits is currently somewhere on the order of \$0.7-0.9/W, and could persist at roughly \$0.5/W post-2016 under current law. All else equal, this persistent federal tax benefit disparity suggests that differentiating state or local incentive levels by roughly this same amount – whether by reducing TPO incentive levels, increasing host-owner incentive levels, or some combination of the two – may be an appropriate action to level the playing field between TPO and host-ownership, presuming that a level playing field so defined is deemed desirable. Though most

¹ For example, in the second half of 2014, roughly 90% of all new residential PV installations in California (the largest residential solar market in the United States) were built without any state incentives. In Arizona (the second largest market), the comparable number was roughly 50%.

state and local PV programs have not, to this point, differentiated incentives in this way, there are a number of programs that have done so, but typically by more modest amounts, potentially leaving room for further adjustment. That said, as discussed further below, any and all such adjustments should first be considered within the specific context and objectives of the state or local market in which each program operates.

The second response witnessed among a number of PV programs involves using public funds to help homeowners capture the potential benefits of host-ownership by creating viable solar loan products where they don't already exist, or by complementing existing private sector solar loan offerings. In either case, credit enhancement tools such as subordinated debt, loan loss reserves, and perhaps targeted interest rate buy-downs can be used (and are already being used in several states) to help reduce the risk facing private lenders (without necessarily leading to loss of funds). By reducing risk, these credit enhancements potentially enable lenders to offer more-attractive terms to already-creditworthy borrowers, or to extend credit to otherwise less-creditworthy borrowers.

Both of these potential actions will continue to be relevant in the future even if the residential ITC expires at the end of 2016, as currently scheduled. The disparity in federal tax benefits is unlikely to change much at that time (the Appendix suggests it could drop from \$0.7-0.9/W at present to \$0.5/W in 2017), given that the commercial ITC available to TPO providers is scheduled to revert from 30% to 10%, rather than expiring altogether. And without the 30% residential ITC available as collateral for the "same-as-cash" tax credit loans that are the cornerstone of most solar loan products in the market today, innovative PV program support for solar loans may continue to play an important role.

Any state or local PV programs interested in further exploring either of these courses of action should first investigate the unique local or state-specific context within which such changes would be made. For example, how many installers are active in the state, and what types of financing options do they offer? Is TPO available, and if so, what is its market share? What state or local incentives are currently offered, and how much room for movement is there? Are there other state or local incentives (e.g., state tax credits) available to PV, and do they favor one type of ownership over another?

Finally, one broader question of interest is how might the responses discussed in this paper – i.e., differentiating incentive levels between TPO and host-ownership, and providing programmatic support to solar loan products – impact overall deployment? Although the answer will depend to some extent on how any changes are implemented (e.g., reducing TPO vs. increasing host-owned incentives), there are also larger related questions worth exploring further, such as to what extent TPO providers practice "value-based" pricing (relative to installers of host-owned systems). For example, if TPO providers have – as recent research suggests – been pricing their products to compete primarily against utility retail rates rather than host-ownership, then the PV program responses explored in this paper may help lead to a more-competitive market that continues to grow even in the face of lower state incentive levels – a future that the entire PV industry should be able to rally behind. On the other hand, if the two primary PV program responses explored herein merely prop up a business model focused on PV system ownership that – for whatever reason – is less attractive to prospective solar customers than is TPO, then reallocating funds for this purpose (and away from supporting TPO) may unnecessarily limit market expansion.

1 Introduction

High up-front costs and a lack of financing options have historically been the primary barriers to the adoption of photovoltaics (PV) in the residential sector. State clean energy funds, which emerged in a number of states from the restructuring of the electricity industry in the mid-to-late 1990s, have for many years attempted to overcome these barriers through PV incentive and, in some cases, loan programs. While these programs (incentive programs in particular) have been popular, the residential PV market in the United States only started to achieve significant scale in the last five years – driven in large part by an initial wave of financial innovation that led to the rise of third-party ownership.

Under third-party ownership (TPO), a PV system host does not own the system, but instead leases it or else buys the electricity it generates through a power purchase agreement (PPA). This financing innovation has enabled many homeowners to install PV for little or no money down, and with monthly lease or PPA payments that are at or below what they would otherwise pay their local utility. As a result, TPO has made significant inroads into the residential PV market, capturing more than 60%, and as much as 90%, of market share among residential systems installed in six key states in 2014 (GTM Research and SEIA 2015).

The success of TPO – which is, at its core, a form of financing – has drawn the attention of both conventional and unconventional lenders intent on capturing a portion of TPO's market share. With the cost PV having declined substantially in recent years, it is now possible for lenders to offer competitive solar loan products that provide financial benefits similar to TPO (e.g., little or no money down and at least cash-flow-neutral) while preserving other benefits of ownership (e.g., free electricity once the loan is paid off). The resulting proliferation of tailored solar loan products over the past two years marks the start of a second wave of financial innovation in the residential PV sector.

The ensuing competition between TPO and solar loans has sparked much debate over the pros and cons of each. This debate has played out in the trade press (Lacey 2015, Wesoff 2014b, Hausman 2015), among industry researchers (Davidson et al. 2015, Feldman and Lowder 2014, Beavers et al. 2013, Dumoulin-Smith et al. 2015), and even in the national press (Brady 2015, Cardwell 2014, Wang 2014), and has generally led to increasing recognition in the market that PPAs/leases may leave money on the table. In fact, some of the larger residential TPO providers have recently launched their own solar loan products, sometimes noting that their loans products will typically provide savings relative to their lease or PPA offerings. On the other hand, TPO continues to offer performance assurance, risk minimization, and tax credit monetization benefits that extend beyond purely financial returns, and so continues to remain popular.

Whether one favors TPO through a lease/PPA or host-ownership through a solar loan, the proliferation of both types of financial offerings has had a profound impact on the growth of the residential PV market – with corresponding implications for the role of state PV programs within that market. For example, the combination of declining costs and increasing access to a variety of financing products has gone a long way towards overcoming the age-old barrier to PV

deployment posed by high first costs. At the same time, state-level PV incentives have become less-critical to deployment, as in many cases they have declined in tandem with installed costs.²

Within this market environment – again, characterized by declining installed costs, dwindling state PV incentives, booming demand, high TPO market share in many states, growing consensus that host-ownership provides greater savings than TPO to most PV adopters (but that TPO offers benefits besides financial returns), and a recent proliferation of solar loan products designed to encourage host-ownership – a number of state (and local) PV program managers have responded by re-orienting their programs, generally in one of two ways (or in some cases both).

The first response involves differentiating state incentive levels by ownership type to reflect the larger federal tax incentives received by TPO providers.³ The second response involves state PV programs using public funds to help homeowners capture the benefits of host-ownership by creating viable solar loan products where they don't already exist, or by complementing existing private sector solar loan offerings. Both responses potentially help to preserve scarce public funding for PV by using remaining incentives more as a tool to fine-tune the market rather than to stimulate it outright, and/or by shifting away from incentive disbursements in favor of financial support that can better sustain fund balances and potentially even provide a return on capital. At the same time, these responses are not yet widespread, perhaps in part because they raise questions about the role of state and local PV programs in the solar market and in part because of potential side-effects on solar deployment that deserve consideration.

This report explores these issues and catalogs these responses in the following manner:

- Chapter 2 describes the evolution of residential PV finance since 2007, focusing initially on the first wave of innovation that brought the rise of TPO, followed by the second and current wave of innovation involving solar loans. Particular attention is paid to the market drivers of each wave.
- Chapter 3 surveys the responses of state and local PV programs to the financial innovation described in Chapter 2. As mentioned above, these responses generally fall into two categories: differentiating incentive levels by ownership type, and/or providing support for solar loans. Each category is explored separately.
- Chapter 4 then discusses some of the issues and considerations that PV programs might face when contemplating differential incentives and/or providing effective support for solar loans. For example, with respect to incentive differentiation, this chapter explores four issues: whether to differentiate at all, whether to differentiate by incentive structure or level (or both), how much of a differentiation in incentive level might be warranted given disparate federal tax benefits (as estimated in the Appendix), and potential implementation pitfalls.

² For example, in the second half of 2014, roughly 90% of all new residential PV installations in California (the largest residential solar market in the United States) were built without any state incentives (GTM Research and SEIA 2015). In Arizona (the second largest market), the comparable number was roughly 50%.

³ This differentiation by owner type is a narrower application of a long-held practice in some states of differentiating state incentive levels based on the ability of recipients to use federal tax incentives. For example, tax-exempt entities are often awarded higher state incentive levels than their taxable counterparts, in recognition of the fact that they cannot benefit from tax credits and accelerated depreciation deductions.

- Finally, Chapter 5 concludes.

The primary aim of this report is to inform PV program managers as to how their existing programs fit within today's evolving market, and to highlight ways in which PV program managers have or might allocate remaining funds given the evolving market, while also discussing some of the issues and tradeoffs involved when considering such changes. It should be noted that the discussion herein is necessarily broad in scope, and each state or local PV program should consider these issues with respect to the tradeoffs involved, and also within the specific market and policy contexts in which they operate.

2 The Evolution of Residential PV Finance in the United States

Up until the late-2000s, most residential PV projects were financed out of homeowner savings (e.g., through a cash purchase) or through home equity loans. As such, the residential market was largely restricted to homeowners with ample savings and/or sufficient equity in their homes to borrow against. Over the years, several state clean energy funds had tried to address this financing gap by rolling out solar loan programs, but in general, these early loan programs met with only mixed success (Bolinger and Porter 2002, Gouchoe et al. 2002), in part because the underlying technology was still very expensive.

All this began to change in the late 2000s with the introduction of third-party ownership in the residential sector – the first wave of financial innovation. SunEdison had previously introduced third-party ownership in the commercial sector several years earlier, but it wasn't until SunRun and SolarCity (eventually followed by many others) extended the concept to the residential sector that the market truly began to take off. More recently, a second wave of financial innovation – triggered by both the successes and limitations of TPO – has been marked by a proliferation of solar loan products that are tailored to the specific cash flow profiles of PV and that are intended to compete with or complement TPO.

This chapter describes this evolution in residential PV finance in the United States, focusing on these two distinct waves of financial innovation since 2007: the rise of third-party ownership (in Section 2.1), and the proliferation of solar loan products (in Section 2.2). Particular attention is paid to market drivers in each case, and Section 2.2 also includes a review of private sector solar loan products.

2.1 First Wave of Innovation: The Rise of Third-Party Ownership

The initial wave of financial innovation in the residential PV sector began in California, following SunRun's introduction of the first residential PV power purchase agreement (PPA) in late 2007, followed shortly thereafter by SolarCity's introduction of the first residential PV lease in early 2008. By 2010, TPO of residential PV had gained market share and spread to other states besides California that also offered attractive incentives. At the same time, other TPO providers (e.g., Sungevity, Vivint, Clean Power Finance, SunPower, NRG) entered the market to compete with SunRun and SolarCity for a piece of the expanding market. By 2013, the vast majority of new residential solar capacity installed in active TPO states was third-party-owned, a trend which held relatively steady in 2014.⁴

⁴ According to GTM Research and SEIA (2015), the proportion of new residential PV capacity installed in 2014 that was third-party owned averaged ~90% in New Jersey, >80% in Colorado, ~80% in Arizona, ~70% in California, ~65% in Massachusetts, and >60% in New York. These six states ranked within the top seven for new installed residential PV capacity in 2014 (Hawaii was in fifth place), and accounted for 78% of all new residential PV capacity installed in the United States in 2014 (GTM Research and SEIA 2015). Looked at another way – by installer market share – SolarCity reportedly captured 34% of the overall U.S. residential market in 2014, followed by either SunRun (whose direct sales unit captured 2%, while its TPO business was described only as being “much larger”) or Vivint at 13% (Litvak 2015). In other words, SolarCity alone captured roughly a third of the entire

The initial success and rapid increase in the market share of TPO is attributable largely to four drivers, the first three of which represent positive innovations that have met critical needs in the marketplace (while the fourth is merely a consequence of tax law):

- **Built-in financing:** TPO converts what had been a high (perhaps in many cases prohibitively high) up-front cost into a series of affordable monthly payments. Packaging the financing along with the installation eliminates the host's transaction cost of having to arrange each separately (that is, if other forms of financing are even available). In addition, expressing costs purely in terms of cents/kWh or a monthly payment (as opposed to – in the case of host-ownership – a large up-front expense coupled with various tax credits and incentives) makes it easier for consumers to evaluate and recognize savings relative to their utility bill.⁵
- **Tax credit monetization:** TPO providers (or, more accurately, their tax equity partners) are often in a better position than system hosts to take advantage of federal tax benefits for solar. Assuming at least some degree of incentive pass-through, this third-party tax credit monetization helps to reduce the size of the host's monthly payments – often to the point where they are lower than what the host would otherwise pay the local electric utility, resulting in positive cash-flow from day one.
- **Reduced performance risk:** TPO reduces the host's technology and operational risk, because the third-party owner is most often responsible for maintaining the system over time, and typically provides a contractual production guarantee. Indeed, some homeowners opt for fully pre-paid lease contracts (rather than host-ownership), presumably in part to capture this particular benefit of TPO.⁶
- **Incremental federal tax benefits:** The opportunity to arbitrage the \$2,000-per-system cap on the Section 25D residential investment tax credit ("ITC"), which was in force from 2006-2008, was perhaps the primary motivation for initially extending TPO to the residential sector (as the Section 48 commercial ITC claimed by TPO providers was not similarly capped).⁷ Ignoring tax depreciation (which also favors TPO), this \$2,000 cap represented an arbitrage opportunity of ~\$2.2/W for an average 5 kW system in 2008 (see the Appendix for details). Although this dollar cap was eliminated starting in 2009, thereby ostensibly placing

market in 2014, while the top three residential installers – all focused primarily on TPO – accounted for well over half of the total U.S. residential market.

⁵ Interestingly, this same innovation may also contribute to or help perpetuate "value-based" pricing in third-party ownership – i.e., pricing PPA or lease contracts just low enough to provide value to the system host (relative to current utility retail rates), even though underlying costs would enable lower prices. If some consumers are content to merely see savings on their utility bills, then they may not bother to try to maximize those savings (e.g., by evaluating competing quotes, including for direct ownership).

⁶ In a pre-paid lease contract, the host pays the present value of all lease payments up-front in one lump sum rather than over time. Thus, from a cash-flow perspective, a pre-paid lease looks more like host-ownership than like a typical lease. By opting to lease rather than own the system, however, the lessee avoids the responsibility of maintaining the system (but also forfeits the residual value at the end of the lease term). Though not explored in this report, indirectly capturing some portion of the incremental federal tax benefits described in the next bullet point (and the Appendix) could be another motivation for choosing a pre-paid lease contract over host-ownership, as might the relative advantage of TPO for tax credit monetization if the homeowner does not have adequate tax liability to immediately benefit from the ITC.

⁷ See the Appendix for an introduction to the residential and commercial 30% investment tax credits for solar.

the residential and commercial ITCs on equal footing (in terms of their 30% face value), the Appendix demonstrates that the practice of “stepping up” the ITC basis through tax equity financing structures has helped to sustain TPO’s federal tax advantage over host-owned systems from 2009 to the present. Looking ahead, and barring any legislative changes, this disparity will persist post-2016 once the Section 25D residential ITC expires and the Section 48 commercial ITC reverts to 10%. Presuming at least some degree of incentive pass-through, TPO’s relative federal tax advantage may contribute to its attractiveness in the market.

As shown later in Section 2.2, the importance of the first two of these drivers – built-in financing and tax credit monetization – has begun to fade somewhat as installed PV costs have declined, making host-ownership more affordable and tax credit monetization less necessary. The recent proliferation of solar loan products is a response to (and, to some extent, also a driver of) these trends. In addition, some have argued that the importance of the third driver – reduced performance risk – has also at least partially waned with the ongoing accumulation of operational experience, the decline in inverter prices (the most likely component to fail over time), and the strengthening of manufacturers’ warranties.⁸ In aggregate, these market developments have led some analysts to predict that TPO’s strong market share will peak in 2014 (Litvak 2014). That said, as shown in the Appendix, the fourth driver – TPO’s claim to larger federal tax benefits – remains in place, and under current law will persist beyond 2016, which (along with what remains of the first three drivers) could help to sustain TPO’s market share even in the face of the rising challenge from solar loans, as described in the next section.

2.2 Second Wave of Innovation: The Proliferation of Solar Loan Products

Research into what motivates homeowners to pursue third-party ownership of PV (i.e., to choose a PPA or lease instead of direct ownership) regularly finds that their inability to afford the high up-front cost of a PV system is a primary driver (Corfee et al. 2014, Rai and Sigrin 2013). In other words, perhaps the primary attraction of third-party ownership is that it is, at its core, a financing product. It is, however, a financing product that has been sustained, to some extent, by relatively expensive capital that is attracted to the sector in part by the significant federal tax benefits available to solar projects – and particularly to TPO solar projects, as noted above and as detailed in the Appendix.

As the cost of PV has dropped considerably in recent years (not only making it more affordable, but also making it easier for more homeowners to efficiently use the tax benefits), a number of public and private sector entities with access to cheaper sources of capital (than tax equity) have entered the market with solar loan products designed to compete with and/or complement third-party ownership. Section 2.2.1 discusses what’s been driving this proliferation of new solar loan products – i.e., the second wave of financial innovation in the residential PV sector – in recent years, while Section 2.2.2 surveys the array of private sector solar loan products available

⁸ For example, most residential string inverters now carry standard 10-year warranties – double the 5 years offered just a few years ago – while micro-inverters often carry 25-year warranties (to match the duration of the now-standard 25-year power output warranty offered by most module manufacturers).

nationwide (or at least in multiple states, including the larger solar markets), with the intent of establishing what is currently on offer and what critical gaps might still exist.

2.2.1 Solar Loan Drivers

A number of factors have driven the proliferation of new residential “solar loan” products in recent years, and especially since the start of 2013:

- **The installed price of PV has declined substantially:** Barbose et al. (2014) show that the median installed price of PV systems of 10 kW_{DC} or less installed in the United States fell by 44% from 2009 through 2013, from \$8.3/W_{DC} to \$4.7/W_{DC} (Figure 1). This substantial price reduction – which continued in 2014 (GTM Research and SEIA 2015) – has made PV ownership significantly more affordable, with monthly loan payments that now fall more in line with utility bill savings.⁹

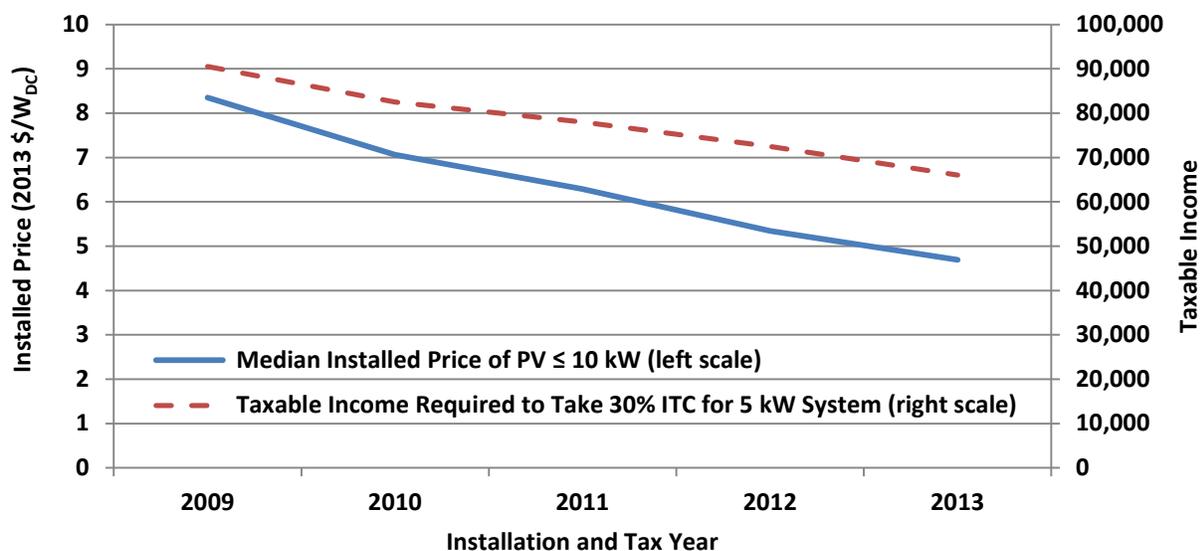


Figure 1. Declining Installed Prices Make it Easier to Use the 30% ITC

- **Falling PV prices make it easier to capture the 30% ITC:** Figure 1 also shows that as the cost of PV has fallen, so too has the amount of taxable income required to efficiently capture the 30% residential ITC – from more than \$90,000 in 2009 to just over \$65,000 in 2013 (assuming a 5 kW_{DC} system and a \$2000 child tax credit). Statistics from the IRS (2015) and the Tax Policy Center (2011) suggest that in 2012 and 2011, respectively, nearly 40% of all individual income tax returns in the United States (considering “all tax units” – i.e., single, joint, and head of household filings combined) reported at least this level of taxable income. The proportion increases to ~60% if focusing only on joint filings from married couples. This compares to just ~15-20% (considering all tax units) and ~40% (for married filing jointly) when considering the earlier threshold household income of \$90,000. Moreover,

⁹ In addition, at installed prices below \$5/W_{DC}, the total cost of a typical 5 kW_{DC} system falls within the \$25,000 single-family cap for FHA Title 1 Home Improvement Loans, opening up the possibility of using that existing loan vehicle for this purpose. As shown later, at least one lender – Admirals Bank – uses the FHA Title 1 loan as the basis for its solar loan product.

these proportions are far in excess of the single-digit percentage of U.S. households that have installed PV to date, suggesting that a large portion (but certainly not all) of the near-term addressable U.S. market has no need for third-party ITC monetization. In other words, at the same time as PV ownership has become more affordable and therefore more accessible to lower-income households, it has also become easier for such households to use the ITC without needing to resort to third-party monetization.

- **TPO contract prices have not kept pace with the decline in installed PV prices.** Recent research is beginning to demonstrate that TPO providers have engaged in “value-based” pricing – i.e., pricing their PPA or lease contracts low enough to provide solid value to the system host (relative to current utility retail rates), even though underlying costs would enable even lower PPA/lease prices.¹⁰ For example, Davidson et al. (2015) analyzed a sample of 1,113 lease and PPA contracts for residential PV systems installed in California from 2010–2012, and found that TPO contract prices within that sample “remained largely unchanged” over this three-year period despite a ~\$2/W decline in installed PV prices (more than twice the \$0.87/W decline in state incentive levels) over that same period.¹¹ Although there is nothing particularly nefarious about value-based pricing – to the contrary, it is a standard profit-maximizing strategy¹² – it does leave the door open to competitors (e.g., loan providers) who are more-willing to price closer to cost.¹³

¹⁰ In other words, under value-based pricing, the PV system host pays more than s/he would have needed to, but may not care (or even be aware) since the PPA/lease is still priced at a discount to utility rates. Value-based pricing stands in contrast to “cost-plus” pricing, under which the TPO provider would price the PPA/lease at the lowest rate that still enables it to cover its costs and generate a normal profit. Efficient or competitive markets are typically assumed to operate on a cost-plus basis, while less-competitive markets may experience value-based pricing.

¹¹ Davidson et al. (2015) present the following hypothesis as for why TPO providers have had success with value-based pricing: “In the absence of sufficiently informed customers, firms can price discriminate, selling systems above their marginal cost at prices influenced by consumers’ willingness-to-pay. A consumer’s willingness-to-pay for PV is, in part, a function of the savings produced by offsetting purchased electricity.” In other words, under-informed consumers have been willing to enter into solar leases and PPAs that provide savings relative to utility rates, even though underlying installed costs would suggest that they could do even better. Davidson et al. (2015) go on to cite “asymmetric information regarding attributes of PV systems and high search and cognitive costs to seek and compare quotes” as two barriers that enable value-based pricing to persist in the face of declining costs. The CEO of one company (EnergySage) that seeks to reduce search costs by allowing consumers to receive and evaluate multiple solar quotes online recently noted that the quote data flowing through his web portal indicates that cash prices have dropped significantly over the past few years, while lease and PPA prices have “remained quite constant” (Dumoulin-Smith et al. 2015). This statement is consistent with the findings of Davidson et al. (2015).

¹² One need look no further than the 2014 Form 10-K filing of the largest TPO provider to find evidence of a value-based pricing strategy. For example, SolarCity’s 2014 Form 10-K filing states: “We compete mainly with the retail electricity rate charged by the utilities in the markets we serve, and our strategy is to price the energy and/or services we provide...below that rate. As a result, *the price our customers pay varies depending on the state where the customer is located and the local utility. The price we charge also depends on customer price sensitivity*, the need to offer a compelling financial benefit and the price other solar energy companies charge in the region. Our commercial rates in a given region are also typically lower than our residential rates in that region *because utilities’ commercial retail rates are generally lower than their residential retail rates.*” [emphasis via italics added] Clearly, the local utility’s retail rate, and whether residential or commercial, plays an important role in SolarCity’s determination of how to set its contract prices (at the same time, the quoted text also demonstrates some level of sensitivity to competitive pressures applied by competing firms).

¹³ Value-based pricing may very well exist in host-owned (e.g., cash sale or loan financed) systems as well (see Gillingham et al. (2014), for example, who show evidence of some value based pricing for primarily host-owned PV systems). That said, a prospective host-owner facing a large up-front purchase that will generate savings that are not always immediately obvious or easy to derive may be more likely to shop around than a prospective TPO customer

- **Interest rates have been at historical lows:** Short-term Treasury interest rates have been hovering around 0% since late 2008, while the 10-year Treasury yield – a better benchmark for mortgages and other consumer loan products – has declined more slowly, falling from around 4% in late 2008 to below 2% in early 2012 (where it has more or less remained since). Needless to say, low interest rates make loans more affordable. While many expect the Federal Reserve Bank to be raising short-term interest rates later in 2015, it is unclear what effect that might have on the yield of 10-year Treasury notes – which is determined by the market rather than by the Federal Reserve, and often serves as the benchmark for consumer loan products of similar duration.
- **PPAs and leases are not available in every state:** At the time of writing, only about half of all states allow homeowners to buy solar electricity directly from non-utility third-party owners (DSIRE 2015). In contrast, solar loans are legal in all fifty states. Gaining an ability to tap into this larger addressable market is one driver of the proliferation of solar loan products – and is also one reason (along with competition from solar lenders) that various TPO providers have recently introduced their own solar loan products.
- **Residential PACE financing roadblocks have left a void (and opportunity):** Property Assessed Clean Energy (PACE) financing programs allow property owners to finance energy efficiency and renewable energy improvements at low cost and over extended periods on their property tax bills. First introduced in California in 2008, PACE programs had been spreading rapidly throughout the United States when the Federal Housing Finance Agency (FHFA) – which regulates Fannie Mae and Freddie Mac, the largest holders of residential mortgages in the United States – effectively stopped the concept in its tracks in July 2010 over concerns about the priority of the lien held by PACE loans. The FHFA took nearly two years to study the matter before issuing an unfavorable ruling in June 2012, during which time residential PACE financing all but dried up. Although some state and local governments have continued to pursue residential PACE by attempting to work around the FHFA issues in a variety of ways (e.g., California recently created a loan loss reserve fund for this purpose), residential PACE financing has so far not lived up to its initial promise (in contrast, commercial PACE, which is largely immune to FHFA concerns, is alive and well). The void left by this once-promising innovation has opened the door to other financing solutions, like solar loans.
- **The success of TPO has attracted attention and invited competition:** A significant increase in the overall size of the residential PV market, driven in large part by the popularity of TPO, has not gone unnoticed by would-be PV lenders. The success of TPO has attracted not only scrutiny of its business model – leading to a growing recognition in the market that PPAs/leases leave money on the table (Davidson et al. 2015, Feldman and Lowder 2014, Beavers et al. 2013, Dumoulin-Smith et al. 2015, Wang 2014) – but also competition from both traditional and non-traditional lenders who believe they can capture some of TPO’s market share, particularly in light of some of the other trends noted above.

who receives a proposal priced 5% (for example) below utility rates. In other words, the very attribute that has made TPO a relatively easier sell – i.e., pay-as-you-go pricing that can be easily compared to utility rates – also potentially makes value-based pricing easier to sustain.

- **Innovative new loan offerings have sparked further interest:** Finally, some of the recent momentum around solar loans is no doubt attributable to the innovative nature of early offerings, which have, in turn, spurred competition and further innovations. For example, the concept of combining a 0% (“same-as-cash”) 12- to 18-month loan for the 30% of installed costs covered by the ITC with a 12-year low-interest loan for the balance – i.e., tailoring the loan repayment to closely match the unique cash flow profile of PV ownership – was a bit of a breakthrough when first introduced back in 2009, but is now a fairly standard feature of most solar loan products, many of which have since added their own twists and innovations to make loans more attractive to consumers. One such innovation is the packaging of performance guaranties – once limited to TPO offerings – with some of the newer solar loan products. These new solar loan products are also easier to obtain than they have been in the past (Dumoulin-Smith et al. 2015), which further fuels demand through increasing familiarity. The next section describes a number of these solar loan products, with the intent of establishing what types of products are already available in the market, which in turn informs where state loan programs might best add value.

2.2.2 Survey of Private Sector Solar Loan Products

This section briefly summarizes some of the more innovative private sector solar loan offerings that have come on the market in the last few years and that are available nationwide (or at least in multiple states, and primarily in the largest solar markets¹⁴). The list of providers and products covered is not intended to be exhaustive; instead, the intent is merely to provide a general sense of what types of products are currently being offered in the market, with the goal of potentially identifying any critical gaps that a state PV loan program might be able to fill. For a broader overview of the current solar loan product landscape, see Feldman and Lowder (2014) or Becker-Birck et al. (2013).

SunPower

The breakthrough concept of combining a “tax credit loan” – i.e., a 12- to 18-month zero-interest loan for the 30% of total system costs covered by the federal ITC – with a more traditional longer-term loan for the balance seems to have originated with PV module manufacturer SunPower back in October 2009, when it partnered with specialty lender Enerbank USA to launch its *Solar Now* loan program. The program, which coupled a 12-month “same-as-cash” (or zero-interest) tax credit loan with a 12-year 6.99% loan, had no application fee or pre-payment penalty, and was marketed through SunPower’s dealer/installer network. Since then, SunPower has partnered with several other lenders, including a \$100 million deal with Digital Federal Credit Union announced in September 2013 and a \$200 million deal with Admirals Bank announced in June 2014. With these new partnerships have come changes to the loan terms as well as to the name of the loan program itself (now called the *SunPower Loan*, in parallel branding with the *SunPower Lease*¹⁵), but the same basic structure of combining a short-term tax

¹⁴ Products that are available only to residents of a single state are not covered here, due both to the sheer number of such products as well as the greater likelihood that state PV loan program managers will already be aware of such products being offered only within their own state.

¹⁵ In one indication of the growing popularity of loans, SunPower recently noted that roughly two-thirds of its U.S. residential sales in 4Q14 were for cash or loans, rather than leases (SunPower 2015).

credit loan with a longer-term loan for the balance is still intact. For example, a recent check of Digital Federal Credit Union's web site for SunPower loans shows a 12- to 18-month same-as-cash tax credit loan in conjunction with a longer-term loan ranging from five to twenty years and featuring interest rates from 4.99% up to 7.74%, respectively. Quality assurance is supported by SunPower's industry-leading 25-year combined product and production warranty, and these loans are available in all fifty states to borrowers with credit scores of at least 670.

Sungage Financial

Massachusetts-based Sungage Financial has offered solar loans since early 2013, and claims to be the first entity not affiliated with a module manufacturer (i.e., SunPower) to offer a dedicated solar-specific loan. Most of its activity to date has been in Connecticut, where it offers the *CT Solar Loan* product with financing (and other support) initially provided by Connecticut's Clean Energy Finance and Investment Authority (CEFIA). In early 2014, Sungage also partnered with the finance crowd-sourcing platform, Mosaic, to enable accredited investors across the country to invest alongside CEFIA (and a third partner, the Hampshire Foundation) in the *CT Solar Loan* portfolio.¹⁶ The *CT Solar Loan* is available through CEFIA-approved installers and features a labor and production warranty over its full 15-year term. The loan is unsecured, has no prepayment penalty, and – following SunPower's lead – offers a tax credit loan component (and re-amortization of the balance, once paid off), with a 6.49% fixed interest rate on the 15-year balance. Maximum loan size is determined by the present value of bill savings, rather than by more-traditional metrics like income, credit rating, or strength of collateral.¹⁷ In October 2014, Sungage announced a \$100 million investment from Digital Federal Credit Union (DCU) to back an expanded loan portfolio not only in Connecticut, but also in Massachusetts, New Jersey, and New York initially, followed by additional states in 2015. In early 2015, Sungage announced several new installer partnerships in California (including with Solar Roof Dynamics, Sun Solar Energy Solutions, and Bland Solar & Air).

Enerbank USA and GreenSky Credit

Neither of these two entities – the former a specialty lender and the latter a finance platform that works with a variety of banks – offers loans directly to consumers. Instead, each partners with PV installers who market their respective loan products – essentially the now-standard offering of tax credit loans, unsecured longer-term loans, or combinations of the two (recall that Enerbank pioneered this concept with SunPower back in 2009) – to prospective clients in all fifty states. Installers pay a fee for each loan that closes, and can also choose to buy down the interest rate offered on the longer loan (e.g., 12-year loans at just 2.99% are possible through a motivated installer).¹⁸ Anecdotal evidence suggests that some (perhaps many) installers roll these fees into

¹⁶ CEFIA sold 80% of the loan payment stream to Mosaic and the Hampshire Foundation, retaining 20% on a subordinated basis (Hunter 2014).

¹⁷ Sizing the loan based on bill savings increases the odds that the borrower will have sufficient funds (from bill savings) to repay the loan. The 15-year performance guarantee helps to ensure that those bill savings will actually materialize as projected.

¹⁸ The fee is structured as a percentage of the amount borrowed, and the percentage is significantly less for the tax credit loan (4-6%) than for the longer-term loan (mid-to-upper teens). Given that the amount borrowed under the longer-term loan (up to 70% of system costs) is also significantly larger than under the 30% tax credit loan, some

their total installed price, thereby charging their customers for access to financing, while also inflating the basis to which the ITC applies. Rolling the cost of financing into the installed price and ITC basis is not too dissimilar from the TPO basis step-up issues explored in the Appendix, and is perhaps one downside of packaging or integrating financing with installation in general (i.e., though perhaps less convenient, the customer could potentially save money by decoupling the financing decision from the purchase decision, and shopping around for both).

Admirals Bank

In April 2013, Admirals Bank launched two variations on the tax credit combo loan, which can be used either individually or in combination. Its *Solar StepDown Loan* is a secured FHA Title 1 loan with a maximum loan size of \$25,000. Borrowers can apply their federal tax credit refund and/or state rebate towards the loan principal and then request a one-time re-amortization (to “step down” the monthly payments) any time within the first 24 months. Qualified borrowers (e.g., with a minimum FICO score of 700) that need a larger loan, up to \$40,000, can instead take a *SolarPlus Loan*, which combines an 18-month same-as-cash unsecured tax credit loan (for up to \$15,000) with a \$25,000 secured FHA Title 1 loan (i.e., the same product that serves as the basis for the *Solar StepDown Loan*) for the balance. These loans are available in all 50 states.

In addition to offering these loans directly to consumers, Admirals Bank also partners with installers or module manufacturers to finance co-branded loans, potentially with additional consumer perks. For example, in June 2014, Admirals Bank and SunPower announced a \$200 million partnership in which Admirals offers lower interest rates to SunPower customers.¹⁹

Digital Federal Credit Union (DCU)

DCU has committed at least \$200 million to finance solar loans to date, but so far only offers those loans through its partners, SunPower (\$100 million investment announced in September 2013) and Sungage Financial (\$100 million investment announced in October 2014). As a tax-exempt federal credit union, DCU is able to offer relatively low-cost capital to finance solar loans.

Mosaic

The finance crowd-sourcing platform, Mosaic, has made several inroads into residential solar loans in 2014. In February 2014, it partnered with Sungage Financial in Connecticut to enable accredited investors throughout the country to finance (through a 15-year investment providing a ~5% return) the *CT Solar Loan* product offered by Sungage (see above). In March 2014, it launched its own *Mosaic Home Solar Loan* product in partnership with installer RGS Energy (initially available only in California), and in July 2014, it began to bundle this product with O&M services provided by Enphase Energy (for systems using Enphase micro-inverters).

installers find the longer-term loan to be prohibitively expensive, and market only the tax credit loan (particularly in states where other long-term financing options are available).

¹⁹ It is not clear whether SunPower (or perhaps ultimately its clients) pays a fee to Admirals Bank to buy down the interest rate, or whether Admirals Bank has willingly reduced the interest rate in order to gain access to SunPower’s nationwide installer network.

Mosaic’s website advertises a zero-down, 20-year loan with an interest rate as low as 4.99% (no escalator), coupled with “tax credit financing” (presumably similar to the short-term, same-as-cash, 30% ITC loans that have become common). Financing for the *Mosaic Home Solar Loan* can be crowd-sourced, but in a sign that the demand for Mosaic’s loans may be outpacing the supply of crowd-sourced financing, in October 2014 Mosaic announced a \$100 million investment from reinsurance company PartnerRe to back the *Mosaic Home Solar Loan* product.

SolarCity

In what is perhaps the best indication of the growing demand for (and competitiveness of) solar loans, in October 2014, SolarCity – by far the largest residential TPO provider – announced its own solar loan program, called *MyPower*. This 30-year loan features a fixed annual percentage rate as low as 4.5%,²⁰ no down-payment, no prepayment penalty, and includes a 30-year warranty package including a production guarantee and remote monitoring. No lien is placed on the home, and a credit score of at least 680 is required. Like most other solar loans, *MyPower* includes a tax credit step-down feature: a balloon payment equal to 30% of system costs is due by June 1 of the year following the year of installation (i.e., as long as 18 months), and serves to reduce the size of subsequent monthly payments.

In a somewhat unique twist that builds upon Sungage Financial’s use of projected bill savings – and hence ability to pay – to size the loan, *MyPower* is amortized and repaid on a \$/kWh basis, and so feels more like a PPA than a loan. Specifically, SolarCity divides the total cost of the system plus interest by the expected system output over thirty years to arrive at the \$/kWh repayment rate. This means of pricing allows customers to easily compare the loan payment to utility rates in order to estimate savings. If the system performs better than expected, the loan will be paid off ahead of schedule; if it performs worse, SolarCity will compensate the customer for the difference on a bi-annual basis.

One implication of this per-kWh payment structure is that the size of repayments will fluctuate from month to month, depending on the output of the system. Homeowners who would prefer a fixed monthly payment, or who do not have sufficient tax liability to claim the full 30% ITC in year one (the 30% balloon payment is due regardless of how much tax credit the customer can claim), may still be better off with a lease. Otherwise, SolarCity expects *MyPower* to offer a compelling value proposition with “a lower cost than PPAs in many locations” (SolarCity 2014c), and projects that half of its new customers will choose *MyPower* over traditional leases or PPAs by as early as mid-2015 (Wang 2014). *MyPower* was initially launched in just eight states where SolarCity is already active, but will eventually be offered in other states as well, as one of the reasons for the new product is to expand the size of the addressable market to include states that do not allow third-party ownership of solar. For example, in early March 2015, SolarCity entered the New Mexico market with *MyPower* as its sole offering.

²⁰ This 4.5% rate reflects a 0.5% discount for customers who elect to have their monthly payments automatically withdrawn. SolarCity’s 2014 Form 10-K notes that “In select California markets, which comprise the majority of MyPower sales, we recently increased the interest rate on the loan to 5.49% per annum.” The 0.5% electronic withdrawal discount would presumably reduce that rate to 4.99%.

3 PV Program Response to Financial Innovation in the Residential Sector

Whether one favors TPO through a lease/PPA or host-ownership through a solar loan, the proliferation of both types of financial offerings has had a profound impact on the growth of the residential PV market – with corresponding implications for the role of state and local PV programs within that market. For example, the combination of declining costs and increasing access to a variety of financing products has gone a long way towards overcoming the age-old barrier to PV deployment posed by high first costs. At the same time, state-level PV incentives have become less-critical to deployment, as in many cases they have declined in tandem with installed costs.

A number of state and local PV program managers have responded to these positive developments by re-tooling their incentive offerings to optimize their expenditures and maintain their relevance. Though by no means uniform, or even widespread, these responses have generally fallen into one of two camps: (1) differentiating incentive levels between TPO and host-owned systems in recognition of the greater federal tax benefits provided to TPO systems, and (2) encouraging the spread of consumer-friendly solar loan offerings to widen the scope of possible financing products and therefore customer demand for solar. Both courses of action potentially help to preserve increasingly scarce public funding for PV by using incentives more as a tool to fine-tune the market rather than to stimulate it outright, and/or by shifting away from incentive disbursements in favor of financial support that can better sustain fund balances and potentially even provide a return on capital. At the same time, these responses are not yet omnipresent, perhaps in part because they raise questions about the role of state programs in the solar market and in part because of potential side-effects on solar deployment that deserve consideration.

This chapter surveys the field of state and local PV programs that have responded in one or both of these ways. The intent is to catalogue the breadth of programmatic responses in order to potentially help inform other programs that have yet to grapple with these issues. Some of the various tradeoffs and considerations that confront program managers in thinking about such changes are addressed in more detail later in Chapter 4.

3.1 Differentiate Incentives by Ownership Type

Several state PV programs have long differentiated between tax-exempt and taxable recipients when setting incentive levels. For example, the California Solar Initiative – by far the largest PV program in the United States in recent years – has differentiated between TPO and host-ownership when setting incentive levels for governmental or non-profit hosts.²¹ The higher

²¹ The “expected performance-based buy-down” (EPBB, available only to systems less than 30 kW) provided to systems owned by tax-exempt governmental or non-profit hosts has been as much as \$0.75/W_{DC} higher than the EPBB provided to TPO systems (but in the final two steps of the program’s declining block structure this premium decreased to \$0.65/W_{DC} and then \$0.50/W_{DC}). Similarly, 5-year performance-based incentives or PBIs (available to systems of 30 kW or larger, as well as to smaller systems that elect the PBI in lieu of the EPBB) have been as much as \$0.11/kWh higher for tax-exempt host-owners, though that premium declined to \$0.06/kWh in the CSI program’s final step.

incentive levels provided to host-owned governmental or non-profit systems are an explicit acknowledgment that these tax-exempt hosts are disadvantaged by their inability to directly reap federal tax benefits.

More recently, as TPO has rapidly gained significant market share in the residential sector, there is a growing recognition that residential host-owned systems are also disadvantaged relative to TPO when it comes to federal tax incentives (despite the fact that residential system owners are also taxable and in many cases are able to use solar tax benefits). As a result, at least a handful of state and local PV programs have extended the concept of incentive differentiation to the residential sector, differentiating between host-owned and TPO systems in terms of incentive levels and/or structures.²² Though motivations for this differentiation are not always publicly stated, several programs note that the differentiation is a response to market trends and the relative success of TPO (which, in turn, is likely partly related to the larger federal tax benefits enjoyed by TPO providers, as estimated in the Appendix). A non-exhaustive summary of these programs follows, by state and in alphabetical order.

Before running through the list of programs, however, it should be noted that there is nothing necessarily alarming about residential TPO systems receiving higher federal tax benefits than identical host-owned systems. Indeed, given the legislative history of the Section 48 and Section 25D credits, it is clear that Congress did not originally intend for these two credits to be equal prior to 2009;²³ nor does it intend for them to be equal after 2016.²⁴ Whether parity in federal tax benefits provided to TPO and host-owned residential PV systems is an inherently desirable goal is subject to debate, and ultimately is a federal policy choice.

On the other hand, the inequality of federal tax benefits has had a significant impact on how the residential PV market has developed over time; both for better (the initial inequity spurred the launch of residential TPO, which has greatly increased the size of the market) and for worse (the resulting high TPO market share in some states may be restricting consumer benefits). At a minimum, state and local PV program administrators should understand the linkages between Federal tax policy and market development, and, depending on their specific goals, perhaps take steps to adjust their programs in response, while also considering the myriad possible tradeoffs, some of which are discussed in Section 4. This is the justification for quantifying the federal tax disparity later in the Appendix, and for comparing it to the incentive level differentiation that has occurred within the following PV programs.

Colorado

Xcel Energy's Solar Rewards program provides a performance-based incentive (PBI) in exchange for the solar renewable energy credits (SRECs) generated by each system over a 20-

²² Interestingly, California is not among them. California differentiates between TPO and host-ownership for tax-exempt, but not taxable, hosts – even though residential (taxable) host-owned systems are also at a disadvantage relative to TPO when it comes to federal tax incentives (as shown in the Appendix).

²³ For example, the residential (Section 25D) ITC only came into existence in 2006, whereas the commercial (Section 48) credit has been on the books for many decades (though, until 2006, at a 10% level). Similarly, the 30% residential ITC was initially capped by Congress at \$2000 per system, whereas the 30% commercial ITC was not.

²⁴ Barring any future legislative changes, the residential ITC will expire at the end of 2016, whereas the commercial ITC will merely revert back to 10%.

year period. For host-owned residential systems installed in 2015, the PBI is \$0.02/kWh for the first ten years (even though Xcel claims the SRECs for the full 20 years), while TPO providers receive \$0.01/kWh over the full 20-year period. Although there is no difference in nominal terms (except for slight impacts from degradation) between these two incentives over the full 20-year period, in present value terms host-owners have a slight advantage. Assuming a system performance of 1,400 kWh/kW-year and a 0.5%/year degradation rate, the present value (at a 6% discount rate) of the difference works out to TPO systems receiving \$0.05/W_{DC} less than host-owned systems. This is down from a \$0.15/W_{DC} differential in 2014, when host-owners received \$0.03/kWh compared to TPO's \$0.01/kWh.

Connecticut

Connecticut has had a long and interesting relationship with TPO. Back in 2008, when private sector third-party ownership of residential solar was still in its infancy nationwide and not yet available in Connecticut, Connecticut's Clean Energy Finance and Investment Authority (CEFIA) launched the *CT Solar Lease* in conjunction with AFC First Financial Corporation, Gemstone Lease Management, and U.S. Bancorp (as tax equity investor). Between August 2008 and February 2012 (when the first phase of the *CT Solar Lease* program ended), 855 homeowners leased PV systems totaling 6.2 MW through the program (Speer 2012). This demonstrated success was, in part, responsible for attracting private sector TPO providers like SolarCity (in February 2012), SunRun (in June 2013) and others to enter the Connecticut market.

Rather than fully concede the TPO market to these private TPO providers, CEFIA chose to both compete with and complement the private sector TPO offerings through a second phase of the program – *CT Solar Lease II* – that launched in July 2013. The rationale for continuing the program in the face of private sector competition rests on two key benefits that it provides. First, the *CT Solar Lease* is a financing tool that *any* qualified installer can offer its customers; in this way, the program helps support installer diversity and the local economy.²⁵ Second, the *CT Solar Lease* is available to a wider array of participants, with lower incomes and credit scores, than the typical private sector offering. For example, the CT Solar Lease requires a minimum credit score of 640, compared to 680 or even 700 for most private sector leases or PPAs.

With respect to the issue at hand – differentiated incentives – CEFIA's tiered residential PV incentive program differentiates between host-owned and TPO systems based both on the structure and level of incentive provided. For a conservatively sized system (i.e., one that is not projected to generate more electricity than has been consumed in the previous 12 months) less than 10 kW, a host-owner will receive (in Step 7 of the program) a "homeowner performance-based incentive" (similar to an expected performance-based buy-down, or EPBB²⁶) of

²⁵ A CEFIA press release announcing the start of the program noted, "The new program will enable homeowners and businesses to choose from a variety of eligible installers throughout Connecticut—not just the select companies that have access to sources of capital and tax equity." Along these lines, it is perhaps worth noting that independent installers who are SunPower dealers, or who work with companies like Clean Power Finance, can also offer third-party ownership to their clients through these channels.

²⁶ An EPBB is a rebate that is designed to encourage proper siting (and hence performance) by using a formula to adjust the size of the rebate based on various performance-related siting parameters, such as tilt, azimuth, and shading. Those installations that adhere most closely to optimal design parameters receive higher EPBB amounts than those that are less optimal.

$\$0.54/W_{DC}$, while a TPO provider will receive a 6-year PBI of $\$0.064/kWh$ (paid quarterly). Assuming system performance of $1140 kWh/kW\text{-year}$ with $0.5\%/year$ degradation, the present value (at a 6% discount rate) of the TPO PBI is $\$0.19/W_{DC}$ less than the comparable host-owned buy-down. Estimated differentials – all favoring host-ownership – from earlier Steps of the program include $\$0.23/W_{DC}$ in Step 6, $\$0.11/W_{DC}$ in Step 5, $\$0.25/W_{DC}$ in Step 4, $\$0.50/W_{DC}$ in Step 3, $\$0.44/W_{DC}$ in Step 2, and $\$0.74/W_{DC}$ in Step 1 (which launched in March 2012). Differential aside, providing host-owned systems with an up-front incentive helps homeowners to overcome PV's high up-front investment costs, while TPO providers are generally less in need of up-front support and better able to handle the logistics of a 6-year PBI.

Maryland

The Maryland Energy Administration provides *Clean Energy Grants* to a variety of residential renewable energy projects, including PV systems of up to $20 kW_{DC}$, which are eligible for a flat grant of $\$1,000/project$. As of November 14, 2013, TPO PV systems are no longer eligible for these grants, “due to the overwhelming success of solar PV leasing, the reduced impact that the grant is having on the market, and direct feedback from the solar industry. This discontinuation will allow MEA to shift available grant funding to other target markets and technologies” (Maryland Energy Administration 2014). Assuming a $5 kW_{DC}$ system, this exclusion of TPO amounts to a $\$0.20/W_{DC}$ difference.

Massachusetts

Under the Massachusetts Clean Energy Center's *Commonwealth Solar II* rebate program (which ended in January 2015, to be replaced by the new *Mass Solar Loan* program described in the next section), residential host-owners qualified for the residential rebate while third-party owners of residential PV systems qualified for the commercial rebate. The base rebate of $\$0.25/W_{DC}$ (up to $5 kW_{DC}$) was the same for both residential and commercial, but there were three potential adders on top of the base rebate, one of which – $\$0.40/W_{DC}$ for hosts that qualified as having a moderate income or home value – was only available to host-owned (not TPO) residential systems.²⁷ Hence, host-owned residential systems received the same incentive level as TPO systems except in cases where the host qualified as having a moderate income or home value, in which case it received an additional $\$0.40/W_{DC}$.

Systems receiving rebates were also eligible for remuneration from the sale of SRECs through Massachusetts' *SREC II* program. Early drafts of the *SREC II* program design included a concept known as “forward minting” of SRECs, intended to promote host-ownership by providing host-owned systems with an up-front payment in exchange for the SRECs that are expected to be generated during the system's first ten years (while TPO systems would earn SREC revenue as SRECs are generated over time). This concept was ultimately dropped in the final program design, in favor of using RPS alternative compliance payments to develop, launch, and finance a new residential loan program. Details of the new *Mass Solar Loan* program are described later in Section 3.2.

²⁷ The other two adders – $\$0.05/W_{DC}$ for use of components made in Massachusetts and $\$1/W_{DC}$ for projects installed in natural disaster relief areas – were available to either host-owned or TPO projects.

Oregon

The Energy Trust of Oregon administers PV rebates for customers of Portland General Electric and Pacific Power. As of April 2015, TPO systems in both utility service territories are eligible for an incentive of $\$0.65/W_{DC}$ up to $\$5,000$ maximum. Meanwhile, host-owned systems in Pacific Power's service territory are eligible for $\$0.66/W_{DC}$ – i.e., essentially the same as TPO – but with a higher cap of $\$6,600$, while host-owned systems in Portland General Electric's service territory are eligible for $\$0.90/W_{DC}$ up to $\$9,000$. Thus, for systems smaller than $7.7 kW_{DC}$ (such that the $\$5000$ cap on TPO rebates is not binding), host-owners are paid $\$0.25/W_{DC}$ more in Portland General Electric's service territory and are treated essentially no differently in Pacific Power's territory. For systems larger than $7.7 kW_{DC}$, the $\$5,000$ cap for TPO systems becomes binding, leading to a greater differential (as system size increases) in both service territories.

Notably, the Energy Trust first differentiated its incentive levels by ownership type at the start of 2014 by *increasing* host-owned incentive levels and/or maximum dollar amounts, rather than by *decreasing* TPO incentives. This increase, however, can be thought of as a small correction to a more-significant across-the-board incentive reduction in mid-2012, which left demand – particularly among host-owned systems – rather lackluster in 2013 (McClelland 2014).

Texas

Although it has huge solar potential (e.g., it has been referred to as “a sleeping giant” (Osborne 2015)), Texas is not known for its solar incentives. That said, there are a number of Texas cities, perhaps most notably Austin and San Antonio, whose local municipal utilities have embraced solar. Both Austin Energy and CPS Energy (San Antonio's local utility), however, differentiate between residential host-owned and TPO systems by not providing incentives to the latter. At April 2015 incentive levels, this results in a differential incentive (in favor of host-ownership) of $\$1.10/W$ and $\$1.60/W$, respectively. In a presentation to City Council in December 2014, Austin Energy made the case that residential leased systems do not need any local incentives, because of the incremental federal tax advantages that they already enjoy (City of Austin 2014).

3.2 Provide Support for Solar Loans

Instead of, or in addition to, modifying incentive levels to account for differential federal tax benefits between host ownership and TPO (as discussed in the previous section), a number of states have implemented and/or modified financing programs in order to support PV deployment via host-ownership (or, as discussed earlier for Connecticut, to broaden the application of TPO). In most cases, the idea is to support PV deployment by helping homeowners capture the benefits of host-ownership through viable solar loan products where they don't already exist, or by complementing existing private sector solar loan offerings. A non-exhaustive summary of these programs follows, by state and in alphabetical order.

Connecticut

Connecticut's Clean Energy Finance and Investment Authority (CEFIA) has been a standout among state clean energy funds in terms of promoting financing programs as an alternative (or at

least a complement) to traditional grants, rebates, and performance-based incentives. As mentioned in the previous section, since 2008 CEFIA has run its own solar leasing program, initially to fill a gap that existed in the state and then, once the major private leasing companies entered Connecticut, to complement their offerings by focusing more on moderate income households.

CEFIA's financial offerings for solar are not limited to leasing, however. As noted earlier in Section 2.2.2, it also supported Sungage Financial's launch of the *CT Solar Loan* product in early 2013. In addition to product development and marketing support, CEFIA provided the *CT Solar Loan* with credit enhancements in the form of a loan loss reserve (\$300,000) and subordinated debt (\$1 million), as well as a \$5 million loan warehouse facility (CEFIA 2014a).²⁸ Since its launch in March 2013, *CT Solar Loan* has financed over 200 projects totaling more than 1700 kW and nearly \$5 million in loans. In October 2014, CEFIA heralded Digital Federal Credit Union's \$100 million partnership with Sungage to support solar loans in Connecticut and other states as a sign that Sungage (and its solar loan concepts) had "graduated" from public sector support to private sector partnerships (CEFIA 2014a). As of April 2015, the *CT Solar Loan* was listed on CEFIA's website as being "temporarily unavailable" while it was "being updated."

Hawaii

With a strong solar resource and a high cost of electricity from imported fuel, Hawaii's solar market has historically been among the fastest growing. Nevertheless, the state is concerned that some Hawaii residents and businesses – including renters, non-profits, and low- to moderate-income homeowners – have not been able to take advantage of existing products (including TPO, but also host ownership) or programs. As a result, on June 27, 2013, Hawaii's governor signed a law authorizing the creation of a new program – the *Green Energy Market Securitization* program, or GEMS – that aims to bridge that market gap and make affordable clean energy finance available to a broader audience.

GEMS is administered by the Hawaii Green Infrastructure Authority, a new state agency created under the Department of Business, Economic Development & Tourism. The program will issue green bonds to raise capital for solar and other green infrastructure loans, and then make use of on-bill repayment – a separate program being created by the Hawaii Public Utilities Commission – to recoup the principal and interest on those loans. In addition to the on-bill repayment mechanism, a "green infrastructure fee" that is assessed on *all* utility customers (and that replaces a portion of the existing public benefits fee), whether or not they participate in GEMS, will support the credit ratings of the green bonds, thereby enabling lower interest rates.

An initial bond issuance of \$150 million occurred on November 18, 2014, in two tranches: \$50 million in 8-year notes yielding 1.47%, and \$100 million in 16-year bonds yielding 3.24%. In March 2015, the Green Infrastructure Authority began accepting applications from nonprofits interested in borrowing GEMS funds to pre-pay a 20-year solar PPA at a discount to utility rates. This initial focus area will have access to more than \$100 million in financing: \$65 million of

²⁸ The \$1 million in subordinated debt represents the 20% of the \$5 million financing commitment (through the loan warehousing facility) that was *not* sold to Mosaic and the Hampshire Foundation (see the write-up on Sungage Financial in Section 2.2.2, earlier).

GEMS funds leveraged by at least \$40 million of tax equity. Similar programs for low-to-moderate income homeowners and renters will be rolled out in the future.

GEMS will initially target underserved consumers by relying, in part, on non-traditional lending criteria like utility bill repayment history and net bill savings expected from a PV system as a measure of ability to pay. On-bill repayment will allow such consumers to more easily finance and pay for PV systems on their utility bills, ideally without any increase in average bill size, and then to eventually benefit from lower utility bills once the loan is paid off.

Separately, the Hawaii Community Reinvestment Corporation administers the *GreenSun Hawaii* program, which provides local lenders with access to a loan loss reserve fund (funded by a grant from the U.S. Department of Energy) which can cover up to 100% of any losses on loans to qualifying energy efficiency and renewable energy investments. PV systems are eligible for this program, but only if the borrower has already installed certain energy efficient appliances. Because the program's loan loss reserve fund reduces their risk, participating lenders can offer more favorable terms and lower interest rates.

Massachusetts

A 2013 study sponsored by the Massachusetts Department of Energy Resources (DOER) concluded that host-owned PV systems provide “substantially higher economic benefit to the homeowner” than TPO systems (Beavers et al. 2013), and also in most cases provide greater benefits to the state. To encourage residential PV host ownership, and after considering other alternatives mentioned in Section 3.1, the DOER created a state-supported solar loan program, to be funded by alternative compliance payments under the state's renewables portfolio standard.

After progressing through several rounds of draft loan program designs (informed by comments from potential participating lenders and other stakeholders), the DOER issued the final program parameters on October 16, 2014. Notable design elements include three different forms of credit enhancement, to be used in combination: an interest rate buy-down (of 3% initially), a loan loss reserve fund (with higher reserves set aside for borrowers with lower credit ratings), and a moderate income loan support payment of either \$0.8/W or \$1.2/W to buy down the loan principal for households with income of less than 120% or 100% of the Massachusetts median, respectively. Like most private sector solar loans currently in the market, this program would also allow the borrower to apply the 30% federal ITC against the loan principal within the first 18 months of the loan and then request a re-amortization of monthly payments. Notably, the *Mass Solar Loan* will replace the *Commonwealth Solar II* rebate program, which sunset in January 2015.

Interestingly, two of the three credit enhancements provided by this program – the interest rate buy-down and the principal buy-down for moderate income applicants – involve cash disbursements from the state. This payout strategy stands somewhat in contrast to the approach of the so-called “green banks” in Connecticut (CEFIA), Hawaii, and New York (New York Green Bank, see below), which believe that their role is principally to lend and recycle their capital, or else pledge it to enhance credit (e.g., through loan loss reserves), rather than to pay it out through rebates and other cash incentives. On the other hand, comments from at least two

entities (one a lender) on the Massachusetts loan program's interim design suggest that the loan loss reserve funds championed by the "green banks" may not always be as impactful as claimed.²⁹

The final program design was officially announced in January 2015, and the DOER has been developing documentation, recruiting participating lenders, and preparing to launch the program.

New York

The New York State Energy Research and Development Authority (NYSERDA) has long offered a variety of consumer financing programs for renewable energy (and energy efficiency) projects. Its two current programs that are most relevant to this discussion are NYSERDA's *Green Jobs-Green New York* loan program and the newly created New York Green Bank, which is a division of NYSERDA.

As part of the NY-Sun solar incentive program, homeowners who install PV using a participating NY-Sun installer can elect to finance their investment through NYSERDA's revolving loan fund (authorized by the *Green Jobs-Green New York Act of 2009*), with the loan structured either as a traditional installment loan (with payments made directly to NYSERDA's loan servicer) or else one that is repaid on the borrower's utility bill (i.e., on-bill repayment).³⁰ Both products have similar terms (e.g., 5, 10, or 15-year maturities, each with an interest rate of just 3.49%); the primary difference is the means of repayment. Borrowers with credit scores as low as 540 will be considered if other lending criteria are met (e.g., debt-to-income ratio of less than 70%, mortgage paid on-time in the previous 12 months, etc.).

The New York Green Bank is a more recent creation. First proposed by Governor Cuomo in January 2013, the Green Bank was capitalized with an initial \$210 million (on its way to \$1 billion) in December 2013,³¹ officially opened for business in February 2014, and announced its first investments in October 2014 (none of which were targeted at residential PV). Broadly, the Green Bank's strategy is to partner with and complement private sector finance to fill gaps and overcome barriers. It will work exclusively within the wholesale (rather than retail or consumer) finance sector, and its participation in deals may include "the role of credit enhancement provider (e.g., a reserve account or a junior interest), lender (e.g., senior, mezzanine or subordinated), or warehouse provider (with the likelihood of being taken out by private sector third parties)" (New York Green Bank 2014). Whether the Green Bank's future investments and

²⁹ For example, a representative from a credit union provided the following comment on the Massachusetts solar loan program's interim design: "The LLR [loan loss reserve] is an additional layer that complicates the program and would more than likely require a third party to administer, adding complexity, time delays and costs that don't outweigh the benefits and returns of the program. We already reserve for loan losses and this would be a waste of government funding and a duplication of effort." (Becker 2014)

³⁰ *The Green Jobs-Green New York Act of 2009* authorized NYSERDA to work with the state's utilities to set up the on-bill repayment option, and to pay those utilities a fee for each loan that chooses on-bill repayment, as a means to defray their cost of implementation.

³¹ \$165 million of the initial funding was redirected from other New York energy programs and \$45 million came from the Regional Greenhouse Gas Initiative.

activities will impact the residential PV sector (e.g., in the way that Connecticut’s “green bank” – CEFIA – has) remains to be seen, but the potential does exist for activity in this area.³²

³² For example, the Green Bank web page states that it will “work with entities already achieving success in clean energy, but whose progress is constrained by the lack of available financing.” Although this statement could potentially apply to the solar loan space, on the other hand recent infusions of private capital (e.g., Admirals Bank on its own and in a \$200 million partnership with SunPower; Digital Federal Credit Union’s recent \$100 million partnership with Sungage Financial and earlier \$100 million partnership with SunPower; SolarCity launching loans) perhaps suggests that there is already (or soon will be) a critical mass of private sector capital supporting solar loans.

4 Discussion of Issues and Considerations

Thus far this report has described the two successive waves of financial innovation that have helped drive the residential PV market to where it stands today (Chapter 2), as well as how a subset of state and local PV incentive programs have responded to this financial innovation and the changes it has brought about (Chapter 3). This chapter, in turn, discusses some of the considerations and tradeoffs that state and local PV program managers may encounter when contemplating the two most common responses from their fellow PV programs to date: providing differentially higher incentive levels to host-owned systems and/or supporting PV deployment through increased support for solar loans.

4.1 Considerations Surrounding Differentiated Incentives

Though some state and local PV programs have differentiated incentives between TPO and host-owned PV systems, many have not. At least four different considerations come into play when thinking about differentiating incentives between TPO and host-ownership. First and foremost is the threshold decision of whether to differentiate at all. If a PV program decides to differentiate, then it must also consider whether to differentiate by incentive level or incentive structure, how much of a differentiation in incentive level is warranted, and how best to implement the differentiation. This section addresses all four considerations in turn.

Whether or Not to Differentiate?

The answer to this threshold question will depend on the goals, mission, and philosophy of each individual PV program, as well as the specific market context in which each program operates.

If a PV program's goals are to maximize near-term residential PV deployment, in part leveraging existing federal tax policy that advantages TPO, then differentiating local incentives to counter the federal tax advantages of TPO may be counterproductive. In fact, in this instance the PV program might achieve its near-term deployment-maximizing goal more quickly by differentially *encouraging* TPO, in order to capitalize on and leverage the larger federal tax benefits that TPO systems receive.³³ This reasoning assumes (without substantiation) that TPO providers use local PV program incentive funds to significantly expand the local market, either by reducing the cost of PV to their customers or through more-aggressive marketing campaigns. If this is not the case (due to value-based pricing, or otherwise), or if a PV program manager believes that – for whatever reason – host-ownership has the greatest prospect for near-term growth, then differentiating local incentives in favor of host-ownership may merit consideration as a way to help maximize near-term deployment and/or more cost-effectively support that deployment.

If, instead, a PV program's goals are, at least in part, to encourage a diversity of PV deployment business models and installers in the interest of longer-term or broader objectives (e.g., local

³³ Though such an approach might maximize the *absolute* dollar amount of federal tax benefits captured by in-state PV projects, it should be recognized that the amount of “leverage” (in the traditional sense of the word – i.e., dollars of federal tax benefits captured per local incentive program dollar spent) may actually decrease under such an approach, as local program spending may be higher than it needs to be.

economic development, or maximizing ratepayer benefits), or to enable consumers to better judge TPO vs. host-ownership based on their respective intrinsic merits (rather than, in part, based on the differential application of federal tax policy), then differentiating local incentives in favor of host-ownership might be considered as a way to contribute towards these goals, presuming that the logistical and practical challenges of doing so can be overcome.

There are no obvious right or wrong answers to the above considerations; there are also likely numerous considerations not noted above that also merit discussion. Moreover, PV program managers also need to be mindful of the local market context in which they operate when contemplating changes to PV program structure or incentive levels. For example, is the current pace of residential PV deployment in the local market considered to be acceptable, too fast, or too slow? Is TPO already well-established in the local market, or just getting started? Are other financing options (other than TPO) readily available? Are there any state or local incentives (other than those controlled by the PV program itself) that differentially favor either host-owned or TPO systems, and that should therefore enter into the calculus? Are future funding levels expected to decline, increase, or stay the same? All of these questions may influence the decision of whether or not to differentiate, as well as how to differentiate if the choice is made to do so. Clearly, there are numerous tradeoffs and consideration that merit careful thought before proceeding down any particular path.

Differentiate by Incentive Level or Structure?

If a PV program decides to differentiate incentives between host-owned and TPO systems, then the next consideration is whether to differentiate by incentive level or structure (or possibly both). There are a number of reasons why a state or local PV program might choose (and why the PV programs highlighted in Section 3.1 have already chosen) to differentiate residential PV incentive levels based on ownership type:

- **Leverage federal tax dollars to preserve state and local funding for PV:** As demonstrated in the Appendix, a residential PV system that is third-party-owned typically receives greater federal tax benefits than if host-owned, which – all else equal (e.g., presuming the same system costs and benefits) – should reduce the amount of additional support that TPO systems require at the state or local level relative to host-owned systems. By reducing TPO incentive levels, a state or local PV program might help to preserve its own funding (albeit potentially with lower deployment levels), while relying more heavily on leveraged federal tax dollars.
- **Drive greater competition in the market:** Recent evidence of value-based pricing among TPO providers (Davidson et al. 2015, SolarCity 2015) suggests that incentives provided to TPO providers are not being fully passed through to system hosts. Other research shows that there are benefits to host-ownership (Feldman and Lowder 2014, Beavers et al. 2013, Dumoulin-Smith et al. 2015), though a degree of value-based pricing is also present in that market (Gillingham et al. 2014). In this situation, reducing TPO incentive levels and/or increasing host-owned incentive levels could introduce more competition into the market (e.g., from installers offering solar loans), which – all else equal – may drive down prices and help to maximize ratepayer benefits in the longer term.
- **Enhance local economies by supporting a broader base of installers:** At least one study (Beavers et al. 2013) examined the local economic impact of TPO (assuming out-of-state

providers) vs. host-ownership (assuming in-state providers) in Massachusetts, and found that a network of local installers had a more positive impact on the state's economy than did TPO provided primarily by out-of-state entities. As discussed earlier, such considerations have been a motivator for policy design in both Connecticut and Massachusetts. Though the assumptions made by the study (largely out-of state TPO vs. in-state installers for host-owned) should be carefully examined, and may not be representative more generally (e.g., TPO providers may be local, and installers of host-owned systems may come from out of state), if they are directionally accurate then differentially supporting host-ownership could help a state or local PV program to recycle ratepayer dollars in-state.

- **Increase diversity in the market:** Setting aside the three previous points, some PV program managers simply may not be comfortable with having the vast majority of PV systems in a given state or locality be third-party-owned (let alone owned by just a few large providers), even though the market scale enabled by TPO has arguably been one of the primary historical drivers for declining PV costs and market expansion. For example, a market with a highly concentrated TPO market share may be more susceptible to the risk of market disruptions caused by, for instance, potential contract default in the event of adverse changes to retail rates or rate structures, or possible deterioration in the financial health of TPO providers for market reasons or due to changes in federal tax policy. While the possible side-effects of diminished installer-level learning and/or economies of scale and deployment facilitation also deserve consideration, encouraging greater competition by reducing TPO incentive levels and/or by increasing incentives for host owned systems might increase the overall resiliency of the market.

There are, however, both practical and philosophical counter-arguments to each of these points. As such, assuming that a state or local PV program does want to differentiate, but does not feel comfortable differentiating incentive *levels* between TPO and host-ownership, those programs might still consider differentiating incentive *structure* in a way that supports host-ownership. For example, providing host-owners with an up-front incentive (e.g., an EPBB) and TPO providers with a performance-based incentive (PBI) over time provides a good match between capabilities and needs. Specifically, host-owners are often most in need of capital to help defray the high up-front cost of PV, while TPO providers have typically already lined up financing (e.g., tax equity) for their projects and are better-positioned than many host-owners to handle the metering and reporting requirements of a PBI. Even if the EPBB and PBI are of the same magnitude on a present value basis, the different incentive structure will still likely provide some incremental support to host-ownership.

Of course, PV programs that are particularly motivated could do both – differentiate incentive structures *and* incentive levels (on a present value basis).

How Much Differentiation in Incentive Level Might Be Considered?

The survey of state and local responses to TPO in Section 3.1 found that those programs that have already differentiated incentive levels by ownership type have typically (with the notable exception of two municipal utility programs in Texas) done so to only a modest degree: from a

low of \$0.05/W_{DC} in Colorado to a high of \$0.25/W_{DC} in Oregon.³⁴ The analysis presented in the Appendix, however, estimates that the incremental federal tax benefits that TPO providers (and their tax equity investors) enjoy relative to host-owned systems have ranged from \$0.7-0.9/W in recent years, and could persist at around \$0.5/W post-2016 under current law. Hence, all else equal,³⁵ and based on the current market environment, there is seemingly room for more-aggressive incentive level differentiation (except for in Austin and San Antonio, Texas, where the differentials are \$1.10/W and \$1.60/W, respectively – i.e., seemingly too aggressive), presuming program managers are so inclined. That said, the analysis presented in the Appendix is general in nature (e.g., nationwide), and – as suggested in several places throughout this report – each state and local PV program is encouraged to evaluate this issue within the specific market environment in which it operates and given the overarching goals of the program.

How Best to Implement the Differentiation?

Of course, very few state PV incentive programs currently offer incentives as large as the \$0.7-0.9/W federal tax benefit disparity, which makes it impossible to reduce TPO incentive levels by that much (presuming full parity is desired), and raises the question of how best to implement the differentiation. In such cases, full parity could still be achieved by eliminating the TPO incentive altogether, while at the same time *increasing* the incentive for host-ownership by whatever amount is needed to reach a combined differential of \$0.7-0.9/W. For that matter, full parity could also be achieved (given adequate funding) simply by *increasing* host-owner incentive levels by \$0.7-0.9/W while leaving TPO incentives unchanged.

How a state PV incentive program goes about implementing these changes could present potentially difficult policy tradeoffs, as no matter how the change is implemented, it will result in winners and losers. Reducing TPO incentives while maintaining host-owned incentives is likely to rile TPO providers, while the opposite extreme of increasing host-owned incentives while maintaining TPO incentives (e.g., the approach taken by the Energy Trust of Oregon at the start of 2014) could potentially aggravate *existing* host-owners who have previously installed PV under a lower incentive. Meanwhile, a combined approach of *partially* reducing TPO incentives while *partially* increasing host-owned incentives in order to reach a \$0.7-0.9/W differential in aggregate might potentially upset *both* of these same parties.³⁶

³⁴ Massachusetts offered a higher differential of \$0.40/W_{DC}, but only in cases where the host-owner qualifies for moderate income or home value status.

³⁵ All else may not be equal if, for example, a state offers a tax credit for residential PV that is available to host-owners but not TPO providers, or vice versa. For example, New York has a residential PV investment tax credit that, up until August 2012, could not be claimed by homeowners with TPO PV (this distinction has since been eliminated). New Mexico offers a “Solar Market Development Tax Credit” of 10% (up to \$9,000) to host-owned but not TPO systems (a recent legislative effort to expand this credit to include TPO systems was vetoed by New Mexico’s governor in April 2015). Finally, Arizona has ruled that TPO PV systems are not eligible for a property tax exemption enjoyed by host-owned PV systems. In addition, market conditions could change going forward, in which case this analysis should be revisited. That said, as shown in the Appendix, perhaps the largest likely shift in market conditions on the horizon – i.e., the scheduled elimination of the residential 30% ITC and the reversion of the commercial 30% ITC back to 10% at the end of 2016 – is unlikely to significantly alter the magnitude of the federal tax benefits that TPO providers currently receive relative to host-owned systems.

³⁶ Though still a ways off, looking ahead to 2017, the scheduled ITC reversion/expiration could potentially present a good opportunity to implement any differential by increasing host-owned incentives sufficiently to make up for the loss of the ITC, while not similarly increasing TPO incentives.

Policy design considerations may also factor in. Increasing an incentive level mid-course – especially in a market that is already growing rapidly – flies in the face of basic incentive design principles, which hold that incentives should start at a level that is high enough to encourage early adopters and then decrease over time as the technology matures. Taken to the extreme, a mid-course increase in incentive levels could potentially even lead to a counterproductive “wait and see” attitude among potential adopters.

Finally, from a deployment perspective, the approach of increasing host-owned incentive levels will almost certainly boost deployment, but at a higher expenditure of public funds – an outcome that seems out of step with current trends towards reducing incentive levels, in some cases amidst declining budgets. Meanwhile, the other extreme of reducing TPO incentives could hurt aggregate deployment going forward.

If differentiating incentive levels depending on system ownership seems too drastic, or if the various tradeoffs and considerations described above make implementation too daunting, a change in the structure of those incentives might be considered, as discussed earlier. Alternatively, a more fundamental change in the underlying *method* of support – i.e., from disbursement of cash incentives to providing support for financing – may be viewed as a more palatable way to promote host-ownership. For example, a state PV program could reduce TPO incentive levels only part-way (e.g., by \$0.4/W rather than by the full \$0.7-0.9/W) and re-allocate that funding towards creating or enhancing residential loan products to support host-ownership. This shift from rebates to loans potentially reduces some of the policy and political tradeoffs described above, since it has less of a direct impact on TPO providers while avoiding the wrath of earlier incentive recipients. It also avoids a potentially counterproductive mid-course increase in host-owner incentive levels by re-directing the funding to loans instead of higher incentives (with the ancillary benefit of the program potentially retaining or even earning a return on the re-directed funds, rather than simply paying them out). Finally, from a deployment perspective, the smaller reduction in TPO incentives is perhaps less likely to harm overall deployment, particularly given the increased support for solar loan products.

4.2 Considerations Surrounding Support for Solar Loans

Whether or not cash incentive differentiation is pursued, support for solar loans (or, for that matter, support for an expansion of TPO as per Connecticut’s approach) may deserve separate consideration. Before pursuing such an approach, of course, a state would need to decide that the logistical and policy issues weigh in favor of such a move, relative to other forms of support. Such considerations might include the complexity of setting up the program, the perceived competition with the private marketplace for financing products, and the potential cost in the case of widespread customer default, among many other issues.

Moreover, how best to support solar loans depends in part on whether or not there are already attractive solar loan products on offer within a given state. If not, then state PV programs might consider a more-comprehensive approach like that taken in Connecticut and New York or, more recently, Massachusetts and Hawaii, in setting up a loan program.

CEFIA's Chief Investment Officer succinctly summarized its approach when announcing the second phase of the *CT Solar Loan* program in February 2014:

Together with Sungage, we created a residential solar loan product that is easy to access and optimized for solar. We then went out and sourced investment partners who understand the industry and recognize the value of these consumer loans, with the green bank aggregating these loans and providing critical credit enhancements. (CEFIA 2014b)

In other words, this approach can involve a partnership between the state PV program, a private sector loan originator/administrator, and private sector lenders willing to buy the loans (perhaps enticed by credit enhancements provided by the state PV program). This approach does *not* require establishing a dedicated fund to actually finance and service the loans, though that is another option (e.g., see NYSERDA's revolving loan fund), albeit one that presumably ties up a larger pool of capital.

In states where private sector solar loan products are already prevalent (and are ideally vendor- and installer-neutral), the general approach outlined above could be significantly truncated, since the loan product already exists and investment partners are already committed. In these cases (which will presumably become increasingly common as the proliferation of solar loan products continues), the question becomes more about how a state PV program can most effectively support what's already happening in the market. In other words, a state PV program might look for opportunities to complement what's already on offer by using its funds to enhance the attractiveness of the existing loan product or to expand access to it.

Various forms of credit enhancement can serve both purposes. For example, pledging and committing a small amount of low-interest subordinated debt alongside senior lenders can reduce their risk, and hence potentially also the interest rate they charge (even if not, the combined loan should still have a lower *blended* interest rate). Likewise, funding a loan loss reserve that lenders can draw upon to cover defaults may also decrease their risk and enable lower interest rates. Alternatively, if targeted specifically at certain demographic groups (e.g., moderate income households), a loan loss reserve may enable lenders to extend loan access to a larger number of potential borrowers. Unlike subordinated debt and loan loss reserves, which don't necessarily diminish a fund's balance (absent defaults), interest rate buy-downs do involve a definite capital outlay, but may nevertheless be another useful tool, particularly if used in a targeted manner to achieve specific goals (e.g., making loan payments more affordable for moderate income households).

These same tools that in today's market environment serve mostly to complement and enhance existing solar loan products might also prove important to sustaining solar loan products in a post-ITC world. As described earlier in Section 2.2.2, the current paradigm for most solar loan products involves a same-as-cash tax credit loan for 30% of costs, in conjunction with a longer-term loan for the balance. The short-term tax credit loan reduces both the "loan-to-value" ratio (a measure of a lender's risk, and a potential determinant of credit availability and/or the interest rate charged) and the amount needing to be financed over longer terms. If the 30% residential ITC expires at the end of 2016, however, the short-term tax credit loan will presumably

disappear along with it, leaving a 30% gap that will, all else equal, push monthly payments higher on the longer-term loan (that is, assuming zero-down financing is even available without the ITC around to reduce the loan-to-value ratio).

In such an environment, state PV programs might use the same credit enhancement tools described above to target the three determinants of monthly loan payments: principal, term, and interest rate. For example, low-interest subordinated loans can reduce the senior lender's loan-to-value ratio and provide a lower blended interest rate. Subordinated debt might also be structured to extend the *term* of private sector loans, thereby reducing the size of monthly payments (or, alternatively, maintaining the same monthly payments on a larger loan principal).³⁷ Loan loss reserves and interest rate buy-downs can serve to indirectly or directly reduce interest rates.

Beyond credit enhancements, there are, no doubt, some “blue sky” ideas for how state PV programs might support solar loans that are potentially worth exploring. Without going very far down this path, one might, for example, look into the feasibility and cost-effectiveness of interest rate hedges as a way to dampen the negative impact of rising interest rates on solar loans. Or, given the considerable investment that many state PV programs have already made in the existing fleet of residential PV systems, along with the importance of operational performance to loan repayment (and to realizing the emissions and other public benefits of PV), perhaps state PV programs might somehow support efforts to reduce operational risk through quality assurance, monitoring, and servicing the existing fleet of encumbered projects.³⁸

³⁷ For example, a 12-year, \$20,000 loan might be structured such that the private sector portion (e.g., \$15,000 at 6% interest) amortizes over the first ten years (during which time the public sector portion is paid interest only) and the public sector portion (e.g., \$5,000 at 3% interest) amortizes over the final two years. Alternatively, a private sector lender that is only willing to lend out ten years might be persuaded to extend a 12-year loan for the same principal amount if the PV fund agrees to make the lender whole on the original 10-year amortization in exchange for receiving the final two years of repayments. Although either of these approaches will provide the fund with a return on its capital (absent default), the return is back-loaded and long-dated, which may limit its appeal.

³⁸ These are services that most TPO providers already provide, but that may be lacking for some solar loan products.

5 Conclusions

The residential PV market in the United States is dynamic, currently characterized by declining installed costs, dwindling state PV incentives, booming demand, high TPO market share in the largest markets (a result of the first wave of financial innovation, which launched TPO), a growing appreciation of the benefits that host-ownership provides, and a recent proliferation of solar loan products designed to encourage host-ownership (the second wave of financial innovation). Within this context, this report has explored two general responses to these developments, taken by a number of (but certainly not all) state and local PV program managers. Both of these responses potentially help to preserve scarce public funding for PV by using incentives more as a tool to fine-tune the market rather than to stimulate it outright, and/or by shifting away from cash incentive disbursements in favor of financial support that can better sustain fund balances and potentially even provide a return on capital.

The first response involves the state or local PV program taking a proactive role as a “market monitor” of sorts, to promote and maintain a competitive market between TPO and host-owned systems by using state or local incentives to correct for the higher federal tax benefits enjoyed by TPO providers. Analysis presented in the Appendix estimates that this disparity in federal tax benefits is currently somewhere on the order of \$0.7-0.9/W, and could persist at roughly \$0.5/W post-2016 under current law. All else equal, this persistent federal tax benefit disparity suggests that differentiating state or local incentive levels by roughly this same amount – whether by reducing TPO incentive levels, increasing host-owner incentive levels, or some combination of the two – may be an appropriate action to level the playing field between TPO and host-ownership, presuming a level playing field is desirable. Though most state and local PV programs have not, to this point, differentiated incentives in this way, there are a number of programs that have done so, but typically by more modest amounts, potentially leaving room for further adjustment. That said, as discussed further below, any and all such adjustments should first be considered within the specific context and objectives of the state or local market in which each program operates.

The second response witnessed among a number of PV programs involves using public funds to help homeowners capture the potential benefits of host-ownership by creating viable solar loan products where they don't already exist, or by complementing existing private sector solar loan offerings. In either case, credit enhancement tools such as subordinated debt, loan loss reserves, and perhaps targeted interest rate buy-downs can be used (and are already being used in several states) to help reduce the risk facing private lenders (without necessarily leading to loss of funds). By reducing risk, these credit enhancements potentially enable lenders to offer more-attractive terms to already-creditworthy borrowers, or to extend credit to otherwise less-creditworthy borrowers.

Both of these potential actions will continue to be relevant in the future if the residential ITC expires at the end of 2016, as currently scheduled. The disparity in federal tax benefits is unlikely to change much at that time (the Appendix suggests it could drop from \$0.7-0.9/W at present to \$0.5/W in 2017), given that the commercial ITC available to TPO providers is scheduled to revert from 30% to 10%, rather than expiring altogether. And without the 30% residential ITC available as collateral for the “same-as-cash” tax credit loans that are the

cornerstone of most solar loan products in the market today, innovative PV program support for solar loans may continue to play an important role.

Any state or local PV programs interested in further exploring either of these courses of action should first investigate the unique local or state-specific context within which such changes would be made. For example, how many installers are active in the state, and what types of financing options do they offer? Is TPO available, and if so, what is its market share? What state or local incentives are currently offered, and how much room for movement is there? Are there other state or local incentives (e.g., state tax credits) available to PV, and do they favor one type of ownership over another?

Finally, one broader question of interest is how might the responses discussed in this paper – i.e., differentiating incentive levels between TPO and host-ownership, and providing programmatic support to solar loan products – impact overall deployment? Although the answer will depend to some extent on how any changes are implemented (e.g., reducing TPO vs. increasing host-owned incentives), there are also larger related questions worth exploring further, such as to what extent TPO providers practice “value-based” pricing (relative to installers of host-owned systems). For example, if TPO providers have – as recent research suggests – been pricing their products at least in part to compete against utility retail rates rather than host-ownership, then the PV program responses explored in this paper may help lead to a more-competitive market that continues to grow even in the face of lower state incentive levels – a future that the entire PV industry should be able to rally behind. On the other hand, if the two primary PV program responses explored herein merely prop up a business model focused on PV system ownership that – for whatever reason – is less attractive to prospective solar customers than is TPO, then reallocating funds for this purpose (and away from supporting TPO) may unnecessarily limit market expansion.

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Appendix: Estimate of Federal Tax Benefits Provided to TPO vs. Host-Owned Systems

Introduction

The disparity in federal tax benefits provided to TPO vs. host-owned residential PV systems stems from two sources: (1) differences in the level and/or treatment of the commercial (Section 48) and residential (Section 25D) investment tax credits for solar; and (2) accelerated tax depreciation being available to TPO but not host-owned residential systems.

The ITC

The Section 48 investment tax credit (“ITC”) for commercial PV systems (including residential systems owned by TPO providers and/or their tax equity investors) has been on the books for decades, “permanently” set at a level of 10% of the project’s “tax credit basis” (i.e., the dollar amount to which the ITC applies). In August 2005, however, the *Energy Policy Act of 2005* temporarily increased the Section 48 ITC from 10% to 30%, and also created in Section 25D of the Internal Revenue Code a new 30% ITC (capped at \$2,000) for residential, host-owned solar systems. Both changes went into effect on January 1, 2006, for an initial period of two years, and in late 2006 both credits were extended “as is” for an additional year (through 2008). Subsequently, in October 2008, the *Energy Improvement and Extension Act of 2008* extended both 30% solar credits for eight years (through 2016), and removed the \$2,000 cap on the Section 25D residential solar credit, ostensibly placing the commercial and residential ITCs on equal footing for systems placed in service from 2009 through 2016. Looking ahead, and barring any future legislative changes, at the end of 2016 the Section 48 commercial ITC will revert back to 10%, while the Section 25D residential ITC will expire altogether.

Alternatively, in 2009, the federal government began to allow commercial entities (but not individual taxpayers) to elect a non-taxable 30% cash grant in lieu of the Section 48 ITC. This grant program, encoded in Section 1603 of the *American Recovery and Reinvestment Act of 2009* (and hence referred to as the “Section 1603” cash grant program), was implemented in response to a shortage of third-party tax equity during the “great recession” that began in late 2008. To be eligible for a Section 1603 grant, PV projects had to have “started construction” by the end of 2011 and must be placed in service by the end of 2016.³⁹

³⁹ Treasury guidance for determining whether or not a project was “under construction” by the end of 2011 has set a fairly low hurdle. Several months into 2015, however, there do seem to be fewer solar projects claiming the Section 1603 grant relative to the ITC. The construction start deadline presumably has much to do with this, though project owners may increasingly favor the ITC for at least two other reasons as well. First, as a tax credit, the 30% ITC is not subject to the budget sequestration haircuts that have reduced the Section 1603 cash grant to 27.39% in the second half of fiscal year 2013, 27.84% in fiscal year 2014, and 27.81% in fiscal year 2015. Second, it is believed that the IRS does not (at least in advance) scrutinize ITC basis claims as closely as Treasury has been scrutinizing Section 1603 grant basis claims.

Accelerated Depreciation

A second way in which TPO and host-owned residential PV systems differ (with respect to federal tax benefits) is that third-party owners can depreciate the systems they own for income tax purposes, while host owners cannot. The flip side of this disparate tax treatment, however, is that third-party owners are taxed on the income that they earn from residential lease or PPA payments, while residential host-owners are not similarly taxed on electric bill savings.⁴⁰ Though TPO providers have sometimes argued that the incrementally higher ITC or cash grant payment that they receive is offset by the tax that they pay on lease or PPA income,⁴¹ this argument ignores the tax depreciation benefits provided by those same income-generating PV systems. Netting these accelerated depreciation deductions (using a 5-year MACRS schedule⁴²) against the income tax payments on PPA/lease revenue yields a net tax benefit (essentially an interest-free loan via the *acceleration* of deductions) to TPO providers that is not available to host-owned systems. This is an *additional* incremental federal incentive provided to TPO providers, above and beyond any incremental ITC/grant payment.

⁴⁰ In contrast to residential host-owners, commercial host-owners are de facto taxed on electric bill savings, because the electric utility bills that they would have otherwise paid would have been a tax-deductible operating expense. Like TPO providers, however, commercial host owners are also able to depreciate the PV systems they own.

⁴¹ For example, SolarCity (2013) notes that “Solar lease payments are taxable as income, and the federal government recovers the cost of incentives paid for financed solar systems over time by collecting income taxes on the lease payments.” Bass (2013) is even more explicit in responding to Jenal (2011): “The other mistaken assumption in this post is that a higher ITC for lease or PPA projects means a higher cost to the taxpayer. Lease and PPA payments are taxable as income, so they can generate a return to the taxpayer on the ITC that cash sales do not.” These arguments often reference a document published by the U.S. Partnership for Renewable Energy Finance (in the interest of full disclosure, this document was authored by Connie Chern, then a Senior Associate with the Structured Finance group at SolarCity) that estimates that the federal government receives a roughly 10% internal rate of return (IRR) on ITC/grant expenditures through the taxation of lease/PPA payments (Chern 2012). This headline finding does not include the impact of depreciation, however; once depreciation is included in the calculations, the government IRR drops to just 1% (Chern 2012). Furthermore, the analysis includes several tax items that boost the government IRR (including tax on a state rebate, tax on the difference between the system’s sale price and installed cost, payroll tax paid by the installer, and income tax paid by the installer’s employees) but that are common to both host-owned and TPO systems. If these common items are excluded from the analysis in order to focus on only those items that differ between host-owned and TPO systems – i.e., income tax on PPA/lease payments and depreciation – the return to the government is negative. This negative return to the government suggests (and is confirmed by our independent analysis later) that a TPO provider’s ability to depreciate the PV systems it owns provides an *additional* incremental federal tax benefit, above and beyond that received solely through a larger ITC or grant.

⁴² MACRS stands for “modified accelerated cost recovery system,” and qualified solar property can be depreciated using a 5-year MACRS schedule (i.e., accelerated relative to PV’s ~30-year expected useful life). In addition, solar investments made in recent years can qualify for 50% or 100% “bonus depreciation” that allows for an even faster depreciation schedule (i.e., as fast as just one year in the case of 100% bonus depreciation). This Appendix ignores bonus depreciation, however, because 5-year MACRS is more conservative, because the amount of bonus depreciation has varied (from 50% to 100%) over time, and because some tax equity investors have reportedly had a difficult time making efficient use of bonus depreciation.

Estimating the Incremental Federal Tax Benefits Provided to TPO Systems

Given the separate histories of the commercial and residential ITCs as described above, the analysis of differential tax treatment between TPO and host-owned systems in this Appendix will be split into three different time periods, each explored individually below:

- 1) 2006-2008, when the 30% residential ITC was capped at \$2000 per system while the 30% commercial ITC was not;
- 2) 2009-2016, when both the Section 25D residential and Section 48 commercial credits were nominally on equal footing – i.e., both at 30% with no dollar cap – with the notable exception of a commercial entity’s ability to elect the 30% Section 1603 cash grant in lieu of the Section 48 ITC; and
- 3) Post-2016, when – at least under current law – the Section 25D residential credit (and the Section 1603 grant) will no longer exist, while the Section 48 commercial credit will revert back to 10%.

Before launching into the analysis, however, it should be noted that there is nothing necessarily alarming about residential TPO systems receiving higher federal tax benefits than identical host-owned systems. Indeed, given the legislative history of the Section 48 and Section 25D credits, it is clear that Congress did not originally intend for these two credits to be equal prior to 2009;⁴³ nor does it intend for them to be equal after 2016.⁴⁴ Whether parity in federal tax benefits provided to TPO and host-owned residential PV systems is an inherently desirable goal is subject to debate, and ultimately is a federal policy choice.

On the other hand, the inequality of federal tax benefits has had a significant impact on how the residential PV market has developed over time; both for better (the initial inequity spurred the launch of residential TPO, which has greatly increased the size of the market) and for worse (the resulting high TPO market share in some states may be restricting consumer benefits). At a minimum, state and local PV program administrators should understand the linkages between Federal tax policy and market development, and, depending on their specific goals, perhaps take steps to adjust their programs in response, while also considering the myriad possible tradeoffs involved. This is the justification for quantifying the federal tax disparity in this Appendix, and using it to inform the main body of this report.

2006-2008

As described in the main document, SunRun launched the first residential PPA in late 2007, followed by SolarCity’s launch of the first residential lease in early 2008. These initial TPO offerings were motivated by the severe disparity between the value of the commercial and residential ITCs, due to the latter’s \$2,000 per-system cap. Although this disparity existed from

⁴³ For example, the residential (Section 25D) ITC only came into existence in 2006, whereas the commercial (Section 48) credit has been on the books for many decades (though, until 2006, at a 10% level). Similarly, the 30% residential ITC was initially capped by Congress at \$2000 per system, whereas the 30% commercial ITC was not.

⁴⁴ Barring any future legislative changes, the residential ITC will expire at the end of 2016, whereas the commercial ITC will merely revert back to 10%.

2006-2008, the fact that residential TPO did not really launch until late 2007 (SunRun) and early 2008 (SolarCity) renders 2008 the single year of relevance during this period.

According to Barbose et al. (2014), the median installed price of PV systems of 10 kW or less in 2008 was \$8.7/W_{DC}, or \$43,500 for a 5 kW system. If third-party owned, this system would conservatively (i.e., assuming no basis step-up – see below) yield a 30% ITC of \$13,050 or \$2.6/W. If host-owned, however, this same system would yield a capped ITC of just \$2,000 or \$0.4/W. This difference of \$11,050 for a 5 kW system, or \$2.2/W, provided a significant advantage to TPO in 2008.

This same system, if third-party owned, would have also benefitted from accelerated tax depreciation (net of tax payments on lease income). To estimate the magnitude of this net benefit, we relied on the following assumptions, some of which are based on Chern (2012) but are modified to reflect conditions in 2008: 5 kW system, \$8.7/W installed cost (and depreciable basis), 30-year system life, 20-year PPA/lease that starts at \$0.23/kWh and escalates at 3.9%/year, a 35% federal tax rate, system production of 1,305 kWh/kW-year with 0.5%/year degradation, a 30% ITC, and 5-year MACRS depreciation. We assume that the 20-year PPA/lease is renewed for another 10 years at a starting price (which, in this case, also escalates at 3.9%) equal to 90% of the rate in effect at the expiration of the original PPA/lease, and we discount everything back to the present using a 6% discount rate (SolarCity 2014a). These assumptions yield a depreciation benefit of \$2.2/W vs. PPA/lease tax payments of \$1.7/W, for a net tax benefit of \$0.6/W, or ~\$2800 for a 5 kW system. This net accelerated depreciation benefit was available to TPO, but not host-owned, systems.

Combining the ITC and depreciation benefits from above yields an overall TPO federal tax advantage of \$2.8/W, or \$13,800, for a 5 kW system installed in 2008.

2009-2016

The \$2,000 cap on the residential ITC was eliminated starting in 2009, initiating a lengthy period (i.e., through 2016 under current law) of nominal equality in the size of the residential and commercial ITCs – i.e., both at 30% with no dollar caps. Hence, one might think that accelerated depreciation would be the only significant difference between TPO and host-owned tax benefits during period. As explained below, however, two subtle yet important distinctions have continued to make the commercial ITC more valuable than the residential ITC over this period, despite their apparent equality at face value.

First, though not quantified in this report, the fact that TPO providers have, since 2009, had access to the Section 1603 grant program, while residential host-owners have not, has provided the former with an incremental financial advantage. For example, residential host-owners with insufficient tax liability to fully absorb the 30% ITC in the year of installation must carry the unused portion forward in time, which erodes its present value. If such host-owners could access the Section 1603 cash grant instead, this erosion of time value would not occur.

Second, regardless of whether the 30% federal incentive is awarded in the form of a tax credit (host-owned or TPO) or a cash grant (TPO only), equivalent federal tax credit/grant benefits

between host-owned and TPO residential PV systems during this 2009-2016 period would require that the “basis” to which the 30% investment-based incentive applies is consistent between host-owned and TPO systems. As explained below, however, this has generally not been the case.

30% of What?

The “basis” on which a host-owner claims the 30% residential ITC typically equals the total amount that the host-owner paid the PV installer for the installation – i.e., the “installed price”⁴⁵ of the system.⁴⁶ In contrast, the basis of a third-party owner claiming the 30% business ITC (or Section 1603 cash grant) is allowed to be (and often is) the appraised “fair market value” (FMV) of the PV system,⁴⁷ which – depending on how the appraisal is conducted⁴⁸ – can be significantly higher than the installed price.

To illustrate, consider the following example taken, in part, from the 3Q14 version of SolarCity’s online *Investor Presentation* (SolarCity 2014b). That slide deck noted that SolarCity’s “total upfront investment” (i.e., including installation, sales, and general and administrative costs) for an average PV system at the time was \$2.90/W, and that average system yielded an FMV of \$4.75/W (SolarCity 2014b). If SolarCity were to sell this average system (that cost it \$2.90/W) to a host-owner in a competitive market at a 20% markup, the installed price on which the host-owner would claim the ITC would be \$3.48/W, yielding a 30% ITC of \$1.04/W. Instead, SolarCity and its tax equity investors claim the ITC on the higher FMV of \$4.75/W, which yields a 30% ITC of \$1.43/W. This \$0.38/W difference in the size of the ITC claimed (which comes to \$1,900 for a typical 5 kW system) stems solely from whether the system is host-owned or third-

⁴⁵ We use the term “installed price” rather than “installed cost” because a PV installer presumably will not sell a system at cost, but instead will build in a profit margin, resulting in an “installed price” that is somewhat higher than the cost of installing the system.

⁴⁶ The “Specific Instructions” for Line 1 of IRS Form 5695 (2013) – where the Section 25D residential ITC is claimed when filing income tax returns – are to “Enter the amounts you paid for qualified solar electric property,” where “Qualified solar electric property costs are costs for property that uses solar energy to generate electricity for use in your home located in the United States.” Filers can “Include any labor costs properly allocable to the onsite preparation, assembly, or original installation of the...property and for piping or wiring to interconnect such property to the home.” In other words, the filer is essentially instructed to enter the amount – including parts and labor – paid to the PV installer for the turnkey installed system (this amount should be reduced by the portion of costs paid for by any non-taxable rebates at the state- or utility-level).

⁴⁷ The IRS defines fair market value to be “The price at which property would change hands between a willing buyer and a willing seller when the former is not under any compulsion to buy and the latter is not under any compulsion to sell, both parties having reasonable knowledge of relevant facts.” When there is an arm’s length transaction between two unrelated parties, the FMV simply equals the transaction price. When no arm’s length transaction occurs, however – e.g., in a lease/pass-through (aka “inverted lease”) structure, or in a partnership flip (aka “joint venture”) structure involving related parties – the IRS requires the use of an appraised FMV to establish the ITC basis. Given that lease/pass-through and partnership flip structures are the predominant financing structures used to finance third-party-owned projects, the use of an appraised FMV to establish the ITC basis is likely to be common among TPO providers.

⁴⁸ The IRS allows the use of three different methods to calculate an appraised fair market value: the cost approach, the “comparable sales” or market approach, and the income approach. The cost approach is based on the cost to build or replace the asset, including reasonable profit. The “comparable sales” approach relies on market data for comparable assets that have been recently sold. The income approach relies on a discounted cash flow analysis of all projected future cash flows.

party-owned (and, by extension, whether FMV can be used to establish the basis to which the 30% credit applies).

This disparity, and more generally the prospect of potentially inflated FMV basis claims among third-party owners of residential solar projects, has been noted in the trade and general press on several occasions (Farell 2011, Jenal 2011, Martin 2011, Salzman 2013, Wesoff 2014a), prompting the Treasury Department (U.S. Department of the Treasury 2011) and later the solar industry (SEIA and CohnReznick LLP 2013) to each issue its own guidance on how to value solar assets for purposes of claiming the ITC or grant.⁴⁹ Charges of misrepresentation have even been publicly levied at (Salzman 2013) and rebutted by (SolarCity 2013) the largest TPO provider over this issue. Finally, in July 2012 the Treasury Department launched an investigation into the incentive claims of several TPO providers (SolarCity 2012, Leonnig 2012), and one of those TPO providers subsequently sued the Treasury Department for failing to pay the full amount of Section 1603 cash grants claimed (Sequoia Pacific Solar I LLC and Eiger Lease Co LLC 2013). Both the investigation and the lawsuit were still ongoing at the time of writing.

This Appendix does not seek to rehash the evidence presented and arguments made to date over this issue; nor does it take a position on the appropriateness of ITC and Section 1603 grant basis claims based on different appraisals of fair market value. Instead, the intent here is merely to establish that a disparity between the basis (and hence the federal tax benefits) that a host-owner and third-party-owner claims for a comparable residential PV system does, in fact, exist, and therefore may have played a role in steering the residential solar market towards third-party ownership in recent years. As such, the documents cited in the previous paragraph are referenced only to the extent that they provide information that is useful in establishing this TPO vs. host-owned basis and incentive disparity.

To that end, many of these documents do in fact provide a wealth of information that is not available elsewhere. Given that many of these documents also focus exclusively on SolarCity – by far the largest TPO provider – and that SolarCity is seemingly the only TPO provider to have publicly addressed this issue through various blog postings and corporate filings or presentations, much of this Appendix necessarily focuses on SolarCity simply due to the availability of data. Given the likelihood of common business practices across most TPO providers, however, the

⁴⁹ These two guidance documents do not agree on the most appropriate method for determining a solar project's fair market value. The Treasury guidance favors the cost approach ("Because cost data for PV systems is increasingly timely and available, this approach tends to be the most concrete and supportable analysis and is favored by the review team") and finds the income approach "to be the least reliable method of valuation given the number of variables that are subject to speculation and open to debate" (U.S. Department of the Treasury 2011). In contrast, SEIA finds that "the cost approach is generally no more important than income or market approach, and is often the least reliable method in reaching a conclusion of fair market value" (SEIA and CohnReznick LLP 2013). Instead, SEIA favors the income method, finding that it "is generally used by market participants in pricing solar assets, and is usually the most relevant method to estimate FMV because it considers the specific contracts and incentives applicable to the solar asset" (SEIA and CohnReznick LLP 2013). As a result, "in many circumstances, the cost and market approaches may need to be given less weight [than the income approach] in reaching a conclusion" about fair market value (SEIA and CohnReznick LLP 2013).

insights gleaned herein based on data pertaining to SolarCity might be thought of as potentially being broadly applicable to many (but perhaps not all) TPO providers.⁵⁰

Estimating the Basis Disparity

The extent of the basis disparity during the 2009-2016 period (or at least from 2009 through the present) can be approximated by combining general knowledge of how various TPO providers structure their businesses with data from state and utility PV incentive programs. Some TPO providers, like SolarCity, are vertically integrated in the sense that they perform all functions along the value chain in-house, including customer acquisition, financing, installation, ownership, and system maintenance. Other TPO providers, like SunRun, are “non-integrated,” in that they typically handle only the financing and ownership elements of the value chain, and farm out other elements.⁵¹ Most importantly for present purposes, this distinction between integrated and non-integrated TPO providers dictates how they acquire the systems they own: integrated TPO providers originate and install all of their systems, while non-integrated TPO providers typically purchase pre-installed systems from independent installers.

This distinction between how integrated and non-integrated TPO providers acquire the systems they own is, in turn, important because it impacts how they report installed system prices to state and utility (but likely not federal – see footnote 50) PV incentive programs.⁵² Non-integrated TPO providers (like SunRun) generally report the price at which they purchased each system (SolarCity 2013).⁵³ In contrast, integrated TPO providers have no system purchase price to use for this purpose, and so instead have historically tended to report each system’s appraised FMV – a value that is already on hand because it serves as the basis on which the 30% ITC or Section 1603 cash grant is claimed (SolarCity 2013, Go Solar California 2014). Because integrated TPO firms have generally reported appraised FMV figures to incentive program administrators, one can compare those figures to the installed prices reported by host-owned systems in order to derive a good approximation of the basis differential on which the 30% ITC or cash grant is claimed.

With data sourced exclusively from LBNL’s *Tracking the Sun* series (Barbose et al. 2014), Figure A-1 shows this comparison among PV systems of 10 kW_{DC} or less that were installed

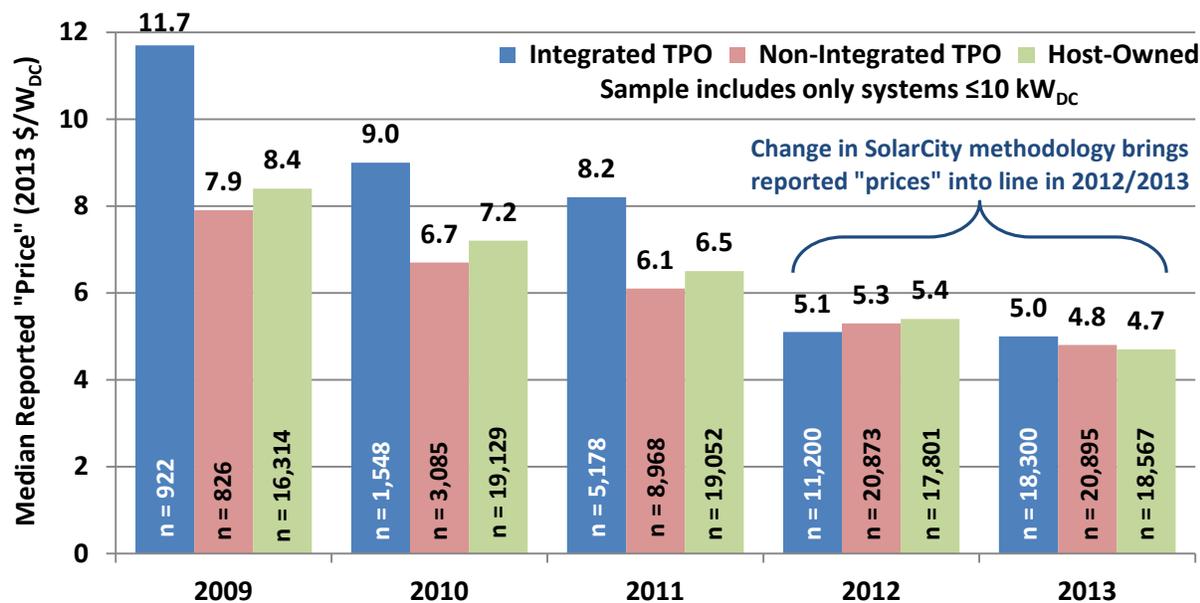
⁵⁰ For example, SolarCity’s rebuttal (SolarCity 2013) of the article in Barron’s (Salzman 2013) argues that the way in which SolarCity calculates the ITC or grant basis is no different from how other TPO providers – both integrated and non-integrated – do it. That said, one reviewer of an earlier draft of this report disputed that assertion, at least with respect to his employer (a provider of both third-party ownership and loan financing).

⁵¹ This distinction is a bit of a moving target, as some installers who were once firmly in the non-integrated camp have been moving towards greater integration. SunRun, for example, acquired the residential division of PV installer REC Solar in early 2014.

⁵² Although the data presented below are drawn from a nationwide sample of state and utility PV incentive programs, that sample is dominated by California’s incentive program, the California Solar Initiative (CSI). In addition, many of the issues analyzed in this section of the report have been discussed most openly in California, given the sheer size of its PV market. As such, although the data presented are nationwide, in some cases the citations are California-specific.

⁵³ For example, SolarCity (2013) notes “When SolarCity’s competitors report for the [CSI] project database, they report the amount they paid the third-party contractor.” Bass (2013) is even more explicit: “In the case of installers that use 3rd parties for leases and PPAs, the price that appears in CSI is the system installation price that the 3rd party paid to the installer.”

nationwide from 2009 through 2013. In all years except 2013, non-integrated TPO systems report lower installed prices than host-owned systems, but the difference is never larger than $\$0.5/W_{DC}$, and declines in later years before disappearing altogether in 2013. In contrast, from 2009 through 2011, the appraised FMV-based values reported for integrated TPO systems are sharply higher than those reported for host-owned systems, with a difference of $\$3.3/W_{DC}$ in 2009, $\$1.8/W_{DC}$ in 2010, and $\$1.7/W_{DC}$ in 2011.



Source: Barbose et al. 2014

Figure A-1. Median Installed Prices Reported to State PV Incentive Programs

The difference between integrated TPO and host-owned (as well as non-integrated TPO) systems largely disappears in 2012 and 2013, however, which can be explained by SolarCity – by far the largest integrated TPO provider – changing the way in which it reports data to state and utility incentive programs. Specifically, starting in 2012, SolarCity began reporting the *appraised cost* rather than the *appraised fair market value* of each system to these state and utility incentive programs (Barbose et al. 2014, Bass 2011).⁵⁴ This change of methodology, however, did *not* extend to ITC and Section 1603 cash grant claims, which continued to be made on the basis of fair market value (Sequoia Pacific Solar I LLC and Eiger Lease Co LLC 2013). The resulting difference in the price reported to state incentive programs and the FMV basis claimed for ITC/Section 1603 grant purposes in 2012 and 2013 necessitates finding some other way to estimate FMVs in those two years, as the integrated TPO data in Figure A-1 are only enlightening (at least for this purpose) from 2009-2011.

⁵⁴ In a November 8, 2011 comment posted in response to Jenal (2011), SolarCity spokesman Jonathan Bass wrote “We are working with the [California] Public Utilities Commission to report our costs on lease/PPA systems in the same way that non-integrated installers report to eliminate this confusion, and allow for apples to apples comparisons among installers” (Bass 2011). Judging by the close alignment of reported values in 2012 and 2013 among all three types of systems in Figure A-1, SolarCity’s change of methodology appears to have accomplished its goal of enabling an apples-to-apples comparison in 2012 and 2013.

Statements made by SolarCity (when rebutting media claims of misrepresentation) and its lawyers (when filing suit against the Treasury Department), however, along with data from the Section 1603 grant program, provide insight into the fair market values on which ITCs and cash grants were paid in 2012 and 2013. For example, SolarCity states that “beginning in June 2011, Treasury began publishing fair market value guidance for solar projects, and SolarCity’s appraised fair market values have been *at or below* [emphasis added] all the guidance that has been provided” (SolarCity 2013). For systems less than 10 kW, that Treasury guidance was “+/- \$7/W” (U.S. Department of the Treasury 2011), and a review of Section 1603 grant payments made to SolarCity subsidiaries for projects installed in California in 2012 suggest that the FMV basis was almost always “at” rather than “below” \$7/W.

Although the Treasury never officially updated its FMV benchmarks after the initial June 2011 guidance, SolarCity’s lawsuit against the Treasury mentions a subsequent downward adjustment delivered via e-mail:

“...on December 5, 2012, Treasury stated in an email that it was revising downward its “Guidance” for California and Arizona residential systems, that the revision was retroactive, and that it would apply to pending applications. The reduction was substantial, reducing benchmark values for California from \$7 per watt of generating capacity to \$6 per watt and reducing benchmark values for Arizona from \$7 per watt to \$5 per watt⁵⁵ – resulting in drastic decreases in the size of cash grants for pending applications that had been made in reliance on the purported Guidance. Treasury gave no explanation for the change at the time, and has given none since. It made this change without even revising the Guidance. The effect of this change, if applied to all pending applications, will run into the millions of dollars.” (Sequoia Pacific Solar I LLC and Eiger Lease Co LLC 2013)

This statement claiming substantial harm from the retroactive basis reduction provides further support for the notion that SolarCity’s 2012 FMVs were mostly “at” rather than “below” the official guidance of \$7/W (and thus would have been significantly harmed by the reduction to \$6/W). It also suggests that, as a result of Treasury’s December 2012 e-mail guidance, SolarCity likely reduced its 2013 FMVs to \$6/W in California (and \$5/W in Arizona); this hypothesis is also supported by SolarCity’s statement (from November 20, 2013) that “SolarCity’s appraised fair market values have been at or below *all the guidance* [emphasis added] that has been provided” (SolarCity 2013). A review of all Section 1603 grant payments made to SolarCity subsidiaries for projects installed in California in 2012 and 2013 confirms that basis claims of \$7/W and \$6/W, respectively, were indeed predominant.⁵⁶

⁵⁵ One reviewer of an earlier draft of this report explained that Arizona’s lower basis (of \$5/W, compared to \$6/W in California) was attributable to Arizona’s lower retail electricity rates (on average, almost 4.5 cents/kWh lower than in California in 2013 according to EIA data) and PV incentive levels, relative to California.

⁵⁶ Incidentally, a similar check of Section 1603 grant payments to non-integrated TPO provider SunRun for systems installed in California in 2012 and 2013 finds similar basis claims of \$7/W throughout 2012, dropping down to around \$6/W in 2013. This finding lends credence to SolarCity’s assertion (in SolarCity 2013) that *all* TPO providers – whether integrated or non-integrated – submit FMV basis claims for ITC and cash grant purposes, and that the only difference between SolarCity and other TPO providers on this matter is how they have reported prices to state and utility incentive programs (at least until 2012, when SolarCity changed its reporting methodology, as noted above, to more closely align with what non-integrated TPO providers and host-owners report).

Based on the combination of direct and circumstantial evidence presented in the previous paragraphs, FMVs of \$7/W in 2012 and \$6/W in 2013 (at least for California, which dominates the market) would appear to be reasonable assumptions (and, as mentioned above and in footnote 56, these assumptions are also supported by analysis of Section 1603 grant payments). Table A-1 combines the empirical data from Figure A-1 with the inferred FMVs for 2012 and 2013 to calculate the incremental federal tax benefits provided to TPO over host-owned systems as a result of ITC or cash grant claims that are based on TPO FMV (first column) rather than host-owned installed price (second column). The third column shows that the basis difference ranges from a high of \$3.3/W_{DC} in 2009 to a low of \$1.3/W_{DC} in 2013, with 2010-2012 ranging from \$1.6-1.8/W_{DC}. Taking 30% of this basis difference (fourth column) yields an incremental federal incentive of \$0.4-0.5/W_{DC} in recent years (excepting 2009), which translates to anywhere from \$1,950 to \$2,700 (depending on the year) for an average-sized 5 kW_{DC} system (last column).

Table A-1. Calculation of Incremental 30% ITC/Grant Provided to TPO Systems

	Median TPO (FMV)	Median Host-Owned (Installed Price)	Difference (TPO - Host-Owned)	Incremental ITC/Grant	
	2013 \$/W _{DC}	2013 \$/W _{DC}		30% of Difference	Applied to a 5 kW _{DC} system
			2013 \$/W _{DC}	2013 \$/W _{DC}	2013 \$
2009	11.7	8.4	3.3	1.0	4,950
2010	9.0	7.2	1.8	0.5	2,700
2011	8.2	6.5	1.7	0.5	2,550
2012	7.0*	5.4	1.6	0.5	2,400
2013	6.0*	4.7	1.3	0.4	1,950

* TPO FMV and host-owned installed price data come from the *Tracking the Sun VII* (Barbose et al. 2014) data shown in Figure A-1, except for in 2012 and 2013, when the TPO FMV is set to match Treasury guidance of \$7/W_{DC} and \$6/W_{DC}, respectively (for reasons explained in the text).

Estimating the Impact of Accelerated Depreciation

To estimate the magnitude of the net depreciation benefit during the 2009-2016 period, we relied on a combination of assumptions from Chern (2012) and SolarCity (2014a). These include a depreciable basis of \$7/W (consistent with the Treasury’s FMV guidance during 2012), a 30-year system life, a 20-year PPA/lease that starts at \$0.20/kWh and escalates at 2.4%/year, a 35% federal tax rate, system production of 1,305 kWh/kW-year with 0.5%/year degradation, a 30% ITC, and 5-year MACRS depreciation (Chern 2012).⁵⁷ We assume that the PPA/lease is renewed for another 10 years at a starting price (which, in this case, also escalates at 2.4%) equal to 90% of the rate in effect at the expiration of the original PPA/lease, and we discount everything back to the present using a 6% discount rate (SolarCity 2014a). These assumptions yield a depreciation benefit of \$1.8/W vs. PPA/lease tax payments of \$1.4/W, for a net tax benefit of \$0.4/W, or ~\$2,000 for a 5 kW system.⁵⁸

⁵⁷ Although some of these assumptions are outdated today (e.g., \$7/W depreciable basis, \$0.20/kWh lease/PPA rate), they were presumably reasonably current back in 2012, based on Chern (2012), and as such are applicable to the historical period over which this appendix seeks to establish the federal tax disparity. A more-recent representation using a \$4.75/W depreciable basis and a starting lease rate of \$0.15/kWh – based on SolarCity’s 3Q14 version of its online *Investor Presentation* (SolarCity 2014b) – is described in the next paragraph (as well as a later text box).

⁵⁸ Like Chern (2012), this analysis assumes a single federal corporate income tax rate of 35% applied to both the depreciation deductions and PPA/lease revenue. But given that TPO providers often finance their PV projects using

Incidentally, this value of \$0.4/W is within the range of “\$0.30-0.40/W” that SolarCity estimates as the “after-tax benefits of accelerated depreciation” in the 3Q14 version of its online *Investor Presentation* (SolarCity 2014b). SolarCity (2014b) likely presents a range rather than a single number because the exact answer depends on several factors, including the claimed FMV, the starting lease price and escalation rate, the expected kWh/kW-year, and whether or not the solar projects are eligible for “bonus” depreciation that has been available in recent years (and if so, whether or not the tax equity investors can make efficient use of it).⁵⁹ The example presented in SolarCity (2014b) uses an FMV of \$4.75/W, a starting lease price of \$0.15/kWh escalating at 2%/year, and a starting efficiency of 1,440 kWh/kW-year. Substituting these assumptions for those outlined above (but holding all others the same as above), the revised analysis yields a net tax benefit of \$0.3/W – i.e., the low end of the range presented in SolarCity (2014b).

Adding the \$0.3-\$0.4/W_{DC} net depreciation benefit to the incremental ITC/grant benefit of \$0.4-\$0.5/W_{DC} in recent years as shown earlier in Table A-1, the combined incremental federal tax benefit accruing to TPO providers since 2009 comes to \$0.7-0.9/W_{DC}, or \$3,500-\$4,500 for a 5 kW system.

It is important to note that this disparity may or may not continue to exist at a similar magnitude throughout the remainder of this 2009-2016 policy period. The portion of the disparity attributable to the ITC will depend in large part upon on how TPO providers price their products and calculate FMV through 2016, while the portion attributable to accelerated depreciation will persist regardless. As shown in the next section, however, even if FMVs were to completely converge with installed prices (i.e., no difference in ITC basis) by the end of 2016, the ITC disparity would still persist in 2017, at least under current law.

“partnership flip” or leasing structures that separate tax and cash benefits and allocate them between the tax equity investor and sponsor, an argument could be made to retain the 35% tax rate for the depreciation deductions (which are most often allocated to the tax equity investor), but use a lower tax rate for the PPA/lease income, most of which is allocated to SolarCity (which is not yet profitable) or to the holders of its asset-backed securities that are repaid via this PPA/lease revenue. If we assume a 15% tax rate (the lowest corporate rate) for the PPA/lease revenue while retaining the 35% tax rate for the depreciation deductions, the net tax benefit of accelerated depreciation increases to \$1.2/W_{DC}, or \$5,900 for a 5 kW_{DC} system.

⁵⁹ As previously stated in footnote 42, bonus depreciation is disregarded in these calculations.

Alternative Approach Using SolarCity's Numbers: 2009-2016 Period

The 3Q14 version of SolarCity's *Investor Presentation* (SolarCity 2014b) provides an alternative means (i.e., not dependent on empirical data) of calculating the imbalance of federal tax benefits provided to TPO providers in the 2009-2016 period. In that version (no longer available online), SolarCity calculates that its total up-front cost for a typical system in 3Q14 was an impressive \$2.90/W (broken out as \$2.19/W for installation, \$0.50/W for sales, and \$0.21/W for general and administrative costs). It also estimates that the same typical system had a fair market value of \$4.75/W (comprised of \$2.40/W for contracted customer payments during a 20-year lease, \$0.55/W for a 10-year lease renewal, and \$1.80/W for federal ITC and depreciation benefits).

The SolarCity costs discussed above do not include profit. To account for profit in a way that approximates the cost of such a PV system to a host-owner, we assume that if SolarCity were to sell this typical system (that cost \$2.90/W) to a host-owner in a competitive market, that it might charge a 10-20% total markup, consistent with the markup that Treasury finds to be acceptable for purposes of claiming Section 1603 cash grants (U.S. Department of the Treasury 2011). In this case, the sale price would be somewhere between \$3.20/W (10% profit) and \$3.50/W (20% profit). The host-owner, in turn, would claim the 30% residential ITC on that installed price, yielding an ITC that ranges from \$0.96/W (given an installed price of \$3.20/W) to \$1.05/W (given an installed price of \$3.50/W). If instead SolarCity were to sell that same system to a tax equity investor at its estimated fair market value of \$4.75/W, then the tax equity investor would claim a 30% commercial ITC of \$1.43/W – i.e., \$0.38-0.47/W larger than the ITC claimed by the host-owner. This incremental ITC estimate of \$0.38-0.47/W essentially matches the \$0.4-0.5/W range found in the empirical data during this period (Table A-1).

For this same typical system, the SolarCity 3Q14 *Investor Presentation* finds “after-tax benefits of accelerated depreciation of \$0.30-0.40/W” (SolarCity 2014b), which exactly matches the range calculated in this Appendix.

Hence, using SolarCity's published numbers for a typical system, along with a reasonable assumption about how that system might be priced if sold to a host-owner in a competitive market, yields a total federal tax benefit imbalance of \$0.68-0.87/W, which essentially matches the range of \$0.7-0.9/W calculated from empirical data.

Finally, the 3Q14 *Investor Presentation* also provides sufficient data to estimate what the federal tax benefit disparity might look like in 2017; those data and calculations are included in the main body of this Appendix, within the *Post-2016* section.

Post-2016

Under current law, the commercial ITC reverts to 10% and the residential ITC expires altogether at the end of 2016. Hence, even if there were no difference in ITC basis between TPO and host-owned systems (i.e., no TPO basis “step-up”), there would still be an ITC disparity in 2017. For example, assuming an installed price of \$3/W in 2017 (equal to SolarCity's 2017 cost target of \$2.5/W plus a 20% mark-up), TPO providers claiming a 10% ITC based on that installed price would receive \$0.30/W, while host-owners would receive nothing.

Perhaps more likely, however, TPO providers will continue to claim the 10% ITC based on appraised FMV, rather than installed price. For example, SolarCity’s online *Investor Presentation* (3Q14 version) includes an example that suggests that, all else equal (i.e., no change to customer lease pricing), the reduction in the commercial ITC to 10% will reduce the FMV of a leased system from \$4.75/W in 3Q14 (under a 30% ITC) to \$3.50/W in 2017 (under a 10% ITC). This \$3.50/W FMV in 2017 is broken out as ~\$3.00/W of contracted customer payments (i.e., no change from the comparable 3Q14 example) and ~\$0.50/W of tax benefits (down from ~\$1.80/W of tax benefits in the comparable 3Q14 example, and including both the ITC and accelerated depreciation). An independent check of the math roughly supports these numbers, with the tax benefits broken out as \$0.35/W (i.e., 10% of \$3.50/W) for the ITC and ~\$0.15/W on net for accelerated depreciation. Given that host-owned systems will not receive any ITC in 2017, this example illustrates that the disparity between TPO and host-owned tax benefits will persist in 2017, and perhaps at a level of around \$0.5/W (or \$2,500 for a 5 kW system) – lower than the \$0.7-0.9/W disparity estimated for recent years.

Summary

The disparity in federal tax benefits claimed by TPO and host-owned residential PV systems varies across the three periods examined in this Appendix. Table A-2 presents the estimated disparities for all three periods, allocated between the ITC and accelerated depreciation (both in $\$/W_{DC}$ terms), and shown in aggregate in both $\$/W_{DC}$ and dollar terms (for a typical 5 kW system). In aggregate, TPO providers have received incremental federal tax benefits (relative to host-owned systems) that range from \$2.8/W (\$13,800) in 2008 – capturing this sizable disparity was the original impetus for launching TPO in the residential sector – to \$0.7-0.9/W (\$3,500-\$4,000) in the current period, and projected to drop to around \$0.50/W (\$2,500) in 2017.

Table A-2. Summary of Estimated Federal Tax Benefit Disparity in 3 Periods Examined

	ITC Disparity ($\$/W_{DC}$)	Depreciation Disparity ($\$/W_{DC}$)	Total Disparity ($\$/W_{DC}$)	Total Disparity (5 kW system)
2008	\$2.2/W	\$0.6/W	\$2.8/W	\$13,800
2009-2014	\$0.4-0.5/W	\$0.3-0.4/W	\$0.7-0.9/W	\$3,500-\$4,500
2017 (projected)	\$0.35/W	\$0.15/W	\$0.50/W	\$2,500

Although the magnitude of the disparity has generally declined over time, and may continue to decline through 2016 if appraisals come into line, the disparity will nevertheless persist post-2016 under current law – *regardless of how the ITC basis is determined* – given that the residential ITC will disappear altogether while the commercial ITC will merely revert to 10%.

There is, of course, some uncertainty in these estimates – particularly for the 2009-2014 period,⁶⁰ and perhaps even beyond the ranges reported – given that there are a number of variables (mentioned earlier) that could shift the answer in one direction or another. That said, given the

⁶⁰ The 2009-2014 period is when the residential and commercial ITCs both have the same 30% face value, which means that determination of the disparity depends on specific assumptions about pricing and appraisal practices, as discussed above. In contrast, the pre-2009 and post-2016 periods both feature distinct differences in the face value of the residential and commercial ITCs, which makes estimating the disparity more straightforward and less subject to interpretation.

multiple methods employed to arrive at essentially the same answer for the 2009-2014 period, the numbers presented in Table A-2 are likely reasonable estimates of the general magnitude of the difference.