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Net Metering and Market Feedback Loops: Exploring the Impact of Retail Rate Design on Distributed PV Deployment

Naïm R. Darghouth, Ryan Wiser, Galen Barbose, Andrew Mills

Energy Technologies Area

June 2015

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Office of Energy Efficiency and Renewable Energy
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Abstract

The substantial increase in deployment of customer-sited solar photovoltaics (PV) in the United States has been driven by a combination of steeply declining costs, financing innovations, and supportive policies. In many U.S. states, a customer's underlying retail rates drives their electricity bill savings from PV under net metering, as all PV generation is effectively compensated at those rates. The current design of those rates and the presence of net metering has elicited concerns that the possible under-recovery of fixed utility costs from PV system owners may lead to *increased* retail prices for all electricity customers, leading to a feedback cycle of *rising* deployment and rate levels. However, a separate and opposing feedback loop could offset this effect, at least partially; if retail rate reforms lead to rates that better reflect temporal patterns in wholesale electricity prices, this could lead to *decreases* in customer bill savings from PV as PV deployment increases, and hence *lower* overall adoption levels. In this paper, we examine U.S. deployment impacts of these two feedback dynamics through 2050 for both residential and commercial customers, across states. Our results indicate that, at the aggregate national level, the two feedback effects nearly offset one another and therefore produce a modest net effect, although their magnitude and direction vary by customer segment and by state. We also model aggregate deployment trends under various rate designs and net-metering rules, accounting for feedback dynamics. Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures; whereas flat, time-invariant rates with net metering are found to lead to higher deployment levels, moving towards time-varying rates, rate structures with higher monthly fixed customer charges, or compensation at levels lower than the full retail rate can dramatically erode aggregate customer adoption of PV in the long term.

1 Introduction

Deployment of distributed solar photovoltaics (PV) has expanded rapidly in the United States, growing by over 400% since 2010 in terms of total installed capacity and averaging 40% year-over-year growth in capacity additions (GTM and SEIA 2015). This rapid growth has been fueled by a combination of steeply declining costs, the advent of innovative financing options, and supportive public policies at the federal, state, and local levels. Key among the supportive policies has been net energy metering (or simply net metering or NEM), which typically compensates each unit of PV generation at the customer's prevailing retail electricity rate. Net metering allows homes and businesses with onsite PV systems to offset their electricity consumption regardless of the temporal match between PV production and electricity consumption. As state incentive programs and federal tax credits are phased out, net metering has become increasingly pivotal to the underlying customer economics of distributed PV.

The rapid growth of net-metered PV has provoked concerns about the financial impacts on utilities and ratepayers (Accenture 2014, Kind 2013, Brown and Lund 2013, Eid et al. 2014). Central to these concerns is the contention that net metering at the full retail electricity price allows PV customers to avoid paying their full share of fixed utility infrastructure costs, thus requiring the utility to raise retail prices, including for non-PV customers, to recover those costs in full (Borlick and Wood 2014). Compounding that concern is the possibility of the feedback effect where increased retail electricity prices accelerate distributed PV adoption, resulting in even higher prices as fixed utility infrastructure costs are spread over an ever-diminishing base of electricity sales (Cai et al. 2013, Costello and Hemphill 2014, Felder and Athawale 2014, Graffy and Kihm 2014).

A wide array of corrective measures—ranging from incremental changes to utility rate design to fundamental changes to utility business and regulatory models—has been suggested to address concerns about under-recovery of fixed costs associated with distributed PV and other demand-side resources (Bird et al. 2013, Fox-Penner 2010, Harvey and Aggarwal 2013, Jenkins and Perez-Arriaga 2014, Lehr 2013, SEPA and EPRI 2012, McConnell et al. 2015). Proposals to modify rate designs for PV customers come in many varieties (Faruqui and Hledik 2015, Linvill et al. 2013, Glick et al. 2014). Frequently they entail reallocating a portion of cost recovery from per-kilowatt-hour volumetric charges to fixed customer charges and/or per-kilowatt demand charges (NC Clean Energy Technology Center 2015), while other proposals involve replacing net metering with alternate mechanisms that compensate PV customers for all or some PV generation at a price different than the retail electricity rate (e.g., using a feed-in tariff or value-of-solar tariff; Blackburn et al. 2014).

Decision-making on these issues, however, is hampered by several key informational gaps. Fundamentally, significant disagreement exists about whether, or the extent to which, net-metered PV under existing rate designs causes retail electricity rates to increase. One aspect of that disagreement revolves around the question of feedback effects: Does distributed PV lead to ever-spiraling rate increases as each successive rate increase further accelerates PV adoption? Prior studies of this issue have generally remained conceptual and hypothetical; few

have sought to quantitatively examine the magnitude or likelihood of effects, with the notable exceptions of Cai et al. (2013), Chew et al. (2012), and Costello and Hemphill (2014). Furthermore, analyses and discussions of retail rate feedback effects have focused only on the possible positive feedback associated with under-recovery of fixed costs. A separate – and potentially offsetting – feedback may occur when increasing PV penetration causes a shift in the temporal profile of wholesale electricity prices (see Table 1). Numerous studies have demonstrated that the capacity value and wholesale market value of PV erode as penetrations increase (Mills and Wiser 2013, Hirth 2013, Gilmore et al. 2015), and Darghouth et al. (2014) explored the implications of this effect for time-based retail rates and the customer-economics of PV systems. No studies to our knowledge, however, have estimated the impact of this effect on the deployment of distributed PV or contrasted it with the fixed-cost feedback mechanism that is the focus of current broader literature.

Key informational gaps also exist with respect to the effect of rate-design changes on PV deployment. Studies have focused on the impacts of retail rate structure on the customer economics of PV (Mills et al. 2008, Darghouth et al. 2011, Ong et al. 2010, Ong et al. 2012) but generally have not translated those findings into deployment effects. Where deployment effects have been explored (e.g., Drury et al. 2013), analyses have considered a relatively narrow range of retail rate structures and have not accounted for the two possible feedback effects between PV deployment and retail electricity prices noted above. Understanding these deployment impacts will be critical for regulators and other decision makers as they consider potential changes to retail rates—whether to mitigate adverse financial impacts from distributed PV or for other reasons—given the continued role that PV may play in advancing energy and environmental policy objectives and customer choice.

Table 1. Feedback mechanisms between PV adoption and retail electricity prices addressed in this paper

Rate Feedback Effect	Description	Affected Rates
Fixed Cost Recovery Feedback	Increases in average retail rates required to ensure fixed-cost recovery	Flat and Time-varying
Time-varying Rate Feedback	Changes in the timing of peak and off-peak periods under time-varying rate structures	Only Time-varying

Our research builds on the aforementioned literature and addresses critical informational gaps for decision makers by modeling customer adoption of distributed PV under a range of rate designs. The analysis leverages the National Renewable Energy Laboratory (NREL) Solar Deployment System (SolarDS) model, which simulates PV adoption by residential and commercial customers within each U.S. state through 2050 and has been used widely for scenario analysis of future PV-adoption trends (Denholm et al. 2009). We build on prior applications of this tool (e.g., Drury et al. 2013) by incorporating the two key feedback mechanisms between PV adoption and retail electricity prices mentioned previously: (a) increases in average retail rates required to ensure utility fixed-cost recovery and (b) changes in the timing of peak-to-off-peak periods under time-varying rate structures (see Table 1). In doing

so, we show whether and under what conditions retail rate changes caused by distributed PV might accelerate or decelerate future PV deployment. Given these feedback dynamics, we then consider deployment trends under a range of possible changes to retail rate design and net-metering rules, including widespread adoption of fixed customer charges, flat vs. time-varying energy charges, feed-in tariffs, and "partial" net metering (whereby PV generation exported to the grid is compensated at an avoided-cost rate). Our results demonstrate that future adoption of distributed PV is highly sensitive to retail rate structures, but that concerns over feedback effects may be somewhat overstated as the two feedback mechanisms operate in opposing directions.

2 Data and Methods

This section describes the SolarDS model, data sources, and assumptions, followed by descriptions of our analysis scenarios and our methods for modeling electricity rate feedbacks. One item on scope deserves note upfront: we do not explore customer defection from the grid as a possible result of combined solar/storage solutions, which may go through substantial price reductions over the study period (Bronski et al. 2014). The reason for this is that the primary tool used in this analysis (SolarDS) is not equipped to evaluate storage solutions or defection decisions.

2.1 SolarDS model, data sources, and assumptions

The SolarDS model simulates the customer adoption of distributed PV using a bottom-up approach (where customer-adoption decisions depend on an economic comparison between PV system costs and reduction in the customer's electricity bill) with data from 216 solar resource regions and more than 2,000 electric utilities. It is an economic model, and assumes that deployment is driven by economic considerations. There are two central elements to the model:

1) **Customer economics of PV.** SolarDS calculates PV system lifetime cash flows based on simulated PV output from NREL's PVWatts model for 216 solar resource regions (Dobos 2014), utility-specific average revenue per kWh (a proxy for retail rates) from U.S. Energy Information Administration (EIA) Form 861, and assumptions about PV system costs, performance degradation rates, and state and federal incentives.

   For input parameters, we assumed the installed prices for PV systems follow a trajectory that draws from the SunShot PV price target (a 75% price decline from 2010 levels by 2020), as described in the U.S. Department of Energy's *SunShot Vision Study* (U.S. Department of Energy 2012): residential PV system prices fall to $1.60/W in 2020 , and commercial PV system prices fall to $1.34/W in 2020 (in 2013 U.S. dollars per peak watt-direct current), assuming an exponential decline in prices through 2020.

   PV compensation under net metering with flat, volumetric retail rates (as are common for U.S. residential customers) is determined by the average electricity rate distribution in each state (differentiated by commercial and residential customers). For retail rates that are

time-varying (time-of-use, real-time pricing, or otherwise), we used the System Advisor Model (Blair et al. 2014) to calculate PV-induced bill savings with and without time-of-use rates, using 2013 rates available to residential customers in each state's largest utility. The ratio of bill savings with time-varying rates to that with flat rates as calculated through this approach was then used to estimate the customer's bill savings from PV under time-varying rates for other utilities in the state, and for both residential and commercial customers. Our demand-charge methodology for commercial customers was not changed from the original SolarDS model; for demand charges that apply to commercial customers, SolarDS assumes that PV can displace 20%–60% of demand charges, depending on the building type, insolation, and season, as calculated using the EnergyPlus model for the original SolarDS. Rate escalation assumptions are from EIA's *Annual Energy Outlook* (EIA 2014a), extrapolated to 2050.

Average utility-specific rates, solar renewable energy credit (SREC) prices, and available state and utility incentives were updated to 2013 levels. State and utility incentives were updated as per the Database of State Incentives for Renewable Energy (DSIRE) database (NCSU 2014). All state incentives and SREC prices are assumed to ramp down linearly to reach zero in 2030, except for incentives that identify an earlier end-date. The federal investment tax credit (ITC) was set to 30% for residential and commercial systems in 2014, and is assumed to revert to zero for residential customers and to 10% for commercial customers at year-end 2016. We assume that 70% of residential systems installed are third-party owned and hence benefit from the commercial ITC.

2) **Customer adoption.** Customer adoption depends on a comparison of electricity bill savings and the cost of the PV system (the "cash flow"). Using the PV system's lifetime cash flow, SolarDS adoption decisions are based on time-to-net-positive cash flow (i.e., payback period) for residential customers and internal rate of return for commercial customers.[1] SolarDS uses highly non-linear customer adoption curves linking payback and rate of return to adoption rates as a percent of maximum market size (adoption curves are available in Denholm et al. (2009)). Maximum market size is based on the number of solar-appropriate households for the residential sector and the available solar-appropriate roof space for commercial customers (see Denholm et al. (2009) for details related to residential and commercial building stock assumptions).

The size distribution of PV systems in the residential sector is based on the distribution of existing PV installations (Barbose et al. 2014).[2] For the commercial sector, PV system size is determined using roof size limitations and load assumptions from Denholm et al. (2009). In each geographical area considered, we aggregated adoption from each customer segment under each rate type and then summed up all installations to the state and national level.

[1] We assume that customers do not foresee the changing rates due to PV penetration levels, and expect net metering to continue to be available over the lifetime of their system.

[2] We recognize that the distribution of PV system sizes may change with time. Lower prices provide some customers incentive to install larger systems, while some rate design choices, such as partial net metering, would encourage smaller systems.

Additional details about the input assumptions for and methodologies used in SolarDS are documented in Denholm et al. (2009).

2.2 Retail rate design and PV compensation scenarios

Eight rate design and PV compensation scenarios are modeled in this analysis, including a reference scenario that provides a baseline (see Table 2). This set of scenarios is by no means intended to be exhaustive, but rather consists of a representative and tractable number of the broader universe of potential rate design options. All scenarios include residential and commercial customer segments and project deployment of customer-sited PV through 2050.

For the reference scenario, we assumed a continuation of the current mix of rate designs and determined the proportion of customers facing flat rates, time-varying rates, and—for commercial customers—demand-charge rates using data from EIA Form 861 and previous SolarDS assumptions (Denholm et al. 2009). We assumed full net metering for the reference scenario, where all customer PV generation is effectively compensated at the retail rate.

Table 2. Rate design and PV compensation scenario assumptions

Scenario	Customer retail rate assumptions	PV compensation assumptions
Reference	Reference mix of flat rates, time-varying rates and demand charges from EIA Form 861 data	Net metering
$10 fixed charge	Reference mix, but with residential rates adjusted with $10 monthly charge	Net metering
$50 fixed charge	Reference mix, but with residential rates adjusted with $50 monthly charge	Net metering
Flat rate	All residential and commercial customers on flat rates	Net metering
Time-varying rate	All residential and commercial customers on time-varying rates	Net metering
Partial net metering	Reference mix	PV generation that displaces instantaneous load compensated at retail rates; PV generation exported to the grid compensated at avoided-cost rate
Lower feed-in tariff	not applicable	All PV generation compensated at $0.07/kWh
Higher feed-in tariff	not applicable	All PV generation compensated at $0.15/kWh

For the scenarios with monthly fixed customer charges, residential PV generation is assumed to only displace the variable portion of the rate. The variable portion of the rate is then calculated for each utility, such that the combination of the variable portion and fixed customer charge is equal to the utility-reported total revenue data from EIA Form 861. For the flat rate and time-varying rate scenarios, all customers are assumed to be on either the flat rate or the time-varying rate, respectively; these scenarios are designed to bound the potential rate mix options. For partial net metering, the PV generation that displaces instantaneous load is assumed to be compensated at the underlying retail rate, while PV generation exported to the grid—assumed to be 50% and 30% of total PV generation for residential and commercial customers, respectively (E3 and CPUC 2013)—is compensated at a lower, avoided-cost rate. That rate depends on regional PV penetration and natural gas prices. Detailed methods for determining PV energy and capacity value can be found in the next section. For the feed-in tariff scenarios, all PV generation is compensated at stipulated (and admittedly somewhat arbitrary) "lower" and "higher" fixed prices, independent of the customer's retail rate.

2.3 Modeling rate feedbacks

The original SolarDS model assumes that retail rate structure and prices are independent of regional PV deployment and escalates those prices at a stipulated rate (e.g., based on retail price projections from the EIA *Annual Energy Outlook*). However, retail rates—and hence the economics of customer-sited PV—are projected to change with increasing PV deployment (Darghouth et al. 2014). In this analysis, we model two separate but interconnected retail-rate feedback mechanisms: fixed-cost recovery and time-varying rate feedback. The factors driving the time-varying rate feedback also affect the partial net metering PV compensation scenario, because exported PV generation is assumed to be compensated at an avoided-cost rate, which is dependent on the regional PV penetration level.

2.3.1 Fixed-cost recovery feedback

When PV is compensated at a retail rate greater than the underlying reduction in the utility's costs from PV (as described in more detail later in the text), we use a fixed-cost recovery adder to supplement the rates such that the utility still achieves full cost recovery. The fixed-cost recovery adder is modeled at the state level, separately for residential and commercial customers, as follows:

$$A_{FCR} = \frac{\left(r_{avg} - v_{PV}\right) \cdot G_{PV}}{L_{tot} - G_{PV}}$$

where $A_{FCR}$is the fixed-cost recovery adder for residential or commercial customers, r_{avg} is the average compensation rate for residential or commercial PV customers, v_{PV} is the calculated utility cost savings from PV, $G_{PV}$is the total residential or commercial customer-sited PV generation, and L_{tot} is the total residential or commercial load within the state. As indicated, the fixed-cost recovery adder, A_{FCR}, is calculated separately for the residential and commercial

sectors using the appropriate compensation rate, PV generation, and load values for each sector.

There is considerable debate about the degree to which PV offsets utility costs and, more broadly, about the value of PV from a societal perspective (Hansen et al. 2013, Denholm et al. 2014, Brown and Bunyan 2014, IREC 2013). We narrowly focus on the value of PV in offsetting utility costs, where the value of PV, v_{PV}, consists of three components: the energy value, the capacity value, and miscellaneous value (which includes avoided transmission and distribution losses, transmission and distribution capacity offsets or additions, and other economic cost savings). Our use of value of PV in this context excludes any additional benefits to society that are not monetized by the utility (e.g. environmental and health benefits). It also excludes shorter term consumer benefits related to lower average wholesale prices.[3]

We assume energy and capacity value depend on regional PV penetration levels, where regions are based on EIA's electricity market module zones, and PV penetration levels include both utility-scale and distributed PV.[4] For the energy value of PV, we assume for simplicity that PV electricity displaces natural gas electric generation as the marginal resources in most regions during PV generation hours. We calculate natural gas generation prices using regional EIA natural gas price projections for the electricity sector and average natural gas plant heat rates (EIA 2014). We assume PV generation displaces less efficient (and therefore more expensive) natural gas generators at low PV penetrations and more efficient ones at higher penetrations: starting from zero PV penetration, PV displaces natural gas generation that is 10% less efficient than average, and this ramps linearly to displace natural gas generation that is 20% more efficient than average at 20% PV penetration, on an energy basis; these assumptions are based on findings from Mills et al. (2013). To estimate PV penetration, we aggregate PV generation at the regional level to account for the interconnected nature of electric grids. Ultimately, this approach results in the energy value of PV decreasing with increasing regional PV penetration.

We also model the declining capacity value of PV with increasing regional PV penetration. Hoff et al. (2008) modeled the relationship between the capacity credit of PV and PV penetration for three electric utilities with different load profiles. Because one driver of PV capacity value is PV's contribution to generation during peak periods, the capacity credit at low PV penetrations tends to be higher for regions with afternoon (summer) peaking periods than for regions with evening (winter) peaking periods. As PV penetrations increase, the marginal capacity credit of PV falls as the net load peaks shift toward evening hours. We use the three capacity credit curves from Hoff et al. (2008) as well as data on state winter-to-summer peak ratios to

[3] In the short term, PV generation can reduce wholesale electricity prices levels during times during which PV generates due to the merit-order effect (Sensfuß et al 2008), hence lowering average wholesale prices, as has been observed recently in Germany and California. However, as unprofitable generators exit the market and older generators retire, new generators will be built such that, in an equilibrium state, all generators are once again profitable. This implies changing wholesale price profiles, but not lower average electricity prices.

[4] As with the PV price assumptions detailed earlier, we assumed regional utility-scale PV deployment consistent with U.S. Department of Energy (2012), modeled by NREL's Regional Energy Deployment System. Distributed PV deployment is from SolarDS scenario results from this study.

interpolate over two curves with the nearest ratio. We then calculate the capacity value of PV at the state level for any given year assuming a capacity cost of $992/kW for new natural gas generation (EIA 2014b). As with energy value, this approach results in a decline in the value of PV with increasing regional PV penetration.

We aggregate all other PV-induced utility cost savings, including avoided transmission and distribution losses as well as deferred (or incurred) transmission and distribution capacity investments and any savings from environmental compliance, into a single "miscellaneous" value adder, which we set to $0.01/kWh based on an earlier analysis (Darghouth et al. 2010) and as a proxy for these potential benefits. Though there is increasing consensus that loss savings are reasonably quantifiable, the value of PV resulting from changes in T&D capacity investments and environmental compliance costs, for example, might increase or decrease with increasing PV penetration, and hence we keep this adder independent of regional PV deployment (Cohen et al. 2014).

In addition to feeding into the fixed-cost recovery and time-varying rate feedbacks, this value of PV estimate, or utility avoided-cost, is also used for the partial net-metering scenario: that scenario assumes that all exported PV generation is compensated at a rate representing the sum of the energy, capacity, and miscellaneous value components of PV (calculated for each state based on regional PV penetration). With an export of some PV generation, this mechanism also partially replaces the fixed-cost recovery adder that compensates for the difference between the retail electricity rate and the value of PV under full net metering.

2.3.2 Time-varying rate feedback

For time-varying retail rates, such as time-of-use or real time pricing, average PV compensation is assumed to change as PV penetration increases, resulting from the shift in the value of PV with penetration. Because the design of time-varying rates varies greatly from one utility to the next, we use existing time-of-use rates as our starting point rather than designing them from the bottom up using standard rate-design methods, as the latter method might produce rates very different from existing ones. As time-varying rates aim towards reflecting marginal cost trends, we then adjust those starting-point PV compensation levels to account for changing (net) peak times and levels using the same methods as described earlier.[5]

In particular, for time-of-use or real-time rates, the average compensation for PV generation depends on the coincidence between PV generation and peak price periods. At low PV penetrations, times of PV generation and peak electricity prices coincide reasonably well for

[5] We do not adjust demand-charge savings with increasing overall PV penetration. Customer demand charges are often based on non-coincident peak load, in which case demand-charge savings from PV would not change with overall PV penetration. For simplicity, we effectively assume widespread use of non-coincident demand charges in this analysis. Demand charges may sometimes be based on coincident (net) peak load, however, in which case PV-induced demand-charge savings would decline with increased overall PV penetration. By ignoring this possibility, we understate the magnitude of the time-of-use feedback effect described later.

afternoon-peaking utilities, hence the value of PV and PV compensation based on time-varying rates can be higher than average rates, as reflected in most time-varying rates available today. As PV penetrations increase, however, the marginal generation cost decreases during the hours when PV generates, driven by the same trends that impact the energy and capacity value of PV as discussed previously;[6] because this is reflected in time-varying rates, we would expect a decrease in PV compensation levels (as found in Darghouth et al. 2014). We therefore model the reduced PV compensation under time-varying rates by decreasing the PV compensation at the same rate as the reductions in energy and capacity value with increasing PV penetration, calculated as described in Section 3.3.1.

3 Results

This section presents our results for the feedback between electricity rates and PV deployment as well as the impact on deployment of varying rate designs and PV compensation mechanisms.

3.1 Feedback between distributed PV deployment and retail electricity rates

In our reference scenario, distributed PV deployment is estimated to increase to roughly 154 GW by 2050. The aggregate or combined impact of the two modeled feedback mechanisms (fixed-cost recovery and time-varying rate) never increases PV deployment by more than 3% in any single year, versus an otherwise identical scenario without these two feedbacks (Figure 1). As such, at least in the reference case and at an aggregate national level, we see no evidence that increased retail electricity prices from distributed PV would lead to a significant acceleration in PV adoption.

The dynamics of the counteracting effects underlying this result are critical to understanding the relationship between PV deployment and retail rates.[7] If we only consider the fixed-cost recovery feedback effect (resulting from the increase in retail rates necessary to recover utility fixed costs), PV deployment increases 8% over the case without any feedback by 2050 (Figure 2). On the other hand, if we only consider the time-varying rate feedback (where bill savings for PV customers decline under time-varying rates due to reduced value of PV), PV deployment decreases by 5% compared with the no-feedback case. In effect, the two feedback mechanisms cancel one another to a large extent (again, under our reference case rate design assumptions and at an aggregate national level).

[6] Mills and Wiser (2013) have modeled the impact of increased renewables on the economic value of solar at high penetrations in California. In a separate paper, Mills and Wiser (2015) also identify strategies that could mitigate this effect, including low-cost bulk storage options or increased customer demand elasticity.

[7] Note that the two countervailing feedback effects do not sum exactly to the total feedback owing to the minor interaction between the two effects.

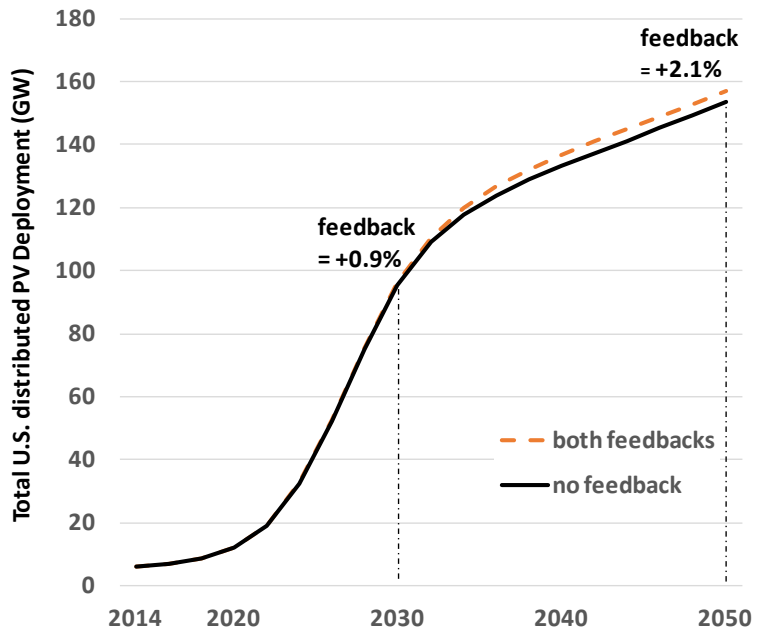

Figure 1. National distributed PV deployment under the reference scenario

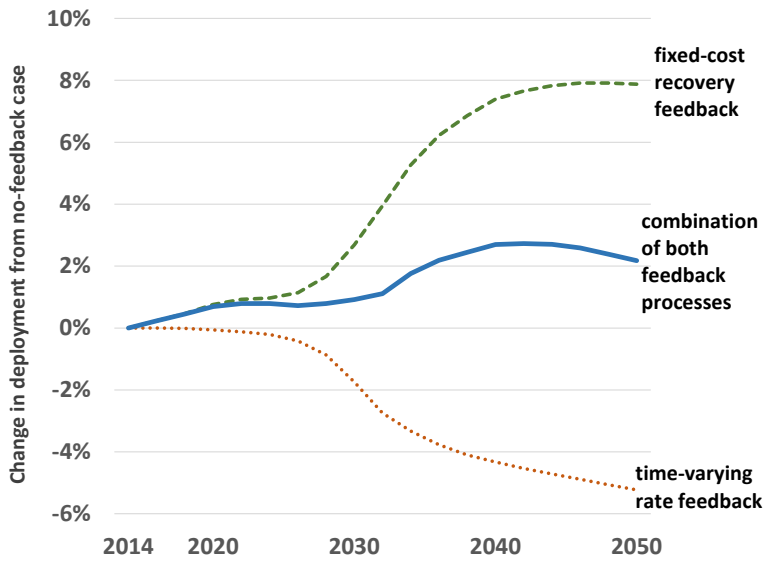

Figure 2. Percentage difference between national PV deployment with and without feedback under the reference scenario, broken out by the two feedback effects

The feedback effects differ between residential and commercial customers owing to the different retail rate structures characteristic of each sector. The rate increase resulting from the fixed-cost recovery adder is present for both flat and time-varying rates in the reference scenario. However, customers with time-varying rates experience a counteracting reduction in PV compensation due to the shifting temporal profile of time-varying rates with increased PV penetration. Most residential customers face flat, volumetric rates in the reference scenario, thus residential deployment increases through 2050 owing to the rate feedback, leveling out at

just above 9% over the reference scenario without feedback (Figure 3), when considering both types of feedback. In contrast, most commercial customers face time-varying rates in the reference scenario, so total commercial deployment decreases by 15% compared with the no-feedback case. Because commercial PV deployment estimated by SolarDS is much lower than residential deployment, the net effect of the feedbacks over both customer segments is only slightly positive by 2050.

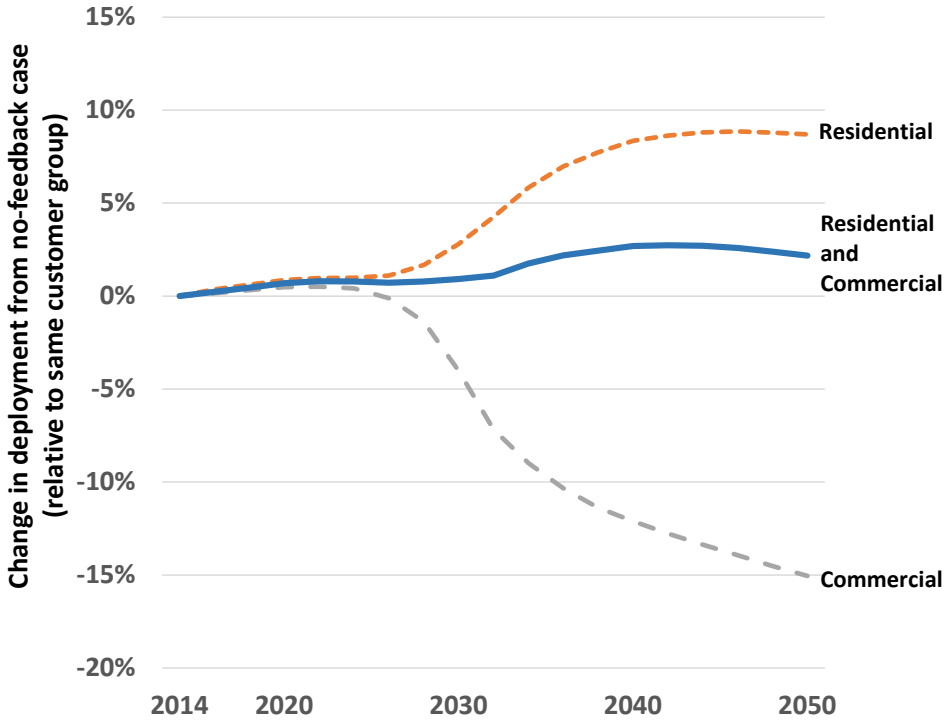

Figure 3. Percentage difference between national PV deployment with and without feedback effects under the reference scenario, broken out by market segment

The results presented to this point are at the national level, and show that the two feedback effects largely cancel each other out in the reference scenario owing to their differential impacts on residential and commercial PV deployment. At the state level, however, feedback effects vary more substantially, as shown in Figure 4 for the year 2050.

For the residential sector, the combined feedback effects increase PV deployment for most states, with a net effect ranging from a 2-6% (based on the 25th/75th percentile values among states) increase in deployment, compared to an equivalent scenario without feedbacks. The variability among states results from differences in residential PV penetration, underlying average retail rates, and percentages of customers on flat rates. States such as California with higher residential PV penetrations and predominantly flat rates experience much stronger feedback effects. States with a higher percentage of residential customers facing time-varying rates have a lower (or even negative) net feedback effect.[8]

[8] In Arizona, for example, where a substantial share of residential customers face time-varying rates, the combined effects of the two feedback mechanisms reduce residential PV deployment compared with the no-feedback case.

Because most commercial customers are already on time-varying rates, the two feedback mechanisms yield a net decrease in commercial PV deployment in most states, as a result of the time-varying rate feedback outlined in section 3.3.2. The magnitude of the commercial customer feedback effects, however, varies substantially across states (i.e., a 9-22% reduction in deployment, based on the 25th/75th percentile values among states, relative to no feedbacks), because the change in energy and capacity value due to increased regional PV penetration varies widely from one region to the next. States with winter evening peaks have a low PV capacity value, even at low PV levels, hence the reduction in value with PV penetration is not substantial and the commercial feedback effect is muted.[9]

As Figure 4 shows, in aggregate considering both feedback effects, most states have a negative total feedback effect, with the median state showing a reduction in cumulative distributed PV deployment in 2050 of 1% relative to the reference case without feedback. This is in slight contrast with Figure 1, which shows a total feedback on a national basis of +2% in 2050. This is because the national results are more-significantly influenced by states with large PV markets, particularly California. Regardless, despite widespread literature suggesting a positive feedback effect, our results suggest that the combined effect of the two relevant feedbacks, at least in the reference case, is generally modest and often negative.

[9] Note that we have chosen not to present state-level results as our focus is on trends at the national level, and while our assumptions capture the macro-level dynamics, they do not necessarily capture the state-level idiosyncrasies related to specific rate levels, mixes, or PV adoption factors, as SolarDS is not designed to make state-level projections.

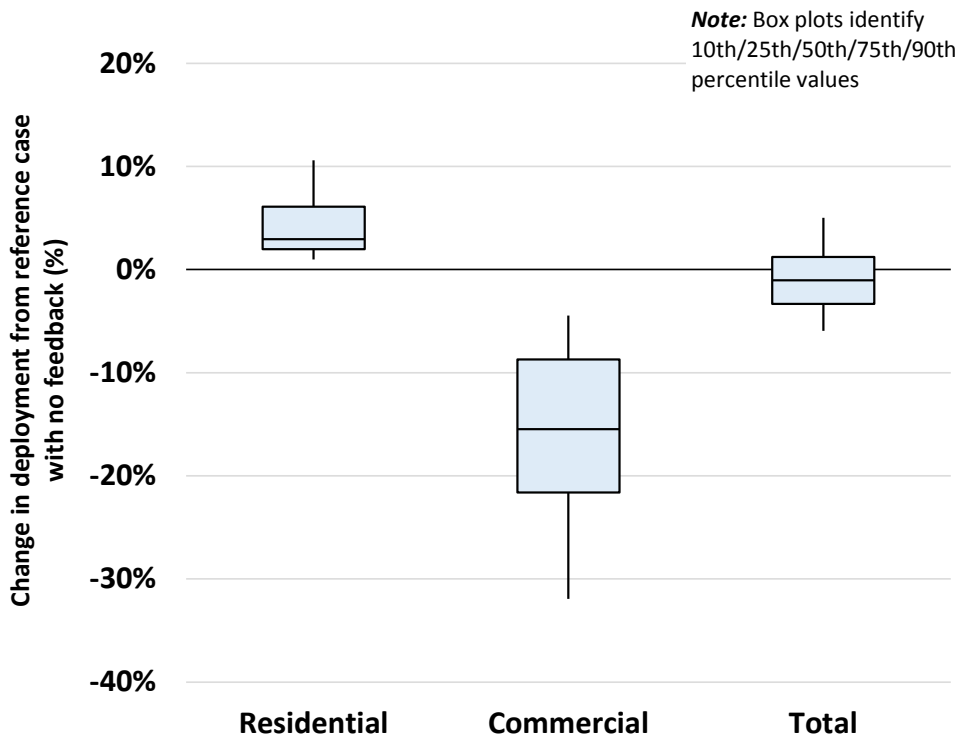

Figure 4. Distribution in feedback effects across U.S. states in 2050, for residential, commercial, and all customers

The results thus far have been for the reference scenario, which assumes residential and commercial rate distributions loosely based on 2013 levels. However, given long-term uncertainties in the rate mix, our scenarios with all customers on a flat rate vs. all on a time-varying rate bound results with respect to the rate mix assumptions (Figure 5). For the flat rate scenario in which all residential and commercial customers are served under a flat volumetric rate, feedback increases PV deployment by 3% in 2030 and 8% in 2050. For the time-varying rate scenario in which all residential and commercial customers are served under a time-differentiated rate, feedback reduces deployment by 6% in 2030 and 25% in 2050. Given the generally expected move, over time, to time-differentiated rates, it would seem that PV deployment feedback effects are predominantly in the negative direction.

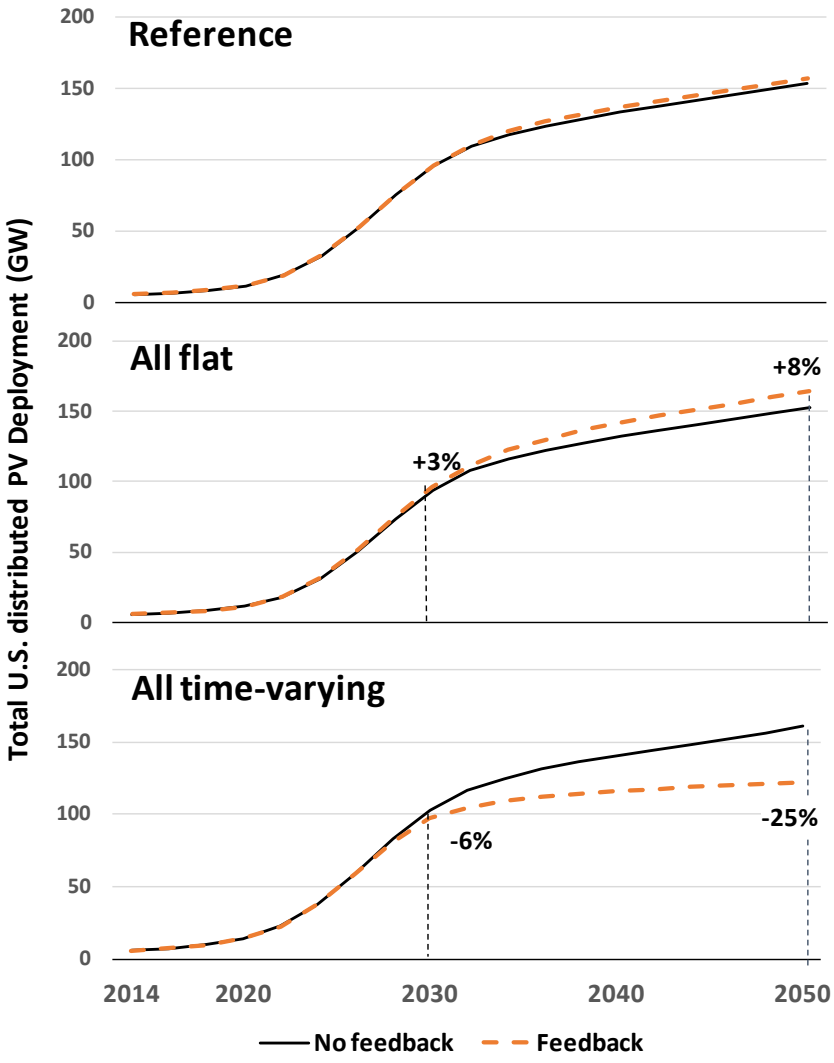

Figure 5. National distributed PV deployment with and without rate feedback for reference, flat rate, and time-varying rate scenarios

Finally, electric utilities and their regulators have begun to consider various changes to rate designs and PV compensation approaches to address concerns over fixed-cost recovery with increasing PV deployment, including the possible positive feedback effect described earlier. These changes have, thus far, been largely directed at residential customers given the prevalence of flat, volumetric rates with no demand charges and lower fixed customer charges. Two specific options sometimes discussed are increased fixed monthly customer charges, and implementation of partial net metering where instantaneous net excess PV generation is compensated at a rate consistent with utility cost savings (typically lower than the retail rate).

Figure 6 presents national residential PV deployment under the reference scenario without feedback and with feedback, and contrasts those results with the fixed-monthly customer charge and partial net metering scenarios, all with feedback. As shown, consistent with Figure 3, the fixed-cost recovery feedback effect leads to residential distributed PV deployment that is

9% higher than without feedback in the reference scenario. The application of monthly customer charges and partial net metering more than offsets this feedback effect, leading to cumulative residential PV deployment that is 17% to 77% lower than in the reference case without feedback. As such, while these rate designs might help address broader concerns from utilities and regulators related to fixed cost recovery issues, they are found to far exceed the levels needed to solely address *feedback* effects.

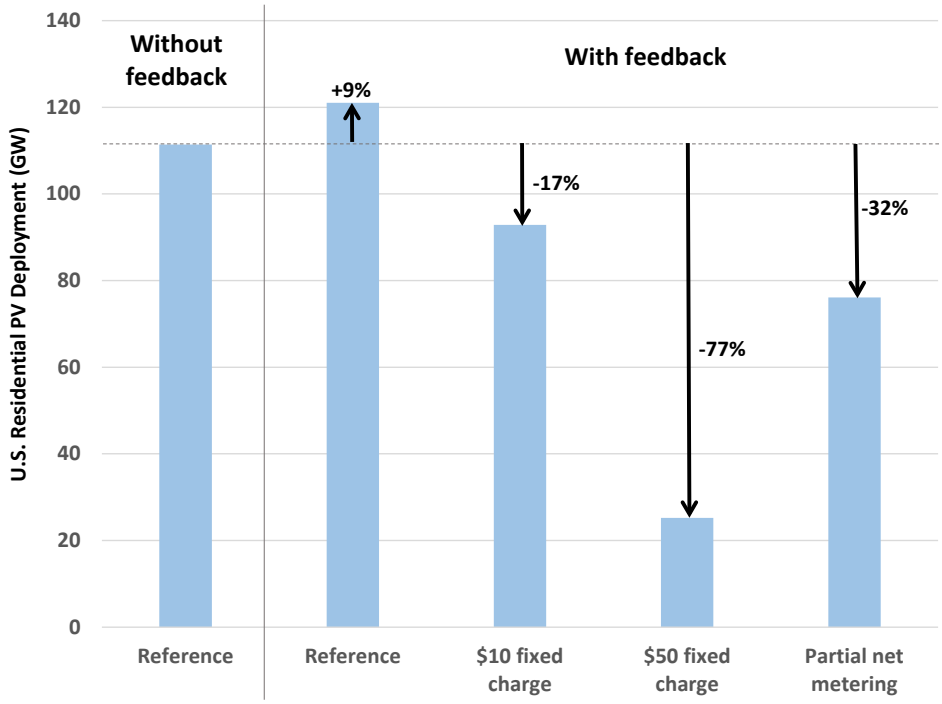

Figure 6. Assessing the degree to which fixed monthly charges and partial net metering offset fixed cost recovery feedback effects for residential customers

3.2 Impact of rate design and PV compensation mechanisms on distributed PV deployment

Whereas the previous section focused on the deployment effects of rate feedbacks, this section shows how various rate designs and PV compensation mechanisms impact total PV deployment, given the presence of those feedback mechanisms. Figure 7 shows the deployment paths for the eight scenarios listed in Table 2, with rate feedback effects included, demonstrating that PV deployment is highly sensitive to rate design choices and PV compensation mechanisms.

The flat rate scenario leads to the highest deployment in 2050, and the lower feed-in tariff scenario leads to the lowest. Most of the rate and compensation scenarios follow temporal trends similar to that of the reference scenario (with different magnitudes), but the time-varying rate scenario follows a different overall trajectory. Specifically, under the time-varying rate scenario, PV deployment is greater than in the reference scenario through about 2030, after which it falls below the reference deployment. This is because, at low solar penetrations,

the higher average compensation for PV under time-varying rates boosts PV deployment. However, as regional PV penetration increases and the energy and capacity value of PV erodes, compensation for net-metered PV generation also erodes under time-varying rates, leading to lower deployment.

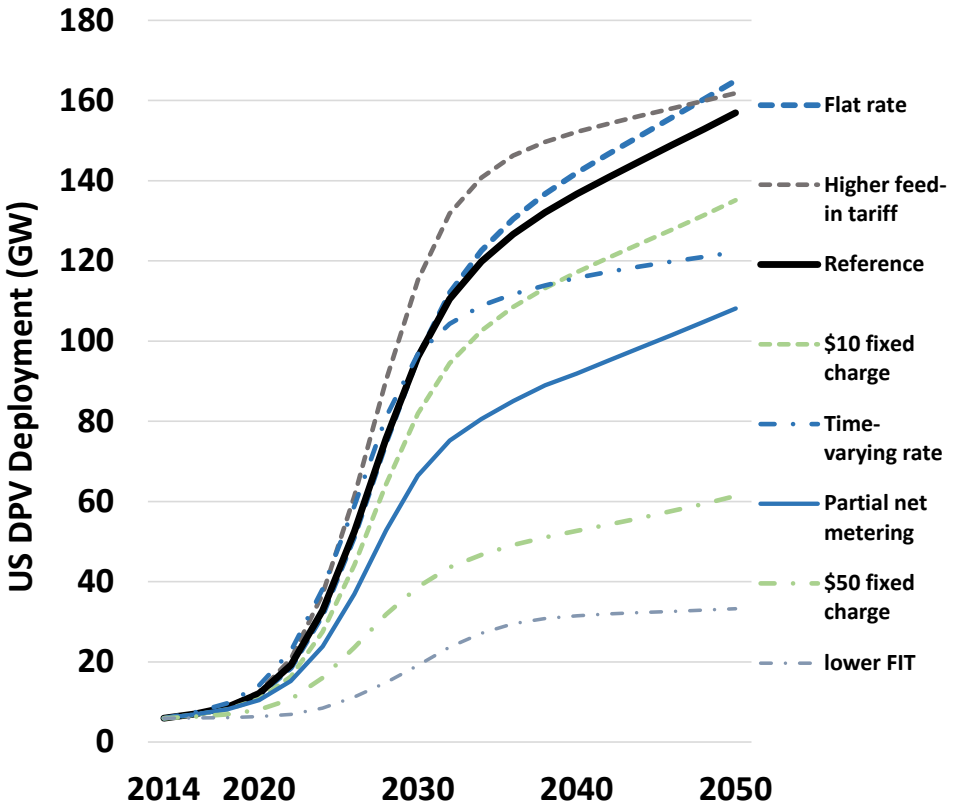

Figure 7. National distributed PV deployment by scenario (with rate feedback effects included)

Figure 8 focuses on 2050 cumulative PV deployment for each of the seven alternative scenarios relative to the reference scenario. Only the flat rate and higher feed-in tariff scenarios increase deployment; all other scenarios reduce deployment. The results indicate that, were all residential and commercial customers on a time-invariant flat rate with no fixed or demand charges, PV deployment would increase by 5% owing to the increased average compensation under that simple rate design. The higher feed-in tariff level of $0.15/kWh also increases deployment relative to the reference scenario; the difference is clearly related to the tariff's magnitude, and higher values would further increase deployment. A lower feed-in tariff level would lead to substantially lower deployment than the reference case, 79% lower for our $0.07/kWh feed-in tariff scenario. Due to the declining value of PV with increased penetration, the time-varying rate scenario leads to a reduction in cumulative PV deployment of 22% in 2050 compared with the reference scenario; as indicated earlier, time-varying rate structures actually increase PV deployment through about 2030.

Both fixed-charge scenarios reduce PV deployment in 2050: a $10/month charge applied to residential customers reduces total cumulative deployment by 14%, and a $50/month charge

reduces deployment by 61%. Partial net metering, where PV generation exported to the grid (i.e., not consumed on site) is compensated at a calculated avoided-cost rate, reduces deployment by 31% because in this analysis the assumed avoided cost from PV is lower than the average retail rate, reducing average compensation and increasing the customer's PV payback time.

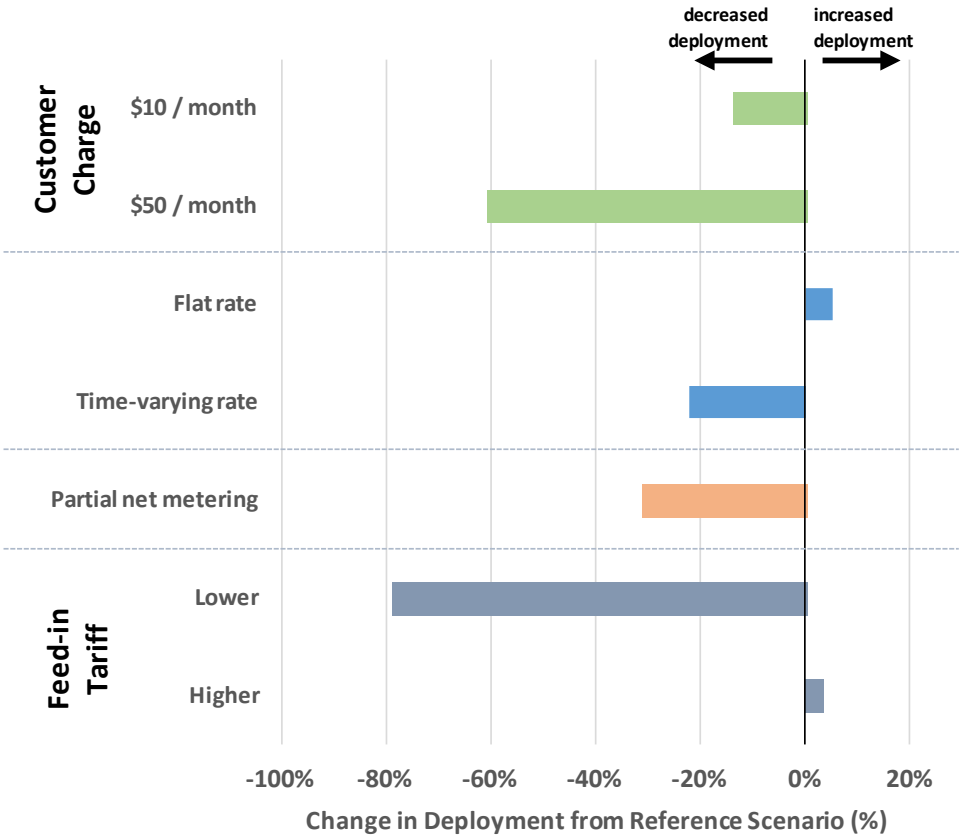

Figure 8. Change in modeled cumulative national PV deployment by 2050 for various rate design and compensation mechanism scenarios, relative to the reference scenario (with rate feedback effects included)

The distributions of PV deployment differences (compared with the reference scenario) across U.S. states vary substantially by scenario (Figure 9). For the two fixed-charge scenarios, the range is relatively small, primarily reflecting differences in the average residential retail rate and average annual customer load across states. For example, states with large annual average customer loads or high average retail rates will see a smaller impact from a given increase in fixed customer charges. The flat rate scenario increases deployment relative to the reference scenario in most states, though only by a modest amount, as a large percentage of customers are already on flat rates.

In comparison to many of the other scenarios, the significance of moving to time varying rates for PV deployment varies rather substantially across states, both in the magnitude and direction of the deployment impact. For about 75% of states, switching all customers to a time-varying

rate reduces cumulative PV in 2050. The states most affected by this scenario are those with the highest PV deployment, where the energy and capacity value of PV erodes the most, along with PV compensation. In regions with low PV penetration, PV compensation under time-varying rates remains higher than the average rate, leading to higher deployment in those states under the time-varying rate scenario than under the reference scenario.

Using PV compensation mechanisms other than net metering produces a wide range of deployment impacts. In this analysis, partial net metering reduces deployment for all states, because the retail rate is always greater than the compensation that we assume applies to instantaneous net excess generation, reducing deployment. For feed-in tariffs, the impact can vary much more across states depending on average retail rates (relative to the feed-in tariff rate), the prevalence of time-varying rates, and PV penetration. For example, in states with lower PV penetration levels, even $0.15/kWh might decrease deployment, as compared with the reference scenario. The range of impacts widens with higher feed-in tariffs owing to the non-linear relationship between bill savings and customer adoption, where the marginal adoption rate increases as the payback time decreases.

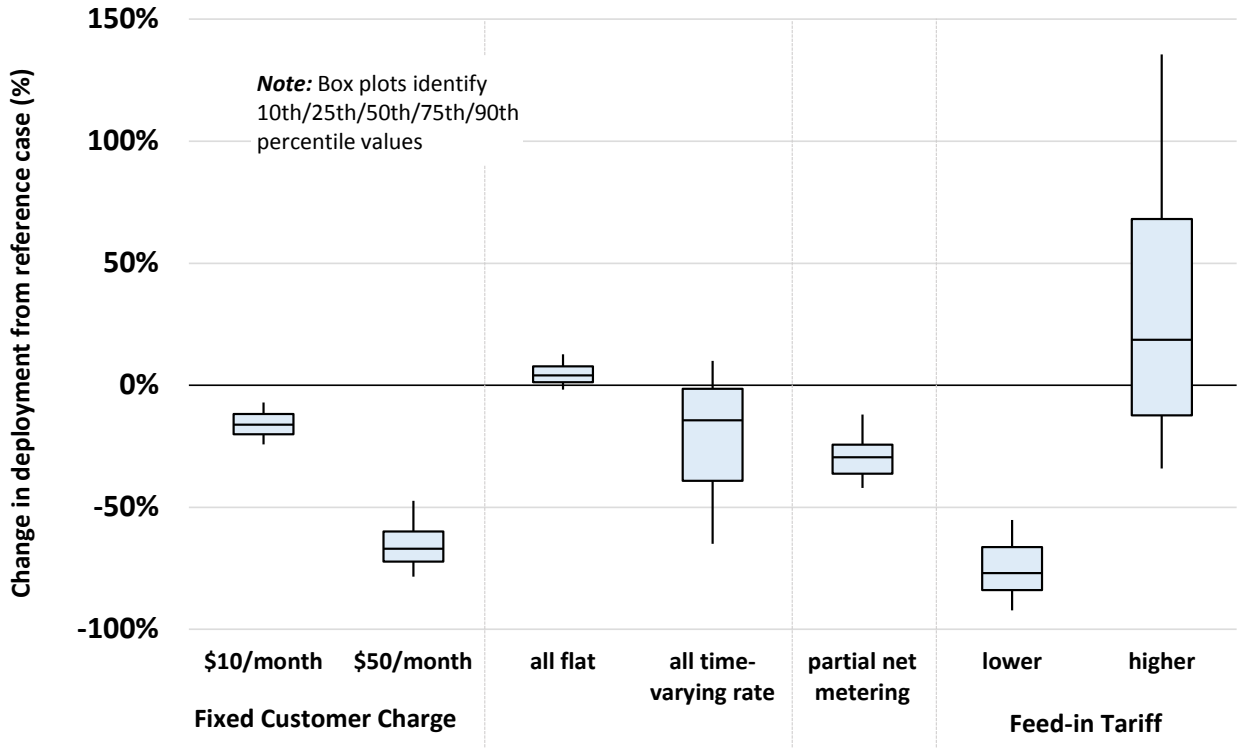

Figure 9. Distribution in deployment differences from the reference scenario for U.S. states in 2050, for all rate design and PV compensation scenarios (with rate feedback effects included)

4 Discussion and Conclusions

There has been significant recent interest in issues related to fixed-cost recovery with increasing distributed PV deployment, and concerns about the "utility death spiral" (Costello and Hemphill 2014, Felder and Athawale 2014, Cory and Aznar 2014, Blackburn et al. 2014, Satchwell et al. 2015). Some observers express concern that increases in net-metered PV adoption may threaten utility profitability, in part owing to a positive feedback loop: as PV deployment occurs, electricity rates increase because utilities must recover the same fixed costs over lower sales, making net-metered PV even more attractive for consumers, and accelerating PV deployment even further. Though our results do not speak comprehensively to the fixed-cost recovery issue or to the impact of PV on utility profitability, they do show that concerns about feedback effects—at least on a national basis—may be somewhat overstated, and that actual feedback effects are quite nuanced.

Our analysis suggests little change in national PV deployment due to rate feedback under our reference scenario, which includes customers on time-varying rates (mostly in the commercial sector) and flat rates (mostly in the residential sector).[10] This is because there are, in fact, two feedback effects of relevance—one related to fixed-cost recovery and the other related to time-varying retail rates—and these two feedbacks operate in opposing directions. The fixed-cost feedback effect is found to increase cumulative national PV deployment in 2050 by 8%. But the feedback associated with time-varying rates reduces cumulative PV deployment by 5%. Current regulatory and academic discussions that focus solely on the fixed-cost recovery feedback therefore miss an important and opposing feedback mechanism that can offset the issue of concern.

Notwithstanding these aggregate national results, the net impact of the two feedback mechanisms can vary substantially across customer segments. In general, the prevalence of flat, volumetric electric rates among the residential customer class ensures a net positive feedback effect with increasing PV deployment in most cases (increasing cumulative national residential PV deployment in 2050 by 9%). In contrast, the prevalence of time-differentiated rates among commercial customers leads to a net negative feedback effect (decreasing cumulative national commercial PV deployment in 2050 by 15%). The net effect of these feedback mechanisms also varies across states, depending on the types of rates offered, the level of those rates, and PV deployment levels. Given these differences, the total feedback effect considering both residential and commercial customers is found to be –6% to +5% in the vast majority of states, and –1% in the median case. Thus, in most states, the feedbacks operate in the opposite direction of the expressed concern and, even where in the positive direction, are rarely particularly large.

[10] As indicated earlier, but deserving reiteration here, we did not explore customer defection from the grid as a possible result of combined solar and storage solutions.

Accounting for these feedback effects, we find that retail rate design and PV compensation mechanisms can have a dramatic impact on the projected level of PV deployment. For example, wider adoption of time-varying rates is found to increase PV deployment in the medium term but reduce deployment in the longer term, relative to the reference scenario based on current rate offerings; the changing pattern of deployment over time, relative to the reference case, is due to the decreasing energy and capacity value of PV with penetration, and the impacts of those trends on time-varying retail rates. The directional impact of feed-in tariffs or value-of-solar rates, on the other hand, depends entirely on the level of the tariff that is offered in comparison to prevailing retail electricity rates. In part to address concerns about the fixed-cost feedback effect (and in part to address many other concerns), a number of utilities have proposed increased fixed customer charges, especially for the residential sector, and/or a phase-out of net energy metering. Though a variety of considerations must come into play when contemplating such changes, our analysis suggests that a natural outcome of these changes would be a substantial reduction in the future deployment of distributed PV: we estimate that cumulative national PV deployment in 2050 could be ~14% lower with a $10/month residential fixed charge, ~61% lower with a $50/month residential fixed charge, and ~31% lower with "partial" net metering. Regulators would need to weigh these impacts with many other considerations when considering changes to underlying rate designs and PV compensation mechanisms.

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