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Can Adoption of Rooftop Solar PV Panels Trigger a Utility Death Spiral? A Tale of Two Cities

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Key Points

The growing penetration of distributed energy resources (DER) such as solar and wind power is causing major changes in the electricity market. One key concern is that existing tariffs incentivize 'free riding' behavior by households, which leads to a cycle of rising electricity prices and DER adoption, thereby eroding utility revenues and start a death spiral. We developed a model using data from two cities in the U.S. to explore this issue.

We found that concerns about a utility 'death spiral' are unfounded in the case of rooftop solar PV adoption, a key source of DER, under existing power policies and prices in the United States.

The rate of solar PV adoption and price increases are likely to be smooth rather than sudden, giving utilities and policy-makers ample time to adapt, at least under the conditions and the range of assumptions we have considered.

The impetus behind the original concerns still calls for a more informed focus on tariff innovations and the interests of participants as well as richer modeling of distribution grids.

Summary

Many leading industry experts and commentators have warned about the threat of revenue erosion for electric utilities posed by the increasing market penetration of distributed energy resources. This is important not only for the companies and their stakeholders, but also for policymakers who expect utilities to make significant investments in the grid to support the transition to a decarbonized electricity sector.

Current U.S. tariff structures typically cover the fixed costs of transmission and distribution (plus regulated profit) with a small charge for connection, plus a charge based on the amount consumed, rather than a charge based on peak requirements. This means existing tariffs may incentivize 'free riding' behavior by households that have invested in solar because they reduce their contribution to the fixed costs through lower purchases from the grid. Thus, distributed generation not only has the potential to lower total revenues, it also can shift the costs of the transmission and distribution system from wealthier customers who can afford PV to lower income customers who cannot afford to install solar panels, raising equity considerations.

We developed an agent-based model to investigate the potential for rooftop solar installations to erode utility revenues. We use data from two distinct locations in the U.S. to assess the impact of residential rooftop solar PV adoption on the revenue streams of two utilities. Our model shows that worries about a utility 'death spiral' due to the adoption of residential rooftop PV, under current policies and prices in the U.S., are unfounded. We found, consistently for a number of scenarios, that the scale of PV penetration is minimal in terms of residential demand reduction and subsequent tariff increases. Also, the rate of adoption would probably be smooth rather than sudden, giving the physical grid, the utility companies, and government policies enough time to adapt.

Although our results suggest that fears of a utility death spiral from residential solar are premature, regulators should, of course, still monitor revenue losses and the distribution of losses from all forms of distributed generation. If these hazards are left unchecked, utilities may struggle to find financing, recover their costs and make new investments. The concerns should lead to a more informed focus on tariff innovations and the interests of participants as well as richer modeling of distribution grids.

Introduction

In this paper, we examine the extent to which solar photovoltaic (PV) penetration can erode utility revenues and undercut the traditional financial model of power companies, leading to a so-called 'death spiral' of the utility business. This question is important not only for the companies and their stakeholders, but also for policymakers who expect incumbent utilities to make significant investments to support the transition to a decarbonized electricity sector.

Ever since its inception, the electricity sector has been made up of large, central generating companies that operate very reliable equipment and distribute power to customers. New, distributed generation technologies with low entry costs, however, have the potential to affect the physical and financial structure of the industry. Rooftop solar PV is one such small-scale technology that can be adopted by a large proportion of a utility company's customers.

The traditional pricing models permitted by U.S. regulators require utilities to cover most of the fixed costs of their investments and operations through charges based on the amount consumed, with a small, fixed, monthly charge covering only a small portion of the fixed costs. Consequently, any reduction in sales due to distributed power could lead to companies charging their remaining customers higher rates, which, in turn, could lead to more customers installing solar – or economizing in some way, a factor that is beyond the scope of our model. If this cycle of price increases and additional installations happens at a high enough rate, utilities could enter into what has been called a 'death spiral.' This loss of revenue and demand can have far reaching impacts as utilities still need to build and maintain transmission and distribution capacity to provide reliability; reliability that extends to homes with solar panels on the roof. Under existing pricing policies, PV owners do not pay utilities for this service for that part of their power demand that is met by PV.

German utilities have written off substantial assets in what looks like a death spiral. An alternative view is provided by van Dinther (2016). He states that the write-offs are due more to the actions of generators rather than the penetration of solar.

The Wall Street Journal has reported extensively on the problems of the German electric utilities, resulting from their inability to respond adequately to the Renewable Energy Act passed by the German government in 2000 (Quitzow et al. 2016). E.ON, for example, has lost tens of billions of dollars over the past 10 years, and announced another $9 billion write-off in November 2015, because of its inability to adapt to the changing regulatory environment. Two key policy objectives have impacted on the German utilities, namely the phasing out of nuclear power by 2022 and achieving 80 percent share of renewables by 2050. This policy impact has been heightened by the granting of grid priority to renewable power generation and the guaranteed fixed feed-in tariffs stipulated in the Renewable Energy Act (Lauber and Jacobson 2016). While the renewables policy in Germany has been considered largely successful in driving the rapid takeup and large installed capacity of solar PV, the problems besetting the German utilities seem to reflect rather their inadequate response to the long-term policy directive of reduction in conventional power generation, and particularly the phasing out by 2022 of the historically profitable nuclear power sector.

Worries about a utility death spiral in Hawaii were also expressed recently, where the penetration of rooftop solar PV is one of the highest in the world, with approximately 12 percent of all households having solar panels. The Economist also argues that the electricity industry in Europe faces an existential threat.

The Edison Electric Institute, a U.S. industry association, warns that the electric industry faces ‘disruptive challenges’ comparable to the effect of mobile phones on wire-based technologies.

This prospect of a ‘death spiral’ raises two important issues: what is the scale of the effect resulting from the expansion of residential solar installations and what is the rate at which the effect will occur? In this paper, we investigate these two issues as well as the higher level issue, important for policymaking, of the robustness of the findings.

In order to address these questions, we use an agent-based model (ABM) in which building owners adopt rooftop PV panels depending on the perceived payback period for their investments, given rooftop PV costs and utility electricity prices. The perceived payback period is influenced by a contagion effect that depends on the number of panels installed in their geographical vicinity. This measure is a rough proxy for attitudes toward either the early adoption of technology or environment, which are determinants of technological dispersion (Bass 1969; Schelly 2014). Our agent-based model allows us to estimate not only the size of the effect, but also the rate at which customer adoption affects the revenues of the utilities. With sensitivity/post-solution analysis of the model we learn much about its robustness, our third main issue. Finally, the agent-based model affords incorporation of imitation effects (influences from neighbors) and, in the future, other customer behavior.

We assess two locations in the U.S. – Cambridge, Massachusetts, and Lancaster, California – under realistic market conditions. We track the installed capacity, solar generation, net demand and rate impacts over a 20-year period and in 200 scenarios to reveal a range of potential outcomes. We find that, even with extensive rooftop PV adoption, the consequences for the electric transmission and distribution business are limited.

The main body of this paper is organized as follows. In the next section, Case Study, we describe the important features of our two study cities, Cambridge, Massachusetts, and Lancaster, California, as they relate to adoption of rooftop PV. Following this, the Model section provides an overview of our agent-based model, including a description of its overall motivation and its detailed mechanics. (A forthcoming technical report will be available from the authors. It will provide full details of the model and its implementation. The source code will also be available). The Setups section discusses the default scenarios for Cambridge and Lancaster, and describes their calibration to real data.

Our Results section presents the results of applying our model to two pricing scenarios, with runs simulating 20 years of activity. We then present our findings from an extensive and systematic robustness analysis of the modeling assumptions, anchored in the default scenarios. A clear picture emerges from these findings, which we explain in the Discussion section. The conclusion contains comments on the policy implications of our findings, assesses limitations of this study and points toward promising opportunities for future research.

In the Appendix, we present some of the growing literature pertaining to the effects of DER and of the adoption of solar PV. The utility death spiral has been much discussed and has received attention in the popular press, especially with regard to developments in Germany (Lacey, 2014). The existing literature, however, largely focuses on the general problem of distributed generation or, as in the case of Germany, on unusual institutional arrangements. For this reason, we relegate our review of this literature to the appendix.

Case Study

Two cities illustrate the potential of solar and provide the case studies for our analysis. Lancaster, California, has had significant PV growth and is known as a solar hub. Located in the western Mojave Desert, this city has some of the best solar resources in the world and, as a result, is home to many utility-scale solar projects and rooftop installations. Local government strongly supports their development. Lancaster requires all new residential developments to install an average of between 0.5 kW and 1.5 kW of solar capacity (maximum production, under ideal conditions) per home built, the first municipality to institute such a requirement (City of Lancaster, 2013). The mayor once said, "We want to be the first city that produces more electricity from solar energy than we consume on a daily basis" (Barringer, 2013). If this city of 160,000 people is able to achieve that goal, it could damage the local sales and revenues of Southern California Edison, the utility that serves Lancaster.

Lancaster is situated in a state with significant solar activity resulting from a favorable investment environment, relatively high electricity prices and abundant sunshine in much of the state. With 4,316 megawatts installed in 2014, California now has about 10,000 MW of solar capacity (SEIA 2015b). About 330,000 customers participate in the state's solar net metering program and 42,000 MWh (megawatt hours) of solar energy was sold back to the grid in 2014. This is a 142 percent increase since 2011 (EIA 2015d).

Because the average solar radiation in Massachusetts is not as strong as in Lancaster due to its higher latitude and more frequent cloud cover, solar panels produce less electricity than do similarly-sized systems in Lancaster. This makes Cambridge, MA, a useful comparison with Lancaster in terms of the potential for residential solar. Massachusetts has made a strong push for solar power. The state has over 800 MW of solar capacity (SEIA 2015b) and aims to have 1,600 MW installed by 2020 (Massachusetts DOER 2014). With favorable net metering provisions and retail electricity prices of 17 cents per kWh, which is slightly higher than California's and 43 percent higher than the national average (EIA 2015b), solar is a potentially cost-effective option for Massachusetts consumers despite a lower rate of insolation.

The city of Cambridge, MA, differs from Lancaster in several ways, providing an opportunity to compare different regional conditions and potential utility impacts. Moreover, Massachusetts has extensive, publicly available data on rooftop capabilities for solar and a detailed solar mapping tool of the city, developed at MIT and other places (Mapdwell 2015). In addition to different solar conditions, Cambridge has fewer people but is more urban, having a population density 10 times higher than Lancaster. The urban composition, along with a 35 percent homeownership rate, reduces the extent of PV adoption, since renters are unlikely to invest in a long-term assets such as rooftop PV (Feldman et al. 2015).

Demographic, housing, and solar resource characteristics and energy prices for Lancaster and Cambridge are summarized in Table 1.

Table 1. Demographic, solar resource and energy price characteristics.

	Lancaster, CA	Cambridge, MA
Population, 2013	159,523	107,289
Housing Units, 2010	51,835	47,291
Homeownership Rate, 2009-2013	60.1%	35.0%
Median Household Income, 2009-2013	$50,193	$72,529
Land Area in Square Miles	94.28	6.39
People per Square Mile	1,692	16,790
Average Annual Solar Radiation (KWh/m2/day)	6.44	4.39
Average Retail Electricity Price from Utility (cents/kwh)	14.8	16.99

Source: U.S. Census; NREL PVWatts Calculator; EIA Form 860. For this table we sourced demographic, solar resource, and energy price characteristics for Lancaster, CA, and Cambridge, MA., demographic and housing statistics from the U.S. Census, solar radiation from NREL's PVWatts Calculator and retail utility prices from EIA (2015e).

Model

We developed an agent-based model that simulates the adoption of rooftop PV panels. In this, the agents are building owners who decide each year whether or not to install PV. The probability that a customer will or will not adopt PV is a function of the perceived payback period and a logistic curve that reflects consumer choice behaviors, (Luce 1959; McFadden 1973). The model is implemented in Python with ArcGIS visualization and is a template we designed to be modified as appropriate for other locations and data sets beyond Cambridge and Lancaster. The model comes in two versions: one uses a dynamic price model and the other uses a static price model. Here we consider the elements that are common to both versions. We discuss their differences when we present our results.

Key inputs to the model are the number of buildings, their corresponding rooftop areas and their locations. The size of buildings is used to determine both their electricity demand profiles and their ability to install PV panels. Their locations are used to determine contagion effects: agents with neighbors who already have PV are more likely to adopt PV. PV adoption in the model is a function of the economics of PV investments, plus a neighborhood effect that is instrumented to be converted to PV cost reductions that lead to quicker paybacks. We represent the strength of the neighborhood effect through altering the shape of the logistic curve, which represents non-captured values embedded in consumer choices – such as attitudes toward the environment and the presence of early adopters – which are variables used in the literature to explain dispersion of new technologies as well as the general responsiveness of consumers making economic or utility-enhancing decisions.

The model treats each building as a single agent, with the logistic curve providing the probability that the building owner chooses to add solar, given electricity price, solar system cost and neighborhood effect. Thus, the model is a stochastic simulation with specific real buildings randomly adding PV. The model increments time in discrete, annual steps over the course of a 20-year period. We choose this horizon because that is the conventional life span of a solar panel. A consumer makes a choice of adding solar or not in each year. We assume that once a building has installed rooftop PV it remains in place for the duration of the simulation and that no new installation is possible. Other model outputs include hourly electricity demand, the number of rooftop PV installations, PV capacity, PV electricity generation and net electricity demand.

Model Mechanics

We use GIS data to calculate buildings' rooftop areas. Based on this value, we assign a probability distribution for each of the 19 types of buildings reported by the U.S. Department of Energy (Deru, et al. 2011; Hendron and Engebrect 2010). Each building type has an hourly electricity demand profile for a typical meteorological year, which varies by city. Finally, the model permits us to constrain the percentage of buildings eligible to install PV solar panels. This is done through the model parameter L in expression (2). Feldman et al., (2015), conclude that only 51 percent of buildings in the U.S. could install solar panels. The analysis, carried out for the U.S. National Renewable Energy Laboratory (NREL), noted that 81 percent of residential buildings in the U.S. have enough suitable space for a 1.5 KW PV installation and that 61 percent of households are non-renters.

In the interests of biasing the model toward overestimating the effect, thereby exacerbating the death spiral problem, we elected not to constrain the number of buildings eligible to adopt PV. $L = 1$ in all of the runs reported here. Since in each year the model adds solar to a fraction of the remaining buildings that have not already added solar, with an infinite horizon all building owners would do so. This bias in the model would become important if the period covered extended well beyond the 20-year time limit, but is not significant with the short horizon used here. To the extent this bias is present, we overestimate the financial impact of solar.

Adoption decisions proceed in two stages. First, buildings adopt PV panels depending on the payback period for a PV investment. The payback period incorporates both installation cost and an imputed benefit from the neighborhood effect. We calculate the payback period with the formula in (1) and we use a mirrored logistic function, similar to the methodology in Paidipati et al., (2008), to determine the probability of solar adoption in a given year.

In (2) x is the payback period in years, L is the maximum probability (1, or 100 percent) or market share for solar, k determines the steepness of the curve and nne is the net neighborhood effect parameter. The reference mirrored logistic function used in this analysis is shown in Figure 1. In this example, buildings would have an 18 percent probability of installing rooftop PV if the payback period is five years.

$$Payback\ \ Period\ (years) =$$
$$x = \frac{PV\ installed\ cost * (1 - nne)}{8760\ hours * PV\ capacity\ factor * retail\ electricity\ price} \tag{1}$$

$$(x) = \ L * (1 - \frac{1}{1+e^{-k*x}}) \tag{2}$$

Note that even with a negative payback not all residences install solar panels. This is because the payback calculation does not include the time cost to the building owner; risk aversion to new, expensive technology; and building owners with a short-term horizon. Realistically, people take time to make important investment decisions.

We add a contagion effect that depends on the number of panels installed in their geographical vicinity. The more installations nearby, the greater the likelihood that a homeowner installs panels. One explanation for this is that people's perceptions of the risks of solar and costs for gathering information are lower when they can talk to neighbors who already have PV installed. This measure of increased likelihood is a rough proxy for follower behavior during early adoption. In contrast to Grazziano and Gillingham (2014), where 'neighbor effect' is measured in units of PV panels adopted if a neighbor installs solar, we instrument the neighborhood effect as the net neighborhood effect (nne): the neighborhood effect (a model parameter) multiplied by the percentage of neighbors having solar, where the set of neighbors consists of the buildings within a radius of 90 feet.

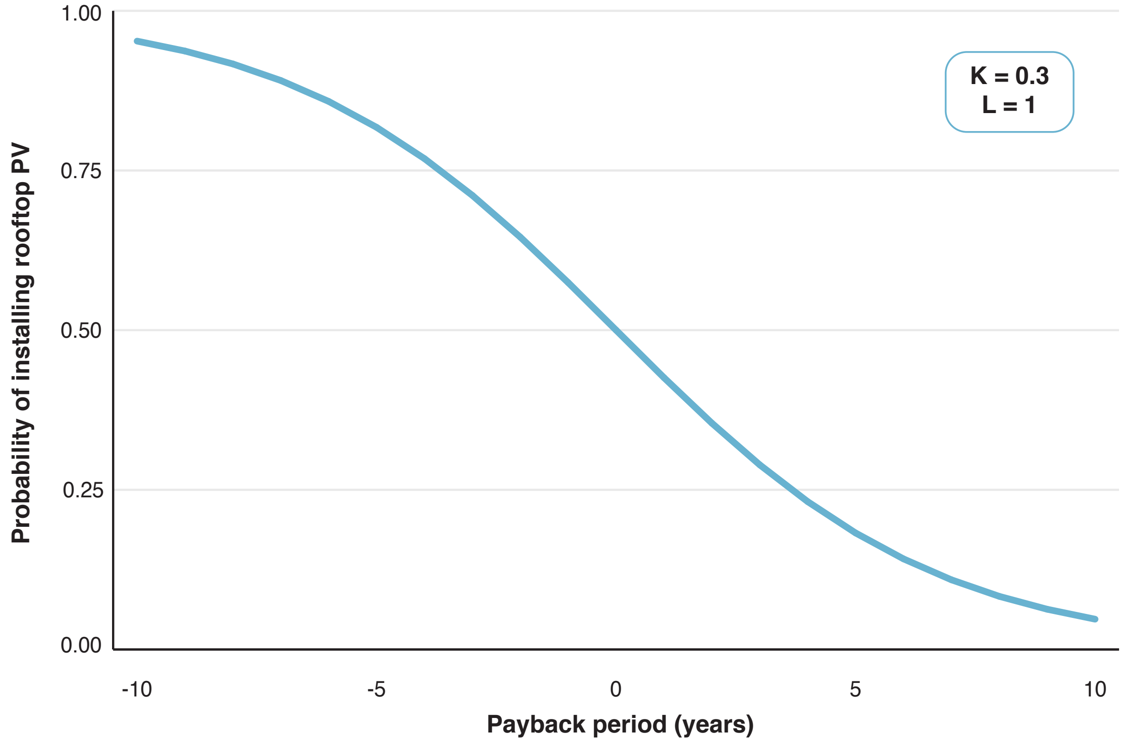

Figure 1. Probability of installing rooftop PV.

Source: KAPSARC analysis.

Later periods in the simulations of payback time reflect lower values of PV costs for agents with neighbors who have already installed solar panels.

The model has inputs for the retail electricity price ($/KWh), the installed cost for rooftop PV ($/Watt), PV capacity factor (percentage of capacity delivered during a year) and a neighborhood effect (a percent discount of PV costs). Each PV option has an hourly electricity generation profile based on its characteristics and a typical meteorological year in the analyzed location. The generation profiles come from the NREL's PVWatts Calculator (NREL, 2015) as applied to the 19 different types of buildings represented in the model and matched to the buildings in Cambridge and Lancaster.

The model simulates the effect on the utility as follows:

We assume the utility has an annual revenue requirement, F, for recovery of fixed costs and allowed profits, denoted by F_0. We calculate this revenue requirement from an initial demand and an initial price of PrF_0. The electricity price in any single year is $F + V$, where V is the generation cost.

We assume that in year 0, at initialization, $F = F_0$ = total demand * $0.08 = total demand * PrF_0. This constitutes the revenue requirement in each year for the utility to avoid a death spiral, i.e. for the utility to continue to be able to earn its permitted return on investments.

The retail price in a given year is $PrF_t + PrV$, with PrV set to be constant as $PrV = initial\ price - PrF_0$. Solar additions decrease the sales of electricity by the amount of solar generation in each year.

Setups

To explore the patterns of rooftop PV installations and their implications in Cambridge and Lancaster, we present a reference case and range of scenarios. The reference scenarios represent the best available data for the current conditions for rooftop PV and electricity in both cities (Table 2).

For our reference scenario assumptions and calculated PV payback periods for Lancaster, CA and Cambridge, MA, the assumptions for PV installed costs were taken from Feldman et al. (2014); capacity factors were calculated with the PVWatts Calculator (NREL 2015) and retail electricity prices are from the U.S. Energy Information Administration (EIA 2015e). The figures for PV installed costs are used in the first year of our simulations. After that the model imposes an annual PV cost reduction, which we derived as an average of the figures reported by the U.S. Department of Energy (2014).

The annual probabilities for rooftop PV adoption in the reference scenarios are 0.0065 and 0.005 for Lancaster and Cambridge, respectively, ignoring neighborhood effects. The logistic curve K-factor, at 0.3, was subjectively assessed. We set the value of K as approximately a threshold between very fast increases in adoption rates – at K and above – and much slower increases. The effect is to bias the model slightly towards faster adoption rates and thus towards overestimating the difficulties for the utilities. We undertook extensive sensitivity analysis on K, and the results are not sensitive to modest departures from K=0.3.

Table 2. Reference scenario assumptions and calculated PV payback periods.

	Lancaster Reference Scenario	Cambridge Reference Scenario
PV Installed Costs ($/KW)	$4,000	$4,000
PV Capacity Factor	20%	15%
Retail Electricity Price ($/KWh)	$0.15	$0.17
Implied Neighborhood Effect	0.15	0.15
Rooftop PV Payback (years)	16.8	18.1
Logistic Curve K-factor	0.3	0.3
Probability of PV Adoption	0.65%	.43%

Source: KAPSARC analysis.

Results

We used a model with two versions: a dynamic version in which prices change annually to reflect solar PV adoption and recovery of fixed costs; and a static version in which prices remain constant but the utility company sees reduced profits from the reduced revenues.

We discuss the dynamic price version first, in which the utility maintains its total T&D revenue, and hence its allowed rate of return, by raising its price, PrFt, to compensate for revenue loss from solar generation. Expressed more precisely, there are two components to the electricity price charged by the utility: the T&D recovery price, PrT_f , initially set at \$0.08/kWh in the model, and the generation charge, PrV, for variable cost of generating power, paid to the presumed deregulated suppliers. We assume that PrV for Cambridge is \$0.09/kWh and \$0.07/kWh for Lancaster. Of course, when prosumers – consumers who also produce energy – provide solar power, the conventional power generators lose revenue and profits. However, in a deregulated environment these can be neglected: we are only concerned with the effects on the regulated utility company and whether it does or does not face a death spiral.

In the dynamic model, we adjust PrF_t (the T&D price) over time, increasing it as solar reduces demand, and we leave PrV unaltered. (See Figure 2, below, for a flowchart of the dynamic price model.)

Specifically, let RRTD, the required revenue for T&D, be \$0.08*total demand (realized in period 0 and which we assume is fixed) = PrF_1*total demand.

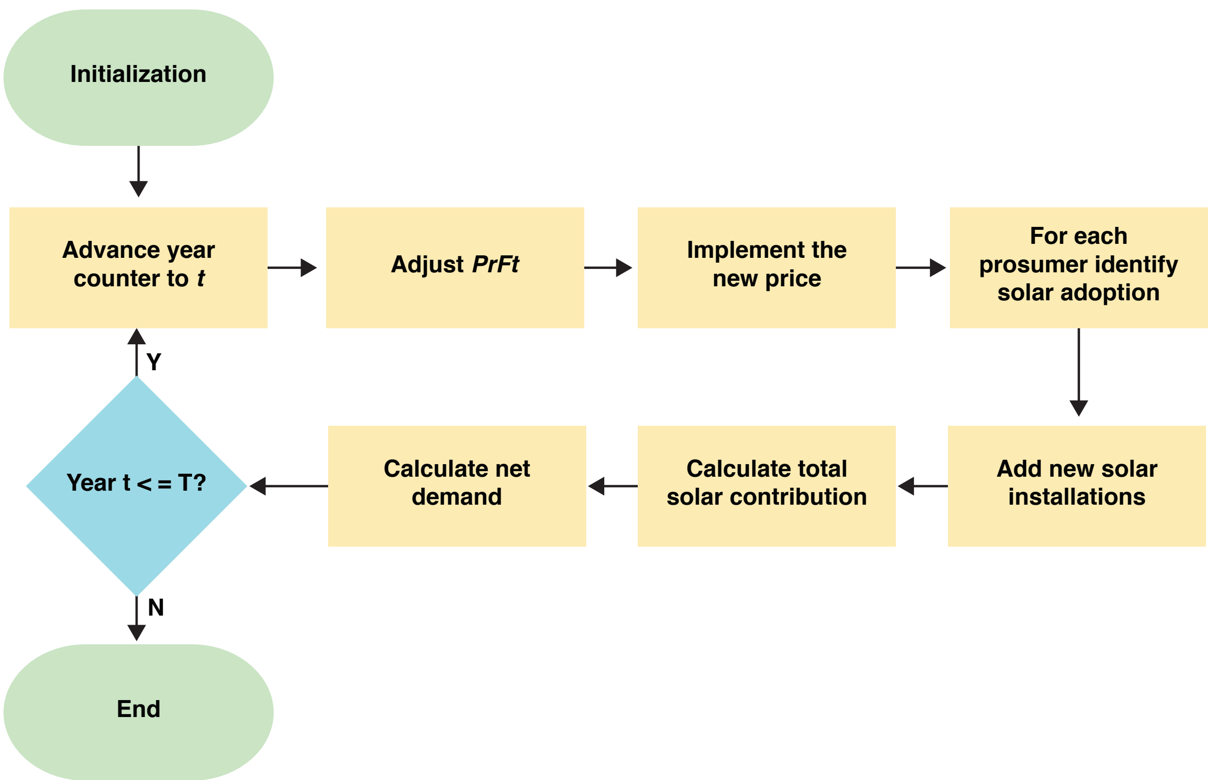

Figure 2. Flowchart for the dynamic price model.

Source: KAPSARC analysis.

For Cambridge, RRTD = $136,910,822= PrF1*total demand, where PrF_t is the transmission and distribution (T&D) recovery price, $0.08 in the reference scenario (i.e., in year 0).

We then adjust PrF_t dynamically in order to keep RRTD constant. The approximation we use is this. At the end of year t-1 we determine the net demand as the total demand – the solar supply, and we apply it as the demand for year t. So, PrF_1= RRTD/(total demand – solar supply) = RRTD/(net demand year t).

In other words, for the revenue to remain constant the price at t+1 has to be scaled by (NET DEMAND(0))/(NET DEMAND (t)) and is P_t=P_0 *(NET DEMAND(0))/(NET DEMAND (t)).

The results of running the Cambridge and Lancaster reference scenarios for 50 runs each, using the dynamic price model, may be described as follows.

At the end of 20 years the total price has risen from $0.17/kWh to $0.171/kWh for Cambridge, and from $0.15/kWh to $0.155/kWh for Lancaster. By that time solar supply (in kWh per year) is approximately 19 million in Cambridge and 137 million in Lancaster. Penetration levels – the percentage of buildings with installed PV – are 36.4 percent in Cambridge and 57.1 percent in Lancaster. Figure 3 is a screen shot from year 20 of a video showing how adoption unfolds in a single representative run over the 20-year period in Lancaster. The full video and code available from https://github.com/KAPSARC/Utilities-of-the-Future/tree/master/2-Utility_Death_Spiral

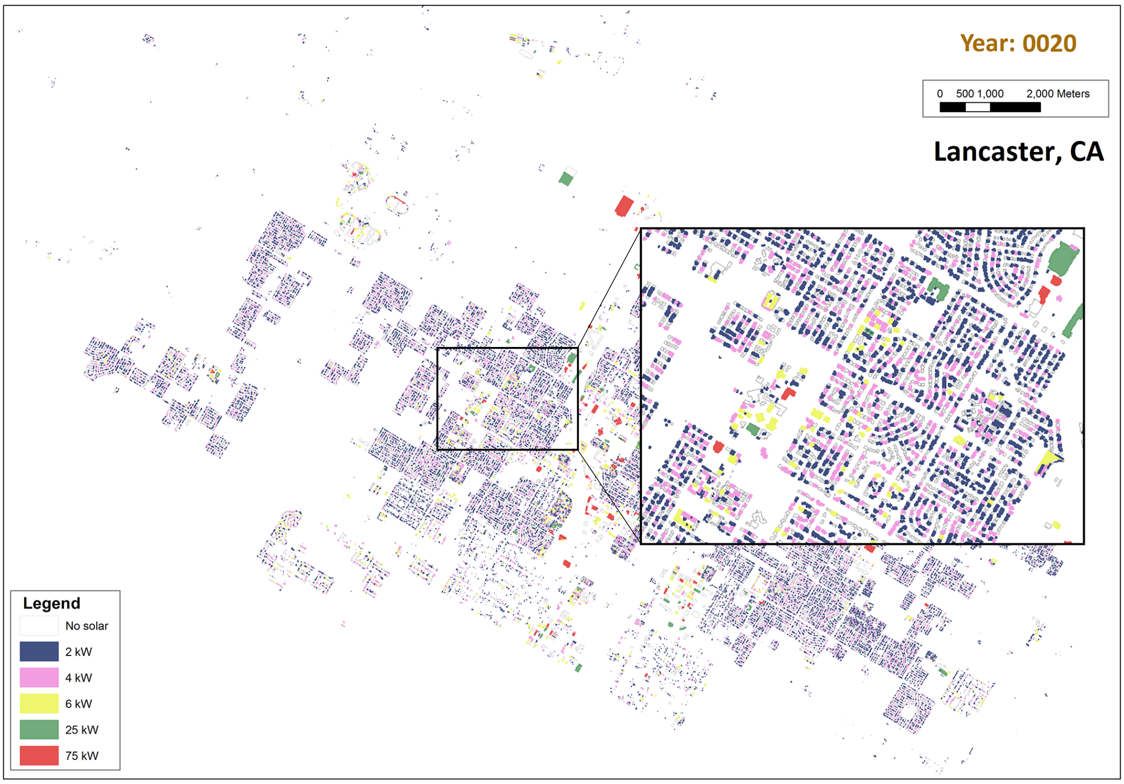

Figure 3. Simulation run for Lancaster, CA shows a snapshot of a representative run of the simulation (year 20). The percent of buildings that have installed rooftop PV is 57.2.

Source: KAPSARC analysis.

The reasons for the small price impact, despite the high penetration rates, are that all of this capacity generates only when the sun is out and the price increase affects just the T&D portion of a consumer's bill.

Examining the results from the static version of the model yields further insights. In this model the price for T&D, which includes revenue for the regulated profits of the utility, remains constant throughout the run. Because demand decreases with the adoption of solar PV and the T&D price does not rise, the utility's profits erode because the revenue shortfalls are taken from profits, not from scheduled payments to retire the capital investment. One of the main aims of the model is to estimate the degree to which these profits decline. Figure 4 presents the high-level flow of control for the static price model.

As in the dynamic case, we completed 50 runs (replications) of the Cambridge and Lancaster reference scenarios. On average, solar PV meets about 1.1 percent of total demand in Cambridge for electric power after 20 years, while the figure is 6 percent for Lancaster. Both numbers vary little among the 50 runs. The disparity in the numbers is credible, given that the capacity factor for relatively sunny Lancaster is 33 percent higher than that for Cambridge. Figure 5 provides an explanation for these differences: Lancaster has a much higher proportion of larger roofs.

To assess the cost to the utility (during year 20), we estimate that the utility receives $0.08 per kWh of demand supplied for recovering its transmission and distribution (T&D) costs. Revenues obtained by means of this charge cover recovery of capital

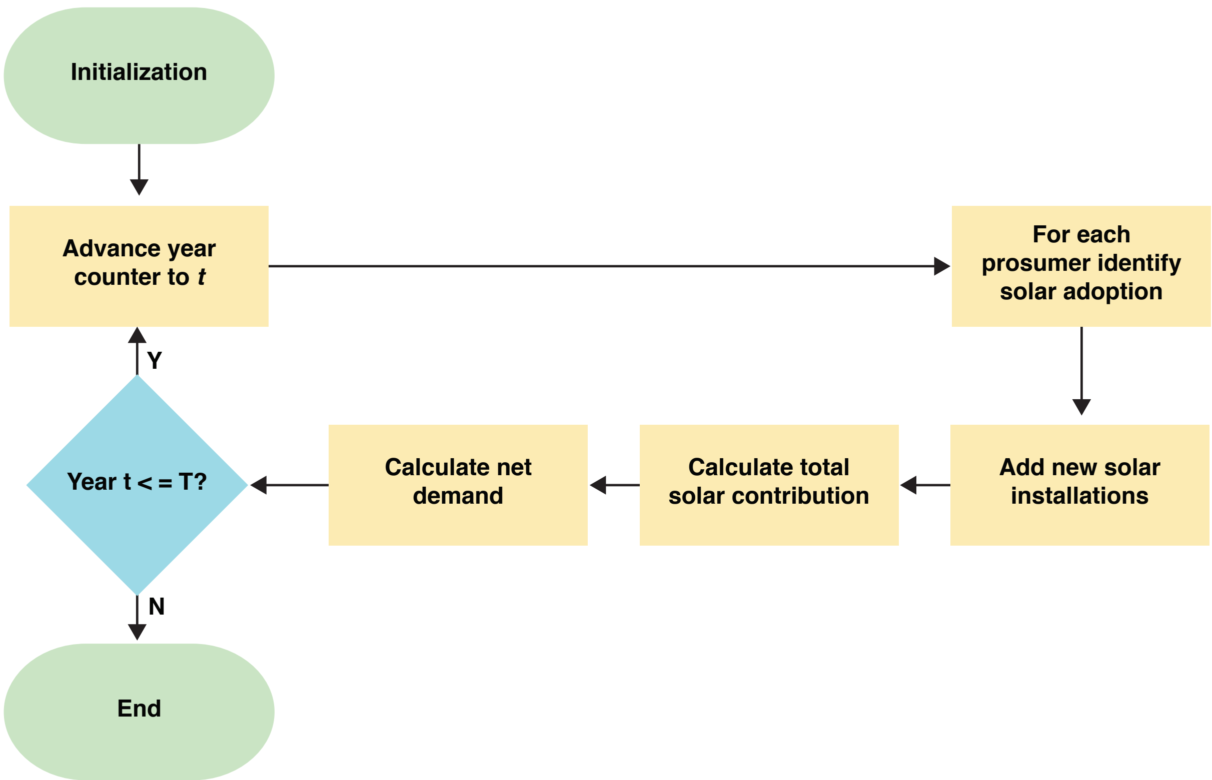

Figure 4. Flowchart for the static price model.

Source: KAPSARC analysis.

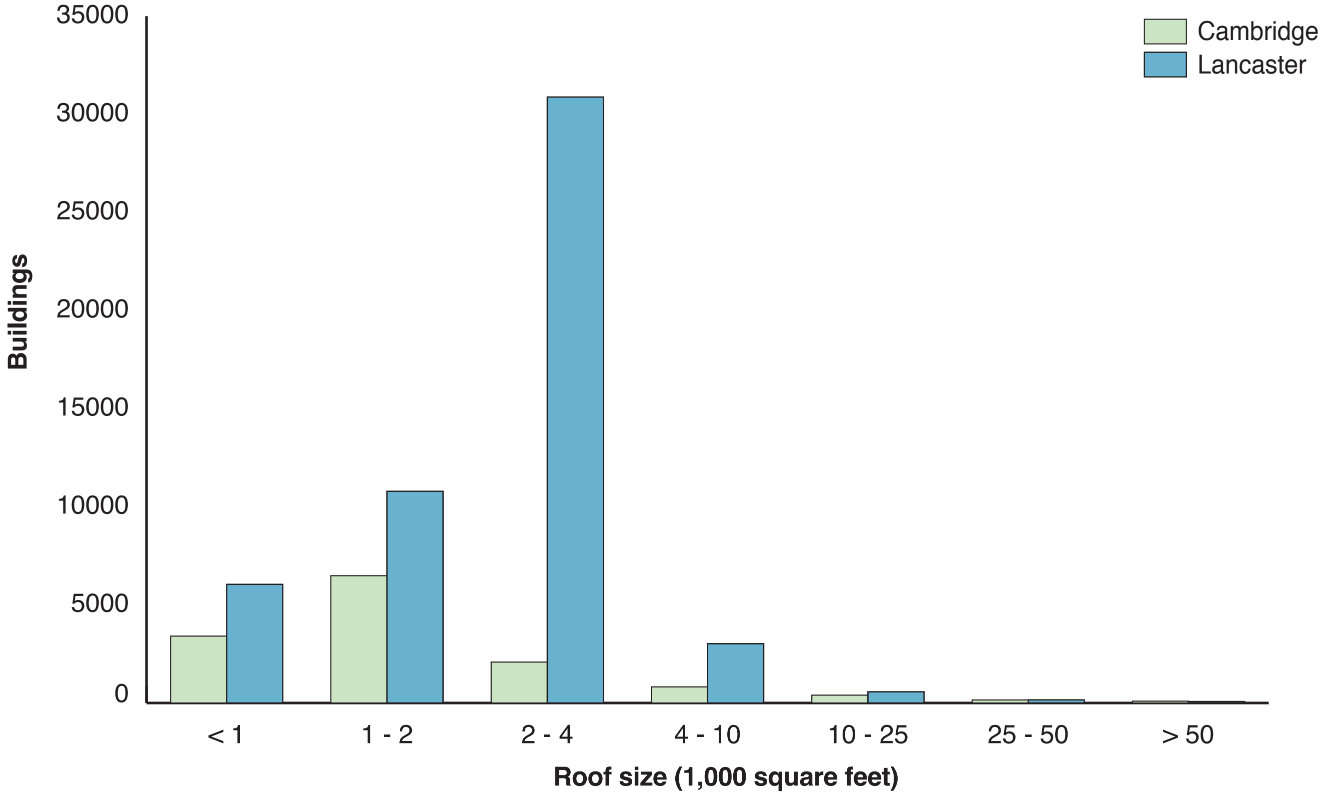

Figure 5. Roof sizes in Cambridge and Lancaster.

Source: KAPSARC analysis.

expenditures by the utility, planned operations and maintenance and regulated profits. The latter we estimate at 10 percent of the revenues thus obtained. The static price model then enables us to estimate the loss of profits to the utility due to solar PV adoption, with the assumption that the price for T&D remains fixed.

Simply put, the Cambridge utility is granted annual T&D revenue of $136,910,822 (=$0.08*total demand = $0.08*1.71E+09). When solar generation is present, the net demand seen by the utility, for which T&D charges are assessed, is reduced by $0.08*solar supply (=$0.08*18,738,720 kWh). This nets out to a loss of T&D revenue to the utility of $1,499,097, which in turn represents a 11 percent profit reduction, on the assumption that 10 percent of the T&D revenue is allocated as profits to the utility. Similar calculations apply to the Lancaster data, yielding a 60 percent drop in profits.

We undertook extensive sensitivity/robustness analysis, related to the reference scenarios. We varied initial electricity price between $0.12 and $0.21 per kWh, solar installation cost between $3000 and $4500 per kW, and neighborhood effect between 0.1 and 0.2. This produced 200 scenarios (10x4x5) in all, each for Cambridge dynamic and Lancaster dynamic. The results are summarized in Figure 6 and Figure 7.

In Figure 6 – Sensitivity results for the dynamic model of Cambridge – and the following charts we rely on the value of the neighborhood effects fixed at its default value of 0.15. Sensitivity runs (not shown) varied its value between 0.1 and 0.2.

The results were not significantly different. In Figure 6, we see that our reference scenario price increases by $0.0006 per kWh at the end of 20 years. In the worst case modeled, we see a price increase slightly above $0.002 per kWh, which would be hardly noticeable by many small customers.

The higher level finding is: (1) the overall behavior of the model is coherent; (2) it is stable; and (3) it indicates no sudden or threshold changes that would ambush either a utility or policy makers, since in fact price increases are smooth and slow. Of course, these findings are valid only for the scenarios examined and the factors modeled.

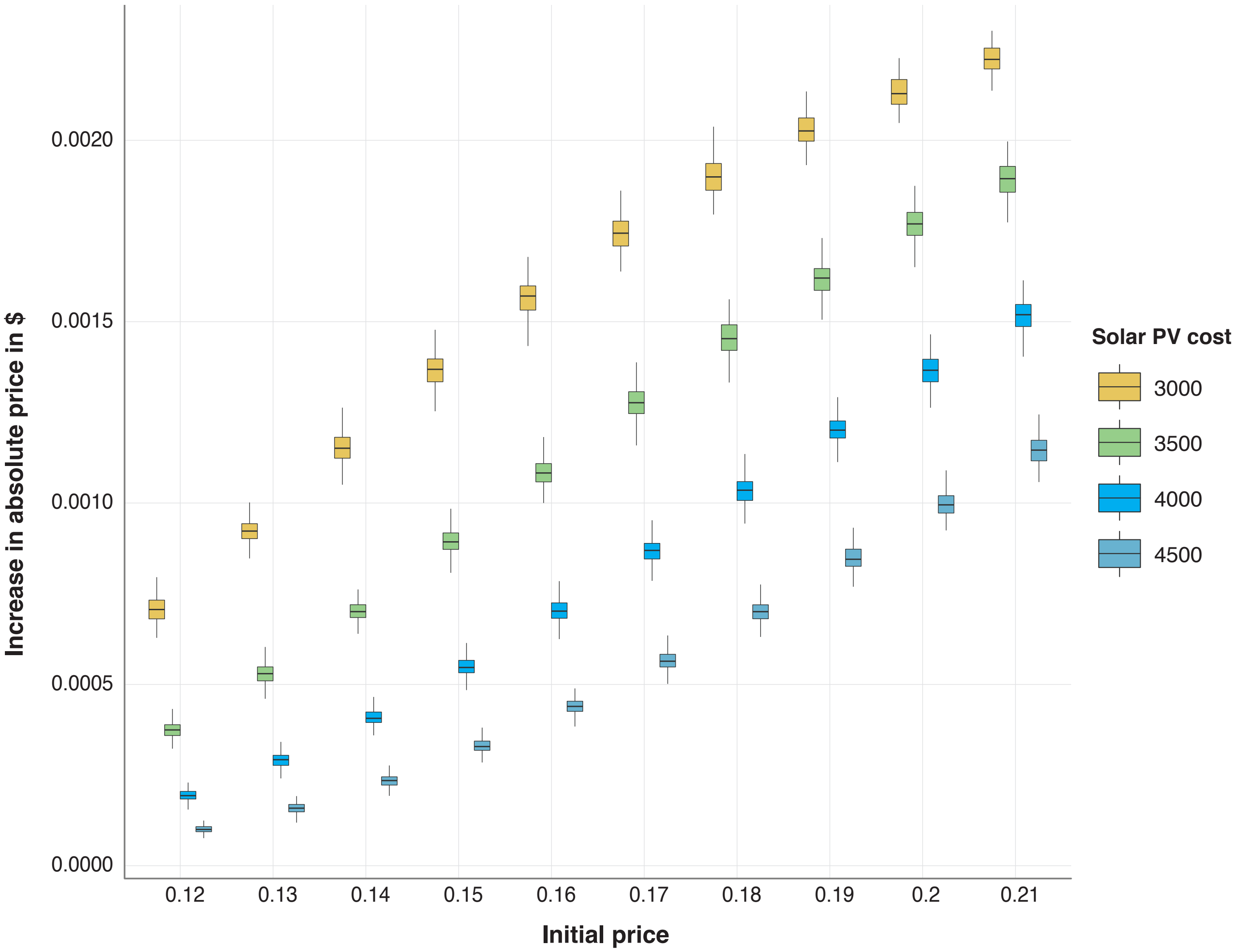

Figure 6. Sensitivity results for the Cambridge dynamic model.

Source: KAPSARC analysis.

For anyone wishing to look beyond these, our model is available for modification as a starting point for further analysis.

In Lancaster, the price increases are higher because of the higher capacity factor and the better economics, as seen in Figure 7.

The worst case is now higher, at a bit more than $0.01 per kWh of increased price. The broad findings regarding stability, robustness, coherence and smoothness remain valid. For Lancaster, the effect on profits for the utility is large if we don't increase prices. This is another insight from our results: the effect is small for the consumers, but large for the utilities, unless prices are raised accordingly. The price increases needed to restore the profitability of the utility, however, are not a major burden on consumers.

In the sensitivity runs for the static cases, the same patterns are obtained. Moreover, we confirm that our conclusions are essentially unchanged when we consider the extreme, hypothetical case of 100 percent penetration and maximum solar PV capacity installed per rooftop. Our results show that the proportions of average electricity demand met by solar PV in the extreme case are 24.4 percent for Cambridge and 42.8 percent for Lancaster (assuming net metering).

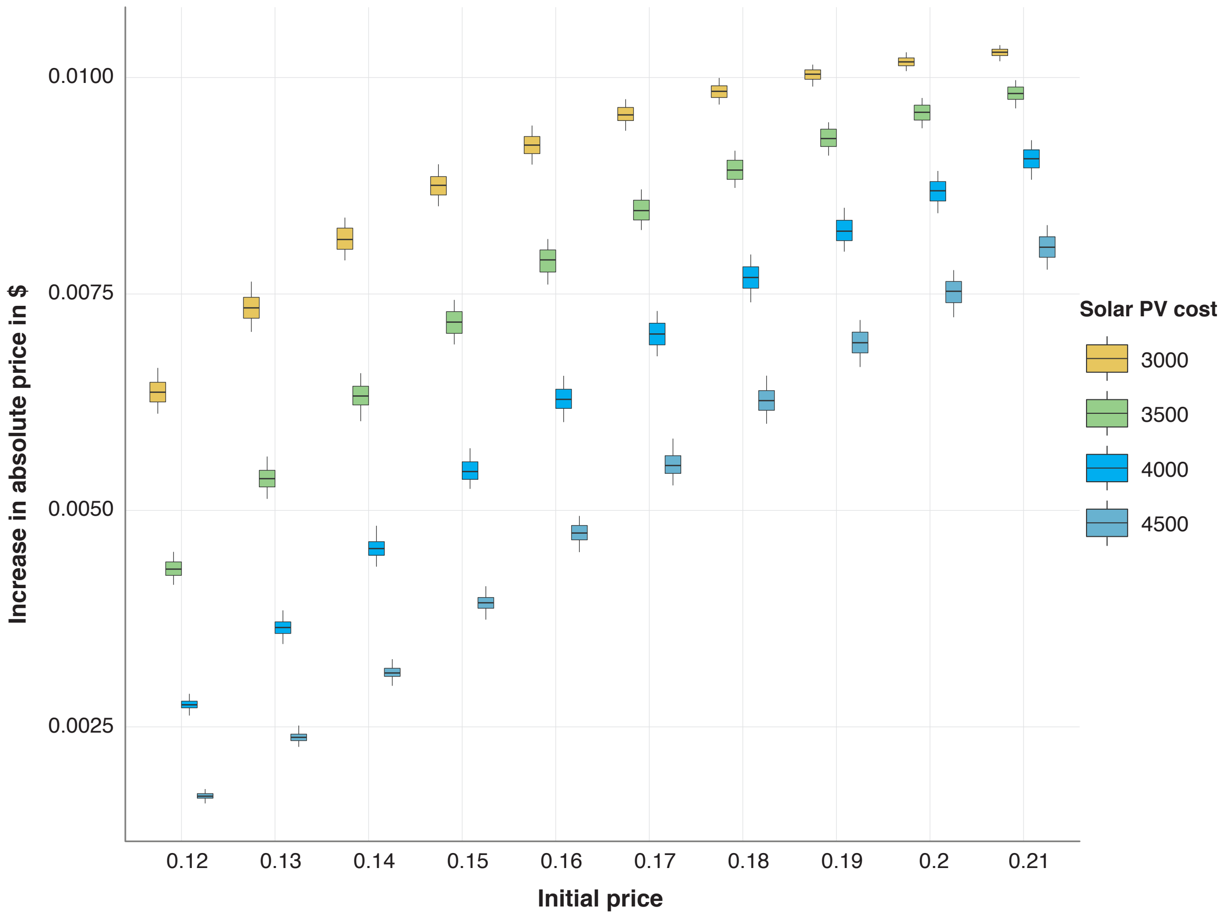

Figure 7. Sensitivity results for the Lancaster dynamic model.

Source: KAPSARC analysis.

Discussion

The widely expressed worry about a utility death spiral is legitimate. There is veritably cause for worry about the effects of any self-reinforcing process. Indeed, as we have seen displayed in our models, initially higher electricity prices do lead to higher levels of rooftop PV adoption, and increasing prices in order to recover lost revenue for fixed costs further increases the level of adoption. Yet with the aid of our models we find little actual cause for concern. So what are these models reflecting that is absent in the anecdotal worry about a runaway process?

There are several factors at work, represented in our models, which prevent rooftop PV adoption from being a runaway process that can overwhelm the utilities. The first is that the maximum amount of rooftop PV is limited by the number of buildings and the rooftop areas they support. These factors are present as real data in our models, data derived from the actual buildings in Cambridge and Lancaster. Second, our models recognize that PV adoption is not instantaneous. Instead it 'diffuses' much, as do new technologies, so as to slow down adoption to a manageable pace. We quicken the pace by including a neighborhood effect, but find that various levels of speeding up matter very little to the results. Third, it is entirely possible in principle that rooftop PV adoption could be limited due, say, to factors one and two, but it still could overwhelm the utilities and their bases of business. Whether this will actually occur depends upon how much solar power is generated, compared to the overall demand. Our models, aided by real data on demand and PV capacities, estimate these quantities.

Given these considerations, it is clear that even with quite substantial rooftop solar PV penetration, in terms of the percentage of buildings adopting rooftop PV, the total amount of power produced is small. Specifically, it is well under 10 percent, which is in turn significantly below the threshold of 15 percent that observers such as Cai et al. (2013) worry about, compared with the total demand for electric power. Moreover, our finding on this is quite robust. For example, the model sizes PV installations based on the size of a building and its type, such as small house, office building, etc. These sizes are standard, e.g., 1.5 kW for a small house, and so on. The resulting estimates are biased high because we do not exclude buildings that are shaded, that are unlikely to adopt solar because of how they are being used, and so on. Even so, the solar effects on prices are small. Thus increasing the productivity of rooftop installations in any realistic manner – e.g., by enlarging them, by employing more efficient collectors – is unlikely to alter our general findings.

The main difference between what the model shows and the outcomes in Germany, briefly discussed in the Introduction, follows from different regulatory regimes in the U.S. and Germany. In the U.S., subsidies for solar come out of general tax revenues (as tax credits) while in Germany the subsidies for solar are added, in terms of a fixed feed-in tariff, to the electricity bill. In addition, some customers, mainly certain large industrial users, are exempt from the price increase, causing an even greater price increase for non-exempt rate payers. That is, from a financial perspective, PV is much more economical with a much shorter payback for non-exempt German customers than for U.S. consumers. Nevertheless, the German policy has led to a tremendous increase in efficiency of PV. As a consequence, PV gets more and more competitive with conventional technologies. We have not examined these effects on deregulated generators. The rapid increase in solar capacity resulted in a reduction of prices paid to conventional generators for electricity in Germany.

Discussion

The lower prices and phasing out of nuclear power were major contributors to the German utilities' losses, resulting in the shutdown of many conventional power plants over the last 10 years or so. Therefore generation, and not distribution, can be seen as the chief driver for the German utilities' potential 'death spiral'.

Neither the U.S. nor the German regulatory regime is inherently superior. The U.S. regime keeps prices lower, avoiding a death spiral. However, not charging customers the full cost of electricity, including PV subsidies, subsidizes consumption and is economically inefficient.

Distributed electricity resources (DER) potentially damage the electric utility business fundamentally in three ways. The first by loss of revenues for recovering fixed costs of electricity transmission and distribution networks. This potential threat is the focus of the present study. To repeat, we found that the threat is minimal with regard to installation of rooftop solar PV. Of course, other forms of DER could well result in significant damage in terms of lost revenues. For example, large scale adoption of community wind and/or solar PV, covering hectares of ground would be quite another matter.

The second potential source of damage to the utility business is loss of revenues for recovering fixed costs of electricity generation. Our study has eschewed this aspect of the problem because in a deregulated environment, common to both Massachusetts and California, electricity generation is undertaken by merchant providers and is not protected by regulation guaranteeing a rate of return. Merchant generators are normally considered to be properly subject to market risks. Prima facie at least, this second potential source of damage is not on the policy table with regard to deregulated utilities that purchase electric power from generators owned by deregulated entities. The matter is different in the case of regulated utilities, which have received approval for construction of generating plant and are entitled to a guaranteed rate of return. In this case the generators have the same status as the transmission and distribution networks and there is, at least potentially, a policy issue to be addressed. That issue is beyond the scope of the present study. Our results would seem to indicate that the net effect on generation costs would be minimal as well, but this has to be a matter subject to further study. We also note that the policy issues with regard to generation may be viewed somewhat differently than those for transmission and distribution. Again, however, this is beyond the scope of our present results.

Finally, the third potential source of damage to the utility business is loss of profits from future regulated generation and/or transmission and distribution facilities. DER in general and solar PV in particular may lead to reduced demand in the future for expansion of regulated facilities, given the assumptions that the utilities abstain from investing in solar PV themselves. In consequence, the facilities will not be built or will be postponed, resulting in a loss of new business (and regulated rates of return) to the utilities. Again, this is beyond the scope of the present study, and we certainly agree that this is fertile ground for future investigation. That said, we also note that the policy case for this third threat is different from the first two, and must generally be seen as much weaker, if not problematic.

Conclusion

Worries that a utility death spiral will result from increased adoption of rooftop PV are exagerated. Absent new information, the threat appears to be minimal under a wide range of assumptions. The modeling exercise reported in this paper has shown that:

- The scale of rooftop PV adoption is unlikely to threaten utilities' basic business model.

- The rate of rooftop PV adoption is likely to be smooth rather than sudden, so there is no immediate need for pre-emptive action.

The modeling results are robust across a broad spectrum of credible scenarios.

This is not, of course, to say that such worries should be entirely abandoned. Continued monitoring, assisted by further model development, is certainly in order, as is examination of the effects of factors not modeled here, such as balancing costs – which are normally not charged as part of the fixed cost recovery funds – and the disruptive effects of new technologies.

Looking forward, at least two additional issues merit prompt attention. The first concerns tariff innovations. Even if the death spiral effect is not a genuine threat, the fact remains that the existing tariff incentives act to encourage the sort of 'free riding' by rooftop PV adopters that inspired the original worries. Because of efficiency and equity considerations, the challenge of instituting appropriate tariffs remains crucial, even if rooftop PV adoption does not by itself constitute a call for urgent policy changes. Given the role of the grid as a backup to shortfalls in solar, a simple policy correction could be to charge homeowners the insurance value of having the grid to cover shortfalls. The second issue relates to extending the agent-based model to include a more articulated, wider, range of prosumer behaviors. This might include such factors as entrepreneurial acquisition of much larger PV capacity, perhaps using land instead of rooftops and demand response regimes, coupled with mandatory participation in balancing by DER producers.

These last two issues are complex, unresolved and vital for the good operation of future distribution grids. If the initial worries about a utility death spiral due to rooftop PV adoption, however misplaced, lead to a more informed focus on tariff innovations and the interests of participants as well as richer modeling of distribution grids, then those who expressed this fear will have performed a valuable service.

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Appendix: Related Work on DER and Impact on Utilities

With technology prices falling and firms offering attractively priced solar products, there is a growing body of research on the adoption of distributed PV. Much of the recent research on distributed PV markets fits into three interconnected areas. The first focuses on the patterns of distributed PV adoption and potential market size. The second covers the implications for utilities and their business models. The third seeks to quantify the value of solar to the grid, in order to provide fair pricing mechanisms and market designs. Kind (2013) outlined in an industry white paper the financial risks to utilities of customers adopting distributed energy resources (DER), including solar PV. This paper falls within the first two areas and touches on the value of solar in reducing net electricity demand.

A 2008 National Renewable Energy Laboratory (NREL) study undertaken by Navigant Consulting modeled the market penetration of rooftop PV in each of the 50 U.S. states, and in several scenarios (Paidipati et al. 2008). The analysis first calculated the technical potential of rooftop PV by inventorying the usable roof space in the U.S., including the effects of shading, building orientation and roof structural soundness. A simple payback period for rooftop PV investments was calculated, so as to arrive at an economic potential. In the base case, the business as usual scenario, a total of 1,566 MW and 57 MW of rooftop PV were projected to be installed in California and Massachusetts, respectively, by 2016.

A 2010 paper, also by NREL, used a similar approach to calculate rooftop PV adoption and identify the factors that have the greatest impact on PV penetration (Drury et al. 2011). The analysis found that lower PV costs had the largest impact on increasing PV adoption, followed by policy options that improve the economics of PV, including net metering incentives and policies pricing carbon emissions of competing energy sources.

Several factors restrict the viability of rooftop PV. A 2015 NREL study identified the limiting factors for rooftop PV, as opposed to the larger opportunities presented by community solar installations (Feldman et al. 2015). The analysis found 81 percent of residential buildings in the U.S. have enough suitable space for a 1.5 KW PV installation. Assuming 63 percent of households consist of non-renters, the study estimates that 51 percent of households could install 1.5 KW PV systems.

Graziano and Gillingham (2014) examined the spatial pattern of rooftop PV adoption in Connecticut. They found that higher density housing and a bigger share of renters decreases adoption. Interestingly, their research also found a ‘neighbor effect’ from recent nearby adoptions that increased the number of installations within 0.5 miles in the following year. They found this neighbor effect diminished over time and space. Rai and Robinson (2015) developed and attempted to empirically validate a spatial agent-based model of rooftop PV adoption that incorporates economic as well as behavioral factors.

Utilities are facing the prospect of customers reducing their net electricity purchases as they adopt rooftop PV. Cai, et al. (2013) simulated the feedback of utility costs and lower sales in a California utility’s territory to assess the implications of rooftop adoption. They found that the ‘death spiral’ feedback reduces the time it takes for PV capacity to reach 15 percent of peak demand only by a maximum of four months.

By implementing a fixed connection charge for rooftop PV, the utility would delay the time needed for PV capacity to reach 15 percent of peak demand by two years. Overall, the authors found utilities could lose a significant portion of their high income customers, which increases risks to the utility, since low income customers are more sensitive to price increases.

The logistic curve represents a starting point for representing consumer behavior. A rich literature on consumer attitudes towards distributed generation is developing. Stern (2014) provides an overall framework for developing a deeper understanding of consumer behavior. Kastnera and Stern (2013) survey the literature on the consumer thinking that underpins their decisions to invest in energy efficiency. Schelly (2014) interviews residents of Wisconsin to understand the motivations of those who adopt renewables, finding that payback is important and environmental concerns are not enough. Gromet et al. (2014) find that promoting the environment can have a negative impact on adopting energy efficiency measures. Bollinger and Gillingham (2012) estimate the peer effects on purchases in neighborhoods. Andrews and Johnson (2016) examine the organizational culture dimensions that influence energy use in corporations.

Ruester et al. (2014) examine how the role of an operator of a distribution system will have to change to accommodate distributed generation. The European industry perspective can be seen in Eurelectric (2013).

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About the Project

The Utilities of the Future project focuses on how new technologies in distributed energy resources (DER) are transforming customer/provider relationships. Advances in distributed generation technologies and associated cost reductions are providing customers with potentially attractive alternatives to standard electric utility service, perhaps turning them into 'prosumers'. Utilities around the world are re-evaluating their business models, and regulators are considering multiple market reforms. The projects aims to develop analytical tools and techniques to help address the key market, regulatory and energy policy issues in a power sector with high penetration of DER.

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