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The impact of retail electricity tariff evolution on solar photovoltaic deployment

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ABSTRACT

This analysis explores the impact that the evolution of retail electricity tariffs can have on the deployment of solar photovoltaics. It suggests that ignoring the evolution of tariffs resulted in up to a 36% higher prediction of the capacity of distributed PV in 2050, compared to scenarios that represented tariff evolution. Critically, the evolution of tariffs had a negligible impact on the *total* generation from PV—both utility-scale and distributed—in the scenarios that were examined.

1. Introduction

Retail electricity tariffs are the primary vehicle by which the costs of electricity consumption are communicated to electric customers. Although the relatively simple design of tariffs cannot perfectly convey the complicated reality of the bulk power system, they are designed to capture many of the important cost-causation trends and communicate them to customers. Given this, an evolution in the technologies and generation mixtures of the bulk power system would likely see a corresponding evolution in the structure of retail electricity tariffs.

For example, in futures with low-cost PV—such as those explored under the DOE's SunShot 2030 targets (DOE, 2016)—modeling suggests that least-cost generation portfolios would include significant amounts of PV generation (Wesley et al., 2017). Under current market environments, these high levels of PV generation would reduce the energy and capacity costs of consuming mid-day electricity (Mills and Wiser 2013; Paul et al., 2016), as illustrated by the curtailment of PV and $0/MWh energy prices observed in California during the spring of 2017.[1] An economically efficient system would pass these price signals on to customers—for example, by changing the time and magnitude of price differentials between on-peak and off-peak hours.

Changes in tariff structures due to an evolving generation portfolio can significantly impact potential adopters of distributed PV (DPV). In the majority of the utility service territories in the United States, the financial performance of DPV is determined by how much they reduce their owner's electricity bills—which is driven by the structure of the electricity tariffs to which the owners subscribe.[2] Tariff evolution is not a mere hypothetical: in the first quarter of 2017 alone, Proudlove et al. (2017) reported that 40 states and the District of Columbia took action related to DPV policy and tariff design. As a specific example, at the time of writing there is an ongoing discussion in the state of California as to the timing of peak hours. The fact that both the California utilities and the Solar Energy Industries Association agree that the current peak window needs to change, although they disagree on how late the window should extend, illustrates the core point: a changing power system mixture can prompt tariff changes, and the details of this tariff evolution matter.[3]

The urgency of better understanding the impacts of tariff evolution is intensified by the rapid adoption of DPV,[4] which increased by 4.2 GW_{DC} in 2016 alone, for a total cumulative capacity of over 16 GW_{DC} (Fig. 1). This installed capacity represents more than 1.3 million individual installations (GTM Research and SEIA, 2017). The deployment

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[1] See https://www.platts.com/latest-news/electric-power/portland-maine/california-oversupply-volumes-grow-iso-curtails-21508104.

[2] In some places, such as Austin, Texas, behind-the-meter PV is compensated through a separate value-of-solar tariff, separating the costs of electricity consumption from the benefits of electricity generation.

[3] See https://pv-magazine-usa.com/2017/03/21/seia-goes-to-bat-over-ci-rates-in-california/ and https://www.greentechmedia.com/articles/read/with-net-metering-secure-california-solar-now-faces-threat-from-time-of-use.

[4] In this work, distributed PV is defined as behind-the-meter PV, and the modeling projections presented in Section 3 specifically refer to behind-the-meter rooftop PV systems.

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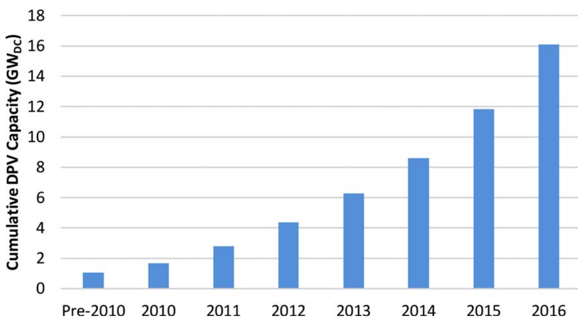

Fig. 1. Cumulative distributed PV (DPV) deployment through 2016 for the United States (GTM Research and SEIA, 2017).

Table 1
Tariff definitions for the two tariff evolution scenarios.

Rate Class	Monthly fixed charges	Non-TOU energy charges	TOU Energy charges	Non-TOU demand charges	TOU demand charges
No Tariff Evolution					
Residential	Ubiquitous	Prevalent	Occasional	None	None
Small C&I	Ubiquitous	Prevalent	Common	Occasional	Occasional
Large C&I	Ubiquitous	Common	Common	Common	Common
With Tariff Evolution					
Residential	Ubiquitous	None	Ubiquitous	None	None
Small C&I	Ubiquitous	None	Ubiquitous	Common	Common
Large C&I	Ubiquitous	None	Ubiquitous	Common	Common

of this technology impacts a diverse group of stakeholders: DPV owners, the rooftop PV industry, non-adopting ratepayers, utility shareholders, and numerous others.

This rapid growth of DPV is projected to continue in the near term (GTM Research, 2017), but long-term DPV deployment is much more challenging to estimate because of uncertainties that can broadly be grouped as either technical or economic (Cole et al., 2016).[5] The two most significant economic uncertainties are the future costs of installing DPV systems and the future compensation received for the electricity produced by those systems. DPV system costs are anticipated to come down over time (NREL, 2016), but the magnitude of cost reductions is highly uncertain and a major driver of DPV deployment projections (Wesley et al., 2016).

This work explores the economic uncertainty related to the compensation mechanism, especially with respect to how retail tariffs might evolve as the penetration of PV increases. Specifically, we develop a methodology for creating utility tariffs for utility customers that is based on the values of energy and capacity from a bulk power system model. These tariffs are applied to a DPV adoption model to understand how DPV deployment might be impacted by utility tariffs that evolve in accordance with the value of energy and capacity.

Explicitly modeling any evolution in the design of tariffs stands apart from most customer adoption models, which commonly rely on a separate model or data set to predict changes in the future cost of electricity, but do not resolve structural changes to the tariffs that would impact DPV's financial performance. The most noteworthy exploration of retail electricity tariff evolution was performed by Darghouth et al. (2016), who investigated the feedback loop between DPV adoption and electricity prices. They found that shifting time-of-use (TOU) pricing could largely mitigate the increases in the average ¢/kWh cost of electricity caused by DPV adoption—preventing the much-discussed "utility death spiral." We build on this work by closely linking a customer adoption model with a capacity expansion model, more accurately resolving the impact of DPV adoption on the total cost of building and operating the electric grid and enabling analysis with harmonized assumptions between the bulk power system and distributed technologies. This model linkage allows for a more thorough exploration of the dynamics between the bulk power system build-out and DPV adoption, including the likely competition between utility-scale and distributed PV that could occur via shifting peak periods and decreased costs of mid-day electricity in tariffs.

As mentioned above, it has been established in previous literature that higher deployment of PV, whether distributed or utility-scale, will lead to lower energy values during hours of solar production and will reduce the capacity value of PV systems. We hypothesize that these lower energy and capacity values, if communicated through utility tariffs, will lead to lower DPV adoption compared to a scenario where tariffs did not evolve from their present-day form. While this hypothesis is fairly intuitive, the magnitude of the impacts is not. The value of this work lies in highlighting the interdependency of PV deployment, energy and capacity value, and tariff evolution, and in providing an initial quantification of this interdependency (Table 1).

2. Methods

2.1. The method

This analysis uses a new method to link the NREL Regional Energy Deployment System (ReEDS) capacity expansion model (Kelly et al., 2016) with the NREL Distributed Generation Market Demand (dGen) customer adoption model (Benjamin et al., 2016) to explore the impact that the evolution of retail electricity tariffs can have on both DPV adoption and the bulk power system. Both models cover the contiguous United States. We summarize the method in Fig. 2 and provide a high-level description below.

1) **Estimating current revenue collection**: In order to best capture regional trends in electricity costs and pricing, we first estimated how much revenue is currently being collected from electricity customers. This was done by curating a set of ~5000 retail electricity tariffs and applying them to a set of ~10,000 representative electricity customers across the residential, commercial, and industrial sectors.[6] The annual bills were weighed by the representativeness of each modeled customer, and then aggregated into 18 regions in the United States that approximately represent the ISO/RTO regions, for an estimate of the present-day revenue being collected in those regions.[7]
2) **Calculating base year system costs and an adder to represent non-modeled costs**: Given that ReEDS only calculates bulk power system costs (e.g. fuel, operations and maintenance, new capacity, long-distance transmission, etc.), it was necessary to somehow represent other non-bulk-power costs such as distribution transmission and customer billing. This value was estimated by aggregating the total energy and capacity costs modeled by ReEDS for the present day by the aforementioned RTO regions and subtracting this value from the estimated revenue collection.[8] Dividing this value by the total electricity sold in the region gave us a ¢/kWh value that was assumed to roughly approximate the regional trends in non-

[5] Although significant, we do not explore the technical issues and uncertainties related to DPV adoption in this work, and we refer interested readers to Bryan et al. (2016) for more information related to higher penetration DPV challenges and opportunities from a technical lens.

[6] More detail on the agent-generation process can be found in the aforementioned documentation of the dGen model (Benjamin et al., 2016).

[7] These revenues could have been obtained from utility financial reporting, but using our set of representative electricity customers harmonized this calculation with future revenue calculations in later modeling years.

[8] A given year's capacity costs were assumed to be amortized over a 30-year window at 8% (nominal) cost of capital. Therefore, each year's total cost modeled by ReEDS was the sum of the preceding 30 years' capacity payments and the given year's total energy costs.