LEAST-COST DISTRIBUTION NETWORK TARIFF DESIGN IN THEORY AND IN PRACTICE

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Overview

Pérez-Arriaga et al. (2017) and Abdelmotteleb et al. (2017) show with simulations and numerical examples that in a new world with active consumers the least-cost distribution network tariff consists of a forward-looking-peak-coincident capacity charge plus a fixed charge. If the capacity-based charge is computed as the incremental cost of the network divided by expected load growth, the tariff is cost-reflective; consumers will make optimal choices with regard to the trade-off between their consumption levels and grid reinforcements. A fixed network charge complements the capacity-based charge to collect the remaining residual network cost in a non-distorting manner.

However, there are many difficulties which constrain the implementation of this theoretical optimal tariff. Abdelmotteleb et al. (2017), Brown and Sappington (2017), Pollitt (2018) and Pérez-Arriaga et al. (2017) discuss possible issues constraining the implementation of improved or more efficient distribution tariffs. In this paper, we go one step further by demonstrating quantitatively how such constraints affect tariff design. We focus on two often-discussed constraints which are of a different nature. The first constraint regards the implementation difficulties related to cost-reflective tariffs. In practice, so-called cost-reflective tariffs are only a proxy for the actual cost driver(s) in distribution grids because it would be too complex to consider all of them or because we simply lack the necessary information. The second constraint has to do with fairness. There is a fear that network tariff reforms, which aim to increase efficiency, will result in an unfair allocation of the network costs, i.e. passive, often smaller or poorer, consumers would see their electricity bills increase.

The paper is structured as follows. After the introduction, the modelling approach is described. Then, the setup and data for a numerical example are introduced. In the core of the paper, the two considered tariff design constraints are introduced, their modelling implication is described, and the results of a numerical example are presented to gain insights into their impact on network tariff design. Lastly, a conclusion is formulated.

Methods

A game-theoretical model is introduced to assess how the distribution network tariff departs from its theoretical least-cost design under the considered constraints. The model allows us to capture the interaction between network tariff design, decentralised decision making of self-interest pursuing active consumers investing in solar PV and batteries, and their aggregated effect on the network costs. The model has a bi-level structure. In the upper-level, a regulator can opt for a combination of capacity-based charges, volumetric charges (with or without net-metering) and fixed charges to recover grid costs. The regulator anticipates the reaction of consumers represented in the lower-level and the tariff is determined in a way that total system costs (incl. network costs, wholesale energy costs and DER investment costs by consumers) are minimised. Modelled consumers can be passive or active. Passive consumers are assumed not to react to prices; active consumers pursue their own self-interest, i.e. their objective is to minimise their cost to satisfy their electricity demand. They have the option to invest in two technologies: solar PV and batteries.

We do runs with a sensitivity for three states of the grid. First, grid costs are assumed to be 100% sunk, a short-term vision, i.e. the grid is over-dimensioned, and the electricity usage of consumers has no effect on the total grid costs. Second, half of the grid costs are considered sunk and the other half prospective, i.e. driven by the coincident consumer peak demand. Lastly, the grid costs are assumed to be driven completely by the coincident consumer peak demand. In the very long run grid costs are also variable as the network capacity will adjust to the coincident peak demand need from the consumers. Further, we assume 50 % active consumers and 50 % passive consumers. The electricity consumption of active consumers is slightly higher than of passive consumers. Results are shown by two metrics: the total system costs as a proxy for cost-efficiency and the increase of network charges paid by passive consumers as a proxy for fairness. All results use a benchmark the case that no consumer is active and all network charges are paid for volumetrically, in € per kWh.

Results

First, we show that without inaccuracy in the network cost driver proxy and no fairness constraint, the least-cost tariff structures do agree with what theory says. Second, we introduce inaccuracy in the network cost driver proxy and find that the network tariff design smartly departs from the theoretical least-cost design in order to minimise the total system costs. We show that if inaccuracy in the network cost driver proxy is not anticipated by the regulator which sets the tariff, the system costs are higher and fairness concerns aggravate when compared to the least-cost tariff anticipating this inaccuracy. Third, we show the trade-off between the system cost and the increase in network charges of the passive consumer. We start by showing the results without inaccuracy and after show the same results with inaccuracy in the network cost driver proxy. It can be seen that the grid cost states strongly influence the feasible solutions and that the two constraints are not independent.

Conclusions

First, we find that both constraints have a significant impact on tariff design. In theory, the least-cost distribution network tariff design has a fixed component that is proportional to the sunk costs, and a capacity component to reflect the costs of grid investments that still have to be made and that can be partly avoided if it is cheaper for active customers to invest in DER. In practice, departing from volumetric charges towards higher fixed charges is often perceived unfair. Also, in practice, the individual capacity or individual peak is often a relatively weak approximation of the actual cost driver(s) of the network. As a result, a three-part tariff combining fixed, capacity, and volumetric charges may be more suitable, even though in theory, volumetric is not to be considered for a least-cost distribution network tariff design.

Second, we find that there is a strong interaction between the two constraints we analysed. If regulators do not anticipate that their implementation of cost-reflective tariffs will be imperfect, the system costs will increase, and the fairness issues will also aggravate. It is therefore important to have realistic estimations of what we know and do not know about the cost-drivers of distribution networks. Limited information is available, suggesting that we need to be careful in setting strong incentives. This is especially true with high shares of active consumers.

Third, the results depend on the state of the grid. If most of the grid investments still have to be made, passive and active consumers can both be made to benefit from cost-reflective tariffs, while this is not the case for passive consumers if the costs are mostly sunk. The standard network tariff design options, i.e. volumetric, capacity, and fixed charges, do not suffice to transfer part of the welfare gains of the active consumers to compensate the passive consumers. Other solutions than standard tariff design would have to be introduced to reach a fairer outcome; examples are low-income programmes, differentiated instead of uniform fixed charges, the recuperation of sunk costs through other means than the electricity bill or the taxation of active customers, which has its own issues.

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