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Electricity distribution tariffs and distributed generation: Quantifying cross-subsidies from consumers to prosumers

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ABSTRACT

An increasing amount of distributed generation (DG) can cause an increase or a decrease on distribution network costs. Tariff design is the main tool for allocating these costs to customers who own and operate DG resources.

Currently, however, either DG units are exempt from paying distribution tariffs or they are subject to tariffs originally designed according to a traditional pricing model without DG in the grids, also known as load-based pricing. Partial recovery of the allowed distribution company revenue requirements or cross-subsidies between customers may ensue from such tariff arrangements.

In this article, pricing, as represented by a combination of net metering and pure volumetric tariffs, is applied in the context of increasing DG. The paper presents a methodology where a Reference Network Model (RNM) is used to investigate the effect of this pricing scheme on the magnitude of cross-subsidies from consumers towards the so-called prosumers for a set of twelve simulations based on real-size networks in the U.S.

For the considered scenarios, the analysis reveals substantial cross-subsidies from consumers toward prosumers. The degree of subsidy varies with the amount of DG connected to the grid and network characteristics. The rate of cross-subsidy tends to be higher for low-density grids.

This paper contributes to the net metering literature with a quantitative assessment of cross-subsidies by comparing allocated payments to different actors with the costs they impose on the system, estimated through an RNM. Moreover, the paper proposed a tariff structure based on *cost causality* by proposing a cost-reflective, volumetric tariff approach through which aggregate load-driven and DG-driven network costs are accordingly allocated to loads and DG units.

1. Introduction

The amount of *distributed generation* (DG) (Ackermann et al., 2001) in distribution grids has increased substantially over recent years in several countries around the world, mainly due to targeted energy policies and DG incentive mechanisms (Peças Lopes et al., 2007).

The term DG may refer to several types of technologies, ranging from traditional combustion generators (such as micro-turbines) to non-traditional ones (such as fuel cells, storage devices, and renewable sources). Photovoltaic (PV) power production and wind turbines belong to the latter category (El-Khattam and Salama, 2004). Despite not being a new concept, DG represents an innovative approach to electric power provision (El-Khattam and Salama, 2004) as it affects network planning and operation. Ensuing technical changes may entail higher or lower network costs than in a *passive network scenario* (where no DG is connected to the grids) (Cossent et al., 2011).

Two complementary mechanisms for an economically efficient DG integration are: (i) valid *economic regulation of Distribution System Operators* (DSOs) that takes into account potential additional costs arising from DG integration and remunerates DSOs accordingly, and (ii) sound *network tariff design* that efficiently allocates network costs to the users of the infrastructure. Both mechanisms are subject to review by national regulatory agencies

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that decide or approve the remuneration schemes for DSOs and set tariff structures or approve the tariffs set by DSOs.

The principles for proper tariff design include cost recovery, transparency, simplicity, stability, equity, and cost causality (Bonbright, 1961). Some of them conflict with each other in the practical application.

The choice of which principles to prioritize over the others usually depends on the regulatory context and priorities (THINK project, 2013), (Sakhrani and Parson, 2010), (Rodríguez Ortega et al., 2008). In this paper, the priority is given to *cost causality*, also known as *cost reflectivity*.

Distribution system tariff design complexity is related to the characteristics of electrical grids. Since grid infrastructure is shared by several users, the cost for providing a service to one user depends on the services provided to other users, as well as on how the system is employed (Sakhrani and Parson, 2010). Moreover, as a result of the long life span of most of network assets, the regulator has to make decisions on behalf of network users that will impact them in the future. Furthermore, besides the difficulty of assigning cost responsibilities to each user category, there might be a need to create different incentives for different network users through tariffs (for example, to encourage load reduction or shifting during peak hours in order to optimize grid utilization).

DG integration poses additional challenges within distribution tariff design due to the difficulty of isolating DG-driven network costs and benefits and allocating them to different user categories (Picciariello et al., 2015). Currently, such challenges generally involve either (1) exemption of DG units from paying network tariffs at all, as in most of EU countries (EURELECTRIC, 2013), or (2) the application to DG of tariff schemes designed for load-only grids (referred to here as load-based pricing). This last case finds one of its most controversial applications in the combination of volumetric tariffs with net metering, adopted in several US States (Baldwin et al., 2014), (Sioshansi, 2014).

Electricity tariffs are also known as *DUoS* (Distribution Use of System) *charges*, and they are paid by network users periodically; another type of network charge, known as *connection charges*, are paid by the network users only when they connect to the grid. Connection charges are not considered in this paper.

In general, the typical elements of an electricity tariff are (Firestone et al., 2006):

- A *fixed charge* (€/period), meant to cover the ongoing cost of connecting the customer and metering its consumption.
- A *volumetric charge* (€/kWh), proportionate to the energy commodity consumed by each customer, and intended to cover the variable network costs related to energy transport and distribution, and
- A *capacity charge* (€/(kW*period)), also known as demand charge, collected on the contracted capacity or, more rarely, on the maximum power used during a specific time period, regardless of the consumption level. This charge is meant to cover the fixed costs of the infrastructure shared with other customers, proportionately to the capacity required by each of them.

All or some of these components can be part of an electricity tariff. Whether and how this traditional structure should be modified to better suit the new paradigm of distributed generation is still a matter of discussion. Moreover, expanded use of new pricing alternatives, such as time-of-use tariffs, might be appropriate.

Especially in the short term, electricity transmission and distribution networks are characterized by relatively high fixed costs and relatively low variable costs (Econ Pöyri, 2008). Therefore, energy-based (or volumetric) tariffs in distribution inherently carry a risk to the utility of not recovering the costs arising from consumption at peak times (Picciariello et al., 2015). When net metering is adopted, and high DG integration is achieved, revenue risk increases due to a potential contraction in the net energy sold to the users of the network (Rodríguez Ortega et al., 2008). This risk is especially high when less advanced meters (providing the total net consumption over a long period of time, usually one or two months (THINK project, 2013)) are used. In this way, the energy withdrawn by consumers, commonly during morning and evening peaks, and the energy fed into the grid during mid-day hours are likely to offset each other, thus avoiding network charges. This is an issue associated with the expanded use of rooftop solar systems (THINK project, 2013), (Interstate Renewable Energy Council (IREC), 2010).

Two types of problems may arise as a consequence of tariff structures that fail to reflect network costs:

I Utilities must absorb the unpaid network costs (a situation commonly referred to as revenue erosion), or

II Utilities must raise tariffs to meet their revenue requirements. In practice, users without self-generation will have more exposure to rate increases, which can be seen as a cross-subsidy towards users with self-production (or "prosumers" that both consume and produce) (Bonbright, 1961), since one customer category ends up paying less for its use of the network than others relative to the costs they impose on the system (Sakhrani and Parson, 2010).

Problem I, the revenue erosion scenario, is likely to happen when the enforced regulatory arrangements do not allow utilities to adjust tariffs because, for example, their revenues are capped; this scenario has been largely envisioned in the literature (Graham et al., 2008), (Brown and Lund, 2013). However, because profit reduction seems to be more closely related to lost sales, it is more a retailer's issue rather than a network operator's issue (Costello and Hemphill, 2014).

This paper discusses the second problem. In particular, the subsidy effect of the combination of volumetric tariffs and net metering are analyzed through a computational model that is applied to twelve real-size distribution grids based on U.S. locations for different levels of PV penetration. The main contribution of the method is to enable a quantification of the cross-subsidy problem by comparing tariffs and costs caused to the system for different types of networks.

The remainder of the paper is structured as follows. Section 2 reviews the literature relevant to this paper. The proposed methodology is described in Section 3 together with a description of the study cases. Section 4 reports the results from the analyses and some insights drawn from the findings. Finally, concluding remarks and policy implications are presented in Section 5.

2. Distribution network charges: literature review

The literature on utility tariff design identifies several guiding principles and methodologies.

In study (Bonbright, 1961), the foundations of public utility ratemaking are laid, by identifying the main attributes of sound electricity tariffs (in terms of both theory and practice) as well as the design criteria for achieving these attributes. In (Sakhrani and Parson, 2010), tariff principles are revisited and categorized into principles related to system sustainability, economic efficiency, and consumer protection. A summary of the currently adopted tariff structures in the EU countries is provided in (EURELECTRIC, 2013).