Applied Energy 210 (2018) 815–826

Contents lists available at ScienceDirect

Applied Energy

journal homepage: www.elsevier.com/locate/apenergy

Designing efficient distribution network charges in the context of active customers

Ibtihal Abdelmotteleb[a,b,*], Tomás Gómez[a], José Pablo Chaves Ávila[a], Javier Reneses[a]

[a] Institute for Research in Technology, Comillas Pontifical University, Madrid 28015, Spain
[b] Electrical and Control Department, College of Engineering and Technology, Arab Academy for Science, Technology and Maritime Transport, P.O. Box 2033, Cairo, Egypt

HIGHLIGHTS

- An efficient distribution network charges method is proposed.
- The method ensures network cost recovery and promotes efficient network investments.
- The method includes forward-looking peak coincidence network charge and fixed charge.
- Customers' response is modeled to compare their reaction to network charge designs.
- Methods including network peak coincidence charge lead to optimal customer response.

ARTICLE INFO

Keywords:
Customer response
Distributed Energy Resources
Distribution network charges
Peak Coincidence Network Charges

ABSTRACT

The transformation of electricity network users from passive to active agents, as a result of decreasing costs of distributed energy resources, requires several adaptions, one of which is revising the distribution network charges. Often current network charge designs do not ensure network cost recovery and lack to incentivize efficient network investments and usage. New network charge methodologies are required to guide and incentivize customers in an efficient way while maximizing system economic efficiency. This paper proposes an efficient methodology that ensures network cost recovery while promoting efficient usage of the network as well as efficient network investments. The proposed network charge design consisting of two components: a peak coincidence network charge (PCNC) and fixed charge. The PCNC is a forward-looking charge as it considers the cost of future network reinforcements required and assigned to customers during peak hours of the network utilization. Fixed charges allocate the residual of the network costs following Ramsey-pricing principles. This paper compares the outcome from economic optimum customers' response to four different network charges: (i) volumetric charges (ii) fixed charges (iii) peak demand charge (iv) PCNC plus fixed charges. Two case studies for two different load profiles are simulated using linear programming to minimize their total costs within each charges design, considering the possibility of buying electricity from the grid and investing on onsite generation or curtail load. Finally, the paper highlights through the case studies how customer's response is highly influenced by different network charge designs, and compares the consequences of these responses in terms of network cost recovery and total system costs. The paper concludes with practical issues that need to be considered for the implementation of the proposed network charges design.

1. Introduction

Traditionally passive electricity customers are becoming active consumers through Distributed Energy Resources (DERs), such as self-generation, demand side management and storage. These changes impose the necessity of redesigning distribution network charges to comply with an efficient network utilization and optimal customer response. In other words, network charges need to ensure network cost recovery in a fair matter while incentivizing efficient network investments and usage. Although the integration of DERs create challenges for Distribution System Operators (DSOs) in the operation of their networks; such as increase in the variability of power consumption, bi-directional energy flows, voltage instability, and reduction in power quality, yet they also create opportunities for the distribution networks

* Corresponding author at: Institute for Research in Technology, Comillas Pontifical University, Madrid 28015, Spain.
E-mail addresses: iabdelmotteleb@comillas.edu (I. Abdelmotteleb), tomas.gomez@comillas.edu (T. Gómez), jose.chaves@comillas.edu (J.P. Chaves Ávila), javier.reneses@comillas.edu (J. Reneses).

http://dx.doi.org/10.1016/j.apenergy.2017.08.103
Received 31 March 2017; Received in revised form 23 May 2017; Accepted 11 August 2017
Available online 11 September 2017
0306-2619/

Nomenclature

Sets

C	customers
G	onsite generators or demand curtailment option
L	load levels

Parameters

D_{lc}	demand at each load level for each customer (MW)
FC_{grid_c}	fixed grid charge for each customer (€/customer)
FC_g	fixed cost of onsite generator (€/MW)
h_l	hours for each load level
PC	Peak Charge based on the maximum individual load (€/MW)
$PCNC$	Peak Coincidence Network Charge (€/MW at peak hours of network utilization)
T	threshold for the network utilization at which PCNC is applied (MW)
T_{lc}	individual threshold per customer at each load level (MW)
VC_g	Variable cost of onsite generator (€/MW h)
VC_{grid}	energy cost for energy withdrawn from the grid (€/MW h)

Positive variables

$C_{g_{cl}}$	installed capacity of onsite generator for each customer at each load level (MW)
C_{g_c}	installed capacity of onsite generator for each customer (MW)
$E_{g_{lc}}$	energy produced by onsite generator during each load level by each customer (MW h)
$E_{grid_{lc}}$	energy withdrawn from the grid during each load level by each customer (MW h)
$E_{grid_{maxc}}$	maximum energy withdrawn from the Grid by each customer (MW h)
$E_{grid_{thlc}}$	energy withdrawn from the grid that exceeds a given threshold at each load level by each customer (MW h)

to be managed more efficiently, by avoiding or deferring network reinforcement. Such opportunities could be attained by the network charges through efficient signals that incentivizes appropriate customer responses. The design of efficient network charges in the context of active customers is a challenging and crucial topic that is currently in a position of debate between regulators, DSOs, customers, and DER suppliers.

The urge to redesigning distribution network charges has been discussed in various researches [1–4]. In [2], European Distribution System Operators (EDSO) for smart grids advised on the need of clear incentives to convince customers to change their energy consumption habits. Moreover, they also indicated that network tariffs must be designed to ensure that consumers generating their own electricity still contribute with their fair share of the distribution network costs. Moreover, as EDSO stated in [3], customers should be able to self-generate and self-consume energy as long as the costs induced by their use of network services is reflected in their bill. However, since self-generation may lead to lower network usage and lower revenues to DSOs, and distribution network tariffs is a main tool to provide price signals to customers [4], thus, network charges should be updated to avoid such impacts. Furthermore, EDSO presented a number of key messages in [3] regarding the revision of current distribution network tariffs, to be more capacity based, and less volumetric based, in order to limit revenue uncertainty for DSOs. They also clarified that the traditionally-designed network tariffs can lead to inefficient network investments, reducing social welfare. Hence, distribution network charges require regular assessment to ensure efficient and fair recovering of network costs while sending appropriate signals to customers [1].

Electricity bills are composed of: Distribution Network (DN) charges, transmission network charges, energy prices,[1] other regulated costs (e.g. renewable subsidies), and taxes. DN charges are usually set by national regulators, with exceptions to several countries: as in Spain, where the government sets it, in Sweden, where it is set by the DSO and supervised by the national regulator, in Norway where DSOs are given a large degree of freedom regarding how to design tariffs based on their allowed revenues, as discussed in [1], which reviews different practices in EU. Moreover, in Poland, DSOs set the tariff according to the rules defined in the Energy Law Act along with the Minister of Economy, and subject to the approval of the regulator [5]. Similarly, in Finland, each DSO has the right to set its own tariffs as long as it follows the rules set by the Energy Authority [6]. Traditionally, DN charges aimed to collect the allowed revenues for the DSO, and were designed to comply principally with charges design principles, among them: equity, simplicity, predictability, stability, consistency, transparency, non-discrimination, and cost-reflectiveness [7]. Traditional DN charging methodologies that have been in practice for years, can no longer serve within the smart grids era, where customers are becoming active and some hypotheses are no longer valid [8], among them: (i) the majority of the distribution pricing methodologies in practice were designed for passive customers with limited DERs options (ii) the majority of the pricing methodologies for distribution systems are not cost reflective; they do not reflect the costs/benefits that consumers and prosumers might bring to the distribution network. This is particularly the case of volumetric charges, where customers may avoid network charges by reducing their energy consumption, but usually not their peak power. Thus, the pricing system cannot efficiently influence how and when network users should use the network.

Furthermore, besides the traditional role of DSOs, new roles are required within the process of smartening of the electricity network. In [7], a broad set of policy objectives related to distribution network charges are identified, with the most significant: (i) efficient operation of the network; (ii) allocating distribution costs amongst network users in a fair and efficient manner; (iii) selecting the right set of investments to develop and enhance distribution grids; (iv) coordinating the distribution network development and the deployment of smart technologies with the development of DERs; (v) extracting demand-side flexibility. Policy objectives (ii), (iv) and (v) are the main focus of this paper, which requires designing distribution network charges that incentivize customer response and efficient network usage to mitigate unnecessary future network reinforcements and at the same time avoid unnecessary customer investments in DERs. Customers may decide to invest in DERs to reduce their bills; either by reducing their energy consumption, or by reducing their peak, depending on whether volumetric or capacity charges are implemented. However, those investments are only to be efficient if cost-reflective charges are applied, considering the customer's actual impact on the system costs. Thus, customer interaction and participation is the main key to optimize the use of the current and future distribution networks, while minimizing investment costs. In [9] the authors discuss how demand flexibility could reduce DSOs' costs and defer physical network expansions. However, there are challenges and barriers to fully benefit from customer response as presented in [10], one of which being the lack of efficient price signals customers receive. Moreover, in [11] the authors recommend certain actions that are needed to capture untapped demand response potentials, highlighting that providing customers

[1] Energy prices are a result of markets, network charges are due to regulated decisions made by the competent authority.

promptly with real-time electricity usage information and price signals to base their actions is crucial.

The network pricing methodology is the influential tool used to encourage customer reaction. Thus, DN charges should be optimally designed to send correct efficient economic signals to customers. A number of researches focused on either the DN charging methodology as in [12–22], or the customer's response to dynamic energy prices as in [23–25]. However, a limited number of researches considered customer's response to DN charges. In [26] the authors compare customer's reaction in terms of household load shifting under energy based tariffs with and without a peak capacity (demand) charge included, and its consequences on peak power demand and active power loss, transformer loading, voltage variations, and cables overloading. In [27] the author presents an empirical case study carried out on a Swedish distribution network, where a demand-based time-of-use network tariff is implemented. The tariff consists of a fixed access charge depending on the fuse size, and a demand-based distribution charge based on the average of the five highest meter readings in peak hours, whereas during off-peak hours there is no network charge. The case study showed that some customers responded to network charges, and changed their behavior to reduce their payments by shifting load to off-peak periods, while others decided to install air heat pumps. In [28] demand response as load shifting and incorporating DERs (such as distributed generation (DG)) are simulated using a Reference Network Model (RNM) to quantify its consequences on the network in terms of benefits and cost increase. Authors in [28] assess the benefits in terms of network deferral under different price response incentives and different network and customers' characteristics and conclude that the existence of a peak demand charge (€/kW) in the final price or tariff paid by customers that penalizes the maximum peak demand is the main driver for reducing incremental network costs, and thus, reducing future investment in networks. In [29], the authors present a framework for assessing the economic efficiency of different long-term network pricing models. Each model is assessed in terms of the investments needed in the network to meet the requirements of the load and generation within its methodology. The presented approach assessed the response of new and existing customers to price signals, by comparing the different pricing methodologies to find the most effective development of the distribution network particularly in the case of increasing distributed generation. The three pricing models considered are postage stamp, MW + MVar-Miles and long-run incremental cost pricing (LRIC). The applied framework demonstrated the differences in future network investment cost driven by each price model. Results showed that network charges can play a vitally important role in influencing the future pattern of generation and demand, and consequently the network development. LRIC is shown to have the highest potential to attract generation and demand to places that lead to the least cost in network reinforcements.

This paper proposes a distribution network charge design, that aims to allocate distribution network charges efficiently to customers. The design could be implemented by DSOs or regulators in order to collect revenues for the regulated activity carried out by DSOs. This paper neither considers the impact of energy prices on customers' response, nor the impact of wholesale and retail activities. The paper focuses on the design of distribution network charges, its effect on customer reaction, and the consequences arising from their decisions. Customers considered are end users connected to the low voltage distribution network, that may be residential, commercial or a combination of both. Customers' reaction could lead to different consequences, such as deficits in network cost recovery, need of network reinforcements, and cross-subsidization between customers. The proposed methodology considers two main aspects that lead to efficient distribution network charges. Firstly, it considers forward-looking component that considers future network investments costs (a peak coincidence network charge), which is an important aspect that is usually unrecognized in traditional charge designs currently in practice. This component promotes efficient use of the network and optimal customers' response that maximizes the system's economic efficiency. The strength of the economic signal is proportional to the current and expected level of network utilization. Strong signals are sent during critical hours, when the network is highly utilized. The signal is weaker as the utilization level of the network is reduced, up to a point when no signals are transmitted during hours of underutilization of the network. Secondly, fixed charges allocate the residual network costs following Ramsey-pricing principles, in order not to distort other economic signals. The proposed design is compared to other traditional network charge design through numerical case studies. The case studies are carried out to predict the customers' optimal reaction to different network charge designs, and compare its consequences in terms of network cost recovery and future system costs. Two case studies using two different load profiles, are presented where network reinforcements are required to compare customers' reaction under four different network charges: (i) volumetric charges (€/MW h) (ii) fixed charges (€/customer/year) (iii) peak charge (€/MW) (iv) the proposed methodology. The case studies were simulated using Linear Programming (LP) on Matlab to optimize the customers' investment decision regarding two DER options considered within each scenario, minimizing their total payments. Finally, the proposed network charge design is assessed and compared to the other designs in terms of system's economic efficiency, and implementation issues related to its practical application are discussed.

This paper is organized as follows: Section 2 discusses different aspects of distribution network charges design. Section 3 presents the proposed efficient distribution network charges design. Section 4 presents the case study and the results obtained, and finally Section 5 draws the final conclusions.

2. Distribution network charges design

DN charges are designed to fulfill desired objectives while following charges design principles. Those charges could be presented in different charge options using a variety of charge components and structures. The charge options implemented within a charges design are aligned with the costs allocation methodology established. This section discusses the desired charge outcomes, traditional charges design principles and new ones recommended to be taken into consideration charge options and currently used methodologies for computing network charges.

2.1. Charges design principles

As the DN evolves to accommodate active customers, a more up-to-date charge design guidelines are required. The main principles for DN charges are well explained in the literature and regulatory practice [21,30,31]. Nevertheless, in [7] those charge regulation principles were elaborated further considering nowadays DN transformation, and are grouped into three main sets:

(i) **System Sustainability Principles** which includes: Sufficiency, Achievability and Additivity. Those principles are related to the DSO's allowed revenues, aiming to allow the full recovery of efficient network costs with a reasonable return, that guarantees a return in line with the relative risk of the investments and financing conditions. In addition, various charge components must add up to give the total revenue requirement to be recovered.

(ii) **Economic Efficiency Principles** aim to provide signals both to DSOs and customers, to act in a way that maximizes social welfare in both the short- and the long- term. These principles are summarized in three aspects: first, productive efficiency, where network services should be provided at minimum cost possible to customers, through incentivizing efficient investment and coordinating distribution investments to minimize the total system cost. Secondly, allocative efficiency, that aims to incentivize customers to use the grid efficiently by promoting peak demand management, leading to a reduction in infrastructure cost for peak demand as well as encouraging system flexibility. Thirdly, cost reflectiveness, that targets customers should be charged according to costs of the services they have received, taking into account their contribution to peak demand and their position in the network.

(iii) **Protection Principles** includes a set of charge characteristics that would safeguard customers: transparency, non-discrimination, equity, simplicity, predictability, stability, and consistency.

The second group of principles, economic efficiency principles, is the main target of this paper. The current changes in DNs and technological developments create many opportunities for efficient network utilization and investment coordination. Thus, DN charges should be designed to reveal these opportunities. Charges design should accommodate those principles and translate them in the form of charge option that embraces them the most. Hence, charge components and structures need to be well designed and aligned to serve this objective.

2.2. Charge components and structures

The design of DN charges is presented in Fig. 1, starting with the charges methodology that is formulated to reach the desired objectives while guided by charges design principles. Then using charge options, the methodology is structured into charging components, leading to the final charge format. This section focuses on the charge options, and its influence on customer's response. There are different ways of charging the use of distribution networks as discussed in [1], nevertheless there are three main components: energy, capacity and fixed charges.

2.2.1. Energy charges

Energy (volumetric) charges are based on the consumption of kW h during the billing period. Volumetric charges have been widely favored as it follows protection principles, conceiving social acceptability while also providing network cost recovery (in cases of no self-generation), and aligning with system sustainability principles. It is frequently used in many countries, following the assumption that residential loads do not much differ from a customer to another and customers are passive. This is also because traditional meters were used, that were unable to provide detailed information such as peak consumed power. Besides, market opening and unbundling of activities and costs, giving supplier change opportunities was uncommon. Thus, the generation and network costs could be lumped into a single price (€/kW h). However, nowadays, with smart meters, energy saving appliances and DERs, this assumption is no longer valid. Consumption load patterns could differ vastly, and customers could potentially avoid part of the network costs by reducing their consumption or invest and operate DERs.

2.2.2. Capacity charges

Capacity (demand) charges are related to the peak consumption of kW during the billing period. Since network costs and investments are driven by capacity magnitudes rather than energy magnitudes, capacity is a better proxy to resemble customer's contribution to network costs. Capacity charges tend to incentivize customers to reduce their peak consumption, However, individual peak consumptions do not necessarily coincide with network's peak, which is the actual network investments driver. It is inefficient to signalize customers to reduce their peak consumption when the network is underutilized. Thus, time for capacity charges is a crucial variant to include in charge designs, to efficiently signalize customers during periods when the network reaches its peak. Capacity charges, if well designed, are potentially able to fulfill economic efficiency principles.

2.2.3. Fixed charges

Unlike energy and capacity charges, fixed charges are not a function

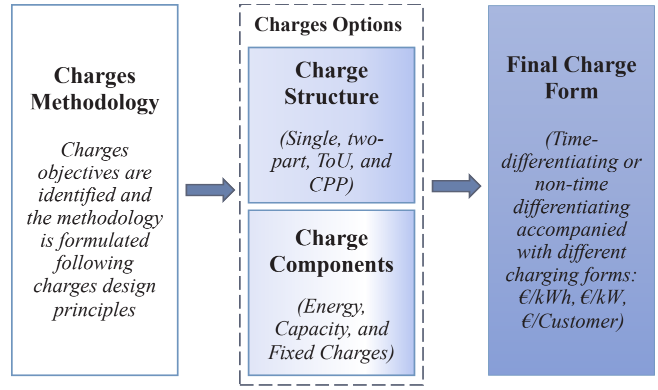

Fig. 1. Charges design stages.

of the customer's profiles during the billing period, they are fixed payments per customer that are done regularly on different temporal basis (monthly, semi-annually, annually, etc.). They are set to cover certain expenses without any intention to incentivize the customers to alter their consumption. As described in [32], fixed charges is an attractive way to minimized deadweight loss (loss in economic efficiency) while raising additional revenue, because they give customers no incentive to change their electricity consumption choices. Thus, when volumetric charges yield to insufficient revenues, a common suggestion is to set a fixed charge that raises sufficient additional revenues to cover the revenue requirement.[2]

Different charge structures are constructed through a selection of charge variables, among them: Flat charges, Two-part charges, Time-of-use (TOU), and Critical-peak pricing (CPP) [34]. Depending on the charge structures, customers are incentivized to change their behavior. ToU charges influence customers to shift their peaks to low price periods, whereas Capacity-based charges influence them to reduce their peaks. Moreover, CPP charges restrict time periods for peak reduction. As explained in [1] this could benefits both DSOs and customers, as it could provide DSOs with an alternative mechanism to minimize grid use costs and can lead to postponement or avoidance of new investments. It also may minimize the impact of intermittent distributed generation on the network and manage congestion.

2.3. Distribution network charges methodologies currently applied in different countries

DN charges methodology is the approach followed to allocate network costs to customers. This vastly differs between countries and even between DSOs within the same country (as in Sweden). Many researches had proposed and discussed a number of methodologies, such as in [12–14,16–22,35]. However, most of them were not practically implemented. A comparison between different countries for DN costs allocation is presented in [8] where most countries used Postage Stamp,[3] or its variant, as in Germany, Spain, Chile and India. In Germany, there is no forward-looking component (that is related to future network investments) in the calculation. Yet, DSOs can apply for investment budgets for planned investment, and its costs are socialized between customers. In Spain, there is not an established methodology, the charges applied aim to recover total costs using two components: an energy and capacity costs per voltage levels assigned to different time periods. According to the customer's energy consumption and the

[2] Notice that fixed charges can be avoided by disconnecting from the grid. In order to avoid this response when it is inefficient measures such as the implementation of exit fees can be taken. However, the implementation of such fees is out of the scope of this paper. For further discussion of this issue refer to Perez-Arriaga et al. [33].

[3] Postage Stamp it is based on dividing the total distribution network cost by the system peak demand to obtain a flat charge per kW.

contracted capacity during different time periods,[4] costs are allocated. As for the case of UK, Postage Stamp is also used in HV/LV networks, while for extra high voltage (EHV) networks, DSOs can choose between Long-Run Incremental Cost pricing (LRIC) or Forward Cost Pricing (FCP). LRIC seeks to quantify the additional costs/benefits to future network investment from a nodal increment (injecting or withdrawing power from a node), while FCP sets prices that can recover the projected network cost over next ten years. In the Netherlands, fixed charges are used to account for administrative costs, and capacity charges are applied according to the installed fuse size, regardless to the amount of energy consumed [1]. Finally, in Australia, recently changes to distribution charges have been introduced, where peak demand charges are applied based on the highest 30-min consumed power during peak periods (3–9 pm weekdays). Long-Run Marginal Cost (LRMC) are included within the peak demand charge, as it is a forward-looking approach, recovering part of the network costs, while the rest is recovered through fixed and energy charges [36].

As discussed, the approaches mainly followed were: Ramsey-pricing when considering fixed payments, Postage Stamp when considering capacity payments and LRIC and LRMC when considering forward-looking charges. These methods do not fully ensure efficient economic signals to customers. Ramsey-pricing as commonly implemented does not encourage customers to react as it does not provide any incentives, thus it is not efficient when customer reaction is required. Postage Stamp incentivizes individual peak reduction, regardless its coincidence with the system's peak, which is the actual network costs driver. Moreover, LRIC and LRMC are efficient as they contain a forward-looking component, yet they are different. LRMC considers future costs arising from an increment the forecast demand, while LRIC is the annualized cost of future investments relative to demand increments [37].

3. Proposed efficient distribution network charges

Designing DN charges following the design principles presented in Section 2.1 is challenging, as some of the principles conflicts with each other, requiring a trade-off among them. The charges design proposed in this paper mainly focuses on the economic efficiency principles, as it is the main driver behind the necessity of new DN charge designs. The objective is to guide customers and DSOs to efficient decisions through the network charges, while ensuring network cost recovery. These decisions should be the optimal in the sense that it maximizes the systems economic efficiency, leading towards short-term efficient network usage and long-term efficient network investment decisions. As the demand for electricity grows or new generation units are connected, network capacity may no longer be able to fully serve the new demand, requiring network reinforcements. In some cases, the network reinforcement could be inexpensive, for example, upgrading a transformer, and in other cases a more expensive approach is required, like building a new line. Customer flexibility could defer those investments which is driven by peak coinciding consumption. If customers can shift or curtail part of their load, network reinforcements could be avoided. Customers benefit as reinforcement costs are to be eventually included in the charge. Thus, they could contribute efficiently by changing their consumption pattern, investing in DERs or by curtailing part of their load. To eventuate this reaction, they need to receive an efficient economic signal through network charges.

3.1. The methodology

The main objectives of network charges are to recover network costs, incentivize efficient customer response, and to defer or mitigate network reinforcements. This could be achieved through efficient network charges that allocate network costs to customers according to their impact on the network. The most important characteristic of efficient charges design, is the economic signals delivered to customers, upon which they would react. These signals should be efficient and aligned with the network's utilization level not individual's peak level. In other words, if the network is underutilized, the charges should not send signals to customers to reduce their consumptions. Yet, when the network is highly used and load growth is expected, customers should be signalized to reduce their consumption, since this would lead to network reinforcements. Thus, network peak is the main driver to network reinforcements. Moreover, whether to meet network future load growth requirements through wiring solutions, or non-wiring solutions, is a decision to be taken in a way that maximizing system's economic efficiency. This is subjected to the elasticity of the customers, and their willingness to participate by changing their load pattern or investing in DERs. If customers are economic rational in the sense that they react to signals in the way that maximizes their benefits, hence they seek to reduce their bills. Customers should be signalized through network charges the need of network reinforcements and associated cost. Upon that they would react deciding whether there are less expensive opportunities to serve or reduce their consumption during critical hours, or they would not respond to the signal received and continue with their regular consumption pattern paying the corresponding network charges.

An efficient method is required to allocate network costs to customers, in a way that incentivizes customers to respond optimally maximizing the system's economic efficiency. This could be achieved if the methods send efficient economic signals that translates the network's current state. Those signals are received by customers during periods when the network is being more utilized (or expected to be soon according to a preventive threshold). These signals provide information about the incremental cost of required future reinforcements. In this proposed efficient method, network costs are allocated to customers through fixed charges and Peak Coincidence Network Charges (PCNC). During network's peak hours, PCNC (€/kW) is allocated to customers according to their contribution. Network peak hours are the hours where the total network's demand exceeds a pre-defined preventive threshold. Depending on the magnitude by which the demand exceeded the threshold, PCNC is applied following a linear relationship. In other words, the further the demand from the threshold, the higher the PCNC. At the end of the billing period, ex-post, PCNCs are allocated to customers according to their measured contribution to the peak hours of the elapsed period. Customers may receive estimated information regarding peak hours ex-ante, however the realized peak remains uncertain and depend on the realized power flows. Based on the revenues collected through PCNC, the residual (remaining) network cost is allocated to customers through fixed charges following Ramsey-pricing principles. The authors in [33] discussed proxies that could be used to apply Ramsey-pricing, such as customer's property tax or property size, where the aim is to use a fair measure. If no peak hours occurred, where the network's consumption exceeded the threshold, thus no revenues are collected through PCNC, then the whole network cost is recovered through fixed charges. Furthermore, if Distribution Locational Marginal Prices (DLMPs), which are LMPs at distribution level, are applied [38], a small surplus would be obtained due to losses and congestions, and it would recover part of the network costs, as shown in Fig. 2.

3.2. Threshold calculation

The pre-defined threshold serves two purposes; first, it aims to alert customers when the network reaches a certain level of utilization. Secondly, it prevents customers from over-reacting beyond what is optimal from the system's perspective. The threshold could be set on different basis, such as deciding on a network reserved capacity, as a security margin to avoid load interruptions. It may also be equivalent to the capacity required for network reinforcements. The latter is a more efficient aspect to link the network's threshold to, as it transmits to the

[4] The contracted capacity limits the maximum power withdrawn from the grid.

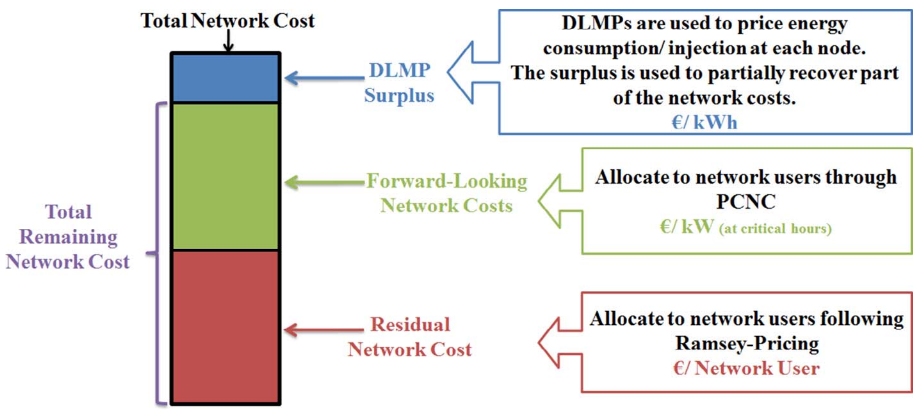

Fig. 2. Distribution network charges design including DLMPs.

customers the actual capacity and cost of network reinforcements. Fig. 3 illustrates how the threshold decides the network peak hours.

3.3. Calculation of future network investment costs

Predicting the cost of network reinforcements is difficult and uncertain, yet, there are different methods that could be used to calculate future network expansion costs. A model could be used as in [39] which presents a rigorous methodology for estimating location-specific LRIC of distribution networks using a long-run distribution network expansion planning (LRDNEP) model, which optimizes the expansions of the network for meeting projected demand growth using the existing grid and a large number of expansion candidates considered. The model decides on the type of network solutions (transformers, lines, voltage control devices) and non-network options (energy storage systems, Distributed Generations (DGs), Demand Response (DR) programs) to be added. In addition, LRDNEP determines the capacity, the location, the years of solutions when the new capacities should be added during the planning period in order to meet the projected future demand at minimum cost. Moreover in UK for HV/LV networks, the coming year's reinforcement cost to accommodate demand growth is forecast based on the present year's expenditure [8]. Similarly, in Brazil, average long-run incremental costs are determined for each voltage level: the ratio of future investment costs and load growth are set in terms of present value. Furthermore, reference network model (RNM) is a very large scale large-scale planning tool for forward-looking engineering-based has been used to assist in developing benchmarks for efficient network expenditures. An RNM emulates the network planning practices of an efficient network and equips the regulator with a forward-looking benchmark that accommodates expected evolutions in network use, technology performance and costs, and network management practices [33,40,41].

Once future network costs are calculated, they are allocated in the forward-looking component of the charge and it is deduced from the total network cost that needs to be recovered. The forward-looking component is to be recovered through PCNC in €/kW during the critical peak hours of the network. An estimation of those hours is announced ex-ante, but the actual hours are only known ex-post. Then, ex-post, knowing the amount of network costs recovered through PCNC, the rest of the network costs is recovered through fixed charges (€/customer).

3.4. Formulation of customer reaction to the proposed methodology

The customer's reaction to the charges design is based upon minimizing total costs while satisfying his load. According to the implemented distribution network charges, each customer optimizes his decision whether to serve his total load from the grid, or to invest in DER(s) and manage his load between both. The objective function is shown in (1), where the decision variables are the amount of energy consumption from the grid (E_{grid}), the investment capacity in DERs (C_g) and the energy consumption from the DERs (E_g). FC_{gridc} is the fixed cost of the grid for each customer, VC_{grid} is the cost of energy withdrawn from the grid, FC_g is the fixed cost of onsite generator, VC_g is the variable cost of onsite generator, and h_l is the number of hours within each load level. This is subject to the boundaries (2)–(4) and equality constraints (5) and (6), which ensure that energy consumption should be below or equal to the installed capacity of the DERs plus allowable capacity from the grid, and the total energy for each customer from all available installed DERs and grid during a certain load level must equivalent to the demand of that same load level (D_{lc}). In addition, (6) maintains a constant DER generation capacity between load levels, restricting one constant maximum production value for all the levels. For simplification, the efficiency conversion for DERs are neglected in this formulation, but they can easily include.

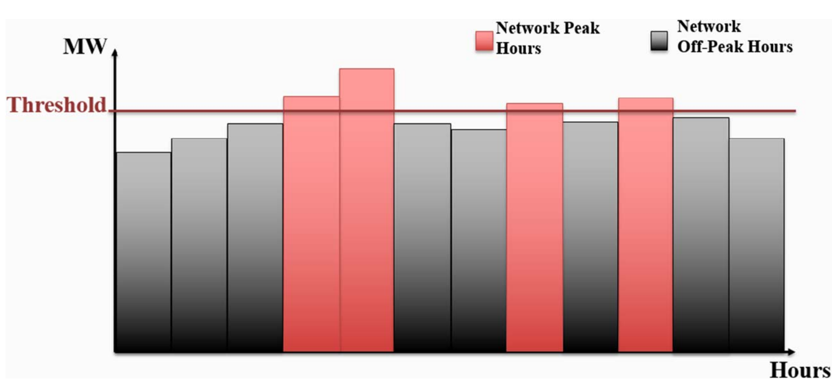

Fig. 3. Network peak hours based on threshold.

$$\underset{E_{grid},E_g,C_g}{\text{Min}} \sum_{c=1}^{C} \sum_{l=1}^{L} \left[\left(FC_{grid_c} + VC_{grid} E_{grid_{lc}} * h_l\right) + \sum_{g=1}^{G} \left(FC_g C_{g_c} + VC_g E_{g_{lc}} * h_l\right) \right] \tag{1}$$

$$C_{gc}^{min} \leqslant C_{g_c} \leqslant C_{gc}^{max} \quad g\in G,\ c\in C \tag{2}$$

$$0 \leqslant E_{grid_{lc}} \leqslant C_{grid\ c} \quad c\in C,\ l\in L \tag{3}$$

$$0 \leqslant E_{g_{lc}} \leqslant C_{gc} \quad g\in G,\ l\in L \tag{4}$$

$$\sum_{c=1}^{C} \sum_{g=1}^{G} E_{glc} + \sum_{c=1}^{C} E_{gridlc} = D_{lc} \quad c\in C,\ g\in G \tag{5}$$

$$C_{g_{cl+1}} - C_{g_{cl}} = 0 \quad g\in G, c \in C,\ l\in L \tag{6}$$

The objective function is further modified for the proposed charge method to accommodate the PCNC charge as presented in (7), subject to (8) and (9). The network's threshold (T) is translated into individual thresholds for each customer (Tc), based on his contribution to the peak hour as in (9).

$$\underset{E_{grid},E_g,C_g}{\text{Min}} \sum_{c=1}^{C} \sum_{l=1}^{L} [(FC_{grid_c} + VC_{grid} E_{grid_{lc}} * h_l) + \sum_{g=1}^{G} (FC_g C_{g_c} + VC_g E_{g_{lc}} * h_l) + (PCNC * E_{grid_{thlc}} * h_l)] \tag{7}$$

$$\sum_{c=1}^{C} E_{gridlc} - T_{lc} = E_{grid_{thlc}} \quad c\in C,\ l\in L \tag{8}$$

$$T_{lc} = \frac{E_{gridlc}}{\sum_{c=1}^{C} E_{gridlc}} * \left(\sum_{c=1}^{C} E_{gridlc} - T\right) \quad c\in C,\ l\in L \tag{9}$$

4. Case studies and results

The selected case studies are a modified version of that presented in [42], and used in [34]. The system consists of a simple 2-bus network as illustrated in Fig. 4. A distribution network of a 2.5 MW capacity is connected to the higher voltage grid and serves several customers. Several assumptions were considered for simplification reasoning; however, more complex models could be extended to include more details. First, as opposing to [34,42], the customers are not grouped into one customer, but divided into four (C1, C2, C3 and C4). The four customers are assumed to be served by the distribution network, and willing to respond to charge designs, based on the economic benefit to be gained. These customers are connected to the grid, but also have two DER options that they could select from as shown in Fig. 4. The first DER option, G1, represents a PV generator with a high annual fixed cost and a low variable cost. The second DER option, G2, represents peak curtailment, with no fixed cost, and a high variable cost. Two case studies with different load profiles as illustrated in Fig. 5 are presented to compare customers' reaction to different tariff designs. The aim is to analyze how each is responding to different charge designs, with respect to their load profile. More customers could be added for a more realistic perspective, along with different factors of willingness to respond for each customer, subject to the value of economic benefit.

The second assumption is the annual load profile of customers, which is assumed to be of discrete nature and represented through 10 load levels, with varying number of hours per each load level. For the first case study, it is assumed that the four customers have identical load profiles, i.e. they all consume their peak demand at the same time. For the second case study, the four customers have different load profiles, with their peak consumption is at different hours. Since the main objective is to target peak hours, load duration curves are used instead of chronological curves, as it is less computationally complex.

The third assumption is regarding G1, PV generator, which has intermittent production nature with high uncertainty. It is assumed that the PV production is approximately 2000 h per year, and coincides with intermediate load levels. Hence, it operates during the 4^{th} and 5^{th} load levels shown in Fig. 5. Stochastic programming could be used to more accurately model PV production, according to the location of installation. In this case, a chronological load curve should be modeled.

Finally, the fourth assumption is regarding future load growth. It is assumed that a load increment of 0.1 MW is guaranteed in the following year. Due to discrete network investments, the least network reinforcement that could be carried out is 0.5 MW. For simplification, it is assumed that network reinforcements are proportional to 20% of the current network costs.

The case studies carried out aim to simulate the customer's reaction to different charge designs. It is only concerned with distribution network charges and not energy prices, thus the energy price is fixed for all charge designs and no surplus is obtained from the energy prices. The customers' reaction to each charge design is modeled using (1)–(9). Each customer optimizes his decision whether to serve his load from the grid, G1 or G2, or a combination of them. The case studies are formulated using LP and implemented in Matlab. Four different charge designs, which pretty much represent current practices, are implemented and compared:

(i) Volumetric Charge

Volumetric charge translates network costs into a €/MWh component based on the expected energy consumption, that is then added to the energy price and presented to the customer as one single price for both network and energy costs. Customers pay according to their energy consumption. Using (1)–(6), volumetric charge design is

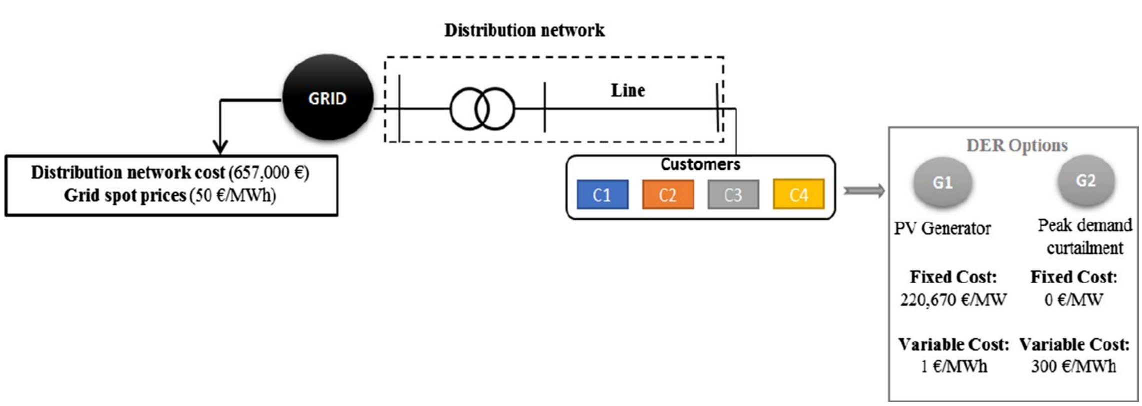

Fig. 4. Case study.

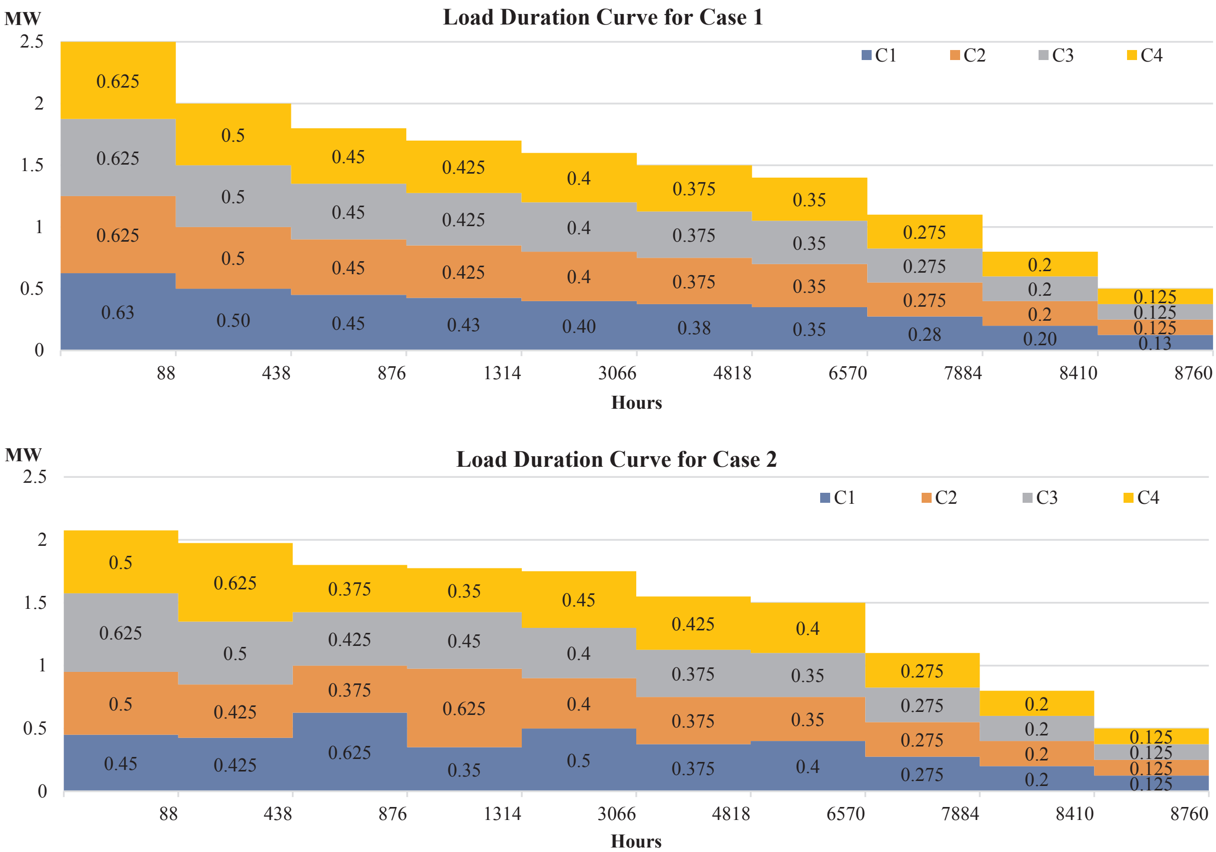

Fig. 5. Load duration curves for cases 1 and 2.

implemented, with FC_{grid_c} set to zero. The volumetric charge for the two load curve cases are different as the total energy consumption is different as shown in Table 1.

(ii) Fixed Charge

A fixed value of the network cost is allocated to each customer. Since there are four customers, each is allocated a quarter of the total network cost. Using (1)–(6), fixed charge design is implemented.

(iii) Peak Charge

Tariffs that are based on individual peak charge depend on the peak consumption of each customer. The peak charge shown in Table 1 is computed by dividing the total network cost among the sum of the total peak capacities. This charge does not consider the hour of peak consumption, but only the magnitude. For implementing the peak charge design, the objective function in (1) is modified to (10), where the grid's fixed cost is removed, and a new term is added representing the charge allocated to the customer based on his maximum grid consumption ($E_{grid\ max}$), subject to (11).

$$\underset{E_{grid},E_g,C_g}{\mathrm{Min}} \sum_{c=1}^{C}\sum_{l=1}^{L}\left[\left(VC_{grid}E_{grid_{l_c}}*h_l\right)+\sum_{g=1}^{G}\left(FC_gC_{g_c}+VC_gE_{g_{l_c}}*h_l\right)\right] + \sum_{c=1}^{C} PC*E_{grid_{maxc}} \quad (10)$$

$$E_{grid_{maxc}} \geqslant E_{grid_{l_c}} \quad c\in C \quad (11)$$

(iv) Proposed Methodology: Fixed Charge + PCNC

This tariff considers the individual peaks coincidental with the network peaks. A threshold is set according to the network reinforcements required. Since the least network reinforcement that could be carried out is 0.5 MW, equivalent to 20% of the current network costs, the PCNC is designed to recover these costs, during the peak hours according to the threshold. Since network investments will account for an 0.5 MW extra capacity, the threshold is set at 2 MW. Using (7)–(9), this proposed method is implemented. The PCNC is set as shown in Table 1, during the peak hours (those above 2 MW), which are 88 h according to the load profiles presented in Fig. 5.

Table 1
Inputs for charge designs.

Charge design	Fixed charge (€/Customer/yr)	Variable charge (€/MW h)	Other charges	
Volumetric charge (for Case 1)	–	103.09	–	
Volumetric charge (for Case 2)	–	100.97	–	
Fixed charge	164,250	50	–	
Peak charge	–	50	262,800	€/MW per year for the peak consumption
Fixed charge + PCNC	32,850	50	2986.36	€/MW during peak hours (above threshold)

Table 2
Customers' response to charge designs and the consequences.

	Charge design		Model decisions			Consequences	
			Consumption from grid	DER investments decision		Total system cost (M€)	Network deficit (%)
				G1 (MW)	G2 (MW)		
Case 1	Volumetric charge		4 * 2218.55 MW h	0.4 * 4	–	1.27	28.3%
	Fixed charge		12378.2 MW h	–	–	1.28	0%
	Peak charge		4 * 0.425 MW	–	0.2 * 4	1.12	32%
	Fixed charge + PCNC		4 * 0.5 MW	–	0.125 * 4	1.156	20%
Case 2	Volumetric charge	C1	2593 MW h	0.35	–	1.30	25%
		C2	2236.05 MW h	0.4	–		
		C3	2218.55 MW h	0.4	–		
		C4	2557.9 MW h	0.35	–		
	Fixed charge		12890.5 MW h	–	–	1.302	0%
	Peak charge	C1	0.425 MW	0.075	0.2	1.180	34%
		C2	0.375 MW	0.25	0.125		
		C3	0.425 MW	0.025	0.2		
		C4	0.425 MW	0.025	0.2		
	Fixed charge + PCNC	C1	0.423 MW	–	0.018	1.172	20%
		C2	0.487 MW	–	0.023		
		C3	0.606 MW	–	0.018		
		C4	0.483 MW	–	0.016		

4.1. Result

The customers' response obtained for each case to the four charge designs are presented in Table 2. The two columns under model decisions, present the obtained customers' decisions regarding the amount of energy or peak demand consumed from the grid, and DER investment decisions. On the right-hand side of the table are the consequences attained as a result to the decisions taken by the customer. The total system's cost is decomposed of the energy paid for grid consumption, cost of generation by G1 and cost of load curtailment through G2, and the revenues earned through distribution network charges for network recovery, from which network deficits are calculated. Fig. 6 compares the decomposition of the system's total cost under different charge designs.

For the first case, where customers had identical load profiles, the decisions taken were similar for each charge design. Under volumetric charges, the customer found a way to avoid part of the network charges by investing in the PV generator. This decision led to a network cost recovery deficit of 28.3%. On the contrary, fixed charges led to full network cost recovery, as the customers had no response and decided to fully supply their load from the grid. This type of response is optimum when no future network investments is required. However, in this current case, where the load is expected to increase in the following period, the cost of the network reinforcement is added to the following year's network cost and will be translated to the customers through an increase of the fixed charge. Thus, although there are no deficits to be transferred to the following period, network reinforcements costs are added which may be avoided with DERs. Furthermore, peak charges and the proposed charges method (PCNC + Fixed charges) have a peak demand component, thus customers react by investing in G2 that acts as peak load curtailment, as its variable cost is much lower than the charge applied (300 €/MW h compared to 262,800€/MW in case of

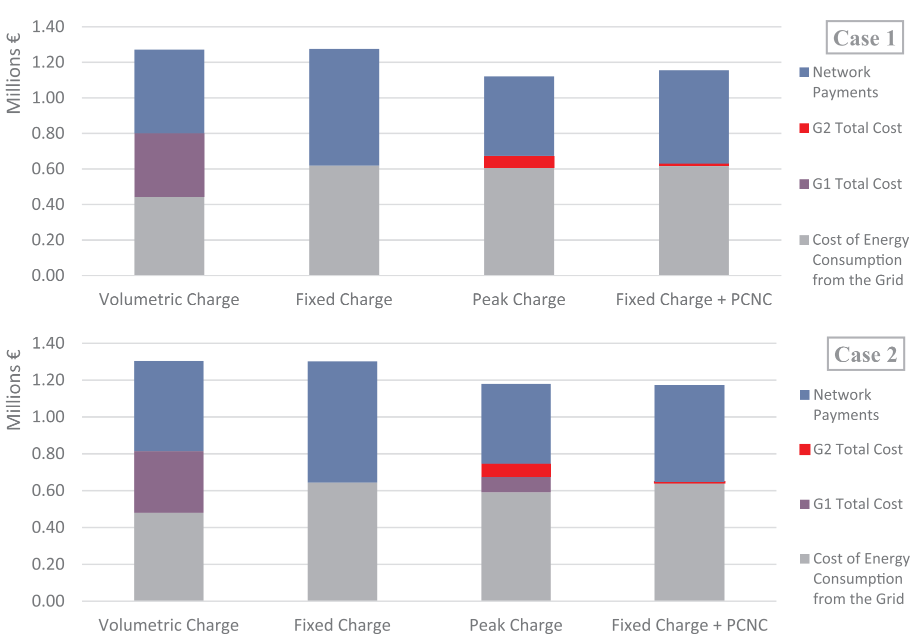

Fig. 6. Comparison of total customers payments decomposition under different charge designs for Cases 1 and 2.

individual peak charges and 2986.36€/MW in case of proposed charges method). Under the individual peak charge method, customers decide to use more load curtailment than under the proposed method. That leads to higher network cost recovery deficits. As shown in Table 2, the deficits generated through peak charges are higher than those through PCNC. It is important to point out that the deficits obtained under the proposed method are to be recovered through the fixed charges at the end of the period, as it is an ex-poste process.

For the second case, customers had different profiles, thus their peak consumption did not coincide at the same time, leading to different reactions for each customer under each charges design. For the volumetric charge, customers again avoided part of the network charge by investing in G1 at different capacities based on their consumption during the 4th and 5th load levels which are the periods when G1 is producing. Under the fixed charge method, customers had no reaction as in the first case. For the peak charge method, with the presented load profiles, customers found room to reduce their payments further by investing in both G1 and using G2. Consequently, that leads to further network cost recovery deficits. Finally, for the proposed method, the individual threshold for each customer is now different, leading to different use of G2. However, the total use of G2 is 0.075 MW, which corresponds to the capacity exceeding the threshold (2 MW).

Overall, the economic efficiency of the charge method is measured by both: the total current system cost, and additional future costs that could be due to transferred deficits, or network reinforcements required. An efficient method is that capable of avoiding expensive alternatives by less costly ones (while considering different periods). As in the case studies presented, the reinforcements required to accommodate the 0.1 MW increase in load costs 20% of the networks cost (657,000€) which is 131,400€. Through PCNC, this was translated into approximately 3000€/MW during peak hours. The participation of customers can avoid the network cost of 3000€/MW by the cost of load curtailment of 300€/MW during those same hours. Overall, this also increases the social welfare, as the avoidance of network reinforcements reduced future network costs that would have been recovered through the network charges of the following period.

In order to compare the consequences of the customers' reaction to the charge designs, both the total system cost and the network deficits should be considered as illustrated in Fig. 7. The grey part of the graph presents the total system cost, which include the cost of energy withdrawn from the grid, total DERs cost, and revenues earned for network cost recovery. The white part illustrates the future network cost, which is the network deficits that are to be transferred to the following period, or the cost of network reinforcements that need to be incurred in the next period to accommodate the expected load increase. As shown in the figure, for both cases, the proposed method led to the lowest total system cost, i.e. highest system economic efficiency. In the case studies presented, fixed energy prices were used for simplicity. The objective is to transmit the status of the network to customers to alert them regarding their impact on the network. Network peaks do not necessary coincide with high energy prices (system peak). For instance, during high renewable production, energy prices are low, attracting higher consumption, which may lead to peak network periods. Since customers react to the whole bill they receive, it is crucial that they differentiate between the two payment components: energy and network, as savings on energy payments should not allow the avoidance of network payments, unless they reduce their impact on the network. Dynamic energy prices along with peak coincidence network charges are the cost-reflective signals customers need to efficiently respond. Implementing dynamic energy prices within the case studies would also lead to efficient customers' response, where both energy and network costs would be minimized.

4.2. Practical implementation issues

Although the proposed method provides efficient economic signals, the presented case studies illustrate and reveal several issues that require further analysis, particularly when considering the practical implementation of the proposed network charges method. Some of these issues are discussed below.

4.2.1. Ex-ante or ex-post computation of network charges?

Certain information regarding the value of the charge and the periods of its application needs to be passed to customers for them to respond and take decisions. Whether the information should be announced ex-ante or ex-post affects widely the reaction of the customers, and the recovery of network costs. The ex-post approach aims to ensure network cost recovery, whereas ex-ante approach is required to influence customers' behavior. In the case of PCNC, if the customers get to know in advance the value of the charge and the hours it will be applied to, they would be able to respond to that information and anticipate their payments. However, establishing ex-ante charges may lead to shifting of critical hours as a consequence to the customers' reaction. Therefore, since this information is about the network usage is only known ex-post, an intermediate solution would be to provide information based on forecasts ex-ante but subject to change ex-post when the charge is actually applied.

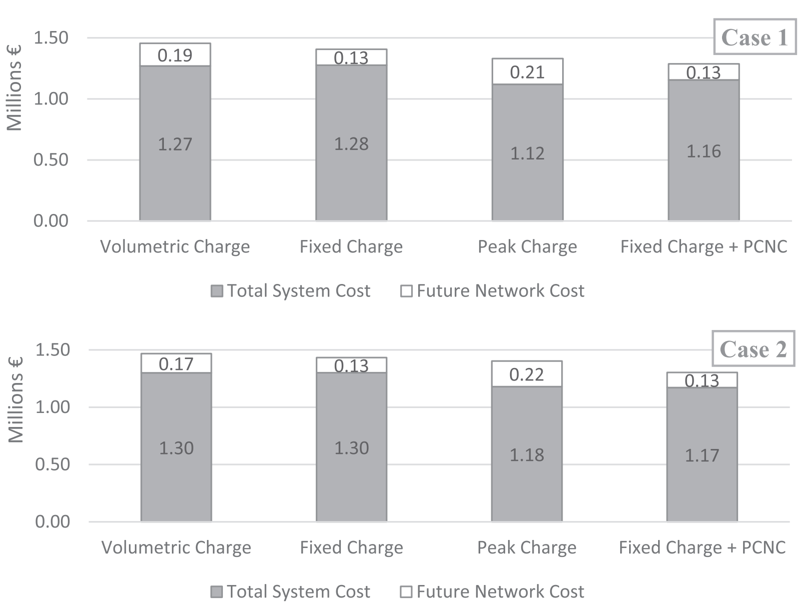

Fig. 7. Comparison of total system cost and future network cost under different charge designs for cases 1 and 2.

4.2.2. Computation of the thresholds to ensure the robustness of the method

Another important key parameter in the implementation of the charges, is its robustness. Charges are considered robust if they can achieve its objectives, or continue to send its economic signals, without being majorly disrupted. Thus, for the proposed method, PCNC should be consistent and not variating greatly. Moreover, if efficient responses are achieved, the PCNC cannot be removed in the following periods, otherwise customers will no longer be incentivized to reduce their consumptions during stressful periods of the network. In addition, to achieve an efficient outcome, the use of thresholds is required to limit the customers' response. The results show that the threshold is essential to avoid overinvestments in DERs. The computation of those values is challenging as it requires an assumption of future demand growth and future network reinforcements needed. Specific methodology needs to be developed to compute both as accurately as possible.

4.2.3. Coordination of customers' response

Coordination of customers' response is crucial for several reasons. One of which is over-investments, which may lead to lower network usage. As each customer is unaware of how other customers are reacting, and over-investment in DERs may occur. This may also create free riding opportunities to those customers who have decided not to invest in any DERs. Free-riding occurs when customer take advantage of a service, without paying for it. This lack of coordination may also create new unexpected peak network hours, if customers shifted the same hours to avoid PCNC hours that were ex-ante forecasted. Alternative coordination solutions can be accomplished by aggregators or auctions mechanisms at the distribution level. This issue needs further investigation to efficiently coordinate customers' reaction.

4.2.4. Locational granularity of the network charges

In actual distribution systems, the network is more complex with customers connected at different voltage levels of the network. Thus, different elements may peak at different moments. The application of PCNC requires the deployment of smart meters that measures of energy consumption and production at short timescales, however public policies are promoting the deployment of these infrastructures. The application of PCNC may have different variants, as customers could be exposed to it during peak hours of the level they are connected to, or they could be exposed to it as a cascaded effect of above levels. This issue requires investigation to analyze the consequences of implementing different variants of the proposed method. Higher granularity increases the computational burden and complexity of the calculations.

4.2.5. Symmetrical network charges

Network peaks could be caused by either high demand as the energy withdrawn from the network increases, or by high generation, as injections of DER into the network increase. Either way, it is considered a peak hour, where PCNC is applied to those contributing to the peak. Network charges should be symmetrical and does not distinguish between consumer, generator, or a storage unit. The aim of PCNC is to send correct signals to those driving network reinforcements, independently of the use.

5. Conclusion

Redesigning distribution network charges is currently an essential step to fully achieve the benefits of customer response. The proposed efficient network charges have two components a peak coincident network charges plus fixed charges. This design sends efficient economic signals during peak network hours, and avoided distorting those signals through fixed charges during periods when the network is underutilized. The main purpose of the fixed charge is to ensure full network cost recovery. For efficient customer response, the peak coincident network charge encourages optimal deployment of DERs. However, to avoid over-investments in DERs, a threshold based on the network usage peak is required at which a forward -looking peak coincident network charges are applied. In addition, peak coincident network charges should only be applied during network stressful periods and encourage network usage during the periods when the network is underutilized. The results showed that the proposed method outperformed the other traditional methods. Through an efficient customer response guidance, it led to higher system economic efficiency. The results obtained where based on the use of fixed energy prices. The use of dynamic energy prices instead, would also lead to efficient customers' response, where both energy and network costs would be minimized.

Although the proposed charge design holds several merits when compared with more traditional charge designs, yet it requires a complementary approach to coordinate customers' responses. A range of different approaches could be complemented to solve these problems that be created due to lack of coordination, for instance, through the role of aggregators or auctions mechanisms at the distribution level. Implementations within this context require further research.

Acknowledgment

The work of Ibtihal Abdelmotteleb is funded through the European Commission's Joint Doctorate on Sustainable Energy Technologies and Strategies (SETS). The authors would like to thank Prof. José Ignacio Pérez Arriaga for his valuable discussions and inputs.

References

[1] CEER. CEER guidelines of good practice for distribution network tariffs. C16-NaN-27–3; January 2017.
[2] Response to the European Commission's public consultation on a new energy market design. European Distribution System Operators for Smart Grids; October 2015.
[3] Adapting distribution network tariffs to a decentralised energy future. European Distribution System Operators for Smart Grids; September 2015.
[4] Picciariello A, Reneses J, Frias P, Söder L. Distributed generation and distribution pricing: Why do we need new tariff design methodologies? Electr. Power Syst. Res. Feb. 2015;119:370–6.
[5] National Report. Energy Regulatory Office, Poland; July 2015.
[6] National Report 2016 to the Agency for the Cooperation of Energy Regulators and to the European Commission. Energy Authority, Finland, 1518/601/2016; 2016.
[7] European Commission-DIRECTORATE B – Internal Energy Market. Study on tariff design for distribution systems; January 2015.
[8] Li F, et al. Distribution pricing: are we ready for the smart grid? IEEE Power Energy Mag. Jul. 2015;13(4):76–86.
[9] Spiliotis K, Ramos Gutierrez AI, Belmans R. Demand flexibility versus physical network expansions in distribution grids. Appl Energy Nov. 2016;182:613–24.
[10] Nolan S, O'Malley M. Challenges and barriers to demand response deployment and evaluation. Appl Energy Aug. 2015;152:1–10.
[11] Shen B, Ghatikar G, Lei Z, Li J, Wikler G, Martin P. The role of regulatory reforms, market changes, and technology development to make demand response a viable resource in meeting energy challenges. Appl Energy Oct. 2014;130:814–23.
[12] Mutale J, Strbac G, Pudjianto D. Methodology for cost reflective pricing of distribution networks with distributed generation. IEEE Power Eng Soc General Meeting 2007;2007:1–5.
[13] Li F, Padhy NP, Wang J, Kuri B. Cost-benefit reflective distribution charging methodology. IEEE Trans Power Syst Feb. 2008;23(1):58–64.
[14] Sotkiewicz PM, Vignolo JM. Allocation of fixed costs in distribution networks with distributed generation. IEEE Trans Power Syst May 2006;21(2):639–52.
[15] Pérez-Arriaga I, Bharatkumar A. A framework for redesigning distribution network use of system charges under high penetration of distributed energy resources: New principles for new problems. MIT Cent Energy Environ Policy Res 2014.
[16] Gu C, Li F. Long-run marginal cost pricing based on analytical method for revenue reconciliation. IEEE Trans Power Syst Feb. 2011;26(1):103–10.
[17] Li F. Long-run marginal cost pricing based on network spare capacity. IEEE Trans Power Syst 2007;22(2):885–6.
[18] Reneses J, Rodríguez Ortega MP. Distribution pricing: theoretical principles and practical approaches. IET Gener Transm Distrib Oct. 2014;8(10):1645–55.
[19] Akinbode OW. A Distribution-class Locational Marginal Price (DLMP) index for enhanced distribution systems. M.S., Arizona State University, United States – Arizona; 2013.
[20] Paul Sotkiewicz. Nodal pricing and MW-mile methods for distribution: have we uncovered missing markets or elements for wholesale power markets? In: Presented at the harvard electricity policy group harvard electricity policy group 42nd plenary session plenary session March 2, 2006 La Jolla, California, La Jolla, California; 02-Mar-2006.

[21] Rodríguez Ortega MP, Pérez-Arriaga JI, Abbad JR, González JP. Distribution network tariffs: a closed question? Energy Policy May 2008;36(5):1712–25.
[22] González A, Gomez T. Use of system tariffs for distributed generators. In: 16th power systems computation conference, Glasgow, Scotland; 2008.
[23] Yang L, Dong C, Wan CLJ, Ng CT. Electricity time-of-use tariff with consumer behavior consideration. Int J Prod Econ Dec. 2013;146(2):402–10.
[24] Torriti J. Price-based demand side management: Assessing the impacts of time-of-use tariffs on residential electricity demand and peak shifting in Northern Italy. Energy Aug. 2012;44(1):576–83.
[25] Klaassen EAM, Kobus CBA, Frunt J, Slootweg JG. Responsiveness of residential electricity demand to dynamic tariffs: Experiences from a large field test in the Netherlands. Appl Energy Dec. 2016;183:1065–74.
[26] Steen D, Tuan LA, Carlson O. Effects of network tariffs on residential distribution systems and price-responsive customers under hourly electricity pricing. IEEE Trans Smart Grid Mar. 2016;7(2):617–26.
[27] Bartusch C, Wallin F, Odlare M, Vassileva I, Wester L. Introducing a demand-based electricity distribution tariff in the residential sector: Demand response and customer perception. Energy Policy Sep. 2011;39(9):5008–25.
[28] Domínguez J, Chaves-Ávila JP, Román TGS, Mateo C. The economic impact of demand response on distribution network planning. In: 2016 Power Systems Computation Conference (PSCC); 2016. p. 1–7.
[29] Li F, Tolley D, Padhy NP, Wang J. Framework for assessing the economic efficiencies of long-run network pricing models. IEEE Trans Power Syst Nov. 2009;24(4):1641–8.
[30] Berg SV, Tschirhart J. Natural monopoly regulation: principles and practice. Cambridge: Cambridge University Press; 1989.
[31] Lévêque F. Transport pricing of electricity networks. Springer Science & Business Media; 2013.
[32] Borenstein S. The economics of fixed cost recovery by utilities. Electr J Sep. 2016;29(7):5–12.
[33] IGNACIO PÉREZ-ARRIAGA. Utility of the future. Massachusetts Institute of Technology; Dec. 2016.
[34] Biggar DR, Hesamzadeh MR. The smart grid and efficient pricing of distribution networks. The economics of electricity markets. Wiley-IEEE Press; 2014. p. 432.
[35] Ignacio Pérez-Arriaga, Ashwini Bharatkumar. A framework for redesigning distribution network use of system charges under high penetration of distributed energy resources: new principles for new problems. MIT CEEPR Working Paper; October 2014.
[36] Victorian electricity distribution network service providers. Final Decision Tariff Structure Statement proposals. Australia: Australian Energy Regulator; Aug. 2016.
[37] Marsden Jacob Associates. "Estimation of Long Run Marginal Cost," for the Queensland Competition Authority; November 2004.
[38] Ibtihal Abdelmotteleb, Tomás Gómez, Javier Reneses. Distribution network cost allocation using a locational and temporal cost reflective methodology. In: 19th Power Systems Computation Conference (PSCC 2016), Genoa; 2016.
[39] Abeygunawardana AMAK, Arefi A, Ledwich G. Estimating and modeling of distribution network costs for designing cost-reflective network pricing schemes. In: 2015 IEEE Power Energy Society General Meeting; 2015. p. 1–5.
[40] Gómez T, Mateo C, Sánchez Á, Frías P, Cossent R. Reference network models: a computational tool for planning and designing large-scale smart electricity distribution grids. In: Khaitan SK, Gupta A, editors. High performance computing in power and energy systems. Berlin Heidelberg: Springer; 2013. p. 247–79.
[41] Domingo CM, Roman TGS, Sanchez-Miralles Á, Gonzalez JPP, Martinez AC. A reference network model for large-scale distribution planning with automatic street map generation. IEEE Trans Power Syst Feb. 2011;26(1):190–7.
[42] Abdelmotteleb I, Gómez T, Chaves-Ávila JP, Reneses J. Incentivizing consumer response through cost-reflective distribution network charges. CIRED Workshop 2016;2016:1–4.