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Designing Electricity Distribution Network Charges for an Efficient Integration of Distributed Energy Resources and Customer Response

Ibtihal Abdelmotteleb

Designing Electricity Distribution Network Charges for an Efficient Integration of Distributed Energy Resources and Customer Response

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Keywords: customer response, distributed energy resources, distribution network charges, local flexibility mechanisms

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ABSTRACT

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A significant transformation has been gradually taking place within the energy sector, mainly as a result of energy policies targeting environmental objectives. Consequently, the penetration of Distributed Energy Resources (DERs) has been escalating, including self-generation, demand side management, storage, and electrical vehicles. Although the integration of DERs may create technical challenges in the operation of distribution networks, it may also provide opportunities to more efficiently manage the network and defer network reinforcements. These opportunities and challenges impose the necessity of redesigning distribution network charges to incentivize efficient customer response.

This PhD thesis focuses on the design of distribution network charges that send correct economic signals and trigger optimal responses within the context of active customers. First, a cost-reflective network charge is proposed that consists of a forward-looking locational component based on the network's utilization level, which transmits the long-term incremental cost of network upgrades. Then, a residual cost component that recovers the remaining part of the regulated network revenues is proposed. The objective of the proposed network charge is to increase the system's efficiency by incentivizing efficient short- and long-term customers' reaction while ensuring network cost recovery. The Thesis presents an optimization model that simulates customers' response to the proposed network charge in comparison to other traditional network charge designs. The model considers the operational and DER investment decisions that customers take rationally to minimize their total costs.

Secondly, an evaluation methodology based on the Analytical Hierarchy Process technique is proposed in order to assess and compare different designs of network charges with respect to four attributes: network cost recovery, deferral of network costs, efficient customer response and recognition of side-effects on customers.

Finally, a framework for Local Flexibility Mechanisms (LFM) is presented, complementing the proposed cost-reflective network charge. It aims to provide distribution-level coordination to mitigate unintended customer responses to network charges, by allowing customers to reveal their preferences and offer their flexibility services. It consists of a short-term LFM that utilizes customers' flexibility in day-to-day network operation, and a long-term LFM that procures customers' long-term flexibility to replace partially or fully network investments in network planning.

SAMMANFATTNING

Författare: Ibtihal Abdelmotteleb

Anslutning: Comillas Pontifical University

Titel: Utformning av nätverksavgifter för eldistribution för effektiv integration av distribuerade energiresurser och kundrespons

Språk: Engelska

Nyckelord: kundrespons, distribuerade energiresurser, distributionsnätkostnader, lokala flexibilitetsmekanismer

En betydande omvandling har successivt skett inom energisektorn, främst som ett resultat av energipolitik för att minska miljöpåverkan. Följaktligen har andelen distribuerade energiresurser (DER) ökat, däribland egenproduktion, efterfrågesidehantering, lagring och elfordon. Även om integrationen av DER kan skapa tekniska utmaningar vid driften av distributionsnät, kan det också ge möjligheter att effektivisera hanteringen av nätverket och skjuta upp nätverksförstärkningar. Dessa möjligheter och utmaningar innebär att det är nödvändigt att omforma nätverksavgifterna för att stimulera en effektiv kundrespons.

Denna doktorsavhandling fokuserar på utformningen av distributionsnätavgifter som skickar korrekta ekonomiska signaler och utlöser optimala svar inom ramen för aktiva kunder. För det första föreslås en kostnadsbeaktande nätverksavgift som består av en framåtriktad lokaliseringskomponent baserad på nätets användningsnivå, som överför den långsiktiga inkrementella kostnaden för nätverksuppgraderingar. Därtill föreslås en restkostnadskomponent som återställer den återstående delen av de reglerade nätverksintäkterna. Syftet med den föreslagna nätverksavgiften är att öka systemets effektivitet genom att stimulera effektiva kort- och långsiktiga kundreaktioner samtidigt som nätverkskostnadsåtervinningen säkerställs. Avhandlingen presenterar en optimeringsmodell som simulerar kundernas svar på den föreslagna nätverksavgiften i jämförelse med andra traditionella utformningar av nätverksavgifter. Modellen tar hänsyn till de operativa och DER-investeringsbesluten som kunderna tar rationellt för att minimera sina totala kostnader.

För det andra föreslås en utvärderingsmetod baserad på Analytical Hierarchy Process-tekniken för att bedöma och jämföra olika utformningar av nätverksavgifter med avseende på fyra attribut: nätverkskostnadsåterställning, uppskjutning av nätverkskostnader, effektivt kundrespons och hänsynstagande till biverkningar på kunder.

Slutligen presenteras en ram för lokala flexibilitetsmekanismer (LFM) som kompletterar den föreslagna kostnadsbeaktande nätverksavgiften. Den syftar till att tillhandahålla koordinering på distributionsnivå för att mildra oavsiktliga kundreaktioner på nätverksavgifter genom att tillåta kunder att avslöja sina preferenser och erbjuda sina flexibilitetstjänster. Den består av en kortfristig LFM som utnyttjar kundernas flexibilitet i den dagliga nätverksoperationen och en långsiktig LFM som ger kundernas långsiktiga flexibilitet att helt eller delvis ersätta nätverksinvesteringar i nätverksplanering.

ABSTRACT

Auteur: Ibtihal Abdelmotteleb

Aansluiting: Comillas Pontifical University

Titel: Het ontwerpen van elektriciteitsdistributienetwerken voor een efficiënte integratie van gedistribueerde energiebronnen en respons van klanten

Taal: Engels

Trefwoorden: respons van klanten, gedistribueerde energiebronnen, kosten van distributienetwerken, lokale flexibiliteitsmechanismen

In de energiesector is geleidelijk een belangrijke transformatie doorgevoerd, voornamelijk als gevolg van het energiebeleid dat op milieudoelstellingen is gericht. Daardoor is de penetratie van gedistribueerde energiebronnen (DER's), zoals zelfopwekking, beheer van de vraagzijde, opslag en elektrische voertuigen, toegenomen. Hoewel de integratie van DER's technische uitdagingen kan veroorzaken bij de werking van distributienetwerken, kan dit ook kansen creëren om het netwerk efficiënter te beheren en netwerkversterkingen uit te stellen. Deze kansen en uitdagingen kunnnen er toe leiden dat distrbutienetwerktarieven grotendeels herzien moeten worden om een efficiënte klantenrespons te stimuleren.

Deze doctoraatsthesis focust op het ontwerpen van distributienetwerktarieven die correcte economische signalen geven en optimale reacties triggeren in de context van actieve klanten. Ten eerste wordt in dit werk een kostenreflecterende netwerkvergoeding geponeerd die bestaat uit een toekomstgerichte locatieafhankelijke component,gebasseerd op het gebruik van het netwerk. De bedoeling hiervan is om de incrementele kosten van netwerkupgrades op lange termijn weer te geven. Vervolgens wordt een restkostencomponent geïntroduceerd die het resterende deel van de gereguleerde netwerkinkomsten recupereert. Het doel van deze netwerkheffing is om de efficiëntie van het systeem te vergroten door efficiënte korte- en langetermijnklantenreacties aan te moedigen en tegelijkertijd netwerkkosten terug te verdienen. Dit werk presenteert een optimalisatiemodel dat de reactie van klanten op de voorgestelde netwerkkosten simuleert in vergelijking met andere traditionele netwerkladingontwerpen. Het model houdt rekening met de operationele en DER-investeringsbeslissingen die klanten rationeel nemen om hun totale kosten te minimaliseren.

Ten tweede wordt een evaluatiemethode op basis van de Analytical Hierarchy Process-techniek voorgesteld om verschillende ontwerpen van netwerklasten te beoordelen en te vergelijken met betrekking tot vier attributen: netwerkkostenherstel, uitstel van netwerkkosten, efficiënte klantrespons en erkenning van neveneffecten op klanten.

Ten slotte wordt een kader voor lokale flexibiliteitsmechanismen (LFM) gepresenteerd, dat een aanvulling vormt op de voorgestelde kostenreflecterende netwerkheffing. Deze methode probeert de coördinatie op distributieniveau te creëren zodat vermeden wordt dat klanten netwerkheffingen proberen te voorkomen. Dit wordt bewerkstelligd door klanten in staat te stellen hun voorkeuren kenbaar te maken en hun flexibiliteitsdiensten aan te bieden. Enerzijds bestaat deze methode uit een LFM voor de korte termijn die gebruikmaakt van de flexibiliteit van klanten bij de dagelijkse netwerkwerking en anderzijds een lange termijn LFM die klanten langetermijnflexibiliteit probeert te contracteren om gedeeltelijk of volledig netwerkinvesteringen in netwerkplanning te vermijden.

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LIST OF ABBREVIATIONS AND ACRONYMS

AHP	**Analytical Hierarchy Process**
CDS	Contract for Deferral Scheme
CP	Customer's Payment
CPP	Critical Peak Pricing
DERs	Distributed Energy Resources
DG	Distributed Generation
DLMPs	Distribution Locational Marginal Prices
DN	Distribution Network
DNs	Distribution Networks
DSOs	Distribution System Operators
DSPPs	Distributed System Platform Providers
EDSO	European Distribution System Operators
EHV	Extra High Voltage
EV	Electrical Vehicles
FCP	Forward Cost Pricing
FTR	Financial Transmission Rights
IPPs	Independent Power Producers
LCL	Low Carbon London
LFMs	Local flexibility mechanisms
LMP	Locational Marginal Prices
LRDNEP	Long-Run Distribution Network Expansion Planning
LRIC	Long Run Incremental Cost
LRMC	Long-Run Marginal Cost
LTIC	Long-Term Incremental Cost
LTMC	Long-Term Marginal Costs
MP	Marginal Participation
MSC	Minimum Service Capacity
OMIE	Operador del Mercado Ibérico Español
OPF	Optimal Power Flow
PCNC	Peak Coincidence Network Charge

PH	Peak Hour
PPA	Power Purchase Agreement
PS	Postage Stamp
PTR	Physical Transmission Rights
PV	Photovoltaic
RC	Reserved Capacity
RES-E	Renewable Energy Sources for Electricity
REV	New York Reforming Energy Vision
RFP	Request for Proposals
RNM	Reference Network Model
RODG	Reliability Options for Distributed Generation
SAA	Simultaneous Ascending Auction
SACA	Simultaneous Ascending Clock Auctions
T	Threshold
TNC	Total Network Costs
TOU	Time-of-Use
TSO	Transmission System Operator
VOLL	Value of Loss Load

1 INTRODUCTION

This chapter illustrates the motivation for this thesis, defines the objectives and scope, and summarizes the main scientific contributions.

1.1 Background

A significant transformation has been gradually taking place within the energy sector, mainly as a result of energy policies targeting environmental objectives. Consequently, the penetration of Distributed Energy Resources (DERs) has been increasing vastly, including self-generation, demand side management, storage, and electrical vehicles (EV). Although the integration of DERs may 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 (Haque and Wolfs, 2016; Walling et al., 2008)), yet they also may create opportunities for the Distribution Networks (DNs) to be managed more efficiently. Such opportunities include network reinforcement deferral, energy losses reduction, peak power reduction, voltage control, ancillary services, improving power quality, and reduction in the load/ generation curtailment (Benysek et al., 2016; El-Khattam et al., 2004; Han et al., 2012; Lopes et al., 2007; Méndez et al., 2006; Piccolo and Siano, 2009; Pregelj et al., 2006; Stanev, 2014). These opportunities and challenges impose the necessity of redesigning distribution network charges to promote efficient network utilization and optimal customer response. Hence, DSOs require upgrading their role in order to efficiently manage the network, incorporating the impact of DERs and active customers into all decisions, for both short-term operation and long-term planning of the network. 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 DN charges has been discussed in various researches (CEER, 2017; EDSO, 2015a, 2015b; Picciariello et al., 2015). In (EDSO, 2015a). 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 charges must be designed to ensure that customers generating their own electricity still contribute with their fair share of the DN costs. Moreover, as EDSO stated in (EDSO, 2015b), 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 charges is a main tool to provide price signals to customers (Picciariello et al., 2015), thus, network charges should be updated to avoid such impacts. Furthermore, EDSO presented a number of key messages in (EDSO, 2015b) regarding the revision of current DN charges, 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 charges can lead to inefficient network investments, reducing social welfare. Hence, DN charges require regular assessment to ensure efficient and fair recovering of network costs while sending appropriate signals to customers (CEER, 2017).

Tariffs, charges, and rates are different terminologies used to refer to fee allocated to customers for the electricity service they receive. Tariffs (or commonly known as rates in the US) are basically a group of charges, where each charge serves a particular component of the tariff. The electricity tariff consists of: distribution network charges, transmission network charges, energy prices and regulated taxes. Energy prices in liberalized retail markets are part of the electricity bill but they are negotiated separately from the regulated tariff components which are fixed by the regulator.The focus of this thesis is the design of the distribution network charge component of the electricity tariff. Moreover, since energy prices play an influential role in customers' reaction, they are considered in Chapter 4 along with DN charges within the evaluation methodology of tariff designs. Since both DN charges and energy prices are considered, it is referred to as a tariff in this thesis.

DN charges are usually set by national regulators, with exceptions to several countries: as in Spain, where the government sets it and the national regulator is in charge of some duties, 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 (CEER, 2017), 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 (Polish Energy Regulatory Office, 2015). 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 (Finnish Energy Authority, 2016).

Traditionally, DN charges aimed to collect the allowed revenues for the DSO, and were designed to comply principally with tariff design principles, among them: equity, simplicity, predictability, stability, consistency, transparency, non-discrimination, and cost-reflectiveness (European Commission-DIRECTORATE B – Internal Energy Market, 2015). 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 (Li et al., 2015), 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 (European Commission-DIRECTORATE B – Internal Energy Market, 2015), 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.

This thesis first deals with the need of redesigning distribution network charges in a way that considers the aforementioned policy objectives. Thus, it proposes cost reflective DN charges that incentivize customer response and efficient network usage to mitigate unnecessary future network reinforcements as well as avoiding unnecessary customer investments in DERs. This is mainly due to customers deciding 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 they are responses to cost-reflective charges that consider 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.

Secondly, the thesis incorporates customers' flexibility with DN charges through complementary approaches to enhance the system's economic efficiency in the short and long term. In (Spiliotis et al., 2016) the authors discuss how demand flexibility could reduce DSOs' costs and defer network reinforcements. However, there are challenges and barriers to fully benefit from customer response as presented in (Nolan and O'Malley, 2015), one of which being the lack of efficient price signals customers receive. In order to capture and utilize untapped demand response potentials, local flexibility mechanisms are proposed that accompany cost-reflective DN charges and align with pre-established economic signals transmitted through them.

1.2 Research Problem and Objectives

The research problem is: ***How to design distribution network charges that send correct economic signals and trigger optimal customer response considering the increasing penetration of DERs.***

As shown in Figure 1.1, DN charges trigger customer reaction, which then has an impact on future network costs. Since customers play a major role in the development of a smart and efficient distribution network, it is essential to ensure they received correct economic signals upon which they react. In addition to these economic signals, they should also be able to realize the benefits of utilizing flexibility services in the DN for themselves, and find it easy and appealing to provide them. This research aims to cover the following objectives:

Obj1- Design an evaluation methodology that could be used as a tool to assess and compare different tariff design.

Obj2- Design cost-reflective DN charges that lead to efficient operational and investment decisions taken from both the customers' and DSOs' sides, while complying with tariff design principles.

Obj3- Simulate customers' response to different DN charge design to assess their reaction and the consequential effects on the system's economic efficiency in terms of network cost recovery and future network costs.

Obj4- Design distribution-level coordination mechanisms to complement DN charges to achieve its objectives through customers' short- and long-term flexibility utilization.

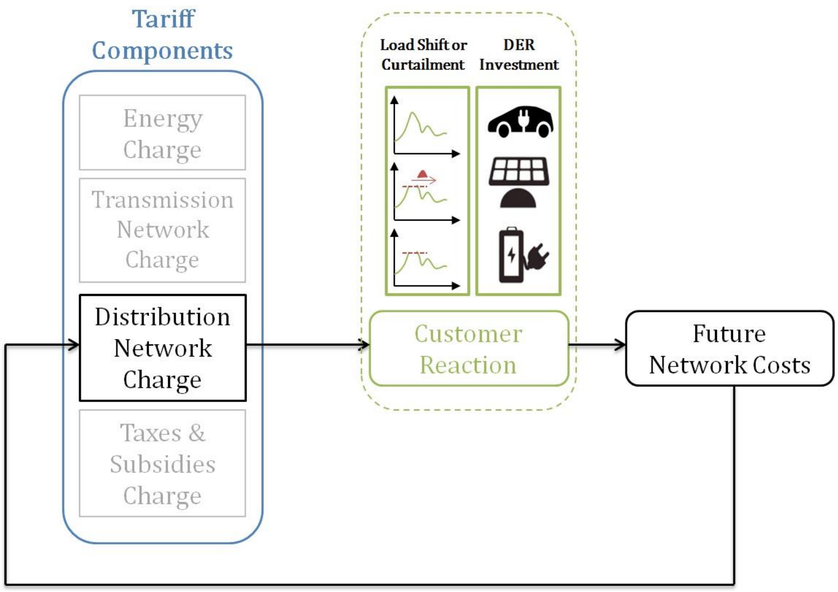


Figure 1.1 Impact of DN Charges on Customers' Reaction and Future Network Costs

1.3 Scientific Contribution

The scientific contributions of this thesis are aligned with the research objectives as presented in Table 1.1. The three main contributions are as follow:

C1- Proposing an evaluation methodology to compare DN tariffs according to four main attributes, and then ranks them according to their total score using the Analytical Hierarchy Process (AHP) decision-making method.

C2- Proposing an efficient cost-reflective DN charge and comparing it to other traditional DN charges through an optimization model that simulates customers' reaction through minimization of customers' total costs. The model aims to ensure that optimal customers' reactions are achieved and consequently enhances the system's economic efficiency.

C3- Proposing local flexibility mechanisms that complement the proposed cost-reflective DN charges. It aims to mitigate concerns associated with the implementation of DN charges and utilize customers' flexibility in the short and long term to enhance the system's economic efficiency. It is a market-based instrument which is applicable in a decentralized way, allowing customer response to be applied in a more localized manner to efficiently influence the utilization of existing network assets, and to promote efficient DER and network investments.

Contribution	Objective	Chapter	Publication
C1	Obj1	4	(Abdelmotteleb et al., 2017)
C2	Obj2 & Obj3	5	(Abdelmotteleb et al., 2018a)
C3	Obj4	7	(Abdelmotteleb et al., 2018b)

Table 1.1 Mapping scientific contributions to research objectives, chapters and publications

1.4 Thesis Outline

The thesis is organized in two main parts:

- **Part I** is concerned with designing cost-reflective DN charges, evaluating and comparing it to other DN charge designs, and simulating customers' response to different DN charges.
- **Part II** is focused on distribution-level coordination and utilization of customers' flexibility in the short and long term. This part complements the cost-reflective DN charges proposed in Part I to mitigate its implementation shortages and coordinate customers' flexibility efficiently.

Part I: Designing Distribution Network Charges

- **Chapter 2** reviews the main steps and characteristics for designing DN charges. This includes the most common practices and a state-of-the-art review of the network cost allocation methods and DN charge structures. In addition, it reviews factors affecting customers' reaction to DN charges and researches that consider it within DN charge design.
- **Chapter 3** complements the literature review presented in chapter 2. It provides a numerical case study that compare different cost allocation methodologies, to better understand their impact on customers' reaction and network cost recovery. This is an intermediate step before proposing the final cost-reflective DN charge design in Chapter 5.
- **Chapter 4** proposes an evaluation methodology to assess and compare DN tariffs. It may be used as a tool for regulators to evaluate DN tariff designs by comparing the performance of each regarding the method's design attributes. The proposed methodology is implemented on the case study provided in Chapter 3 to illustrate how the assessment of different DN tariff designs is carried out.
- **Chapter 5** proposes a cost-reflective DN charge that consists of a fixed charge and a forward-looking component: peak-coincidence network charge, which is linked to the network's utilization level. In addition, an optimization model is formulated comparing customers' response to the cost-reflective DN charge and other DN charge designs in terms of operational and DER investment decisions, based on minimizing customers' total costs.

Part II: Distribution-Level Coordination & Customers' Flexibility Utilization

- **Chapter 6** highlights the implementation concerns regarding the practical implementation of the proposed cost-reflective DN charge proposed in Chapter 5, which requires customers' response coordination and efficient utilization of their flexibility. It reviews existing proposal regarding utilization of customers' flexibility in the short and long term.
- **Chapter 7** proposes local flexibility mechanisms (LFMs) that complement cost-reflective DN charges proposed in Chapter 5. It consists of short- and long-term LFM. Short-term LFM aims to extract and utilize customers' flexibility in the short term, providing a hedging mechanism against high and volatile network charges. While long-term LFM aims to procure customers' long-term flexibility to replace network reinforcements when existing flexibility is insufficient.

Finally, **Chapter 8** concludes the thesis and provides final recommendations and discussion regarding areas for future work.

PART I: DESIGNING DISTRIBUTION NETWORK CHARGES

This part of the thesis focuses on the design of distribution network charges. It reviews the state of art of designing network tariffs and network cost allocation methodologies in Chapter 2, and further extends it with a numerical case study in Chapter 3. An evaluation methodology to compare distribution network tariffs is proposed in Chapter 4 that acts as a tool for decision makers to assess the performance of different tariff designs. Finally, based on conclusions drawn from Chapters 2, 3 & 4, a cost-reflective distribution network charge design is proposed in Chapter 5 along with a model to simulate customers' response to the proposed network charge design and compare it to other traditional ones.

2 Distribution Network Charge Design: Research Background

Distribution network (DN) charges that have been designed to serve passive customer can no longer serve emerging new active ones. This chapter discusses why new network charge designs are required and the main objectives they should fulfill in section 2.1. For those designs to be well configured, they should be well-aligned with network tariff principles and adapt three mains steps: follow an effective cost allocation methodology, translate it into appropriate charge structures and components, and finally present them into a final form. Section 2.2 reviews tariff design principles, different network cost allocation methodologies, charge options (structures and components), and presents network charge designs currently implemented in different countries. Furthermore, for network charges to be efficient and achieve their objectives a number of characteristics should be considered; one of the main characteristics is triggering efficient customer reaction as discussed in section 2.3. Finally, approaches to assess DN charges are reviewed in 2.4.

2.1 Why Redesign Distribution Network Charges?

Traditionally, distribution costs have been allocated on energy (volumetric, per MWh) and/or demand (per kW) basis. There are two basic approaches. The volumetric charge consists of full averaging of all distribution costs, fixed and variable, into a single per kWh charge. The second charge approach consists of averaging losses plus some portion of other distribution costs into a kWh charge, and the remaining distribution costs are allocated through demand charges based on kW demand at coincident or non-coincident peak or contracted demand. Nowadays, as DERs' penetration escalates and becomes more widely deployed in DNs, the DN becomes more active rather than passive. Customers no longer share similar energy profiles, as they may withdrawal, inject or store energy during different times of the day. Therefore, averaging network costs is no longer accurately reflecting the costs each incur. In addition, active customers may avoid part of network costs through self-consumption (which is when customers use their own onsite generators to supply their energy needs), leading to cross-subsidizing passive customers. Thus, new pricing mechanisms are required. Distribution network charge design requires fulfilling three main aspects; firstly, it ought to fully recover the cost of the distribution network. Secondly, it should be cost-reflective, imposing the correct charges to customers according to their impact on the network. Finally, it has to send effective economic signals to network customers, incentivizing efficient reaction in the short term by shifting or reducing their consumptions or injections, and in the long term by customizing their investment decisions, for example whether to install photovoltaic (PV) generators or not. Those signals should be, as much as possible, easy to understand, implement and determine. They should be designed to avoid consequences of inefficient charge design as discussed in (EDSO, 2015b):

- **Revenue uncertainty for DSOs:**

DSOs require stable and predictable revenues in order to ensure a secure and stable supply of electricity. Formerly, when electricity consumption was stable or steadily increasing by a few percent every year, matching costs and revenues was not an issue for DSOs. However, as consumption patterns are changing, along with the increasing penetration of DERs, the uncertainty for ensuring full cost recovery to DSOs increases. This is particularly the case when volumetric network charges are implemented. The uncertainty is reduced when peak demand charges are applied, and full cost recovery is achieved when ex-post fixed charges are applied as shown in (Abdelmotteleb et al., 2018a, 2016a).

- **Inefficient DER investments by customers lead to lower social welfare**

Traditionally designed network charges may lead to customers taking inefficient investment decisions. This is mainly due to incorrect economic signals customers receive. Current DN charges encourage customers to reduce their total consumption, in the case of volumetric charges, and peak consumption in the case of peak demand charges, regardless to the moment of consumption. Moreover, for prosumers, traditional network charges do not incentivize them to reduce their injection at peak production times. As a result of the growing network peaks, DSOs are required to reinforce the network. The cost of adapting the network to a few peak periods is high and is paid by all customers. A more economic solution for society would be to avoid network reinforcement by modifying network usage habits during network peak utilization hours. Thus, network charges should be designed to include incentives for that purpose.

- **Cross-subsidization between customers**

Cross subsidization may occur between customers regardless whether they own DERs or not. This is because current network charges do not reflect the true costs of supplying network services to each customer. Some customers currently pay more than the costs caused by their usage, while other customers, in particular those that use a greater proportion of their energy at peak times, pay less than the costs caused by their usage. This is because existing network prices over-recover for off-peak use of the network and under-recover for peak use (AEMC, 2014). Moreover, in the case of prosumers, since network costs incurred by the DSO are not lowered, the costs of DERs connected to the network lead to higher network charges paid by non-generators. Prosumers avoid part of their share of network costs through self-consumption, while their avoided share of the network costs is transferred to others customers. Authors of (Eid et al., 2014) discuss the effects on cross-subsidies, cost recovery and policy objectives evolving from different applied net-metering and charge designs for a residential customer. Moreover, the analysis in (Strielkowski et al., 2017) shows that the increase of solar PV in UK resulted in a transfer of wealth and costs between customer groups. Hence, prosumers lead to increase network charges, as well as changes in the allocation of network payments between customers. This aspect should be considered within network charge design.

Therefore, in (EDSO, 2015a) , the authors advice that network charges should be designed to ensure that customers generating their own electricity still contribute their fair share of the DN costs. Thus, net metering and volumetric distribution network charges should be avoided, as prosumers pay a lower bill, including a reduced contribution to network costs. In addition, the authors advise that investments in DERs should be driven by a clear market signal.

2.2 Design of Distribution Network Charges

The design steps of DN charges are presented in Figure 2.1, starting with the charge's methodology that is formulated to achieve the desired objectives while guided by tariff design principles. Then using charge options, the methodology is structured into charge components, leading to the final charge format.

2.2.1 Tariff design principles

As the DN evolves to accommodate active customers, a more up-to-date DN charge design is required. The main principles for DN charges are well explained in the literature and regulatory practice (Berg and Tschirhart, 1989; Lévêque, 2013; Rodríguez Ortega et al., 2008), and they are: sustainability/sufficiency, equity/non-discriminatory, economic efficiency, additivity, simplicity, consistency, stability and transparency. In those charge principles are elaborated further considering nowadays DN transformation, and are grouped into three main sets:

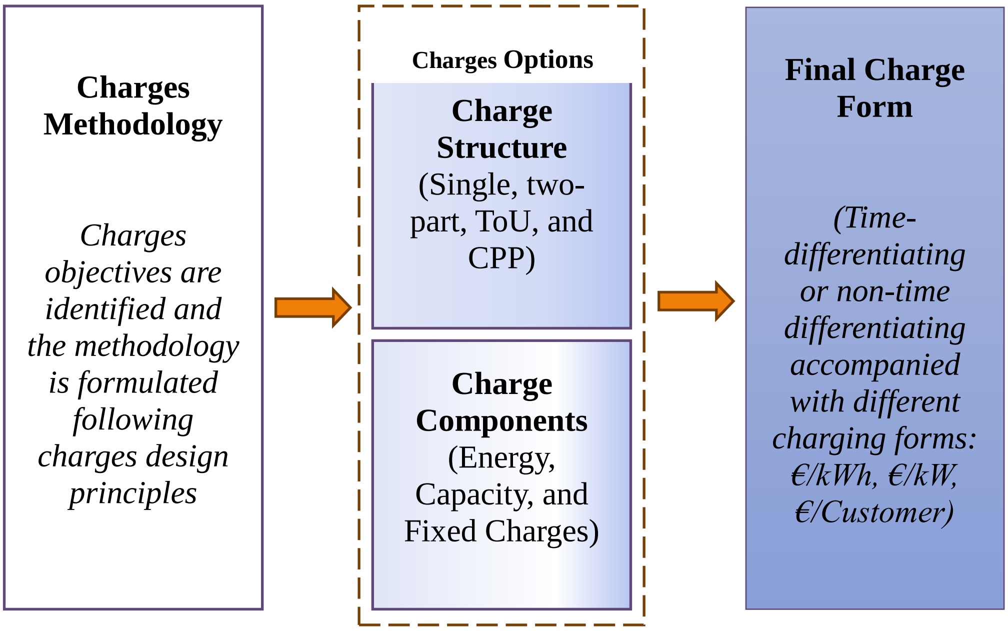


Figure 2.1 Charge Design Stages

(i) **System Sustainability**, 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 guaranteeing 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** aims 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 the minimum possible cost 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 network peak management, leading to a reduction in infrastructure cost for network peak as well as encouraging system flexibility. Thirdly, cost reflectiveness, where customers should be charged according to costs of the services they have received, taking into account their contribution to network peaks and their location in the network.

(iii) **Protection** 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 research. 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. Charge design should accommodate those principles and translate them in the form of charge option that embraces them the most. Hence, cost allocation methodologies as well as charge components and structures need to be well designed and aligned to serve this objective.

2.2.2 Network cost allocation methodologies

Numerous methodologies could be designed and implemented. Many researches proposed and discussed different approaches to design DN charges by allocating DN costs to consumers using different criteria. Table 2.1 summarizes and compares different cost allocation methodologies. Postage Stamp (PS) and Contract Path are non-flow based methods that are used due to their simplicity. Whereas, MW-Mile and MW-MVar methods are based on the magnitude, the path and the distance traveled by the transacted power between the points of injection and withdrawal (Li et al., 2008). MW-Amp is another very similar method based on marginal changes in current, as opposed to power (Sotkiewicz and Vignolo, 2006a). Moreover, Marginal Participation (MP) method allocates the cost of a line on the basis of the marginal impact that a network user has on the line flow. It is a flow based method that uses marginal participation sensitivity of a line (also called power transfer distribution factor, PTDF) (González and Gomez, 2008; Mekonnen et al., 2013; Rudnick et al., 1995). Average Participation methods, also known as Bialek's and Kirschen's power tracing methods, rely on the use of proportional sharing of flows into and out of any node (Rubio-Oderiz and Perez-Arriaga, 2000). Moreover, there are methods based on Long-Term Marginal Costs (LTMC) pricing, which uses analytical equations to evaluate the impact of nodal injection on long-run network development costs (Gu and Li, 2011; Li, 2007); and Long-Term Incremental Cost (LTIC) pricing, which uses a traditional system planning approach to determine the required reinforcements and the corresponding investment schedules with and without each transaction (Gu et al., 2012; Li et al., 2009).

Besides, Short-Term Marginal Costs (STMCs), also known as Locational Marginal Pricing (LMP), is an energy pricing method based on the marginal cost of accommodating a marginal increase in the transacted power (Akinbode, 2013; Perez-Arriaga et al., 1995; Reneses and Rodríguez Ortega, 2014). It is used to price energy at each node, and its surplus is used to recover part of the network costs. In (Siano and Sarno, 2016), the authors illustrated the benefits gained through the implementation of LMPs in the distribution level.

Several authors had combined methods together as they act complementary to each other while providing more merits. In (Paul Sotkiewicz, 2006), the authors combined LMPs with MW-Mile. The method seems promising as it introduces LMPs within the distribution network; however, the MW-Mile is not suitable for distribution networks as it is only applicable to bilateral transactions where the points of injection and reception are known, which is difficult to apply with disperse deployment of DERs. The authors of (Pérez-Arriaga and Bharatkumar, 2014) proposed a cost-reflective method based on allocating the incremental costs associated with network cost drivers to customers using weighted average computed through customers' contribution to cost drivers. This approach is a blend of an incremental and average cost approach. The approach relies up on the use of a reference network model (RNM) to identify the key drivers of DN costs, and then the allocation of those costs according to network utilization profiles that capture each customer's contribution to and share of total system costs. Another similar approach that also uses RNM is presented in (Rodríguez Ortega et al., 2008), but without considering DERs. The method is divided into three steps: the definition of a tariff structure, the allocation of total costs to each cell of the tariff structure, and the computation of the final rates.

Another different approach proposed in (Gruber et al., 2017) is based on polluter (customers) pays principle which is an environmental economics concept that allocates network costs amongst customers according to the costs-by-cause. It is based on the concept of polluters have to bear the costs of pollution prevention, control costs of administrative measures and cost of damage.

2.2.3 Charge components

There are different ways of charging the use of distribution networks as discussed in (CEER, 2017), nevertheless there are three main components: energy, capacity and fixed charges.

- **Energy Charges**

Energy (volumetric) charges are based on the consumption of kWh 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. They are 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. Thus, the generation and network costs could be lumped into a single price (€/kWh). 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 investing in DERs.

- **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 differentiation 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 fulfil economic efficiency principles.

Name		Methodology	Load Flow?	Merits	Demerits	Ref.
Postage Stamp		It does not require any power flow calculations and it does not account for the network distance and network configuration. The basic assumption of this method is, entire network is used, regardless of the actual facilities that carry the service. The charges are allocated on the basis of average embedded cost and the magnitude of customer's transacted power.	No	Simplicity	Does not account for the actual system usage and/or congestion in the system. No locational pricing signals are provided by this method.	(Ilić et al., 1997)
Contract Path		It is based on the assumption that network transaction can flow along specified and artificial electrical paths. This method refers to the specified geographical distance between the generator and consumer, regardless of the physical path. After the artificial contracted paths are defined, network costs will be assigned using post-stamp rate.	No	Simplicity	Does not reflect actual flows through the network, which may include loop and parallel path flows. Thus, the actual path taken by a transaction may be quite different from the specified contract path, involving the use of network facilities outside the contracted systems.	(Ilić et al., 1997)
Marginal Participation		It allocates the cost of a line on the basis of the marginal impact that a network user has on the line flow. It is a flow based method that uses marginal participation sensitivity of a line (also called power transfer distribution factor, PTDF), which is the change in the flow of the line when the injection or withdrawal at a node is increased by 1 MW. Distribution factors based on DC power flows are used to calculate the marginal participation sensitivity of a line to allocate charges among the network users, i.e., to transaction-related net power injections. It depends on system configuration, selection of reference bus, and power flow directions.	Yes	Sends efficient locational signals.	Computationally extensive. Requires individual network asset cost.	(González and Gomez, 2008)
Average Participation/ Power Tracing	**Bailek's**	Relies on the use of proportional sharing of flows into and out of any node. Assumes that nodal inflows are shared proportionally among nodal outflows.	Yes	Can provide solutions to the questions as how much of the power output from a particular generator goes to a particular load, or how much of the demand of a particular load comes from a particular generator.	It does not consider the existence of counterflows, the tracing of power flows is not based on engineering principles, and the allocation of costs to generators and loads is arbitrarily fixed. Requires individual network asset cost	(Soares et al., 2015)
	Kirschen's	Relies on the use of proportional sharing of flows into and out of any node. Based on a set of definitions for domains, commons and links.	Yes	Able to work well under various system-loading conditions.	It is a simplified approach since the contributions from the generators (or loads) to a particular common will be proportionally assigned to the loads (or generators) and line flows within that common. Requires individual network asset cost	(Soares et al., 2015)
MW-Mile		Flow-based pricing scheme where power flow and the distance between points of injection and withdrawal reflect network charges.	Yes	Ensures the full recovery of fixed network costs and reflects, to some extent, the actual usage of the networks.	It is only applicable to bilateral transactions where the points of injection and reception are known. It does not transmit adequate economic signals to the network users.	(Li et al., 2008; Paul Sotkiewicz, 2006; Wang and Li, 2007)

Amp-Mile	Based on marginal changes in current, as opposed to power, in a distribution asset with respect to both active and reactive power injections multiplied by those injections.	Yes	Explicitly accounts for flow direction to provide better long-term price signals and incentives for DG to locate optimally in the distribution network and to alleviate potential constraints and reduce losses. Provides signals based on location and peak usage.	Is applicable only on radial networks since currents are relative to the thermal capacity of distribution network. Does not recover full embedded cost unless and until system is fully loaded.	(Sotkiewicz and Vignolo, 2006a)
Locational Marginal Pricing	It is the marginal cost of accommodating a marginal increase in the transacted power, which is calculated using optimal power flow method.	Yes	Send short-run efficient time and location differentiated price signals to load and generation.	Its surplus is insufficient to cover the costs of the network.	(Akinbode, 2013; Paul Sotkiewicz, 2006; Sotkiewicz and Vignolo, 2006b)
Long-Run Marginal Cost Pricing	It is defined as the marginal cost of supplying an additional unit of energy, when the installed capacity of the system is allowed to increase optimally in response to the marginal increase in demand. In this pricing methodology, the marginal operating and reinforcement costs of the power system are used to determine the final prices for a network transaction. The marginal operating cost is the same as the SRMC, and the reinforcement cost is determined with a similar approach using a long run incremental cost.	Yes	It incorporated both capital and operating costs for the system as a whole. Compared with the SRMC, LRMC provides a simpler calculation process since the values are calculated based on long term plans.	While they are stable within an annual time frame, they tend to be more volatile for calculation of network values on a year to year basis, as they are affected by the timing of individual investment decisions	(Gu and Li, 2011; Li, 2007; Wang and Li, 2007)
Long-Run Incremental Cost Pricing	This method entails all the costs including the reinforcement cost to accommodate a new network transaction. The standard LRIC pricing method uses a traditional system planning approach to determine the required reinforcements and corresponding investment schedules with and without each transaction. First, preliminary calculation is done where all the cost and investment data are prepared. Then the computations of annual revenue requirement and present worth revenue requirement (PWRR) of each reinforcement project takes place. The change in PWRR with and without all the reinforcement projects is calculated and allocated to each transaction.	Yes	Straight forward	The forecasting reinforcement cost scenarios becomes difficult to predict and inaccurate with time. Thus, LRIC methodology is difficult to numerically evaluate.	(Gu et al., 2012; Li et al., 2009)

Table 2.1 Network Cost Allocation Methodologies

- **Fixed Charges**

Unlike energy and capacity charges, fixed charges are not a function of the customer's profiles during the billing period, for 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 (Borenstein, 2016), fixed charges are an attractive way to minimize 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.

2.2.4 Charge structures

Different charge structures are constructed depending on their time variation, among them: Flat charges, Two-part charges, Time-of-use (TOU), and Critical-peak pricing (CPP) (Biggar and Hesamzadeh, 2014). 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 (CEER, 2017) this could benefits both DSOs and customers, as it could provide DSOs with an alternative mechanism to minimize network use costs and can lead to postponement or avoidance of new investments. It also may minimize the impact of intermittent distributed generation (DG) on the network and management of congestion. Table 2.2 summarizes and compares different charge structures (Faruqui and Lessem, 2012), along with examples for countries that implement each tariff structure (CEER, 2017; European Commission-DIRECTORATE B – Internal Energy Market, 2015).

	Description	Influence on Customers	Implemented in
Standard ToU	Different prices for peak and off-peak periods. Periods are defined in advance.	Incentivizes customers to shift their network usage to off-peak periods. Prices of peak periods are not as high as during CPP.	Spain (>15 kW) Slovenia France
Peak-Coincidence/ CPP	Price spikes during limited number of hours per year when critical network event occur. Charge is allocated to customers based on their contribution to the network's peak.	Incentivizes customers to reduce their network usage during network peaks. However, day-ahead notifications are required to be sent to customers when network stress events are predicted.	Australia
Peak (Any time)	A pre-determined charge is applied to customers based on their peak within a specified period (ex. month).	Incentivizes customers to reduce their peak during all times, However, individual peak does not necessarily coincide with network's peak.	Czech Republic Estonia Finland Portugal

Defined Capacity Allowance	A fixed maximum capacity is allocated to customers, according to charges are allocated. Customers may not be physically able to exceed their allowable capacity (fuse trips) or may be allowed for an additional charge.	Incentivizes customers to always keep their capacity below the defined allowance, not only during specific periods.	Spain Netherlands
Inclining Block Tariffs	Charge increase from a tariff block to another. Customers are signalized as their energy consumption reaches a tariff block's threshold.	Incentivizes customers to reduce their consumption at times most convenient to them, regardless network's status. It should be noted that it is difficult for customers to monitor their consumption.	Egypt South Africa

Table 2.2 Distribution Network Charge Structures

2.2.5 Distribution network charges currently applied in different countries

The DN charges used to allocate network costs to customers vastly differ between countries and even between DSOs within the same country (as in Sweden). Many researchers have proposed and discussed a number of methodologies, such as in those discussed in section 2.2. However, most of them were not practically implemented. A comparison between different countries for DN costs allocation is presented in (Li et al., 2015) where most countries used Postage Stamp, 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 contracted capacity (limits the maximum power withdrawn from the network) during different time periods, 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 (LRIC) pricing 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 (CEER, 2017).

Finally, in Australia, recently changes to distribution charges have been introduced, where peak demand charges are applied based on the highest 30-minute consumed power during peak periods (3pm to 9pm weekdays). Long-Run Marginal Cost (LRMC) is 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 (AER, 2016).

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 advocates the use of the inverse elasticity rule to optimize the efficiency of the allocation of the costs of monopolies under some conditions (MIT, 2016). 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 of the forecast demand, while LRIC is the annualized cost of future investments relative to demand increments (Marsden Jacob Associates, 2004).

2.3 Customers' reaction to distribution network charges

Network pricing 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 section 2.2, or the customer's response to dynamic energy prices as in (Klaassen et al., 2016; Torriti, 2012; Yang et al., 2013). However, a limited number of researches considered customer's response to DN charges. In (Parra and Patel, 2016), the authors discussed how the tariff design affects the short-term and long-term decisions of a consumer through a PV-coupled battery system. In (Steen et al., 2016) the authors compare customers' 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 (Bartusch et al., 2011) 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 (Domínguez et al., 2016) demand response as load shifting and incorporating DERs are simulated using a Reference Network Model (RNM) to quantify its consequences on the network in terms of benefits and cost increase. Authors in (Domínguez et al., 2016) 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 (Li et al., 2009), 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 DN 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.

In (Vallés, 2017; Vallés et al., 2018) the potential benefits of integrating demand response into the distribution network planning and operation decisions are demonstrated. A comparison between dynamic distribution network tariffs based on ToU and demand response feedback programs (which is demand response programs with less intrusive forms of intervention, based on the provision of feedback on electricity consumption) within the residential sector is carried out using a proposed consumer model that estimates a distribution function of demand flexibility as a function of the value of the economic incentive. The function reveals information regarding the expected level of responsiveness for a given incentive. Results of a case study implemented on a large Spanish distribution network showed that the performance of dynamic tariffs is higher than that of feedback programs.

Although customers' response is the main factor in promoting efficient distribution networks, and mitigating costly network reinforcements, efficient customer behavior is difficult to attain, and requires clear signals as well as strong incentives. In order to increase efficiency of the whole system and maximize social welfare, it is crucial to fully engage customers and increase their participation. This is required at the local level much more than previously. Depending on industrial customers to provide flexibility is not efficient enough. Small customers located at the low voltage network are also required to participate. Thus, it is essential to understand the factors that affect customers' response to network charges. According to the research project S3C (S3C Consortium, 2013), customers' energy usage decisions are influenced by a number of factors related to both the behavioral and situational aspects. Behavioral factors relate to financial gains, non-monetary motivators (like beliefs, values, habits, and routines), social influences (like norms and leadership), and personal capabilities (like knowledge, skills, and financial means). Situational factors, amongst others include institutional ones (laws, and regulations), culture, infrastructure and social networks (CEER, 2017; S3C Consortium, 2013). In order to stimulate customers' engagement, the following factors should be considered as shown in Figure 2.2:

- **Presentation of information**

The way information is presented to customers affects widely their response. The simpler the charge design, with less complexity to comprehend, the more likely customers will be able to participate and interact. It is essential to increase customers' awareness towards their energy and network usage, for them to understand their effect on network costs. Customers will not be able to respond to price signals if they cannot relate price structures to their usage decisions (AEMC, 2014). In addition, the way information is presented on the smart meter affects customer´s reaction. As shown in the experiment carried out in (Bager and Mundaca, 2017), demonstrating the financial losses on the smart meter can widely affect the response of the customer. Moreover, it is easier for customers to understand high prices rather than rebates. This is because rebates are calculated relative to a customer's reference demand which makes it difficult for customers to estimate the savings they make by changing their profile (CEER, 2017).

- **Use of automation and enabling technologies**

Price signals transmitted through DN charges may not be sufficient enough to stimulate manual behavioral responses from customers. According to (CEER, 2017), from a consumer perspective and especially for residential consumers, the value and potential for flexibility use is complex and can be hard to comprehend. Thus customers on their own may find it difficult to realize the value of their flexibility and modify their profiles in response to DN needs. Enabling technology might overcome this obstacle, as the customer's participation is facilitated through automation. Enabling technologies include display devices that allow customers to track and manage their electricity usage, by communicating real-time prices and energy usage as in the Australia's Smart Grid Smart City project (AEFI Consulting Consortium, 2014). The display device shows text messages to inform the customer regarding price changes and peak events. Moreover, practical experiences and wider studies show that enabling technology can substantially increase the peak load reduction by customers. Automated customer response can reduce peak load by an additional 10–20% compared to without technology (CEER, 2017). In addition, the analysis carried out in (Faruqui et al., 2017) regarding the impact of several studies of time-varying charges on customers' behavior, showed the magnitude of customers' response is stronger when they are provided with enabling technologies. Furthermore, the analysis of 15 pilot studies presented in (Faruqui and Sergici, 2010), concluded that while ToU tariffs lead to reductions in peak demand by 3–6%, CPP lead reductions of 13–20%, and when combined with enabling technologies, CPP achieved reductions of 27–44% in peak demand.

- **Customers are loss-averse**

According to (Nicolson et al., 2017), loss-aversion is an influential factor that affect customers' decisions. The authors presented the results of a survey experiment conducted on a sample of 2020 British customers. Loss-aversion has been measured amongst the customers and the results suggest that it is likely to restrain customers' consumption. The results showed that 93% of customers are loss-averse, i.e. they care more about avoiding financial losses than making savings. Similarly, in (Bradley et al.,

2016) the authors explored the role of loss-aversion in reducing peak electricity demand. The hypothesis was that households were motivated to shift all of their electricity use to off-peak periods in order to avoid losing part of the potential reward. Through the 10 participating households, a reduction in peak demand of 56–59% was estimated. Moreover in (Spurlock, 2015), analyses carried out showed that households are more likely to reduce peak consumption when they are in a loss domain of their value function than in a gain domain.

As smart meters are widely being deployed, customers are expected to play a more active role in achieving a more efficient, secure and stable network. Yet, this is subject to the information and incentives they receive, and which they act upon. Customers need a clear economic signals and incentives to convince them to change their energy consumption/ injection habits. Customers act rationally to economic incentives, and their willingness to respond varies according to the value of economic benefit they are expected to gain. These economic incentives are transmitted through the pricing methodology deployed. Influencing customers to modify their profile with prices is based on the microeconomic theory of utility maximization and consumer rationality (Gyamfi et al., 2013). This theory is based on the notion that customers evaluate the pros and cons of different choices or actions, and select either the most beneficial or the least costly to them. Common practices regarding incentivizing customer response were mainly related to energy pricing, such as ToU, dynamic pricing, and CPP, where customers would modify their load patterns appropriately to reduce their bills (Faruqui and Sergici, 2010; Gutiérrez-Alcaraz et al., 2016; Herter and Wayland, 2010; Higgins et al., 2014). This would usually exhibit a good match between renewable production and demand. However, energy cost is only a part of the total bill customers pay, which composes of transmission network component, distribution network component, taxes and other regulated costs. Similarly to energy pricing, distribution network pricing requires to follow some kind of a dynamic pricing approach that reflects the network's status, and the impact imposed by each customer, rather than traditionally designed approaches, in order to efficiently incentivize customers to behave accordingly.

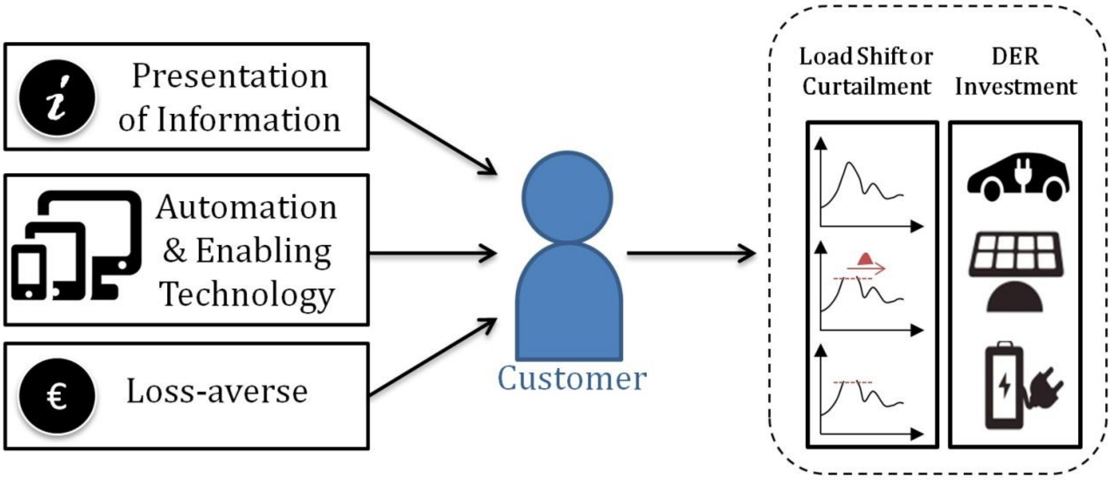


Figure 2.2 Factors that Trigger Customer Response

2.4 Assessing Distribution Network Charges

Each DN charge design holds certain pros and cons. On what basis should a tariff be evaluated? What criteria should be used to promote a tariff design over the other? Some kinds of benchmarks are required to refer to in order to assess network charge designs. This issue has not been widely addressed in previous researches. In (Li et al., 2009), the authors presented 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 consumers to pricing signals, by comparing the different pricing methodologies to find the most effective at encouraging the economic development of the distribution network particularly in the sense of increasing distributed generation. The three pricing models that were considered were 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.

Moreover, in (Jargstorf et al., 2015) the authors proposed a tariff efficiency measure that is divided into two aspects in order to measure the cost reflectivity of a tariff. The first aspect is related to the minimization of the costs of the grid in the future, and the costs of the reaction while meeting the demand. The other aspect is related to the reflective allocation of the costs for the existing grid. A third aspect that was less focused on was the profitability of the business case of local generation. The paper addressed how to measure those aspects, given the consumers' reaction. Both mentioned papers focused on measuring to which extent the applied tariff design was capable of reducing future network costs through different approaches. Yet, there are other aspects that should also be considered when assessing tariff designs, as in (de Sa Ferreira et al., 2013), where the authors discussed different attributes including economic efficiency, revenue adequacy, simplicity and prevention of cross-subsidization.

2.5 Chapter Remarks

Well-designed DN charges are essential to both promote optimal short-term network usage, and guide efficient long-term network development. With an increasing penetration of DER, ill-designed DN charges will become even more problematic. Therefore, new cost-reflective network charge designs are required that allocates DN costs to those who cause them, inducing more efficient customers' behavior.

Network charges that develop on a cost-reflective basis will tend to vary by time and location, and should be symmetrical (for both network injections and withdrawals). They should recover DN costs in a way that signalizes the cost of future augmentations to meet network peaks. Since network reinforcement are based on network's peak (i.e. network capacity being used at the same time), capacity charges that are linked to network peaks are most convenient in ensuring all customers contribute efficiently to the recovery of a DN allowed revenue. Thus, allocation of network costs based on contribution to network-peak coincidence seems a promising approach.

Another promising approach is designing network charges that reflect the true locational variation of network costs. This could be done by applying marginal participation approach, which is more cost-reflective as it includes the location, but also much more complex.

Furthermore, for customers to respond to network charges, they should be able to understand and react to them. That requires efficient price signal, improving DN charge incentives, and facilitating customer and third party participation. Moreover, customers should be appropriately rewarded if they adapt their consumption/injection patterns in a way that reduces network's need for future investments.

3 COMPARING COST REFLECTIVE NETWORK CHARGES: NUMERICAL EXAMPLE

Cost-reflective network charges are challenging to design as it requires trade-offs between tariff design principles, particularly simplicity and economic efficiency. As discussed in Chapter 2, combining different network cost allocation methods together may more efficiently lead to achieve the desired DN charges outcomes. This chapter is an extension to the literature review presented in Chapter 2. It proposes and compares advanced approaches that combine network charges and energy prices. It aims to analyze and quantitatively compare the effect of different DN charge designs on customers' response through their pavement, and on network cost recovery. This analysis will contribute to identify the attributes upon which DN charge designs could be compared and assessed, which is further explained in the evaluation methodology of DN tariff designs in Chapter 4. In addition, drawbacks and shortages of the DN charges are highlighted to assist in reaching a more efficient cost-reflective DN charge proposal in Chapter 5. Hence, this chapter presents a numerical example to compare two network cost allocation methods discussed earlier in Chapter 2: Marginal Participation (MP) and Peak Coincidence Network Charge (PCNC), a variant of Postage Stamp (PS), along with distribution locational marginal prices (DLMPs) as an efficient energy pricing approach.

The cost-reflective tariff design proposed here integrates both energy prices and DN charges. Since customers do not react to DN charges solely, but to the retail price as a whole, and particularly to the energy prices, it is sensible to consider energy prices along with DN charges. First, DLMPs are used to price energy consumption/injection at each node. Then, a surplus is earned through DLMPs that is assigned to recover part of the network cost, while the remaining network costs is recovered through either MP or PCNC. These proposed DN charges plus DLMPs are compared to traditional tariff designs that are commonly implemented in different countries. The analysis and results are published in (Abdelmotteleb et al., 2016b).

3.1 DLMPs

DLMP is similar to Locational Marginal Prices (LMP) used in transmission networks. It is the marginal cost of accommodating a marginal increase in the transacted power at each network node. It is calculated using Optimal Power Flow (OPF) methods. DLMPs and LMPs are known to transmit efficient short-term signals to customers (both generators and consumers), as they capture the hourly state of the network into individual locational prices associated with the cost of providing energy, taking into account the effect of network losses and congestion. The major difference between LMP used in transmission and DLMP, are the losses and congestion portions. In transmission networks, losses are insignificant in comparison to congestion, whereas in distribution networks, losses have a more relevant role due to the high resistance to inductance ratio. Moreover, congestions are rare in DLMP calculations since distribution network topology is generally radial and feeds from one point. Thus, DLMP in distribution systems consists of two main components; the energy price, which refers to the price at the reference bus, plus the cost of marginal distribution losses due to transmitting power from the reference bus to each network node (Shaloudegi et al., 2012). However, the surplus resultant from the application of DLMPs is insufficient to cover the remaining infrastructure and other fixed costs of the network. Consequently, complementary network charges are needed to fully recover the network costs and to send efficient long-term signals to customers. DLMPs are charged as €/MWh, where network charges are charged as €/MW.

DLMPs are computed through an optimal power flow (OPF), which aims to maximize the social welfare. The objective function presented in (3.1) maximizes the difference of consumer benefit and the total cost of active and reactive power generation, where G is the generator set, D is the customer set, $C_{pi}(P_{gi})$ is the active power production cost of generator i, $C_{qi}(Q_{gi})$ is the reactive power production cost of generator i, where C_{pi} and C_{qi} are input values introduced into the model; $B_i(P_{di})$ is the benefit of the consumer, P_{gi} and Q_{gi} are the active and reactive power output of the generator on bus i, P_{di} and Q_{di} are the active and reactive power demand on bus i (Swami, 2012). This is subject to network constraints expressed (3.2)–(3.5). Equations (3.2) and (3.3) present power flow equations, which is a set of equations that characterizes the flow of real and reactive powers through a network, where N is total number of buses in the network, V_i and V_j are the magnitudes of the voltages of bus i and j, respectively, δ_i and δ_j are the voltage angles of bus i and j, respectively, and Y_{ij} and θ_{ij}, are the magnitude and angle of ij^{th} element of the bus admittance matrix, for each hour t (Swami, 2012). Line limits expressed in (3.4) refer to S_l^{max} which is the maximum apparent power that could be transmitted through line l, and $S_{l,t}$ is the apparent power flowing through line l at time t. The voltage at each node should be within the specified range as in (3.5).

$$\max\left[\sum_{i\epsilon D} B_i(P_{di,t}) - \sum_{i\epsilon G} C_{pi}(P_{gi,t}) - \sum_{i\epsilon G} C_{qi}(Q_{gi,t})\right] \tag{3.1}$$

$$P_{gi,t} - P_{di,t} = \sum_{j=1}^{N} V_{i,t}\, V_{j,t}\, Y_{ij} \cos(\delta_{i,t} - \delta_{j,t} - \theta_{ij}) \tag{3.2}$$

$$Q_{gi,t} - Q_{di,t} = \sum_{j=1}^{N} V_{i,t}\, V_{j,t}\, Y_{ij} \sin(\delta_{i,t} - \delta_{j,t} - \theta_{ij}) \tag{3.3}$$

$$S_{l,t} \leq S_l^{max} \tag{3.4}$$

$$V_i^{min} \leq V_{i,t} \leq V_i^{max} \tag{3.5}$$

DLMPs are the shadow prices of the real power balance equality constraints in (3.2). They send short-term economic signals using efficient energy prices. Thus, they enhance market trading through optimal operation and dispatch of resources. A surplus is obtained as presented in (3.6) through the difference between load payments at each node $DLMP_i \times P_{di}$ and generator market revenues at each node $DLMP_i \times P_{gi}$. This surplus is used to recover total network costs (TNC) in (3.7), although typically it will be only a small portion for the case of DNs. Whereas the remaining network costs (RNC), which are the majority of the total costs, are recovered through network charges that are allocated to network users using either PCNC or MP.

$$\text{DLMP Surplus} = \sum_{i\epsilon D} DLMP_i \times P_{di} - \sum_{i\epsilon G} DLMP_i \times P_{gi} \tag{3.6}$$

$$\text{RNC} = \text{TNC} - \text{DLMP Surplus} \tag{3.7}$$

3.2 Network charges: PCNC and MP

3.2.1 PCNC

Under this method, network costs are allocated to customers based on their contribution to the network peak utilization hours, which may be due to high load consumptions or generation injections. This method yields simplicity, as it is straightforward and understandable by all customers. If peak network hours are accurately forecasted, customers could anticipate their charges in advance, sensing the difference in payments by modifying their contribution to network's peak hour. PCNC is a variant of postage stamp (PS). There are other simpler PS approaches not considered that charge the users according to their contracted power or installed capacity instead of their contribution to the network peak utilization periods. This is because the network's investment costs are driven by network peaks rather than individual peaks, which do not necessary coincide at same moments.

PCNC allocates costs to customers in €/kW according to their contribution to network's peak utilization hour(s), which may be due to consumption or injection as in (3.8), which is for the case of a network's peak that is dominated by demand. This aims to guide the customers through their long-term decisions, affecting DER investment decisions while ensuring the recovery of the network costs. Equation (3.8) is based on the number of stressful hours considered. If there is more than one network peak utilization hour, then RNC will be allocated between those hours proportional to their utilization level.

$$\mathrm{PCNC_t} = \frac{\mathrm{RNC_t}}{\sum_{\mathrm{i \in D}}(\mathrm{P_{di,t}} - \mathrm{P_{gi,t}})} \tag{3.8}$$

3.2.2 Marginal Participation (MP)

This method allocates RNC of each network line (branch) on the basis of the marginal impact that each customer has on the corresponding line flow at the times of maximum utilization of that line. It is a flow based method that uses marginal participation sensitivities (also called power transfer distribution factor, PTDF). Distribution factors based on DC power flows are used to calculate the marginal participations to allocate costs among the customers, i.e., to transaction-related net power injections (Mekonnen et al., 2013; Rudnick et al., 1995). This method depends on the system configuration, the selection of a reference bus, and the power flow directions. The selection of the reference (slack) bus was a major issue in transmission when considering this method, as the assigned costs to each customer are based on the selected reference bus. Thus, the cost allocation would depend on an arbitrary decision. However, that argument is not relevant in distribution, as the reference bus is considered the upper grid (the point of intersection between transmission and distribution). This method´s main drawbacks are that it requires to evaluate the network asset individually not as a whole, i.e. cost of each network asset should be provided separately, and secondly, the method is more sophisticated to be understood by all customers.

3.3 Information notification

Another important aspect of DN charge design is the information to be passed onto customers, which includes two parts: the charge and its accompanying period. Whether the information should be announced ex-ante or ex-post affects widely the reaction of the customers, and also the recovery of network costs. In this cost-reflective method, the information is provided through three phases, as illustrated in Figure 3.1: ex-ante, real time-operation, and ex-post. In ex-ante, the hourly day-ahead DLMPs and the expected (according to forecasts) network peak hour(s) are announced. This information is subject to change closer and during real time operation, when the actual generation and demand values are known. Then, ex-post, network charges are allocated according to the actual peak hour(s) of the elapsed period, which may or may not concur with the information provided ex-ante. According to the actual peak hours of the network, PCNC is allocated.

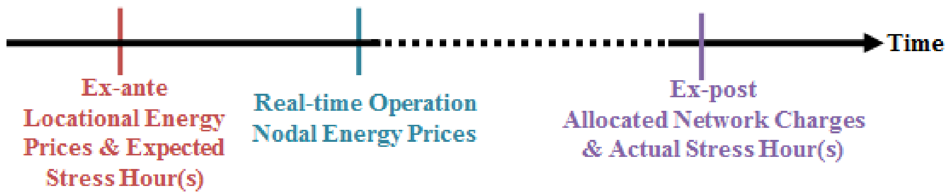


Figure 3.1 Cost-Reflective Method's Information Timeline.

3.4 Case Study

The aim of this case study is to first investigate how customers' payments and DSO income from DN charges differ between different cost allocation methodologies. Secondly, how they are further affected by DER integration. The DER investments have already been done, they are not considered as a reaction to the cost allocation methodologies. Instead, customers' payments are used to compare the performance and effect of different DN charge designs on customers.

For the traditional tariff design, three case studies were implemented: the first case is based on energy charges (100% energy), the second is based on demand charges (100% demand), and the third is based on 50% energy-50% demand, i.e. the total network cost is recovered using a two-part tariff with one single price associated to energy (€/MWh) and one other to demand (€/kW), upon which each recovers 50% of the total cost. The proposed methodology uses DLMP for short-term signals to recover partially the network costs, whereas the remainder is retrieved through either PCNC method or MP method. PCNC method is based on each customer´s contribution to the network's peak hour. Whereas MP method distributes the remainder of each branch's cost among the customers according to their participation during the hour of the branch's maximum utilization.

3.4.1 Case study data

All case studies were carried out on the distribution network of the IEEE 34 Node Test Feeder, an actual feeder located in Arizona, illustrated in Figure 3.2 and explained in (Abdelmotteleb et al., 2016b; Schneider et al., 2018). The network is mostly medium voltage, apart from nodes 21 and 22 that are low voltage. The network (feeder) was modeled using a modified version of Matpower (Zimmerman et al., 2011) and according to network details available in the Appendix (Schneider et al., 2018). The modified version includes voltage regulator (VR) control in order to limit the voltages along the feeder within ±5% of the nominal voltage. The network is connected to the upper grid (Grid) which symbolizes the generation and transmission network, upon which nodal prices are calculated and presented to the distribution network. Hourly day-ahead prices used, available in the Appendix, are extracted from the Spanish electricity market OMIE (Operador del Mercado Ibérico Español) data, which manages the spot market in the Iberian Peninsula (OMIE, 2015). It is assumed that at each node, a number of customers are grouped together, and the profile of each customer is generated using a load profile generator software (Pflugradt et al., 2013).

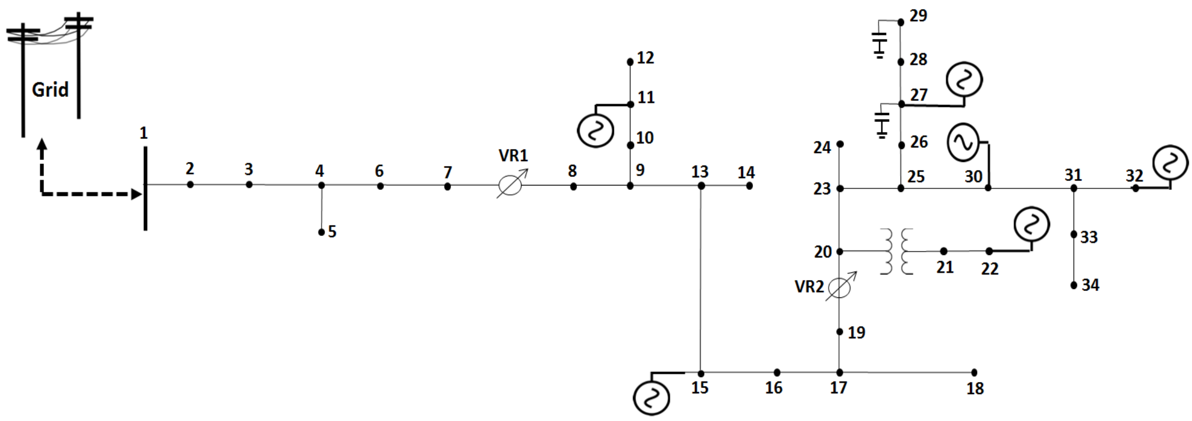


Figure 3.2 IEEE 34 Node Test Feeder

Although tariff periods usually last a year or longer, the simulation period considered for this case study is one day, corresponding to a network's peak day. Peak hours are critical periods of the network, where managing the network's operation could be challenging for the DSO. DERs and demand response may have positive impacts, subject to the DN charge design implemented. Thus, the scope of one peak day is implemented to analyze the payments assigned to customers within each tariff design. The scope of this case study does not consider seasonal variations between demand and PV generation along the year, which could be considered with potential different situations of maximum utilization of the network.

Each case study runs over one day (01:00 – 24:00), where that day is assumed to be a critical day of the year upon which the total cost of the network is divided equally among the year. The total cost of the DN for the considered day is €943.66. It is calculated based on the cost of all assets within the network according to the RNM (reference network models) library, which is a computational tool for planning and designing large-scale smart distribution networks (Domingo et al., 2011; Gómez et al., 2013). The total cost is the sum of the annuity of the network which is calculated with a rate of return of 5% over 40 years, and the yearly operation and maintenance cost that is assumed to be 5% of the initial cost per year (apart from transformer which is assumed 10% of the initial cost). Detailed cost data is available in the Appendix. The daily cost of each network asset is provided in Table 3.1.

For the three traditional cases, a flat energy charge was set to 39.40 €/MWh. Total energy and peak demand consumptions per customer are shown in table 3.2. Network charges were calculated for each case to recover the network costs based on no DER integration. It was set to 43.65 €/MWh for the first case where it is based solely on the energy consumption, 601.63 €/MW for the second case where it is based solely on the individual peak demand consumption, and half each of those values for the third case

(21.82 €/MWh and 300.82 €/MW) where half of the network costs are recovered through energy consumption and the other half through demand.

Branch No.	Bus From	Bus To	Cost (€)
1 + Substation	1	2	91.06
2	2	3	5.16
3	3	4	96.17
4	4	5	12.81
5	4	6	111.89
6	6	7	88.71
7 + VR 1	7	8	26.04
8	8	9	0.80
9	9	10	3.77
10	9	13	26.50
11	10	11	106.23
12	11	12	30.31
13	13	14	6.68
14	13	15	2.18
15	15	16	53.04
16	16	17	1.35
17	17	18	51.47
18	17	19	95.58
19 + VR 2	19	20	26.04
20	20	21	7.83
21	20	23	12.72
22	21	22	25.78
23	23	24	3.57
24	23	25	15.13
25	25	26	0.73
26	25	30	5.24
27	26	27	3.50
28	27	28	9.45
29	28	29	1.38
30	30	31	6.95
31	31	32	2.23
32	31	33	0.73
33	33	34	12.61
	Total (€)		943.66

Table 3.1 Network Daily Cost

3.4.2 Results

The case studies were executed to compare between the traditional and the cost-reflective tariff designs. Within each tariff design, traditional and cost-reflective, several case studies were carried out. First, with no DER integration, and then DERs were added to the network in the form of PV generators. Five PV generators were added, as shown in Figure 3.2, each with an installed capacity equivalent to the maximum consumption of the node it is connected to. The total PV installation in the network is 1 MW corresponding to 64% of the network’s peak load, and producing 6.13 MWh per day which corresponds to 28% of the network’s energy consumption. The grid is the main source of generation in this network and considered the only available generation during the cases of no DER integration. With DER integration, PV generators having zero variable cost are dispatched first. Figure 3.3 presents the total load, the PV production and the net load over the implementation period. As shown in the figure, the main hours of PV production fall between 10:00 and 16:00, with peak production at 13:00.

The PV generation is used originally for self-consumption, covering the local demand at the node it is connected to. Any excess generation is then used to cover the rest of the demand in the network, beyond so, is exported to the upper grid (Grid). During this study case, the PV production was distributed as 77.4% for the local demand, 22.6% for the network demand and there were no exportations to the Grid.

The integration of PV led to a number of variations in the network. First, it reduced the losses within the network by 46%, due to a reduction in the amount of energy acquired by the upper grid. In addition, the PV reduced the DLMPs in the hours of its generation as shown in Figure 3.3. It also shifted the hour of peak load from 16:00 to 20:00. Figure 3.4 shows how the DLMPs changed across the feeder and with and without PV.

Bus	Peak Capacity (MW)	Peak Capacity (During PV) (MW)	Total Energy (MWh)	Total Energy (During PV) (MWh)
1	0	0	0	0
2	0.0275	0.0275	0.363	0.363
3	0.0275	0.0275	0.362	0.362
4	0.008	0.008	0.068	0.068
5	0.008	0.008	0.059	0.059
6	0	0	0	0
7	0	0	0	0
8	0	0	0	0
9	0.0025	0.0025	0.025	0.025
10	0.0175	0.0175	0.185	0.185
11	0.0845	0.084	1.024	0.667
12	0.0675	0.0675	0.943	0.943
13	0.0245	0.0245	0.322	0.322
14	0.02	0.02	0.256	0.256
15	0.0055	0.005	0.040	0.020
16	0.048	0.048	0.631	0.631
17	0.002	0.002	0.007	0.007
18	0.002	0.002	0.014	0.014
19	0	0	0	0
20	0.0075	0.0075	0.066	0.066
21	0	0	0	0
22	0.25	0.196	4.485	3.001
23	0.0245	0.0245	0.253	0.253
24	0.001	0.001	0.005	0.005
25	0.089	0.089	1.170	1.170
26	0.0045	0.0045	0.030	0.030
27	0.432	0.331	5.200	2.801
28	0.034	0.034	0.356	0.356
29	0.072	0.072	0.962	0.962
30	0.174	0.172	3.095	2.059
31	0.061	0.061	0.775	0.775
32	0.048	0.047	0.619	0.395
33	0.014	0.014	0.147	0.147
34	0.014	0.014	0.157	0.157
Total	1.57	1.41	21.62	16.10

Table 3.2 Customers' Peak Demand and Energy Consumption with and without PV Integration

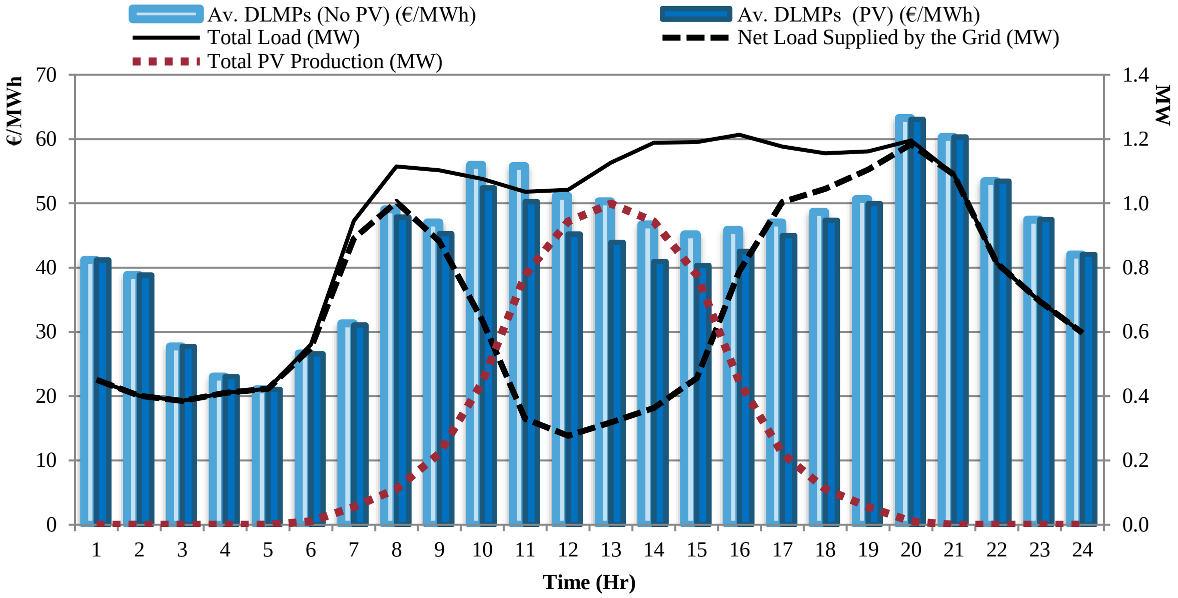


Figure 3.3 Total load, Net Load Supplied by the Grid, Photovoltaic Cells (PV) Production and Average DLMPs during the Implementation Period

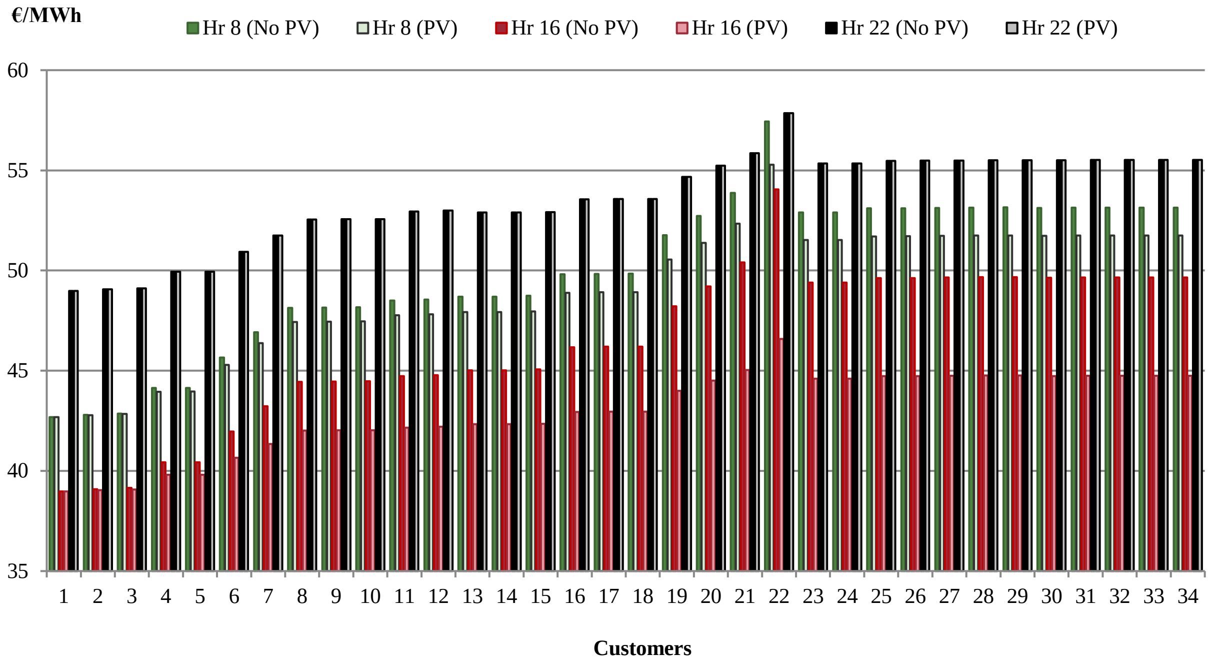


Figure 3.4 Comparing DLMPs during Different Hours with and without PV Integration

A comparison between the payments of each customer, which include both energy and network payments, for each case is shown in Tables 3.3 and 3.4, along with the total network income received for the network in each case. The customers' payments under the traditional tariff design methods and the proposed cost-reflective method are laid out in Tables 3.3 and 3.4 respectively.

	Traditional Methods									
	Case 1 (50% Energy – 50% Demand)						Case 2 (100% Energy)		Case 3 (100% Demand)	
	Case 1 (No PV)			Case 1 (PV)						
Bus	Energy (€)	Demand (€)	Total (€)	Energy (€)	Demand (€)	Total (€)	Energy (No PV)	Energy (PV)	Demand (No PV)	Demand (PV)
1	-851.55	0.00	-851.55	-634.14	0	-634.14	-852	-634	-852	-634
2	22.23	8.12	30.35	22.23	8.12	30.35	30.15	30.15	30.55	30.55
3	22.14	8.12	30.26	22.14	8.12	30.26	30.03	30.03	30.49	30.49
4	4.14	2.41	6.55	4.14	2.41	6.55	5.61	5.61	7.48	7.48
5	3.60	2.41	6.01	3.60	2.41	6.01	4.89	4.89	7.13	7.13
6	0.00	0.00	0.00	0	0	0.00	0	0	0	0
7	0.00	0.00	0.00	0	0	0.00	0	0	0	0
8	0.00	0.00	0.00	0	0	0.00	0	0	0	0
9	1.56	0.75	2.31	1.56	0.75	2.31	2.12	2.12	2.51	2.51
10	11.30	5.26	16.57	11.30	5.26	16.57	15.34	15.34	17.80	17.80
11	62.69	25.42	88.11	40.80	25.13	65.94	85.04	55.35	91.18	76.52
12	57.74	20.31	78.05	57.74	20.31	78.05	78.33	78.33	77.77	77.77
13	19.69	7.37	27.06	19.69	7.37	27.06	26.71	26.71	27.41	27.41
14	15.67	6.02	21.69	15.67	6.02	21.69	21.26	21.26	22.12	22.12
15	2.46	1.65	4.11	1.25	1.61	2.87	3.33	1.70	4.89	4.03
16	38.61	14.44	53.04	38.61	14.44	53.04	52.37	52.37	53.72	53.72
17	0.46	0.60	1.06	0.46	0.60	1.06	0.62	0.62	1.50	1.50
18	0.87	0.60	1.47	0.87	0.60	1.47	1.18	1.18	1.76	1.76
19	0.00	0.00	0.00	0	0	0.00	0	0	0	0
20	4.04	2.26	6.30	4.04	2.26	6.30	5.49	5.49	7.11	7.11
21	0.00	0.00	0.00	0	0	0.00	0.00	0.00	0	0
22	274.54	75.20	349.74	183.72	58.99	242.72	372.42	249.23	327.06	236.21
23	15.48	7.37	22.85	15.48	7.37	22.85	21.00	21.00	24.70	24.70
24	0.30	0.30	0.60	0.30	0.30	0.60	0.41	0.41	0.80	0.80
25	71.65	26.77	98.42	71.65	26.77	98.42	97.19	97.19	99.65	99.65
26	1.84	1.35	3.20	1.84	1.35	3.20	2.50	2.50	3.89	3.89
27	318.31	129.95	448.26	171.46	99.47	270.93	431.79	232.59	464.72	309.27
28	21.79	10.23	32.02	21.79	10.23	32.02	29.56	29.56	34.48	34.48
29	58.86	21.66	80.52	58.86	21.66	80.52	79.84	79.84	81.19	81.19
30	189.44	52.34	241.78	126.04	51.76	177.80	256.98	170.97	226.58	184.62
31	47.46	18.05	65.51	47.46	18.05	65.51	64.38	64.38	66.64	66.64
32	37.86	14.44	52.30	24.15	14.28	38.43	51.36	32.76	53.24	44.10
33	9.03	4.21	13.24	9.03	4.21	13.24	12.25	12.25	14.23	14.23
34	9.61	4.21	13.83	9.61	4.21	13.83	13.04	13.04	14.61	14.61
Total	471.83	471.83	943.66	351.37	424.07	775.44	943.66	702.74	943.66	848.14

Table 3.3 Comparison between Customers' Payments under Traditional Tariff Designs

	Proposed Cost-Reflective Method										
	(No PV)					(PV)					
Bus	**DLMP (€)**	**PCNC (16:00)* (€)**	**PCNC Total (€)**	**MP (€)**	**MP Total (€)**	**DLMP (€)**		**PCNC (20:00)* (€)**	**PCNC Total (€)**	**MP (€)**	**MP Total (€)**
1	-979.99	0	-979.99	0	-979.99	0.00	-681.37	0	-681.37	0	-681.37
2	15.48	9.43	24.92	1.00	16.48	15.47		20.53	36.00	2.07	17.54
3	15.09	12.12	27.21	1.34	16.44	15.07		16.38	31.45	1.74	16.81
4	3.02	2.97	5.99	0.63	3.65	3.00		4.98	7.98	1.05	4.05
5	2.58	4.14	6.72	13.68	16.26	2.55		1.49	4.04	13.12	15.67
6	0	0	0	0	0	0		0	0	0	0
7	0	0	0	0	0	0		0	0	0	0
8	0	0	0	0	0	0		0	0	0	0
9	1.15	0.61	1.75	0.27	1.42	1.11		0.84	1.95	0.38	1.49
10	8.93	8.19	17.12	4.06	13.00	8.61		13.31	21.91	6.49	15.09
11	48.04	29.14	77.18	70.13	118.17	30.66	-7.24	63.53	86.94	86.17	109.59
12	44.12	30.62	74.73	96.03	140.15	42.60		42.43	85.03	101.81	144.40
13	15.12	13.63	28.75	6.47	21.59	14.59		12.01	26.60	5.88	20.46
14	11.88	7.79	19.67	10.38	22.27	11.48		9.41	20.89	11.29	22.77
15	2.00	2.46	4.46	1.17	3.18	1.07	-1.32	3.79	3.54	1.86	1.62
16	30.35	19.21	49.55	10.35	40.70	29.06		36.50	65.56	20.49	49.55
17	0.38	0.11	0.49	0.06	0.44	0.35		0.34	0.69	0.19	0.55
18	0.69	0.34	1.04	51.66	52.35	0.65		0.25	0.90	51.61	52.26
19	0	0	0	0	0	0		0	0	0	0
20	3.36	2.11	5.48	1.44	4.81	3.20		4.25	7.45	3.10	6.30
21	0	0	0	0	0	0		0	0	0	0
22	225.20	166.03	391.22	139.89	365.08	137.12	-2.20	117.64	252.56	116.16	251.08
23	13.04	12.72	25.76	8.97	22.02	12.28		15.58	27.86	11.73	24.01
24	0.26	0.19	0.45	3.70	3.96	0.25		0.39	0.64	3.87	4.12
25	59.22	31.82	91.04	23.29	82.51	56.16		67.67	123.83	52.77	108.93
26	1.45	0.84	2.29	0.61	2.07	1.38		0.91	2.30	0.71	2.10
27	263.73	298.85	562.57	222.26	485.99	133.41	-11.19	158.55	280.77	127.05	249.27
28	18.27	9.61	27.87	10.20	28.46	17.30		25.85	43.15	23.36	40.66
29	48.78	38.63	87.41	36.56	85.34	45.79		54.74	100.53	51.10	96.89
30	153.17	89.42	242.58	68.43	221.60	96.82	-1.34	130.83	226.30	105.01	200.48
31	39.27	26.83	66.10	23.81	63.08	37.11		44.80	81.90	39.13	76.24
32	31.55	20.54	52.09	20.67	52.21	19.42	-2.82	36.10	52.69	33.77	50.36
33	7.55	4.19	11.75	4.28	11.84	7.15		8.26	15.40	7.66	14.81
34	7.95	9.50	17.45	20.66	28.61	7.38		8.77	16.14	20.55	27.93
Total	91.64	852.01	943.66	852.03	943.67	43.53		900.12	943.66	900.12	943.66

*Peak hour

Table 3.4 Comparison between Customers' Payments under Proposed Cost-reflective Tariff Design

3.4.3 Observations

Proposed vs traditional network cost allocation methodology considering DER integration

The effect of PV installation causes a modification in customers' payment as well as in the total network income, as shown in Tables 3.3 and 3.4. In Table 3.4, an extra column is introduced for the DLMP payments, indicating the payments received by each customer with PV (highlighted in green) for the power injected into the network. Firstly, individual payments by each customer varied. On one hand, for the traditional methods (cases 1, 2 and 3), a reduction in the energy payments for the PV investors is observed in Table 3.3 (rows 11, 15, 22, 27, 30 and 32), while that of the passive customers remained the same. The demand payments are related to the individual peak consumption of each customer. The PV investors, such as 22 and 27, are able to reduce their peak consumption, and thus are charged less demand payments.

On the other hand, for the proposed cost-reflective tariff design, since network charges are ex-post, customers' payments were adjusted due to the integration of PV, according to their contribution to the network's peak in the case of PCNC and to the branch´s maximum utilization in the MP method. Originally, the network's peak was at 16:00, after the integration of PV, the peak changed to be at 20:00, as shown in Figure 3.3. Thus, customers' payments increased/decreased according to their contribution to the new network's peak hour in the case of PCNC method. Those network users with peak demand coinciding with network's peak demand, after the PV integration at 20:00, are assigned higher payments that those with peak demands at 16:00. As for the MP method, payments changed according to the contribution of each customer to the hour of maximum utilization of each branch, which changed for most of the branches after PV integration, as illustrated in Table 3.5. Moreover, a reduction in the DLMP prices was noticed due to PV production, as shown in Figure 3.3, particularly during the hours of maximum PV production, which led to a reduction in the DLMP payments of all customers.

Secondly, the total income of customers' payment was affected under the traditional tariff method, but not under the proposed one. As demonstrated in Table 3.3, the total cost to be recovered is 943.66 €, which corresponds to the income received by the traditional methods without PV integration, as well as by the proposed method with and without PV integration, as shown in Table 3.4. However, due to PV production using the traditional methods, a reduction in the total income occurred. This reduction is highly influenced by the size of the energy component within the tariff design. As energy component increases, network cost deficits increase. Hence, volumetric tariff (100% energy) led to least network income with PV integration. Under the traditional methods, costs are allocated ex-ante; thus, the integration of PV is not taken into account prior the annunciation of tariffs. In addition, this deficit is also due to inefficient allocation of the costs. Customers with PV generation are capable of reducing their energy consumption through self-generation, reducing their energy payments. Thus, they are assigned less network costs, although they may have not necessarily reduced their impact on the network.

			Hour of Max Utilization	
Branch No.	Bus From	Bus To	No PV	PV
1 + Substation	1	2	16	20
2	2	3	16	20
3	3	4	16	20
4	4	5	20	20
5	4	6	16	20
6	6	7	16	20
7 + VR 1	7	8	16	20
8	8	9	16	20
9	9	10	20	20
10	9	13	16	20
11	10	11	20	20
12	11	12	20	20
13	13	14	20	20
14	13	15	16	19
15	15	16	16	19
16	16	17	16	19
17	17	18	16	16
18	17	19	16	19
19 + VR 2	19	20	16	19
20	20	21	16	19
21	20	23	16	20
22	21	22	16	19
23	23	24	20	20
24	23	25	16	20
25	25	26	16	19
26	25	30	20	20
27	26	27	16	19
28	27	28	20	20
29	28	29	20	20
30	30	31	16	19
31	31	32	20	20
32	31	33	16	16
33	33	34	16	16

Table 3.5 Hour of Max. Utilization of each Branch with and without PV Integration

On the contrary, the proposed method ensures network cost recovery in conjunction with the allocation of the network costs to customers in correspondence to the costs they impose on the network. The method combines between ex-ante, which is the DLMP part and ex-post, regarding the network charges part.

Ex-ante vs Ex-post

Traditional DN tariffs follow ex-ante approaches, where charges are communicated to customers prior the tariff period. Based on that given information, customers react and may deviate from their expected profiles that charges were initially computed based upon, and consequently lead to network cost recovery deficits. In the proposed cost-reflective DN charges, the allocation of DN costs is ex-post, which eliminates the risk of network cost deficits. Customers are informed ex-ante with the expected charges, which provide initial economic signals that ought to be adjusted at the end or during the tariff period.

Active and passive customers: PCNC Vs MP

The cost-reflective cases illustrate different customer payments, where some are benefitting while others are not due to the DER integration. Figure 3.5 compares four different customers; 13 and 25 are passive customers, whereas 22 and 32 were passive customers and shifted to be prosumers (active customers) by installing PV. The active customers benefitted a great reduction in DLMP payments through self-generation, and by exporting to the network during hours of excess PV generation, as shown in Table 3.4. Although both customers 22 and 32 decided to invest and install PV, customer 22 is highly benefitting while customer 32 is not. Both users benefitted from the decrease in

DLMPs and self-generation. However, due to the profile of each, the network costs were assigned benefitting customer 22 and penalizing customer 32. Customer 22's profile peaks at 16:00, which originally coincided with the feeder´s peak hour, at 16:00, while user 32's profile peak did not coincide. After the PV integration, the peak hour of the feeder shifted to 20:00, coinciding with customer 32's peak and no longer with customer 22's peak. Thus, customer 22 benefitted by a reduction in network payments. Whereas customer 32 was assigned higher payments, resulting in an inappropriate investment decision taken by customer 32.

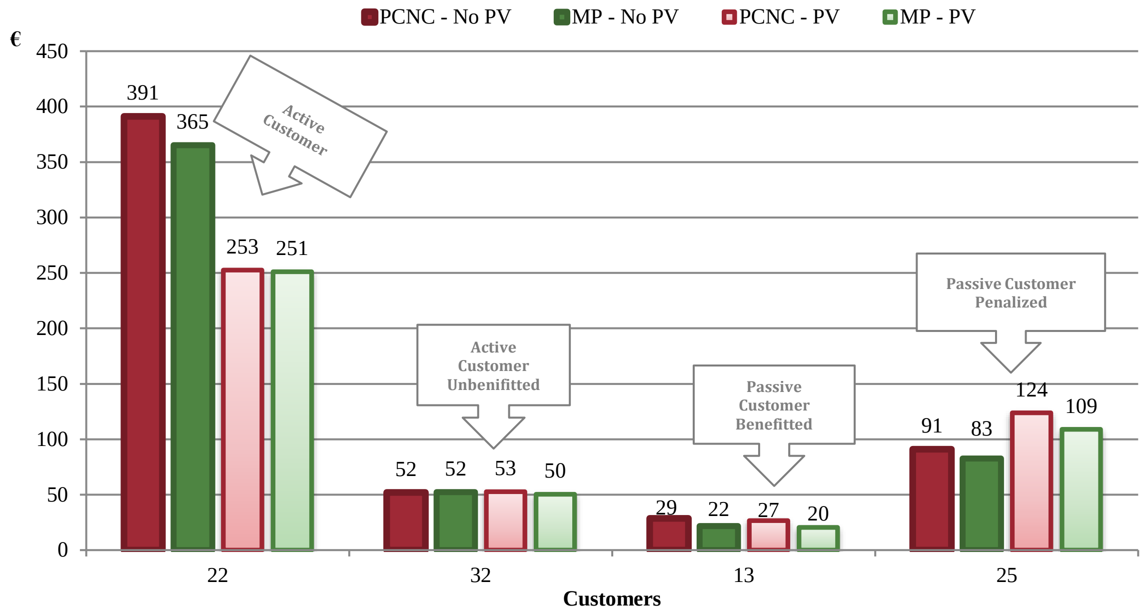


Figure 3.5 Comparing Active and Passive Customers' Payments under Proposed Cost-Reflective Tariff Design

Moreover, the passive customers are also affected by their neighbors' decisions. Although they all benefitted by the lower DLMP prices, they did not all benefit with lower network payments, as it mainly depended on the load profile of each customer. Customer 25 has a profile peaking at 20:00, while customer 13 has a profile peaking at 16:00. For both PCNC and MP methods, customer 25 is penalized after the integration of PV and allocated higher costs, due to PV integration, while customer 13 is benefitted by less costs allocated to him, as illustrated in Figure 3.5.

In summary, the proposed method aligns the costs allocated to each customer to their impact on the network following cost causality principle. For both the active and passive customers, those who benefit the network by reducing their impact are conjointly benefitting themselves with lower allocated costs. While those who participate in increasing the impact on the network, are penalized with a greater share of the network costs. In addition, PCNC and MP methods are both profitable and detrimental to customers. Thus, both methods are capable of sending influential signals to the encouraging customers to alter their profile. However, PCNC method is more robust than MP, requiring more customers to change their profile, in order to change the network's peak hour. Whereas, the MP method is branch depended, thus, the hour of maximum utilization could differ more frequently, based only on a limited number of customers using a particular branch. These issues will be subject to further investigation. In addition the MP method is difficult to be understood by customers and hence respond to it.

3.5 Chapter Remarks

The proposed cost allocation methodology consists of two parts, first using DLMPs to allocate energy prices, and secondly, to allocate network charges to each customer through cost causality principle using either PCNC or MP method. The proposed method is compared to the traditional cost allocation method highlighting critical issues related to the deployment of DERs into DNs. Firstly, the traditional cost allocation methodology lacks the capability to recover the total network costs during DER integration, emphasizing a growing flaw in the use of these types of methods as DNs accommodate higher penetrations of DERs.

Secondly, the proposed method clearly allocates costs aligning with the customers' impact on the network. The PV integration led to a decrease in DLMPs during the hours of PV production, which all customers (active and passive) benefitted from under the proposed methodology. Moreover, the proposed methodology also captured a shift in the network's peak hour, upon which allocated the network charges corresponding to customer´s impact. This favored all customers of profiles not coinciding with the new peak hour and penalized the rest.

Besides, the analysis carried out was based on one peak day, considering the DN costs to be recovered during it, where practically, this is not the case. Another approach is to forecast the number of expected peak hours within the tariff period and assign DN costs to each hour corresponding to its average weight. Then, for each peak hour, the assigned DN costs may be recovered through either PCNC or MP.

Furthermore, there are important remarks to consider for designing efficient network charges in networks with DER integration, which will be considered in the final cost-reflective DN charge proposed in Chapter 5:

1) Volumetric-based network charges do not recover network costs. A demand-based charge should be included in the tariff design to ensure network cost recovery. The demand charge should be based on network's peak rather than individual peak, as it is the main driver for network investments.

2) DLMPs are efficient in providing locational signals, reflecting network losses and congestions. However, within the distribution network and particularly LV networks, DLMPs may frequently change, causing unstable economic signals sent to customers. Moreover, DLMPs only recover a small portion of the total network cost, requiring other network cost allocation methods to accompany it in order to recover the rest of network costs.

3) Network charges should follow a methodology that could be easily understood by customers, even though it might not be as cost-reflective or sophisticated as other approaches. Customers' engagement is an essential key to achieve high

system's economic efficiency. Thus, the network charges should send economic signals that are clear and easy to comprehend, in order for customers to understand and respond to it.

4) Economic signals sent by network charges should be well designed to correctly influence customers. In case of networks that are not highly utilized, network charges with demand-based component may incorrectly encourage them to reduce their network usage. Thus, network charges should be aligned with the network's utilization level.

5) Network charges should send efficient short-term as well as long-term signals, guiding customers to efficient DER investment decisions that benefit them as well as the network.

Finally, network charge designs should reflect a balance between economic efficient signals and practical considerations. Hence, regulators should be able to compare and assess different charge designs. In general, when comparing PCNC and MP, PCNC is a more efficient network charge method. This is because it is less complicated computationally, and easier to be understood by customers. Thus, an efficient customer response is more likely. Besides, since network charges are based on the network's peak utilization rather than individual utilization of network assets, the economic signals sent through PCNC are more stable. In order to more efficiently assess different DN charges, an evaluation methodology is required that identifies the main attributes upon which DN charges are compare. This is the focus of Chapter 4.

4 Evaluation Methodology of Tariff Design

Cost-reflective tariffs are promising in the way that they reflect the actual costs incurred by each consumer/generator. They are seen as a means of ensuring greater social equity by reducing the largely invisible cross-subsidies embodied in flat-rate tariffs (Hobman et al., 2016). However, there are arguments and doubts whether cost-reflective pricing would yield desired outcomes. Hence, a proposed evaluation methodology based on four attributes is presented in the chapter which aims to evaluate and compare different tariff designs. It is implemented through the case study presented in Chapter 3. The customers' payments under different tariff designs are generated to evaluate how different tariff designs perform within each of the proposed attributes. The analysis and case study carried out here are published in (Abdelmotteleb et al., 2017).

4.1 Proposed Evaluation Methodology

The proposed evaluation methodology considers the energy prices along with the distribution network charges that are determined by regulators and implemented for a certain period of time, within which various customers' reactions to the implemented network charges and energy prices are generated. Figure 4.1 illustrates the tariff cycle, starting at stage one when the method is implemented. Then, as a consequence, in the second stage consumers react to energy prices and network charges. Those signals guide the customers through operational decisions in which they would modify their consumption/injection patterns. Some customers could further react taking long-term DER investment decisions as shown in the third stage, or as in the fourth stage, customers may be incentivized to participate in providing price-response demand services. Thus, based on prices and customers' reaction to it, payments are allocated. In the fifth stage the money is collected, where the part associated with energy prices is traded in the market and the remaining is assigned to recover the network costs. Finally, in the sixth stage, adjustments to the network tariff are made by the regulator to adapt it to the network's new circumstances to ensure the recovery of the network costs in the following period.

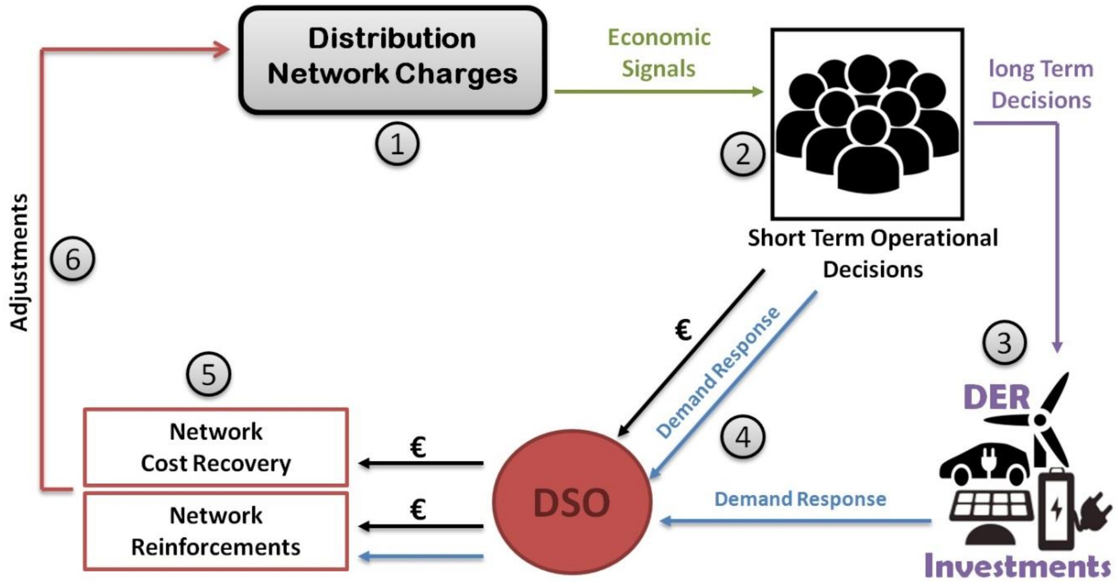


Figure 4.1 Distribution Network Tariff Cycle

From an economic efficiency point of view, DN charges should be designed to fulfill three main objectives: firstly, to fully recover the DN costs, secondly to defer or mitigate, if possible, network reinforcements, and thirdly to allocate the network costs to customers following economic efficiency principles. The third objective is a very critical issue, since the payments allocated to each customer will be an influential tool used to guide their behavior towards the network. It is crucial to ensure that correct signals are received by all customers through those payments. Incorrect signals may result in poor customers' responses, undesired reduction in their network usage or, in extreme cases, network disconnection. Thus, costs should be assigned to customers based on their impact on the network. In other words, those having positive impacts on the network (such as reduction in losses or mitigating network reinforcements) will be rewarded or otherwise penalized.

The proposed evaluation methodology provides a way to measure the performance of different tariff designs in order to evaluate, compare and capture the points of strength and weakness of each design. It is assumed that customers have economic rational behavior, as they make decisions that result in the most optimal benefit for them given a set of constraints. The outcomes to be assessed are referred to as attributes. There are four proposed attributes to be assessed, which we consider as the most relevant for comparing tariff designs for active customers, in addition to the main regulatory tariff principles discussed in section 2.2.1. The evaluation methodology assess the performance of different tariff designs through the four design attributes illustrated in Figure 4.2: (i) network cost recovery, (ii) deferral of network reinforcements, (iii) efficient customer response, and (iv) recognition of side-effects on customers.

Analytical hierarchy process (AHP) is then used to evaluate each of the candidate tariff designs according to their performance in each of the four attributes.

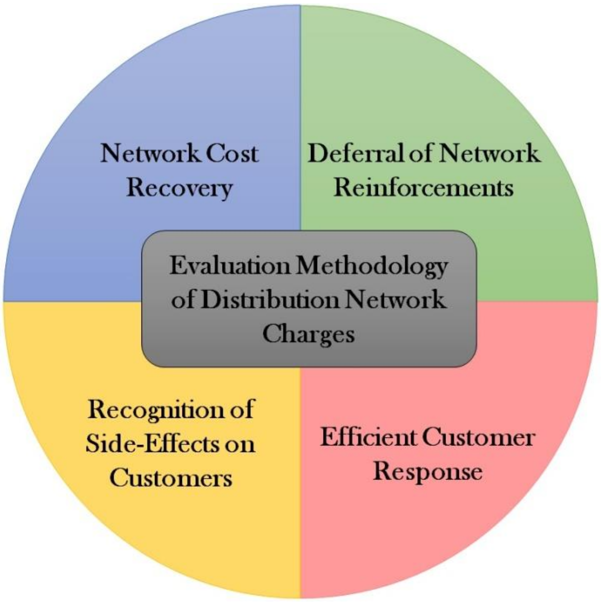


Figure 4.2 Evaluation Methodology Attributes of Distribution Network Charges

4.2 Tariff Design Attributes

4.2.1 Network cost recovery

Tariffs are expected to recover distribution network costs. If tariffs are predefined ex-ante, prior to its period of application, it cannot ensure full cost recovery. Thus, it is expected that the total amount collected through consumers' payments would depart from the allowed amount. The issue of unrecovered network costs is to be of concern if a considerable difference is detected, resulting in a major deficit or surplus. Deficits would be due to customers who had reduced their network or energy usage if the tariff is designed according to those drivers, while surpluses would be due to those who increased it. This deficit is then transferred to the following period, to be included in the readjusted tariff. When comparing tariff designs, this attribute aims to find which of them ensures network cost recovery.

4.2.2 Deferral of network reinforcements

Network reinforcements are postponed, unless no other alternative approach is available. Therefore, customers need to be advised prior to making reinforcement decisions. The tariff design should be able to capture the reinforcements needed in a network and alert those customers potentially responsible for it through economic signals. Either they react to the signal, reducing their impact, or do not react and are assigned the reinforcement costs. When comparing tariff designs, this attribute aims to find which of them is capable of signaling the need of network reinforcements. Tariffs that consider the utilization level of the network are likely to perform better in this attribute.

4.2.3 Efficient customer response

Customer response could be achieved in different ways and over different time horizons. Short-term customer response considers the change in the consumption/injection profile of customers responding to dynamic prices (price-response). Thus, the tariff design should encourage customers to react to prices in order to optimize the use of the network. Tariff designs that price energy dynamically instead of flat rates, and allocate network charges targeting critical hours of the network, are more customer response motivating.

Furthermore, consumer response could be extended to long-term decisions, as investing in DERs. Customers need to be well guided through investment decisions, as incorrect signals received by customers, may lead to inefficient DER investment decisions adopted by them. From the customers' perspective, they will rationally invest in DERs if they benefit, i.e., if their payments would be reduced. From the system's perspective, customers' DER investments would reduce system costs, or otherwise it would increase the stranded costs. Thus, customers should be well guided to invest in DERs only when it would enhance the system's economic efficiency. When comparing tariff designs, this attribute aims to asses which design is able to or has a higher potential to encourage customers to modify their profile pattern efficiently and reduce system costs, while is also capable of correctly influencing customer's DER investment decisions.

4.2.4 Recognition of side effects on customers

For any tariff design, several side effects could be generated, mainly due to cross-subsidization and fairness issues, requiring certain trade-offs to be considered. Within tariff design, the main trade-off is between efficiency and fairness, particularly regarding customer cost allocation that should avoid undue discrimination. Fairness issues are tackled through a number of issues, such as the location factor. Should customers located away from the generation be penalized with more payments? Or is it fair in order to promote efficient cost allocation? To which degree is the fairness goal more important in matters of regulatory process, or more important in regulatory outcomes, is a question that commissioners' response varied to widely according to a survey carried out in (Jones and Mann, 2001). Other side-effects could be through customers avoiding network charges which leads to cross-subsidization. As active customers invest in DERs and become prosumers, this affects their payments as well as it may affect the rest of the consumers' payments, depending on the tariff design. A well-designed tariff will generate positive side-effects on the rest of the customers when DER investments have been done in a context of system efficiency, reducing their payments or at least maintaining them. Whereas, a poorly designed tariff would generate negative side-effects on customers, allocating to them higher payments in following tariff periods. When comparing tariff designs, this attribute aims to find which is more effectively able to recognize those side effects.

4.3 Analytical Hierarchy Process (AHP)

Analytical Hierarchy Process (AHP) decision-making method is used to quantitatively compare different tariff designs. AHP attempts to determine the relative importance, or weight, of the considered tariff designs in terms of each attribute using pair-wise comparisons (Saaty, 2008). It is used for solving different types of multi-criterion decision problems based on the relative priorities assigned to each criterion's role in achieving the stated objective. Using a benefit measurement (scoring) model that relies on subjective managerial inputs on multiple criteria, these inputs are converted into scores that are used to evaluate each of the possible alternatives (Handfield et al., 2002). Figure 4.3 illustrates the hierarchy levels of the decision-making problem. First level presents the problem's objective, followed by the second level presenting the criteria (attributes), and finally, the third level presents the alternatives (tariff design options). Prior to the decision being made, the regulator should decide on the priority each attribute has over the other. Then, using a scale of numbers (1–9), each tariff design is compared with the other, indicating how many times more important or dominant one is over the other with respect to each attribute.

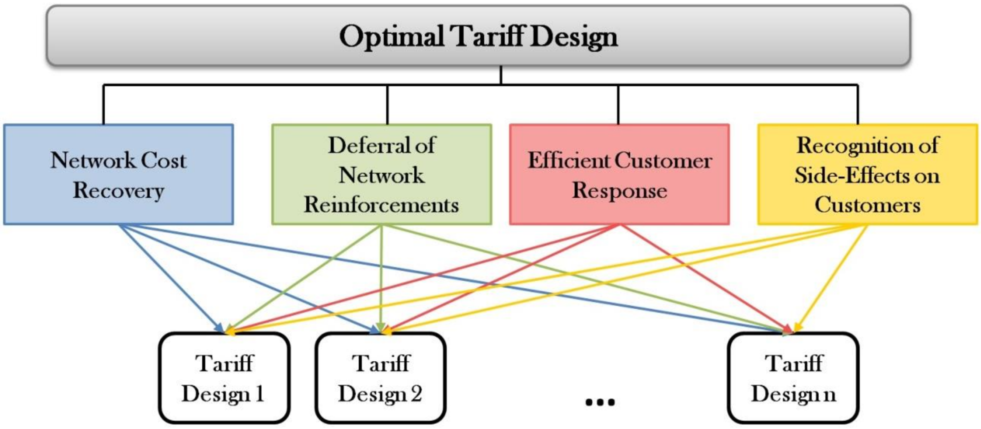


Figure 4.3 Tariff Design Evaluation using Analytical Hierarchy Process (AHP).

4.4 Case Study

The proposed evaluation methodology is implemented within this case study to assess different tariff designs regarding the four aforementioned attributes. It aims to highlight the strengths and weaknesses in the considered cost-reflective tariff design and compare it with traditional tariff designs. This evaluation then contributes in proposing the final enhanced DN charge design in Chapter 5. The traditional cost allocation method varies from a country to another. For the traditional tariff design, three cases are considered: the first case is based on energy charges (100% energy), the second is based on demand charges (100% demand), and the third is based on 50% energy-50% demand. A fourth case representing the proposed cost-reflective tariff design previously explained in Chapter 3 is considered which is based on DLMPs and PCNC. Since the analysis carried out in Chapter 3 showed that PCNC is more efficient than MP, the rest of this thesis focuses on PCNC. The proposed tariff design evaluation methodology is implemented using results of the case study carried out in section 3.4.

4.4.1 Tariff design attributes evaluation

1) Network Cost Recovery

For the traditional tariff design, the three case studies led to different degrees of cost recovery. Table 4.1 presents the results obtained by the three case studies regarding cost recovery with and without PV. It shows that full cost recovery is obtained with no PV. However, due to PV integration, a major reduction was observed with the energy payments and a minor one in the demand payments. Thus, the use of volumetric tariffs leads to a greater deficit than that of demand tariffs. These deficits are to be included in the following period tariffs. On the contrary, the cost-reflective method provides part of the tariff ex-ante to guide the customers through their short-term decisions as they plan their injection/consumption profiles, while the rest of the tariff is ex-post to ensure the full recovery of the network costs.

Cost Allocation Basis	**Total Cost Recovered (€)**	
	No PV	**PV**
100% Energy	943.66	702.74
100% Demand	943.66	848.14
50% Energy-50% Capacity	943.66	775.44

Table 4.1 Network cost recovery under traditional tariff designs.

2) Deferral of Network Reinforcements

Network reinforcements are linked to the network's peak hours, which is the main aspect to consider when comparing tariffs in this attribute. Tariff design based on 100% energy does not consider this aspect, as it is purely based on energy consumption. Thus, as shown in Figure 4.4, customers with no PV do not receive any changes in their payments, while prosumers, those invested in PV (customers 11, 22, 27, 30, and 32) are able to reduce their payments. For the 100% demand tariff, it is based on individual peaks, which does not particularly coincide with network peaks. Thus, customer payments do not reflect the network's status or needs. Customer Payments based on 100% demand are shown in Figure 4.5. The performance of the 50%-50% tariff falls between the two mentioned tariff designs.

For the cost-reflective tariff design, DLMP payments are allocated to customers along with PCNCs. PCNCs were allocated based on their contribution to the network's peak hour, which changed from 16:00 to 20:00 with the integration of PV. Figure 4.6 illustrates the payments per customer under cost-reflective tariff design with and without PV. PCNC payments, which are based on network peaks, clearly signalize consumers regarding their contribution to the network as shown in Figure 4.6. In Figure 4.8, the contribution to the network's peak hour with and without PV integration (hours 20 and 16, respectively) is compared for prosumers 27 and 30. The contribution of prosumer 27 to the peak was reduced, and prosumer 30 was increased. This is reflected in their PCNC payments in Figure 4.6, but not in the network payments under 100% energy method as shown in Figure 4.4.

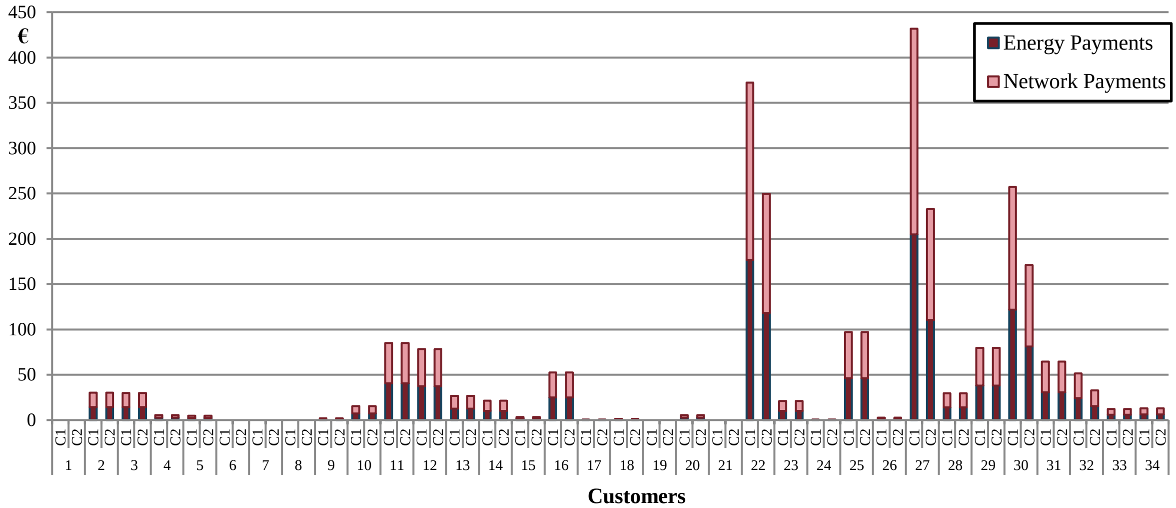


Figure 4.4 Traditional Tariff Design based on 100% Energy: change in customer payments of 1 day due to PV integration. C1 = no PV case, C2 = PV case

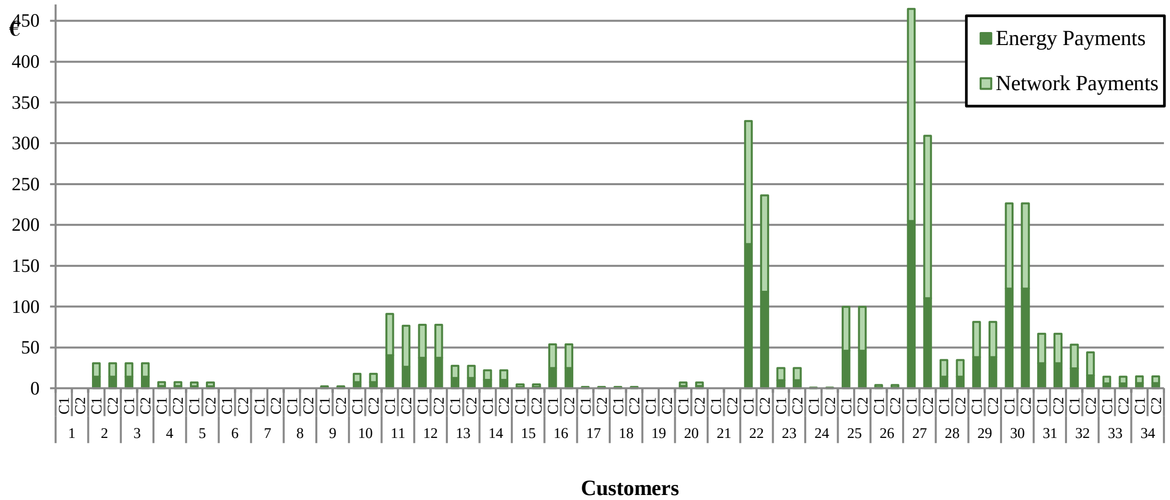


Figure 4.5 Traditional Tariff Design based on 100% Demand: change in customer payments of 1 day due to PV integration. C1 = no PV case, C2 = PV case

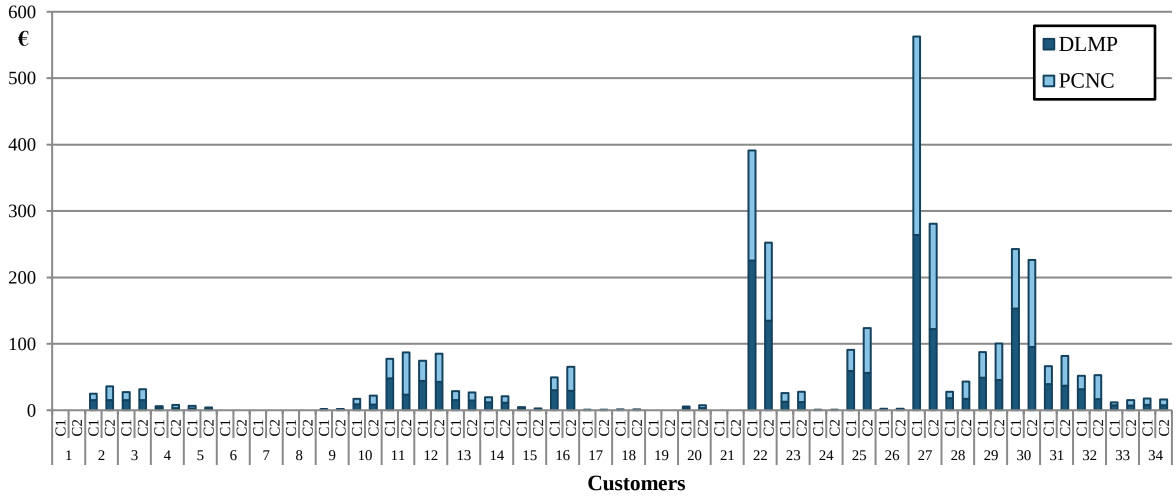


Figure 4.6 Cost-Reflective Tariff Design: Change in customer payments of 1 day due to PV integration. C1 = no PV case, C2 = PV case

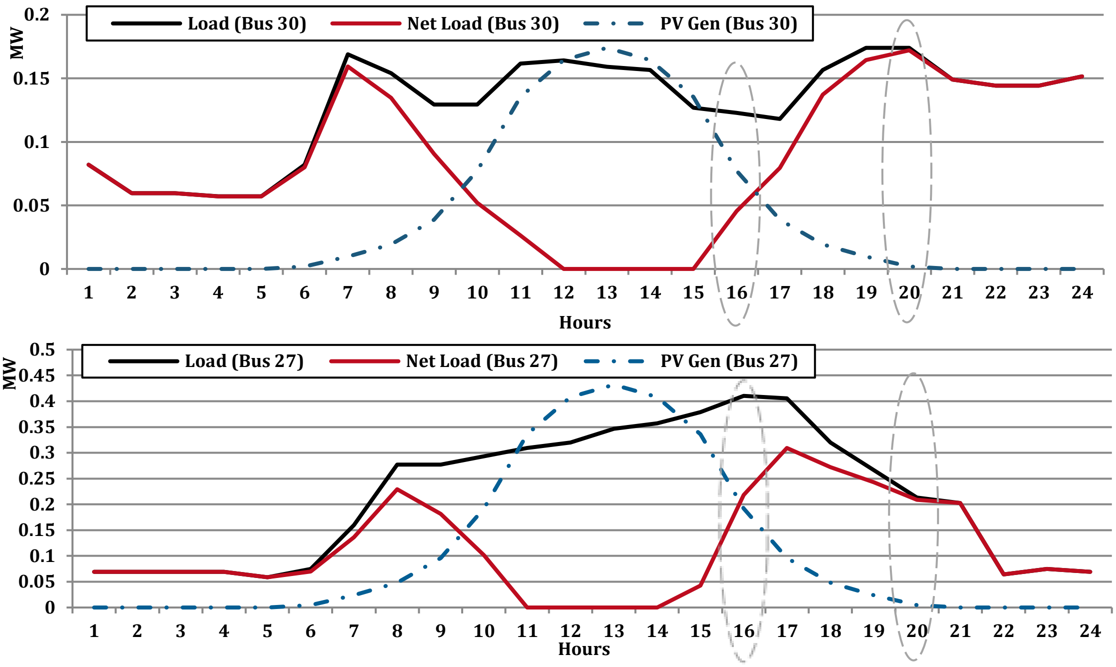


Figure 4.7 Load Reduction through Self-generation for Customers 27 and 30

3) Efficient Customer Response

The traditional tariff design uses flat energy tariffs, which does not provide any incentives to customers to react to it. Whereas, in the cost-reflective tariff design, the dynamic energy prices through DLMPs encourages customers to modify their consumption/injection profiles. DLMPs increase down the feeder due to losses as illustrated in Figure 3.4, which attracts customers to install generation or reduce their consumption. Besides, the network charges are allocated according to the network's peak, incentivizing customers to reduce their consumption during those hours.

Furthermore, traditional tariffs are misleading regarding DER investment decisions. Customers are able through DERs to avoid network payments, as shown in Figure 4.4. However, this is not the case under the cost-reflective tariff design, as only customers 22 and 27 were allocated lower payments as their contribution to network's peak hour was reduced through their DER installation. Thus, the cost-reflective method guides customers through investments that reduce the system's peak, not individual peaks.

4) Recognition of Side-Effects on Customers

For the traditional method, as shown in Figures 4.4 and 4.5, only those who invested in PV were benefitting, and those investment decisions did not impact the rest of the customers. However, they would be affected in the following period as the tariffs are adjusted to suit the network's new situation. Both the energy and the demand charges will increase, and cross-subsidy between active and passive customer appears, where passive customers pay more network costs while active network users pay less (Eid et al., 2014). Whereas in the cost-reflective method, during the integration of DERs, DLMPs were reduced noticeably as shown in Figures 3.3 and 3.4, benefitting all customers. In addition, network charges are allocated based on the contribution to peak hours, with no discrimination between prosumers and consumers. As shown in Figure 4.6, only prosumers that contributed less to the network stressful hour reduced their payments. The rest of the prosumers were allocated higher payments, mitigating the side-effects generated by traditional tariffs. Moreover, the fairness issue regarding allocation of costs with locational granularity was only tackled in the cost reflective method through DLMPs. Although some customers and regulators may disagree whether the locational factor t should be considered within the tariff design, it reflects real costs of the network, as well as it promotes nodes that would provide efficient DER integration.

4.4.2 AHP evaluation of tariff design attributes

The AHP evaluation is carried out using a model called AHP Excel Template (Goepel, 2013) . First, the performance of each tariff design in each attribute is calculated using the customer payments during PV integration, and the results are illustrated in Table 4.2. For the first attribute, network cost recovery, the cost-reflective method scored 1, indicating full network cost recovery and the 100% energy scored the least, corresponding to 74%. For the second attribute, deferral of network reinforcements, customer payments were used to calculate the performance of each tariff design. Deferral of network reinforcements is linked to the network´s peak hour, thus, payment should be in line with this hypothesis. The MW contribution of each customer during the network’s peak hour, is set as a reference. The customer network payment´s contribution should follow that reference. The absolute difference in contribution between the reference and each tariff design for each customer is summed and shown in Table 4.2. The cost-reflective method showed the least difference, while the other tariff designs performed similarly. As for the third attribute, efficient consumer response, the reference was based on energy payments following DLMPs. DLMPs are efficient economic signals for customers that consider dynamic prices along with the locational aspect. Again, differences in payments are illustrated in Table 4.2, where the cost-reflective method scored zero difference, and 100% demand scored the greatest difference in payments. Finally, for the fourth attribute, recognition of side-effects on customers, two aspects where considered to affect consumers that have not installed PV: the change in total customer payments of those who did not install PV due to PV integration (which was the case only in the cost-reflective tariff design), and the deficits in cost-recovery that are to be reallocated in the following period (which varied for each tariff design apart from the cost-reflective). As shown in Table 4.2, 100% demand scored the least side-effect on consumers, while 100% energy scored the highest.

The best tariff design is the one which achieves the most convenient trade-off among the different attributes, rather than the one which optimizes each single attribute. The AHP generates a weight for each attribute according to the decision maker’s (regulator’s) pairwise comparisons of the attribute. Within each attribute, the AHP assigns a score to each tariff design according to the decision maker’s pairwise comparisons of the options based on that attribute. The scores in Table 4.2 were used for the pair-wise comparison to calculate the relative importance for the tariff designs within each attribute.

Tariff Designs	Design Attributes			
	1	2	3	4
50% energy-50% demand	0.82	0.1707	241	167.7
100% energy	0.74	0.1753	590	240
100% demand	0.9	0.1707	725	95.4
DLMP + PCNC	1	0.008	0	127.7

Table 4.2 Performance of each tariff design in each attribute.

Finally, the AHP combines the attribute weights and the tariff designs' scores, reaching a final score between 1 and 9 for each tariff design as presented in Table 4.3. This final score for each tariff design is the weighted sum of the scores it obtained with respect to all the attributes. The overall AHP evaluation is presented in Figure 4.8, showing that the cost-reflective method scored the highest, followed by 100% demand, 50% energy-50% demand, and finally 100% energy.

Tariff Designs	Design Attributes			
	1	2	3	4
50% energy-50% demand	3	9	3	3
100% energy	4	9	6	5
100% demand	2	9	7	1
DLMP + PCNC	1	1	1	2

Table 4.3 Relative Performance of each Tariff Design for each Attribute.

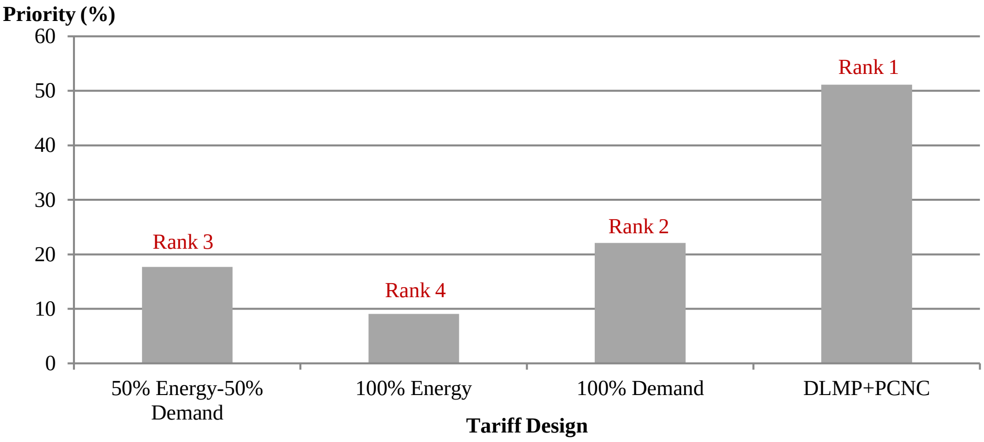


Figure 4.8 AHP Evaluation of Tariff Design.

4.5 Chapter Remarks

Traditional tariff designs, based on assuming passive electricity customers, can no longer serve or deal with the new paradigm of smart DNs and active customers, calling for new tariff designs. Cost-reflective tariffs are required to act as a communicating link between DSOs and network users including consumers, DER owners, or both. The aim is to provide efficient economic signals that reflect the network's status. Those tariff designs need to be assessed following an evaluation methodology that includes all desired objectives to guide regulators and policy makers to make their decisions.

Through AHP, four tariff designs were compared, showing that the cost-reflective design is the most capable of achieving the desired outcomes, followed by tariffs based on demand solely, or considering the demand component. In addition, the AHP showed that tariffs that are based solely on energy are leading to inefficient customer responses and poor network cost recovery. Moreover, dynamic pricing is crucial in tariff design to optimally guide consumers through short- and long-term decisions. The guidance could be more efficient when combined with the locational aspect, as in DLMPs. In addition, the locational factor could be included within the PCNC if applied on feeder to feeder basis, providing granularity to the tariff design.

The results presented were based on a single day case study, which may differ if a different day with other seasonal conditions or a year-long time frame with weekly and seasonal variations in demand and PV output were considered. The objective was to present how the proposed evaluation method could be used as a tool to compare different tariff designs, while mainly focusing on attributes related to system economic efficiency. Moreover, the AHP results presented are based on equal weight of each attribute, which could vary between regulators according to their preferences and contextual frameworks. Furthermore, the evaluation methodology could be extended to add other attributes such as those included in tariff design principles (discussed in section 2.2.1), for example simplicity, acceptability and affordability. It may also include other attributes such as Information and Communication Technology (ICTs) requirements (for example smart meters). The addition of other attributes into the evaluation methodology along with reassigning the weight for each attribute will highly impact the results and may favor other tariff designs over the proposed cost-reflective tariff.

Finally, the proposed evaluation methodology is carried out by assessing the performance of each tariff design regarding the four attributes. The analysis uses customers' pavements to weight and compare each attribute. These payments are not a reaction to the tariff design, instead they present how the payments would change from one tariff design to another using historical profiles. However, customers' rational response to tariff designs is another important aspect that should be considered to analyze how customers react to an implemented tariff design, in regard to their operational and investments decisions. This is further explained in Chapter 5, along with the final enhanced cost-reflective DN charge design.

5 Designing Efficient Distribution Network Charges

Designing DN charges following the design principles presented in section 2.2.1 and the evaluation methodology presented in Chapter 4 is challenging, as some of the principles conflict with each other, requiring a trade-off among them. The main challenge is to ensure that efficient short- and long-term price signals are transmitted, in a practically implementable way. The cost-reflective design proposed in Chapter 3, which consists of DLMPs and PCNC, was shown to be more efficient when compared with traditional designs. However, the PCNC design could be further improved to consider the network's utilization level. This will consequently lead to more efficient short-term operational and long-term investment decisions, increasing the system's economic efficiency.

As the demand for electricity grows or new distributed generation units are connected, network capacity may no longer be able to fully serve the new requirements, requiring network reinforcements. Customer flexibility, if well utilized, could defer those investments which are driven by peak coinciding network usage. If customers shift/curtail part of their load/injections and/or investments in DERs, network reinforcements could be avoided. Customers would benefit as reinforcement costs are to be eventually included in the charge. To perceive this reaction, customers need to receive efficient economic signals through network charges.

This chapter proposes a cost-reflective DN charge design that guide customers and DSOs to efficient short-term and long-term decisions. As mentioned, the DN charge is an enhancement to that proposed in Chapter 3 and evaluated in Chapter 4. As shown in Chapter 4, the cost-reflective PCNC charge outperformed traditional charge designs. The assessment in Chapter 4 was based on customers' payments and not rational customers' response. In this chapter, reaction of customers in term of operational and investment decisions is simulated through an optimization model that bases customers' reaction on minimizing their total costs. Both the proposed DN charge design and traditional DN charge designs are implemented in the optimization model to compare customers' decisions and the consequent effect on the system's costs. The methodology and case studies in this chapter are published in (Abdelmotteleb et al., 2018a).

The methodology and characteristics of the proposed DN charge design are discussed in sections 5.1 – 5.5. Furthermore, customers' reaction to DN charges is formulated in section 5.6 and a case study is carried out in section 5.7 to compare between customers' reaction to the proposed and traditional DN charges. Finally, implementation concerns regarding the proposed DN charge design are discussed.

5.1 The Methodology

Efficient charge designs should send economic signals 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 is expected that the usage will continue to increase, customers should be signalized to reduce their network usage (whether consumption or generation), otherwise that would lead to network reinforcements.

Thus, network peak is the main driver to network reinforcements. Moreover, whether to meet network future requirements through wiring solutions (through network investments), or non-wiring solutions (through DERs), is a decision to be taken in a way that maximizes system's economic efficiency. This is subjected to the elasticity of the customers, and their willingness to participate by changing their consumption/injection pattern and/or investing in DERs. Customers are assumed to be economic rational in the sense that they would react to signals in the way that maximizes their benefits, hence they would seek to reduce their bills. They 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 needs during critical hours, or they would not respond to the signal received and continue with their regular profile paying the corresponding network charges.

The proposed cost-reflective method allocates network costs to customers in a way that incentivizes them to respond optimally maximizing the system's economic efficiency. Efficient economic signals that translate the network's current state are sent to customer through the DN charge. 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 method, network costs are allocated to customers through fixed charges and Peak Coincidence Network Charges (PCNC), which is a forward-looking network charge. This cost-reflective charge design is an enhanced extension to that proposed in

Chapter 3, as it considers the network's utilization level. This is because economic signals should only be transmitted to customers to trigger their response when required, otherwise optimal customer reaction will not be obtained. PCNC are applied when the network's utilization level increases to the extent than network upgrades are required. When the network's utilization level is normal or underutilized, no signals should be transmitted, hence only fixed charges apply as they do not induce customer reaction, and they do not distort economic signals established through PCNC. A pre-defined preventive threshold for the network's capacity is set to identify whether the network is considered highly utilized (further explained in section 5.2). When the network's utilization level exceeds the threshold, this is considered a peak hour.

During network's peak hours, PCNC (€/kW) is allocated to customers according to their contribution to the network's peak. Depending on the magnitude by which the network's utilization level 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 (MIT, 2016) discussed proxies that could be used for residential customers to apply Ramsey-pricing, such as customer's property tax or property size, where the aim is to use a fair measure. As for industrial and commercial customers, similar measures could be used, yet other policies should be considered as excessive fixed costs may cause industries to relocate. If no peak hours occurred, where the network's utilization level exceeded the threshold, no revenues are collected through PCNC, and then the whole network cost is recovered through fixed charges. Furthermore, if Distribution Locational Marginal Prices (DLMPs) are implemented, a small surplus would be obtained due to losses and congestions, and it would recover part of the network costs, as shown in Figure 5.1.

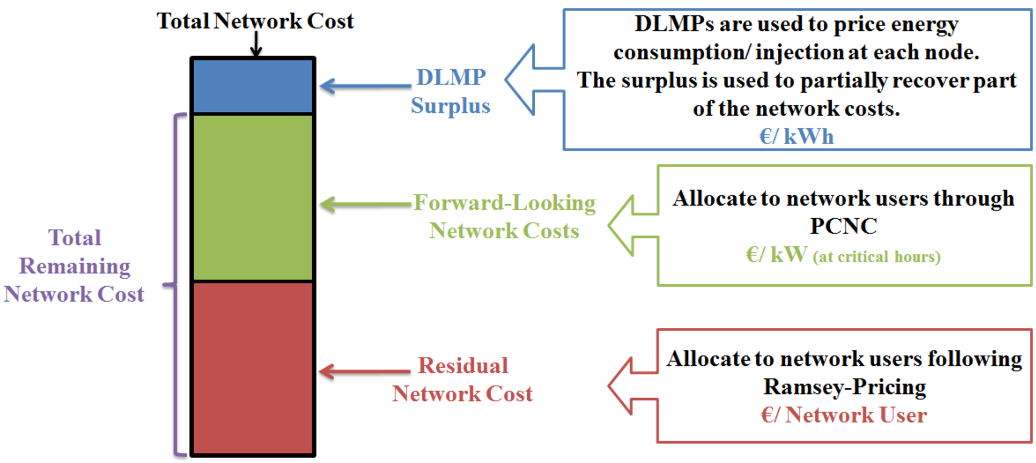


Figure 5.1 Distribution Network Charges Design including DLMPs

5.2 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 customers the actual capacity and cost of network reinforcements. Fig.5.2 illustrates how the threshold identifies the network peak hours.

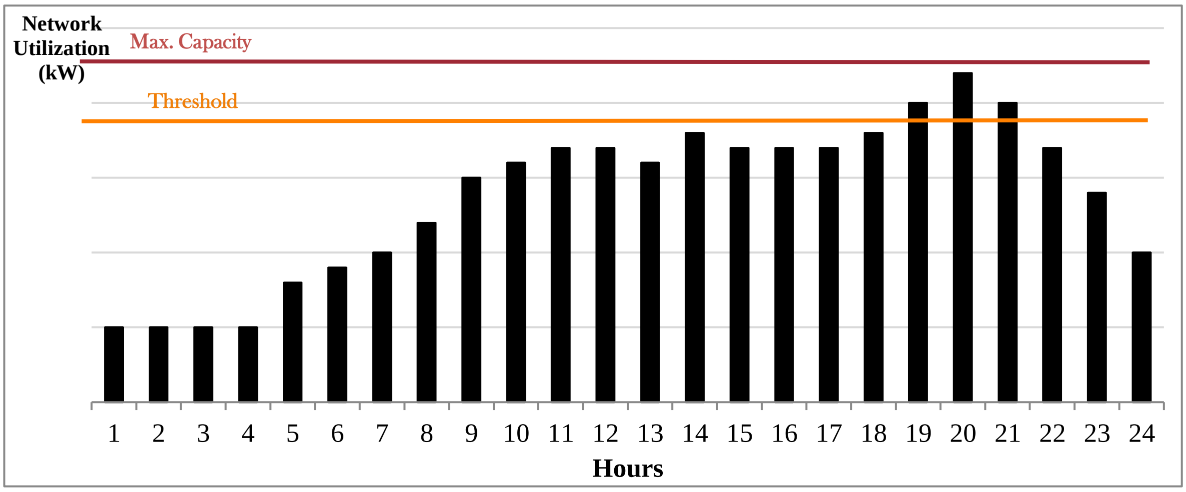


Figure 5.2 Network Peak Hours based on a Preventive Threshold

5.3 Calculation of Future Network Investment Costs

Predicting the cost of network reinforcements is difficult and includes a high uncertainty regarding future network utilization forecasts, yet, there are different methods that could be used to calculate future network expansion costs. For example, in the UK, for HV/LV networks, the coming year's reinforcement cost to accommodate demand growths is forecasted based on the present year's expenditure (Li et al., 2015). 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 the present value. Moreover, computational models may be used to calculate future network investment costs. In (Abeygunawardana et al., 2015), a long-run distribution network expansion planning (LRDNEP) model is used for estimating location-specific Long Run Incremental Cost (LRIC) of distribution networks. It optimizes the expansions of the network for meeting projected demand growth using the existing grid and a large number of expansion candidates. The model decides on the type of network solutions (transformers, lines, voltage control devices) and non-network options (energy storage systems, DGs, demand response 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. Furthermore, another similar model is the Reference Network

Model (RNM), which is a very large-scale planning tool for forward-looking engineering-based that has been used to assist in developing benchmarks for efficient network expenditures. RNM emulates the network planning practices of an efficient network operator and equips the regulator with a forward-looking benchmark that accommodates expected evolutions in network use, technology performance and costs, and network management practices (Domingo et al., 2011; Gómez et al., 2013; MIT, 2016).

During the planning phase, different scenarios with varying forecasted levels of energy withdrawal/injection are carried out to calculate the optimal network costs required to accommodate the expected increase in network utilization level. Once future network costs are calculated, they are allocated in the forward-looking component of the charge which is the PCNC in €/kW during the critical peak hours for the network. It aims to signalize the customers during network peak hours with the corresponding cost of network upgrades. Hence, customers are given the opportunity to respond by either continuing to use the network during peak hours, or to find other cheaper alternatives. An estimation of those hours is announced ex-ante, but the actual hours are only known ex-post. Ex-post, payments received through PCNC are deduced from the total network cost that needs to be recovered, and the rest of the network costs is recovered through fixed charges (€/customer).

5.4 Local Economic Signals

PCNC is a geographically local charge; in other words, it is applied only to customers that affect potentially saturated network assets. Since customers are connected at different voltage levels of the DN, allocation of PCNC to each customer becomes a complex task. Different elements of the network may peak at different moments; resulting in the application of PCNC having different variants. Hence, customers could be exposed to PCNC during peak hours of the voltage level they are connected to, and they could be exposed to it as a cascaded effect of above levels. As shown in Figure 5.3, residential customers could be exposed to PCNC during peak hours of the feeder they are connected to, and to peak hours of the LV transformer, and to peak hours of the primary feeder connected to the sub-transmission substation. As granularity increases, the computational burden and complexity of the calculations also increase.

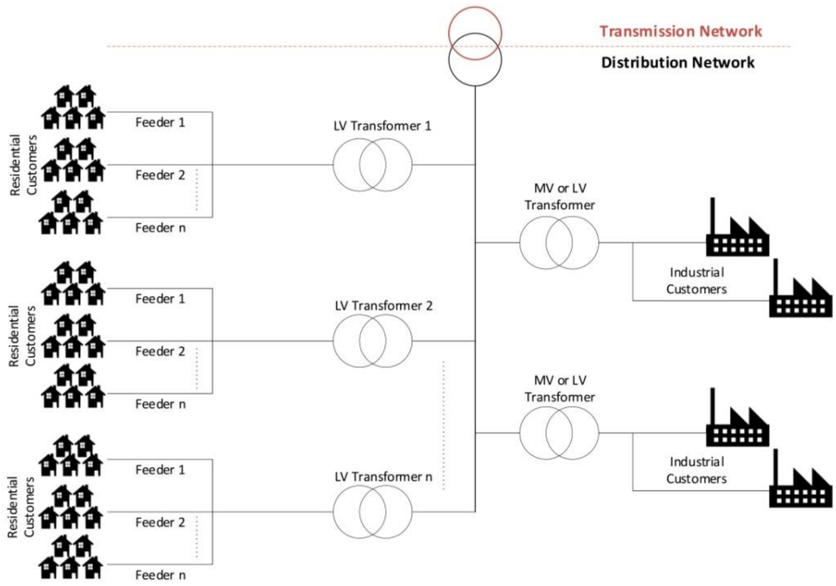


Figure 5.3 Example of Distribution Network Configuration

5.5 Symmetry of 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. Figure 5.4 presents a simple distribution network, where G represents aggregated injections and L represents aggregated consumption. When the consumption increases, the resultant flow is to the right (as shown by the red arrow), whereas when the injections increase, the resultant flow is to the left (as shown by the green arrow). 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 final use behind the meter. During a peak hour, PCNC is allocated to those causing the network peak, and is received by those contributing to reduce the network's utilization level symmetrically. For example, as shown in Figure 5.5, the threshold (T) is set as 90% of the network's maximum capacity. In this simple case in which a transformer of 1MW capacity is considered, hence T is 0.9 MW. The aggregated injections (G) are equivalent to 2 MW, and aggregated consumptions (L) are equivalent to 1.05 MW. Hence, the resultant flow is 0.95 MW to the left due to excess injection. Thus,

G is charged: 2 x PCNC

L is paid: 1.05 x PCNC

Network's income: (2-1.05) x PCNC

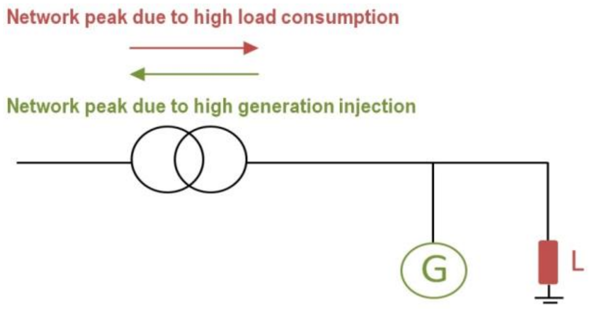


Figure 5.4 Symmetrical Network Charges

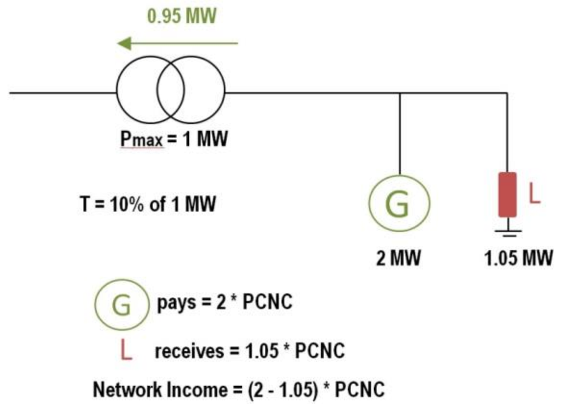


Figure 5.5 Example on Symmetrical PCNC

The proposed symmetrical network charges aim to signalize the customers causing network peaks and reduce their network usage, while also encouraging those that can contribute in reducing network's utilization level. This is done by means of the economic signals sent through the PCNC, but subject to customers' reaction to it. Hence, its essential to simulate and compare the customers' reaction to the proposed network charge to other traditional methods. The customers' response simulated here is different from that in Chapter 4, which considered customers' payments to compare customers' reaction to different network charges. In this chapter, customers' response is simulated in terms of operational and investment decisions when exposed to different charge designs. Within each charge design, each customer will be supposed to react in a rational way that would minimize his/her total costs. This demonstration is crucial to understand how network charges may influence customers' response, and how it will consequently influence the system's total cost, and which design will induce optimal reaction. The formulation of customers' reaction is presented in section 5.6. Case studies are analyzed in section 5.7, comparing customers' reaction to the proposed and other traditional network charges. The formulation and the case study consider only distribution network charges, thus a constant energy price is assumed in all cases.

5.6 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 (5.1), 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_{grid} 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 DER, VC_g is the variable cost of DER, and h_l is the number of hours within each load level. All sets, parameters and variables used in the formulation are defined in Table 5.1. This is subject to the boundaries (5.2) – (5.4) and equality constraints (5.5) and (5.6), 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 be equivalent to the demand of that same load level ($D_{c\,l}$). In addition, (5.6) maintains a constant DER generation capacity between load levels, restricting one constant maximum production value for all the levels. For simplification, the efficiency conversions for DERs are neglected in this formulation, but they can be easily included.

Sets:	
C	Customers
G	Onsite generators or demand curtailment option
L	Load levels
Parameters:	
$D_{c\,l}$	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)
$T_{l\,c}$	Individual threshold per customer at each load level (MW)
VC_g	Variable cost of onsite generator (€/MWh)
VC_{grid}	Energy cost for energy withdrawn from the grid (€/MWh)
Positive Variables:	
$C_{g\,c\,l}$	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)
$C_{grid\,c}$	Maximum power withdrawn from the Grid by each customer (MW)
$E_{g\,c\,l}$	Energy produced by onsite generator during each load level by each customer (MWh)
$E_{grid\,c\,l}$	Energy withdrawn from the grid during each load level by each customer (MWh)
$E_{grid_{max_c}}$	Maximum energy withdrawn from the Grid by each customer (MWh)
$E_{grid\,th\,c\,l}$	Energy withdrawn from the grid that exceeds a given threshold at each load level by each customer (MWh)

Table 5.1 Formulation's Sets, Parameters and Variables

$$\underset{E_{grid},E_g,C_g}{\mathrm{Min}} \sum_{c=1}^{C}\sum_{l=1}^{L}\left[\left(FC_{grid\,c} + VC_{grid}E_{grid\,c\,l} * h_l\right) + \sum_{g=1}^{G}\left(FC_g C_{g\,c} + VC_g E_{g\,c\,l} * h_l\right)\right] \tag{5.1}$$

$$C_{g\,c}{}^{min} \le C_{g\,c} \le C_{g\,c}{}^{max} \qquad g \in G,\ c \in C \tag{5.2}$$

$$0 \le E_{grid\,c\,l} \le C_{grid\,c} \qquad c \in C,\ l \in L \tag{5.3}$$

$$0 \le E_{g\,c\,l} \le C_{g\,c} \qquad g \in G,\ l \in L \tag{5.4}$$

$$\sum_{c=1}^{C}\sum_{g=1}^{G} E_{g\,c\,l} + \sum_{c=1}^{C} E_{grid\,c\,l} = D_{c\,l} \qquad c \in C, g \in G \tag{5.5}$$

$$C_{g\,c\,l+1} - C_{g\,c\,l} = 0 \qquad g \in G,\ c \in C,\ l \in L \tag{5.6}$$

The objective function (5.1) is used to model the traditional DN charge designs, but it does not consider the PCNC and the threshold. Hence, further modifications to (5.1) are carried out to account for the proposed charge method to accommodate the PCNC charge as presented in (5.7), subject to (5.8)-(5.9). The network´s threshold (T) is translated into individual thresholds for each customer (T_c), based on his contribution to the peak hour as in (5.9).

$$\begin{aligned}\underset{E_{grid},E_g,C_g}{\mathrm{Min}} \sum_{c=1}^{C}\sum_{l=1}^{L}\Bigg[&\left(FC_{grid\,c} + VC_{grid}E_{grid\,c\,l} * h_l\right) \\ &+ \sum_{g=1}^{G}\left(FC_g C_{g\,c} + VC_g E_{g\,c\,l} * h_l\right) + \left(PCNC * E_{grid\,th\,c\,l} * h_l\right)\Bigg]\end{aligned} \tag{5.7}$$

$$\sum_{c=1}^{C} E_{grid\,c\,l} - T_{c\,l} = E_{grid\,th\,c\,l} \qquad c \in C,\ l \in L \tag{5.8}$$

$$T_{c\,l} = \frac{E_{grid\,c\,l}}{\sum_{c=1}^{C} E_{grid\,c\,l}} * \left(\sum_{c=1}^{C} E_{grid\ c\,l} - T\right) \qquad c \in C,\ l \in L \tag{5.9}$$

5.7 Case Study

The selected case studies are a modified version of that presented in (Abdelmotteleb et al., 2016a). The system consists of a simple 2-bus network as illustrated in Fig. 5.6. A distribution network of a 2.5MW capacity is connected to the higher voltage grid and serves several customers. In the presented case study, the network peak is due to an increase in load consumption. Several assumptions were considered for the sake of clarity; however, more complex models could be extended to include more details. First, as opposing to (Abdelmotteleb et al., 2016a; Biggar and Hesamzadeh, 2014), the customers are not grouped into one customer, but divided into four (C1, C2, C3 and C4). The four customers are assumed to be supplied by the distribution network, and willing to respond to charge designs, based on the economic benefits to be gained.

These customers are connected to the grid, but also have the option to choose to serve their energy needs from two available DER options as shown in Fig. 5.6. 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 load curtailment actions, with no fixed cost, and a high variable cost. Two case studies with different load duration curves as illustrated in Fig. 5.7 are presented to compare customers' reaction to different tariff designs. The aim is to analyze how each customer 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, subject to the value of the economic benefits.

The second assumption is the annual load duration-curve of customers, which is assumed to be of discrete nature and represented through 10 load levels, with varying number of hours per 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 occurring 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 hours per year, and coincides with intermediate load levels. Hence, it operates during the 4th and 5th load levels shown in Fig. 5.7. 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 0.1MW is guaranteed in the following year. Due to discrete network investments, the least network reinforcement that could be carried out is 0.5MW. For simplification, it is assumed that network reinforcements are equal to 20% of the current network costs.

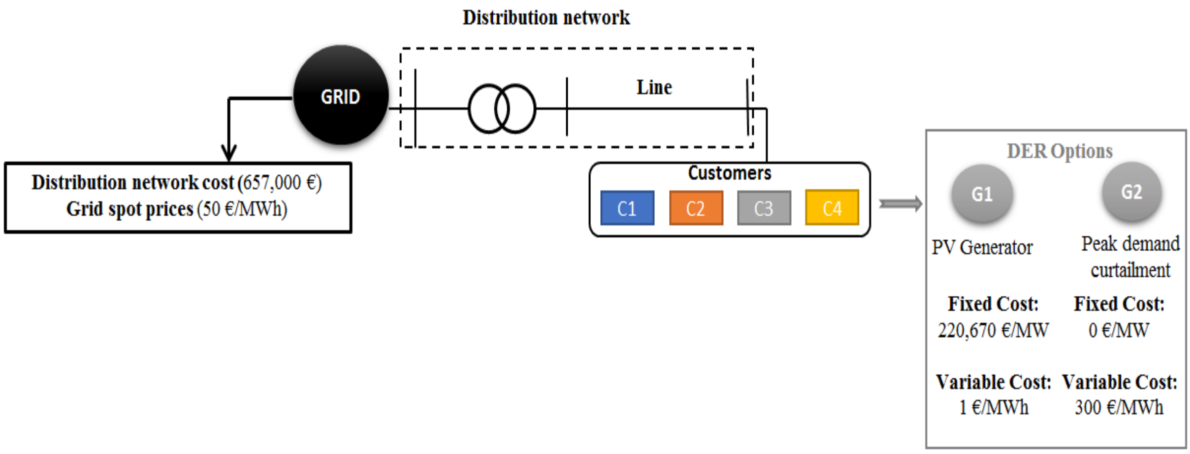


Figure 5.6 Case Study

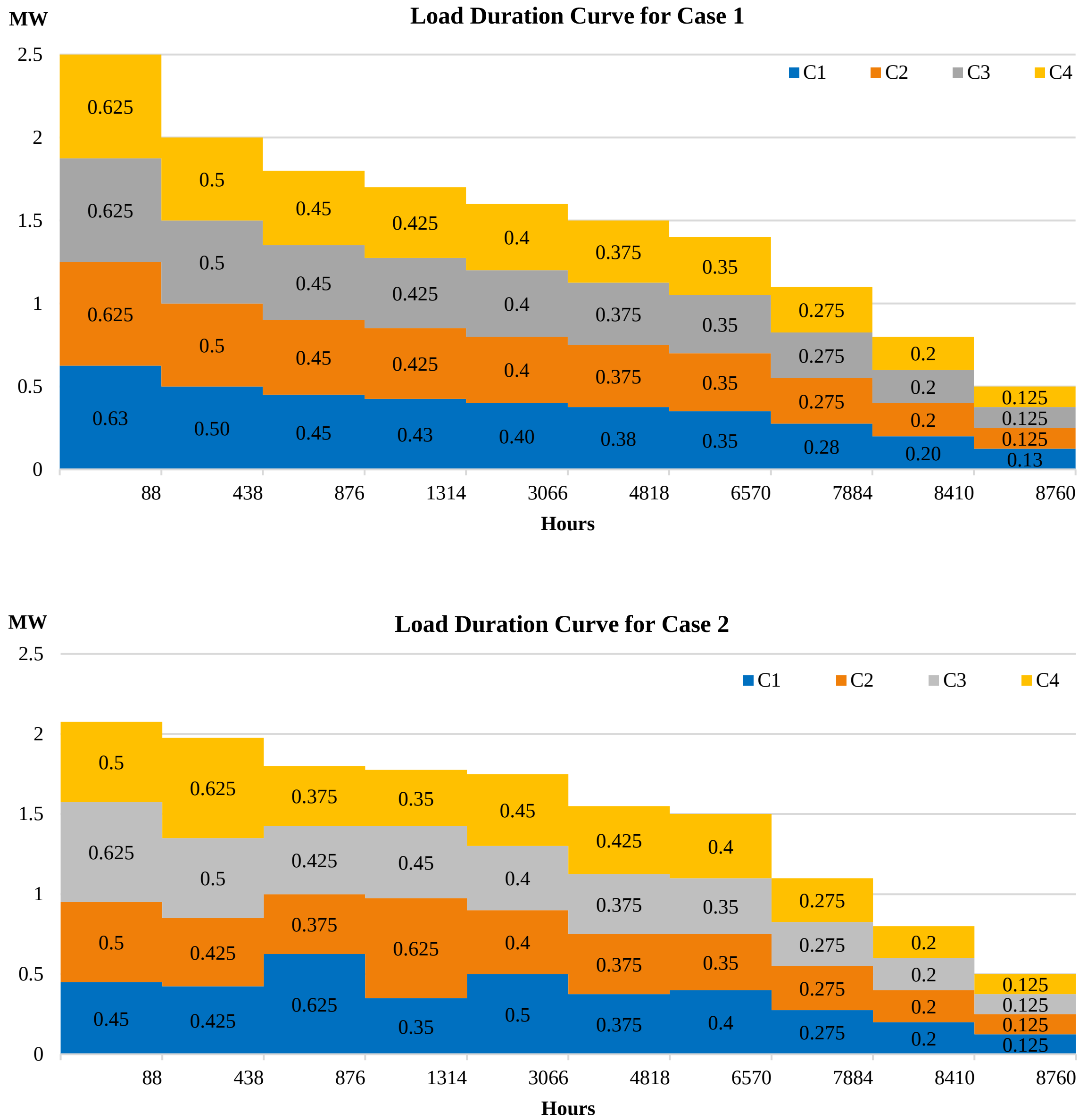


Figure 5.7 Load Duration Curves for Cases 1 and 2

The case studies 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 network surplus is obtained from the energy prices. The customers' reaction to each charge design is modeled using (5.1)-(5.9). 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 linear programming and implemented in Matlab. Four different charge designs, which try to represent current practices, are implemented and compared:

- **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 (5.1)-(5.6), volumetric charge design is 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 5.2.

- **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 (5.1)-(5.6), fixed charge design is implemented.

- **Peak Charge**

Tariffs that are based on individual peak charge depend on the peak consumption of each customer. The peak charge shown in Table 5.2 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 (5.1) is modified to (5.10), 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 (Egrid max), subject to (5.11).

$$\begin{aligned}\underset{E_{grid},E_g,C_g}{\mathrm{Min}} \sum_{c=1}^{C}\sum_{l=1}^{L}\left[\left(VC_{grid}E_{grid_{c\,l}} * h_l\right) + \sum_{g=1}^{G}\left(FC_g C_{g\,c} + VC_g E_{g\,c\,l} * h_l\right)\right] \\ + \sum_{c=1}^{C} PC * E_{grid_{max_c}}\end{aligned} \tag{5.10}$$

$$E_{grid_{max\,c}} \geq E_{grid\,c\,l} \qquad c \in C \tag{5.11}$$

- **Proposed Methodology: Fixed Charge + PCNC**

This tariff considers the individual peaks coincident 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 0.5MW, 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 0.5MW extra capacity, the threshold is set at 2MW. Using (5.7)-(5.9), this proposed method is implemented. The PCNC is set as shown in Table 5.2, during the peak hours (those above 2MW), which are 88 hours according to the load profiles presented in Figure 5.6.

Charge Design	Fixed Charge (€/Customer/yr)	Variable Charge (€/MWh)	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	2,986.36	€/MW during peak hours (above threshold)

Table 5.2 Inputs for Charge Designs

5.7.1 Results

The obtained customers' response for each one of the four charge designs are presented in Table 5.3. 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, the consequences obtained as a result to the decisions taken by the customer are shown. The total system's cost is split in the energy paid for grid consumption, the cost of generation by G1 and the cost of load curtailment through G2, and the revenues earned through distribution network charges for network recovery, from which network deficits are calculated. Figure 5.8 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 customers 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 are 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 reinforcement costs are added, although they may be avoided with DERs. Furthermore, peak charges and the proposed charging methodology (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 €/MWh compared to 262,800€/MW in case of individual peak charges and 2,986.36€/MW in the case of the proposed charging 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-post process.

			Model Decisions			**Consequences**	
	Charge Design		Consumption from Grid	DER Investments Decision G1 (MW)	DER Investments Decision G2 (MW)	Total System Cost (M€)	Network Deficit (%)
Case 1	Volumetric Charge		4 * 2218.55 MWh	0.4 * 4	-	1.27	28.3%
	Fixed Charge		12378.2 MWh	-	-	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 MWh	0.35	-	1.30	25%
		C2	2236.05 MWh	0.4	-		
		C3	2218.55 MWh	0.4	-		
		C4	2557.9 MWh	0.35	-		
	Fixed Charge		12890.5 MWh	-	-	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	0.200		
	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		

Table 5.3 Customers' Response to Charge Designs and the Consequences

For the second case, customers had different profiles, thus their peak consumption do 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 0.075MW, which corresponds to the capacity exceeding the threshold (2MW).

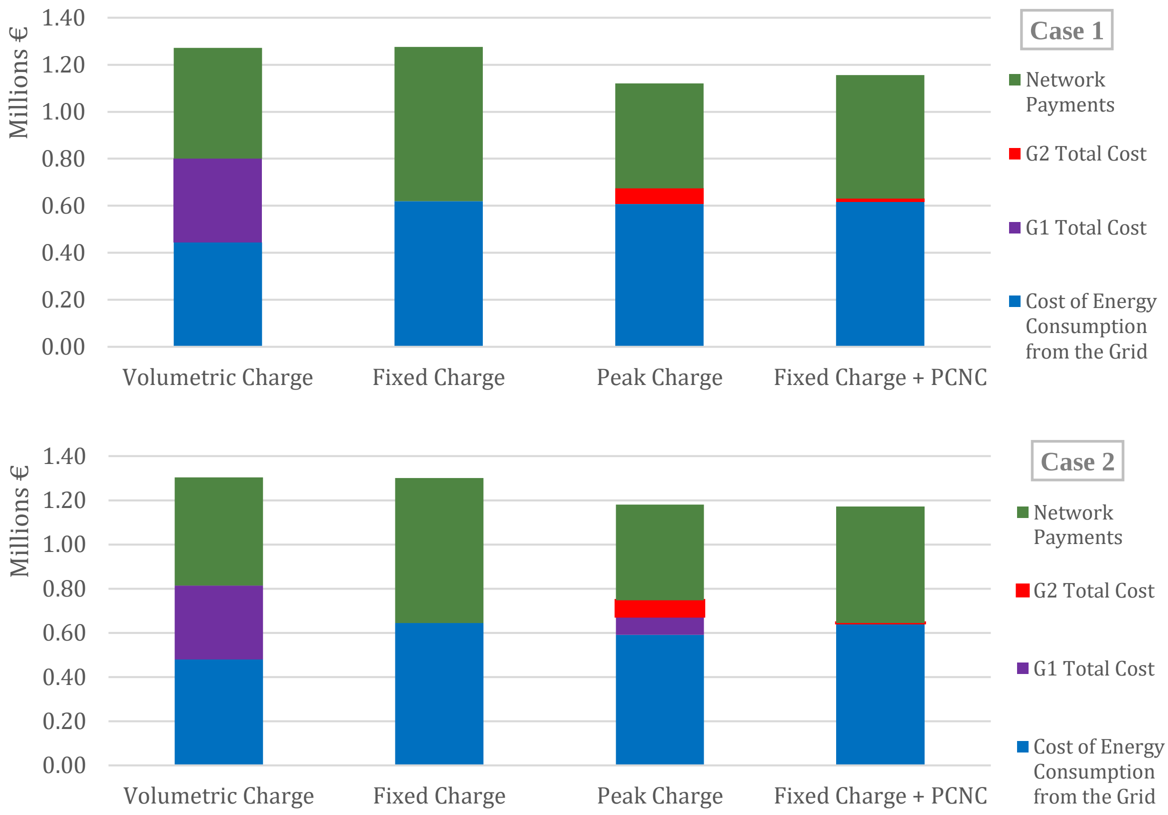
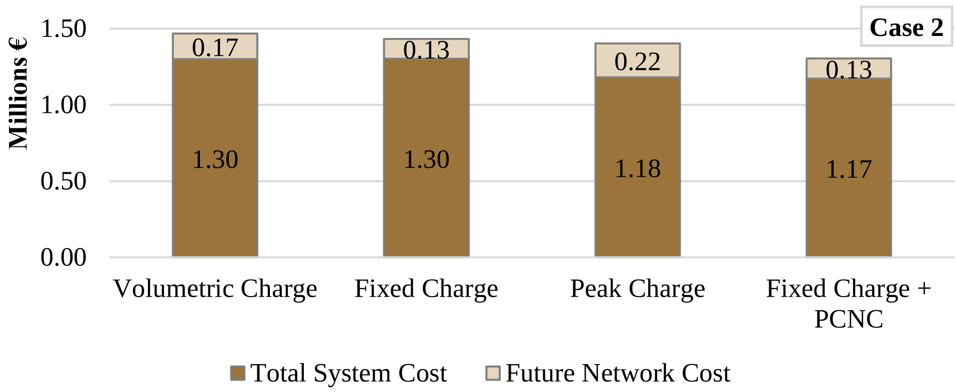


Figure 5.8 Comparison of Total Customers Payments Decomposition under different charge designs for Cases 1 and 2

Overall, the economic efficiency of the charge method is measured by both the total current system cost, and the additional future costs that could be due to transferred deficits, or required network reinforcements. An efficient method is that capable of avoiding expensive alternatives by less costly ones (while considering different periods). As in the presented case studies, the required reinforcements to accommodate the 0.1MW 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 Figure 5.9. 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 presented case studies, 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.



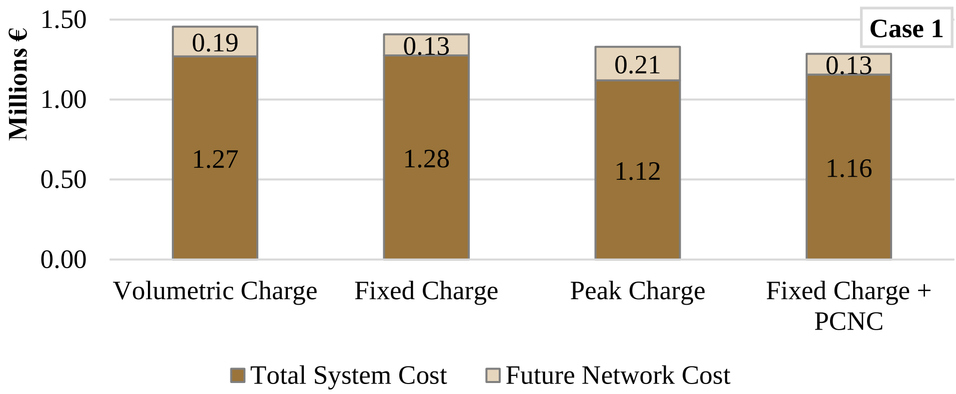


Figure 5.9 Comparison of Total System Cost and Future Network Cost under different charge designs for Cases 1 and 2

5.7.2 Observations

The case study presented considered two DER options: distributed generator in the form of PV and demand response. Other DER options may also be implemented such as distributed storage and electric vehicles, which may be simulated using chronological load curves instead of load levels, to optimize the charging and discharging of the devices during different time periods in the sense that reduces customer's payments.

Moreover, in practice, DER investment decisions are not solely dependent on customer's cost minimization. Customer's decisions are not totally rational, they are influenced by other factors as previously mentioned in 2.3, such as the presentation of information as well as the availability of automation and enabling technologies. Their behavior is also highly impacted by the level of financial gain/loss and risks they are exposed to.

Moreover, DER investments are not exclusively driven by DN charges. Although the case study focuses on this part of the total tariff customers receive, yet in practice, the rest of the tariff components: transmission network charge, energy prices and taxes affect their decisions. Depending on the weight of each of these components within the tariff, and to which extent they are dynamic, different reactions from the customers' side may be obtained.

Finally, the case study demonstrated a simple distribution network in order to illustrate customers' reaction to the proposed DN charges. The proposed charge design may be scalable and replicable, and could be applied to larger networks with higher population density as well as in different distribution network areas, following scalability and replicability analysis proposed in (Rodríguez, 2017).

5.8 Practical implementation issues

Although the proposed method provides efficient economic signals, the presented case studies illustrate and reveal several implementation issues as discussed below.

5.8.1 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.

5.8.2 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 it 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 varying 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 over-investments in DERs.

5.8.3 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 is further discussed in Part II of the thesis.

5.9 Chapter Remarks

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: peak coincident network charges (PCNC), and fixed charges. This design sends efficient economic signals during network peak utilization hours, and to avoid distorting those signals, fixed charges are implemented 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 PCNC is 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 and 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.

Moreover, the model used to demonstrate customers' response to DN charges in this chapter is concerned with the operational and DER investment decisions customers take when exposed to different DN charges, and how this would affect the system's economic efficiency. This is different from the model presented in Chapter 4, which aims to compare different DN charges based on their impact on customers' payments. The two models are independent to each other with different objectives. If the outcome of the optimization model presented here, which is the optimal DN charge design, needs to be assessed in respect to the tariff design evaluation attributes, then customers' payments should be first generated and used to implement the evaluation tariff methodology proposed in Chapter 4.

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. The coordination of customers' response is crucial for several reasons, as it could eliminate some of the concerns and implementation issues mentioned earlier. One of them is to avoid inefficient DER investments, which may lead to lower network usage. Customers may invest in DERs as a way to reduce their contribution during network peaks and consequently PCNC payments. As each customer is unaware of how other customers are reacting, along with the uncertainty of PCNC, under- or over-investment in DERs may occur. This lack of coordination may also create new unexpected peak network hours, if customers shifted to the same hours to avoid PCNC hours that were ex-ante forecasted. Thus, coordinating customer responses will consequently allow PCNC to be more predictable, stable and socially accepted.

PART II: DISTRIBUTION-LEVEL COORDINATION & CUSTOMERS' FLEXIBILITY UTILIZATION

This part of the thesis focuses on the design of flexibility mechanisms that utilizes customers' flexibility within the distribution level. It reviews the state of the art of short- and long- term flexibility utilization designs in Chapter 6, identifying their shortages and highlighting possible room for further improvement. In Chapter 7, a framework for distribution-level flexibility mechanisms is proposed that complements the proposed distribution network charges in Chapter 5, mitigating its shortages and concerns while following its pre-established economic signals.

6 Distribution-Level Coordination

In theory, network charge design acts as a driver to influence the way customers manage their energy needs. As previously discussed in Chapter 5, the most efficient designs are those demand-based and particularly those that consider network peak-coincidence, rather than individual peaks. They send economic signals to customers reflecting the network's status when network reinforcements are needed and its associated costs. Customers may respond to these price signals in four different ways to meet their electricity demand: continue purchasing energy from the grid, producing energy through DERs, shifting load, and curtailing load/generation injections. Although well-designed network charges may lead to efficient customer responses by revealing their flexibility potentials (which is defined as the ability of modifying energy injection and/or withdrawal patterns in response to an external signal to contribute in solving network operational problems), some unintended consequences may be gained. Such consequences in the short term are related to the creation of unexpected peaks. This mainly occurs as a result of customers avoiding high price signals during peak hours, by shifting their load or energy injections to other non-peak hours that might coincidentally evolve into a peak hour. Moreover, these consequences may also affect customers' long-term investment decisions. Customers may under-invest in DERs due to market uncertainty, or over-invest in DERs to guarantee they fully satisfy their load during peak hours while avoiding high network charges (PCNC). Either way, optimal system efficiency is not achieved.

As shown in Figure 6.1, DN charges trigger customer reaction, which then consequently has an impact on future network costs. It is crucial to develop market-based instruments which are applicable in a decentralized way, allowing customers' response to be applied in a more localized manner to efficiently influence the utilization of network assets. Moreover, those instruments should not distort the economic signals obtained through cost-reflective network charges. Hence, some kind of flexibility mechanism is required within the distribution level that accompanies network charges in order to efficiently coordinate customers' responses, embracing and well valuing their flexibility while guiding them through efficient short-term and long-term decisions.

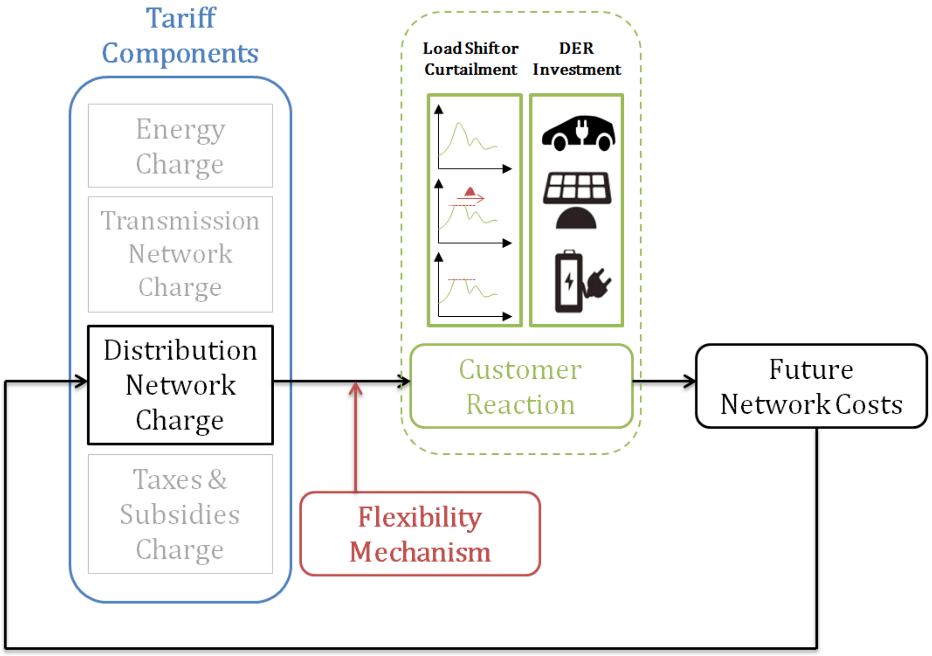


Figure 6.1 Introducing Flexibility Mechanism to Enhance Customer Response

This chapter focuses on the need of distribution-level market-based coordination mechanisms that complement efficient cost-reflective distribution network charges. Such mechanisms aim to maximize the value of flexibility, employing it in a way that enhances the system's total economic efficiency, while rewarding those that provide it. In addition, it discusses distribution-level mechanisms designed to procure customer flexibility to provide network services.

The main reasons that drive the need for distribution-level coordination are discussed in section 6.1.Then, in section 6.2, flexibility products that can be traded at the distribution level are presented, which could provide network short- and long-term cost-efficient solutions. Existing proposals for short- and long-term flexibility utilization are presented in sections 6.3 and 6.4 respectively, which are mostly market-based approaches such as auctions. Hence, a review on auction designs, parameters and implementation prerequisites and concerns within the distribution-level is presented in section 6.5. Auctions are mainly used for short-term flexibility utilization, whereas for long-term flexibility utilization, demand response contracts are needed to guarantee customer' engagement. A review on demand response contracts is presented in section 6.6. Finally, chapter remarks are concluded in section 6.7.

6.1 Why is Distribution-Level Coordination Required?

Dynamic cost-reflective network charges play a major role in incentivizing customers' response, yet the complexity of their design increases the uncertainty of customers' engagement, and thus it is difficult for DSOs to fully involve them within their short-term operational and long-term planning decision-making processes. In order for DSOs to account for customers' flexibility (which includes load and generation shifting/curtailment) as a real and effective alternative to grid investments, DSOs need to be able to count on the availability of these resources when needed. Lack of knowledge regarding actual power flow makes it difficult for DSOs to predict where and how often network challenges may occur (CEER, 2017). Thus, some means of distribution-level coordination are required to effectively integrate and coordinate customers' flexibility into the planning and operation of electricity networks. This coordination would firstly complement cost-reflective network charges, compensating its implementation shortages and allowing it to be more stable, predictable and socially accepted. Secondly, it would utilize customers' flexibility in the short-term reducing network operational costs, and in the long-term, to promote efficient customer DER investments, ensuring an optimal mix between network reinforcements and other solutions.

6.1.1 Complement cost-reflective distribution network charges

As previously mentioned, the most efficient designs are those demand-based and particularly those that consider network peak-coincidence, rather than individual peaks. Although well-designed network charges may lead to efficient customer responses by revealing their flexibility potentials, some unintended consequences may be obtained, as follows:

- Since network peaks are difficult to predict ex-ante, PCNC are applied ex-post. Thus, there is high uncertainty in the value of the PCNC and when it is expected.
- When customers are engaged and respond to the network charges, uncoordinated responses might generate new challenges. For instance, creating unexpected network peaks as a consequence of avoiding the expected ones.
- Customers' might over- or under-invest in DERs. Some may over-invest to insure themselves against high network charges (PCNC), or under-invest due to financial risk. On one hand, DSOs and the society may miss the opportunity of more cost-efficient solutions to replace network investments as customers decide to under-invest in DERs. On the other hand, over-investment in DERs may cause technical conflicts within the network related to the network's operation, control, and stability. In addition, it may result in less network usage and increasing network costs, leading to network cost recovery deficits. Thus, customers' DER investment decisions should be well guided and linked to the networks needs.

6.1.2 Utilize customers' flexibility

Customers' flexibility provides opportunities to DSOs to manage their networks in a more efficient and flexible manner in the short- and long-term. The use of customers' flexibility may be employed to assist the network through a range of services such as for managing network congestions. For DSOs to consider local flexibility as an alternative to network reinforcements, they should be able to supervise, coordinate and utilize it when needed. Thus, as discussed in (Oosterkamp et al., 2014), distribution-level coordination is required for several reasons. First, to be able to supervise and manage customers' flexibility to enhance operational decisions. Secondly, to ensure that customers' flexibility services are available and could be relied upon to replace network investments. Thirdly, to incentivize DER investments in locations that promotes most advantages to the DN. For example, the installation of small-scale DG close to loads can reduce losses as well as postpone network investments. Moreover, certain types of DERs may also have the ability to offer different network ancillary services to DSO and transmission system operator (TSO), such as voltage control, frequency control and reactive power support. Thus, coordinating customers' response by incentivizing them to optimally allocate most efficient DER types depending on network needs will generate many benefits for the network operation and eventually achieve network cost reductions.

6.2 Flexibility Products and Services to be Traded at the Distribution Level

Customer may provide different flexibility services and products to the DSO that helps to efficiently operate the DN in the short term and may avoid costly network investment in the long term. As shown in Figure 6.2 and discussed in (EDSO, 2018), there are a number of flexibility services that are linked to the network charges and could be traded in the short and long term. Within the short term, customers' flexibility could be used to assist in network congestion management. This is mainly concerned with network's capacity management, where customers can shift their injections/ withdrawals away from network high utilization hours. There is no obligation on the customers' to provide flexibility; they are driven by some kind of financial gains. As for the long-term flexibility products, they serve as alternatives to network investment. Thus, customers' providing these flexibility products must be committed to provide their services upon being called by the DSO. Their services could be in the form of providing firm capacity, by injecting or withdrawing energy during network utilization hours, or providing voltage/power quality support.

Utilization of customers' flexibility requires engaging them through well-designed distribution-level flexibility mechanisms that enable extraction and management of their flexibility while correctly valuing it. Thus, customers will benefit most from a system of network charges, mechanisms and markets that are aligned with network's needs, providing solutions that are economically optimal, in both the short and long term. Thus, innovation in new distribution-level market designs that facilitate customer's participation and coordinate them in an efficient way will enhance the system's economic efficiency. These markets/mechanisms should ensure a level playing field for all types of DERs to compete transparently and correctly compensating them for their flexibility services. There is a number of existing proposals for customers' flexibility extraction and utilization both in the short and long term, and they are further discussed in sections 6.3 and 6.4 respectively.

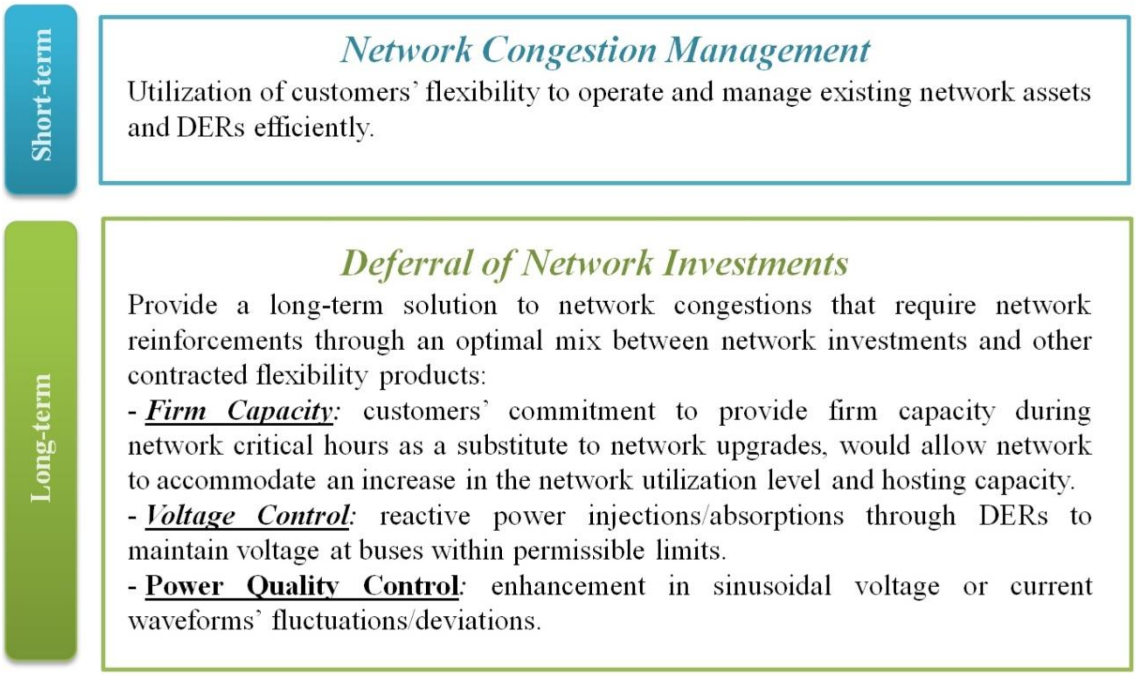


Figure 6.2 Distribution-level Flexibility Products & Services

6.3 Short-term Customers' Flexibility at the Distribution Level

Short-term utilization of customers' flexibility aims to assist the DSO in the operational decisions. In Europe, different attempts for the use of flexibility have been undergoing, including local flexibility markets (a market for alleviating local distribution constraints) and flexibility contracts with aggregators. For example, in Germany, the traffic light system has been implemented, where the network may fall in one of three categories: green light when there are no network congestions, and customers are allowed to use it freely; yellow light when there is a risk for network congestions, and negotiations starts between DSO and customers in order to maintain system stability and solve congestions, and red light when network congestions and DSO along with the TSO solve the congestion by using remedial corrective actions (BDEW, 2015; EDSO, 2013).

A number of pilot projects have been carried out in different countries presenting different ways of utilizing customers' flexibility. For examples, in Finland, two Finnish companies offered a locally and remotely controlled flexibility solution. OptiWatti, offered domestic heating flexibility solutions based on optimizing the heating of individual rooms/ spaces depending on the user´s needs, electricity prices and weather forecast. Multiple sensors are combined with the end-user´s preferences in a learning control system that operates on end-user's behalf. Whereas, Fortum offered a remotely optimizing flexibility solution by installing additional equipment. The system is also able to alternate between oil and electrical heating depending on the electricity price (Nordic Energy Regulators, 2016). Another example is the Smart Grid Vendée project in France. It is a five-year project carried out to develop the use of DER flexibility services through market models. It includes, testing market designs, active management of the medium voltage grid, increases in grid hosting capacity, and new demand response mechanisms (Smart Grid Vendée, 2017), (Bigliani et al., 2015).

Furthermore, in North America, the New York Reforming Energy Vision (REV) is a state initiative that calls for restructuring the way utilities (which in North America have similar functions to DSOs in Europe) and energy companies sell electricity. It aims to maximize the utilization of resources and reduce the need for new infrastructure through expanded demand management, energy efficiency, renewable energy, distributed generation, and energy storage programs. This requires regulated utilities to act as distributed system platform providers (DSPPs) that will own the DN as well as create markets, tariffs, and operational systems to enable behind-the-meter resource providers (Bigliani et al., 2015).

Distribution-level flexibility markets in the literature are referred to as flexibility market (Esmat et al., 2017; Roos, 2017; VDE, 2015), micro-market (Faber et al., 2014; Kriukov et al., 2014; Olivella-Rosell et al., 2016), local market (Kamrat, 2001; Menniti et al., 2014; Rosen and Madlener, 2012), decentralized market (Bne, 2016), where they all aim to utilize customers' flexibility to relief network congestion and/or network upgrades. Within the iPower project (N. C. Nordentoft et al., 2013), the need of a flexibility clearinghouse (FLECH) is discussed. FLECH is meant to facilitate DSOs to announce services and aggregators to bid upon. According to (Heussen et al., 2013), FLECH is a service-oriented platform that facilitates the business process of specifying, contracting, delivering and settlement of DER flexibility services. Moreover, in (Zhang et al., 2014), FLECH is presented as an aggregator-based flexibility market that operates at the distribution level for solving thermal and voltage congestions.

The traffic light concept, earlier explained in the German example (BDEW, 2015; EDSO, 2013) and shown in Figure 6.3, is used as metaphor for the DN status and the required customer engagement and flexibility. Within the yellow phase, which is an alert state, the DSO has an emerging congestion and willing to procure flexibility for relieving it. Different market designs were proposed for this purpose. A framework for distribution level flexibility market (Flex-DLM) for congestion management is proposed in (Esmat et al., 2018). FM operates as a day-ahead market, offering flexibility services for potential network congestions. It considers aggregated customer flexibility bids and payback preferences in its decision process. The model is based on two stages: first flexibility service activation, and then payback effect assessment (Esmat et al., 2016). Moreover, the FM model has been extended to a DSO decision support model that manages congestion with objective of minimizing DSO costs, while considering customer preferences and uncertainties (Esmat et al., 2017). Engaged customers are compensated by direct incentive payments and tariff reduction during payback periods.

The Regional Flexibility Market (Regioflex) (VDE, 2015) also operates during yellow traffic network status. Regioflex uses market-based mechanisms to avoid critical regional network situations as an alternative to the network expansion. DSO calls for flexibility services when required. Customers and aggregators then offer flexibility options according to their portfolio, and the DSO contracts the needed flexibility and compensates the customers.

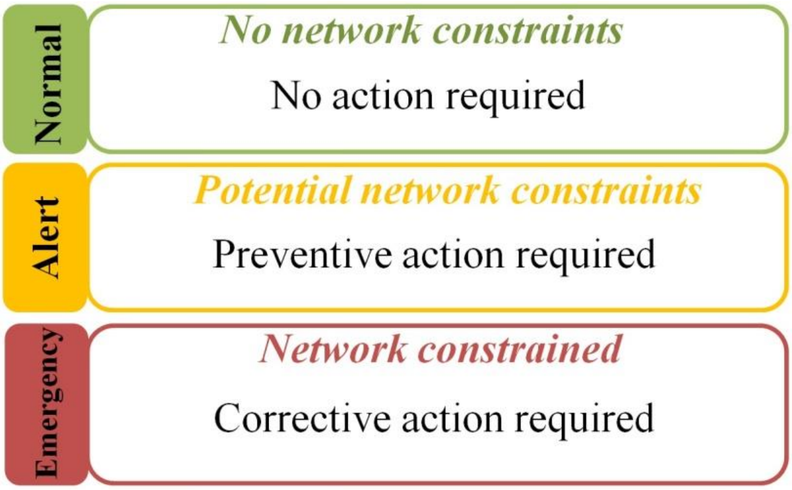


Figure 6.3 Distribution-level Traffic Light Concept

Another local market design is the de-flex-Market model in (Bne, 2016). The model requires willing customers to sign a contract for a timeframe of at least one year, where the total length of the operation period which is the restricted network capacity use, does not exceed one month. According to the congested assets and flexibility needs, the DSO identifies the size of the aggregated distribution grid area and contacts registered customers within that area. Engaged customers that provide flexibility services are compensated by direct incentive payments. A customer that violates the network restriction requirement is exposed to a non-compliance fee.

The most efficient way to well coordinate customers at the distribution-level is through market-based approaches, as it leads to optimal solutions. Most of the aforementioned local flexibility markets procure or utilize customers' flexibility through auctions. Auctions allow an adequate level playing field in which competition is fostered and flexibility services can be provided on competitive basis. Auction designs are reviewed in section 6.5, as well as the necessary implementation assumptions and prerequisites.

6.4 Long-term Customers' Flexibility at the Distribution Level

Long-term customers' flexibility utilization aims to replace network reinforcements partially or fully. It allows DSOs to optimally mix between network investments and other solutions during the network's planning phase. Smart DER connections would benefit both the DN and the DER owners, as have been shown in the cost-benefit analysis studies carried out in (Anaya and Pollitt, 2017, 2015). The objective is to design a cost effective DER services procurement model that provides additional network capacity during critical network periods or provides other ancillary services when needed. Different procurement models have been proposed earlier and discussed in (Poudineh and Jamasb, 2014). An administrative approach proposed in (Hoff et al., 1996) calculates a break-even price at which the DSO is indifferent between undertaking conventional reinforcement and alternative approaches. The main concern of this approach is that it does not consider maximizing social welfare as it lacks market-based mechanisms and opportunity cost of scarce resources. Thus, maximum economic efficiency is not achieved.

Furthermore, a market-based approach is proposed in (Trebolle et al., 2010) called reliability options for distributed generation (RODG). It takes into account the network investment deferral effects from DG integration. The DG firm capacity procurement is based on a sealed bid auction. Another market based approach is proposed in (Poudineh and Jamasb, 2014) called contract for deferral scheme (CDS). It is similar to RODG, but it integrates a portfolio of DERs rather than DGs only. Moreover, the CDS contract is based on a descending clock auction. Under the CDS scheme, the DSOs can enter into contracts with DGs, storage operators, and demand response and energy efficiency providers, who offer available capacity when needed. The market participants under a contract will be obliged to have available the required capacity at the time of network constraints. In return, the DSO offers them a capacity payment (€/kW). Similarly, a staircase capabilities market is proposed in (Gimon et al., 2013), which is an iterated sequence of long-term, small-volume requests for proposals (RFPs) for new capabilities of DERs to match anticipated system needs.

Similar to ancillary services market developed by TSOs, recent proposals for DSOs have been discussed, which offer thermal (capacity) and voltage congestion relief solutions. In (Madureira and Peças Lopes, 2012) a market framework addressing voltage control in multi-microgrid systems is presented, which is a Var market for MV distribution systems that involves DERs. In addition, different flexibility services electric vehcile can offer in ancillary markets, particularly for the low voltage network, are discussed in the Nikola project (Andersen et al., 2014). In (Roos, 2017) a market for joint procurement of transmission and distribution system services from demand flexibility called Flexibility Activation Market is proposed.

The majority of the previous studies and proposals for customers' flexibility utilization are decoupled from the economic signals transmitted through distribution network charges. Thus, a gap remains to link customers' flexibility services to pre-established economic signals received by customers' through DN charges. Short-term flexibility designs mainly follow corrective methods rather than preventive. When network congestions are predicted, customers' flexibility is procured to resolve the congestions and customers are financially compensated. A more efficient approach would be in line with the proposed DN charges in Chapter 5, incentivizing customers to reduce their network usage during expected network congestions by allowing them to book their capacities in advance. This proposal is further discussed in Chapter 7. Approaches to utilize customers' flexibility would generally follow auctions to foster competition. An overview on auction designs, parameters and implementation prerequisites and concerns within the distribution-level is presented in section 6.5. Moreover, the existing proposals reviewed for utilizing long-term flexibility do not consider short-term flexibility mechanisms as a first approach prior implementation of long-term flexibility approaches. Hence, economic efficiency is not guaranteed, as some of the network upgrade requirements or long-term flexibility procurement could be avoided by efficiently utilizing existing network assets and DERs. A more efficient approach will be to first implement flexibility mechanisms to extract exisiting customers' flexibility, then procure extra flexibility if needed through long-term flexibility mechanisms. The procurement would follow market-based approaches during the selection phase. Then, to guarntee customers' engagement, contracts are issued. An overview on demand response contracts, terms and types is presented in section 6.6.

6.5 Implementation of Auctions at the Distribution Level

6.5.1 Overview on auctions

Flexibility utilization approaches discussed earlier are generally based on auctions, as they lead to most cost-efficient solutions. As defined in (Maurer and Barroso, 2011), an auction is an allocation procedure based on a precise evaluation criterion specified by the auctioneer, and a pre-defined publicly available set of rules designed to allocate or award objects or products on the basis of a financial bid. It aims to allocate a product (in this case the available network capacity above threshold) through a fair, open, transparent, non-discriminatory manner. A good auction design elicits information from bidders regarding their willingness to provide the product being procured. It should also stimulate competition among the potential suppliers of the product being auctioned, with the objective of ensuring a socially more efficient allocation/use of resources (Maurer and Barroso, 2011).

Within the electricity sector, auctions have been widely used in many countries to promote the competitive procurement of electricity-related products, this includes: trading energy and capacity, transmission congestion rights, and ancillary services (Batlle et al., 2014; Batlle and Rodilla, 2010). Auctions were first introduced at the generation level in the 1990s for long-term electricity contracts, Power Purchase Agreement (PPA), between state utilities and Independent Power Producers (IPPs) (Maurer and Barroso, 2011). Then, when a competitive generation market had emerged, new electricity auctions were introduced, that are more sophisticated targeting specific market requirements, such as ensuring supply reliability. Reliability products, known as reliability options, are used for customers to hedge prices and to guarantee system adequacy. This may include requirements for installed capacity, firm capacity or firm energy (Mastropietro et al., 2017). Moreover, due to the urging need of increasing renewable generation, as a consequence of policy objectives and climate change challenges, incentive mechanisms were introduced to attract investment such as feed-in-tariff. Shortly later, long-term electricity auctions were promoted at the security-of-supply level, where Renewable Energy Sources for electricity (RES-E) support framework started to move towards renewable energy auctions (Del Río and Linares, 2014; Mastropietro et al., 2014).

At the transmission level, auctions had also played a role. Physical and financial transmission rights (PTR and FTR) were auctioned to allocate the network's capacity in order to hedge against high prices during network congestions (Batlle et al., 2014). At the distribution level, the only auctions that took place was regarding signing PPAs with IPPs, which were in charge of building power plants and delivering electricity by a certain date (Maurer and Barroso, 2011). Other than that, no auctions were carried out at this level. Recently, a number of researches propose introducing auctions at the distribution level, into the so called flexibility markets or demand response markets, where customers are the bidders, offering flexibility to the DSO or aggregator, which acts as the auctioneer (Esmat et al., 2016; Ottesen et al., 2016; Ramos et al., 2016; Reihani et al., 2016; Spiliotis et al., 2016; Zhang et al., 2014). Moreover, auctions at the distribution level could promote efficient allocation of other electricity-related products, such as network capacity allocation coordination, and DER investment coordination.

6.5.2 Auction design elements and types

An auction is designed based on its bidding, clearing and pricing rules. The bidding rules define the structure of the bids and when they can be submitted. For example, the bidders might be allowed to bid just a price, or a set of paired prices and quantities. These bids could be submitted only once as in the case of a sealed-bid auction, or successively, as in the case of a dynamic auction. In order to determine the winner of the auction, a clearing process is used. It states the basis upon which the bids will be compared and how the evaluation process will take place, and thus the allocation of the product to the winner bidders. After the clearing process, the price at which the auction is closed is determined. The pricing rule could follow a pay-as-bid rule, or a uniform price rule determined by the marginal bid.

There are many different type of auctions discussed in (Maurer and Barroso, 2011), each has different design and objectives. A review on how effective and efficient auctions could be designed is available in (Klemperer, 2004). The major types of auctions are sealed-bid, dynamic, hybrid and combinatorial. Table 6.1 compares between the major types of auctions.

Sealed-bid auctions are commonly used, either for a single product or multiple units of the same product. Its main advantage is that it is simple, and could follow first-price, pay-as-bid, or uniform price rule. However, it is in some cases considered inefficient as the bidder is unable to reveal information regarding other participants, and thus cannot accordingly modify their own bids. Dynamic auctions are based on multi-round bids, which are efficient as they allow bidders to adjust their bids between rounds based on the information they reveal. Clock auction is a type of dynamic auction, where prices are defined by the auctioneer at the start of each round. Then prices decrease from a round to another in descending clock auctions, and increase in ascending clock auctions. Rounds keep on going until the quantities offered are equal to the target quantity to be procured. Clock auctions are considered very efficient as they allow strong price discovery. There are also simultaneous ascending/descending clock auctions, which could be used when multiple products that could be substitutes to each other are offered. The simultaneity gives the bidders the option to shift from a product to another.

Moreover, combinatorial auctions are used for package purposes, when the bidder is willing to participate only if he will receive a certain combination of products. Although it is complex, it solves the problem bidders face with the exposure to unwanted outcomes. Finally, hybrid designs are used when no one specific auction design is able to fulfill the required objective. It is a way of combining characteristics of different designs together. A common two-phase hybrid auction takes place in Brazil, which combines descending clock and pay-as-bid. In the first phase bidders submit quantity bids. Then in the second phase, winners of the first phase bid prices for the quantities that they were allocated (Dutra and Menezes, 2005; Maurer and Barroso, 2011).

		Bidding	Clearing	Pricing	When to use
Sealed-bid	First-Price	Single price for a single product	Lowest-price bidder	Price offered by lowest-price bidder	One single product
	Pay-as-Bid	A schedule of prices and quantities	The auctioneer gathers together all the bids, creating an aggregate supply curve, and matches it with the quantity to be procured	Winners pays according to the price they provided	Multiple units of the same product
	Uniform Price			All the winners receive the same price, which is the market clearing price	
Dynamic*	Clock	Quantities for pre-defined price	Each round is cleared according to the submitted quantities. The auction stops when submitted quantities are equal to available quantity.	Price for each round is pre-defined by the auctioneer	Multiple units of same product with unknown price
	Simultaneous Clock				Multiple units of different products that are substitutes for each other, and price unknown
Combinatorial	Sealed-bid or Dynamic	Prices for pre-defined products, or prices and product combination	Follows the pricing and clearing rules mentioned for sealed-bid or dynamic auctions		Multiple products that are complementary to each other
Hybrid	Sealed-bid or Dynamic	Follows the bidding, pricing and clearing rules of each phase			When no one specific auction design can fulfil the required objective

* There are different types of dynamic auctions; Clock auction is demonstrated as an example.

Table 6.1 Comparison between Major Auction Types

6.5.3 Auction implementation prerequisites

The promotion of market-based mechanisms, such as auctions, at the distribution level is subject to a number of prerequisites as shown in Figure 6.4.

- **Smart meters** rollout is essential to communicate economic signals to customers. An almost complete roll out is expected by 2020 within most European countries (European Commission-DIRECTORATE B – Internal Energy Market, 2015).
- **Distribution-level monitoring** along with smart meters will allow distribution level auctions to be established efficiently, as more information regarding

network operation is acquired. In addition, enhanced communication with customers will engage more customers to participate in auctions.

- **Information Management** may be carried out by independent agents or by the DSO. Ownership, access and sharing of the data between network agents (DSO, TSO, intermediates) needs to be well-defined by policy makers and regulators to ensure a fair, efficient, transparent and non-discriminatory environment (EURELECTRIC, 2016). It is essential to share relevant information with all parties and create an adequate level playing field for flexibility services to be traded on a competitive basis while considering data privacy (EURELECTRIC, 2016).

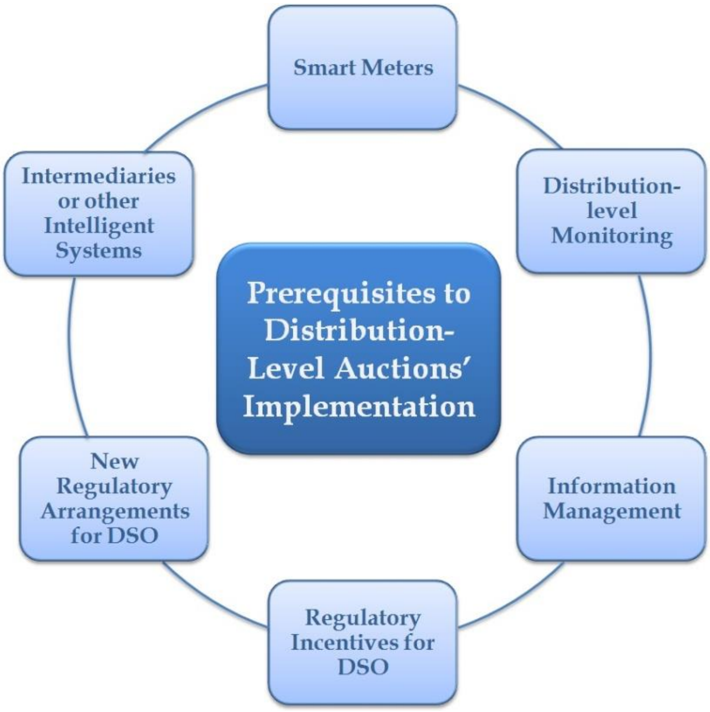


Figure 6.4 Assumptions for introducing Distribution-level Auctions

- **Regulatory incentives for DSOs** to encourage the deployment of necessary digital technologies that enable advanced monitoring and communication is one of the main prerequisites for introducing auctions into the distribution level. Thus, reforming regulation to enable new roles for DSOs related to innovation and full integration of DERs is another essential step. In addition, incentives are needed to encourage DSOs to put in equal footing traditional network solutions and flexibility contracts for network deferrals.
- **New regulatory arrangements for DSOs** to develop new activities are required to allow DSOs to procure services through market-based mechanisms. Hence, terms and conditions for distribution level market arrangements need to be well defined and authorized by energy regulators (Lavrijssen and Carrillo Parra, 2017).
- **Intermediaries or intelligent systems** are required to facilitate the participation of customers in auctions. It should be noted that most residential customers find it difficult to participate in auctions and to react providing flexibility services. Only a limited number of residential customers would actually be engaged. The

rest of the customers will not react, use intelligent systems such as smart home devices, or assign intermediaries to act on behalf of them. Intermediaries are capable of gathering detailed information regarding different types of customers and their potential to provide demand response services. They are aware of the magnitude and cost of demand response that different appliances can provide. Besides, they consider other parameters such as response time span, storage characteristics, appliance usage constraint, and the kind of compensation customers require (Ikäheimo et al., 2010). They act as mediators or brokers between customers and the DSO. They possess the technology required for performing demand response services, as well as they are responsible for the installation of the communication and control devices at customer premises (Gkatzikis et al., 2013).

6.6 Overview on Demand Response Contracts

Demand response contracts govern customers' engagement by setting the rules of relationship between the customer and the DSO/ intermediaries. Thus, they improve DSOs' forecasts and certainty regarding including customers' flexibility in their planning phase. They could be issued based on bilaterally agreement or following market-based mechanisms. Bilaterally conducted contracts do not certainly promote efficient allocation or use of resources. Hence, well-designed contracts could be issued to winners of auctions or other market-based mechanisms, to ease and ensure customers' participation particularly in long-term flexibility services, while ensuring efficient allocation of network resources.

First, customer selection for long-term flexibility products will follow market-based approaches. Then, selected customer would sign contracts with the DSO or intermediaries, allowing them to act on their behalf. There is a diversity of contract types discussed in (He et al., 2013; Zhou et al., 2012), that differ according to the set of terms each includes. Types of contract could be price-based: ToU, CPP, dynamic pricing, fixed load capping, dynamic load capping, or control-based, that include having access to customers' appliances through direct load control.

Where legislation allows, DSOs have signed flexible contracts with customers, where they are remunerated for providing services to resolve network constraints (EURELECTRIC, 2016). This has been mainly the case with commercial and industrial customers, where the DSO is able to limit their withdrawal/injections to certain number of times per year, for a limited duration, at critical moments under agreed conditions (EDSO, 2015b). In UK, a Power Responsive program, facilitated by the National Grid, is an example for industrial and commercial demand response programs that use different forms of flexible technology such as demand response and storage to reduce network peaks (Power Responsive, 2017). The program has been applied to different sectors such as manufacturing, transport, education and retail, and the case studies have shown significant savings.

Previously, such contracts were not common for residential customers. However, recently many residential demand response programs have been implemented. For example, the Low Carbon London (LCL) project demonstrates a dynamic Time-of-Use tariff which aims to promote customers to manually shift their demand by delaying actions or turning off appliances (Mark Bilton et al., 2014). The report discusses different customer response options, their benefits, and metering requirements. Moreover, the introduction of intermediaries, such as aggregators, had also facilitated the engagement of customers.

6.6.1 Contract terms

A contract governs the relationship between the customer and the DSO or the intermediary through financial terms such as price risk and financial compensation, and non-financial terms such as volume risk, complexity, loss of autonomy and loss of privacy (He et al., 2013). Price risk is only present in price-based contracts, where customers are exposed to alternating prices, as in the case of dynamic prices. If customers do not respond appropriately to signals, they might eventually experience higher bills than expected. Thus, usually contracts that involve high price risk will include high financial compensations. Financial compensation could have different forms, such as discounts, rebates, lower off-peak energy prices, and payback options.

As for the non-financial terms, they are more concerned with customer preferences and their comfort. Some customers would prefer low complexity, as they would not like to deal with signal volatility, or get involved into difficult decisions. Moreover, volume risk is related to the uncertainty of available energy for consumption. This is mainly the case for contracts that impose consumption caps in certain periods, or that allow load control/ curtailment. Consequently, there is an impact on the customer's privacy and autonomy. Loss of privacy is related to customers revealing some personal information, and loss of autonomy is when customers loses part of their freedom in managing their appliances (He et al., 2013).

6.6.2 Assurance of customers' commitment through contracts

Demand response contracts are either incentive-based or price-based. In both cases, there is a financial gain that customers seek in order to provide withdrawal/ injection profile modifications. Incentive-based programs pay customers for profile modifications through bill credits or a discount rate, which is in addition to or separate from electricity prices. Price-based program provides customers with different electricity prices at different times. Such programs indirectly encourage users to dynamically change their energy usage patterns according to the variance of electricity prices. According to their new pattern, they are rewarded with bill savings (Albadi and El-Saadany, 2008; Deng et al., 2015).

Dynamic capping is a dynamic volume-based contract, which could be used to limit customers' injections/withdrawals during peak hours. Customers sign contracts with DSOs or intermediaries allowing them to curtail part of their load/generation during peak hours, or they receive a signal to reduce their load/generation, which they are obliged to follow. DSOs or intermediaries fix hourly withdrawals/injections caps/floors with day-ahead or up to an hour-ahead notice, reflecting network conditions. Such contracts do no pass any price risk onto customers, but expose them to volume risk. The complexity customers face is regarding modifying their withdrawals/injections frequently, which may be reduced through automation of residential appliances. The appliances are automated to operate during low prices. Customers do not need to interact; they only need to set their preferences, such as temperature set point (Dupont et al., 2014).

On one hand, according to (Darby and McKenna, 2012), automation has a number of potential drawbacks: the enabling technology can be expensive, it reduces user control, and it can reduce users' awareness of their energy-related practices, which may result in unintended consumption. However, on the other hand, automation can protect consumers against complexity and volatility, which is the main discouraging reason for consumers to not respond. Thus, another solution to limit customers' injections/ withdrawals during peak hours is through direct control contracts. Through these contracts customers are directly controlled via a signal which adjusts or switches load/generation, which is more reliable compared to a real-time signal for profile adjustments (Haring and Andersson, 2014; Mathieu et al., 2013). Direct control contracts include load/generation shedding, and intentional brown outs. Brown outs are related to partial or temporary reduction in voltage which in turn reduces the consumption while maintaining power quality within limits (Eid et al., 2016). Compared to dynamic capping, as shown in Table 6.2, direct control involves higher degrees of autonomy and privacy loss, as customers need to disclose their private information to third parties and allow them to control their load/ generation fully or partially.

	Dynamic Capping	**Direct Control**
Type of signal	Volume-based	Control-based
Signal Volatility	Dynamic	Pre-defined
Price or Volume Risk	Volume risk	None
Loss of Privacy	None	High
Loss of Autonomy	Limited	High
Automation Required	Limited	High
Customer Interaction	High	None

Table 6.2 Comparison between Dynamic Capping and Direct Control

6.7 Chapter Remarks

This chapter highlighted the main drivers for distribution-level coordination; to complement efficient DN charges discussed in Chapter 5, and utilize customers' flexibility in the short and long term. A number of proposals for short- and long-term LFMs were reviewed, and a number of conclusions are reached:

- Existing short-term flexibility designs are decoupled from network charges and generally based on customers' flexibility procurement in exchange for financial compensations. The use of pre-established economic signals transmitted by the DN charge could better incentivize customers' engagement and efficiently help extracting their flexibility.
- Existing long-term flexibility designs aim to procure customers' flexibility service to replace network investments. However, they do not consider existing customers' flexibility in their design. Hence, economic efficiency is not guaranteed, as some of the network upgrade requirements or long-term flexibility procurement could be avoided by efficiently utilizing existing network assets and DERs.
- Thus, a gap remains to link customers' flexibility services to pre-established economic signals received by customers' through DN charges. Efficient designs of local flexibility mechanisms are required to utilize and procure customers' flexibility in the short and long term. They should follow DN charges to ensure optimal reactions and efficient DER investment decisions are conducted from the customers' side, as well as efficient network reinforcement decisions are executed from the DSO's side.
- For flexibility mechanisms to be implemented in the distribution-level, there is a number of prerequisites that should be considered, one of which is the installment of smart meters and enabling technologies, through which signals and alerts are transmitted to customers.

  Auctions should be well-designed to ease customers' participation in providing their flexibility services in an efficient manner.
- Demand response contracts are needed to guarantee customers' engagement in providing long-term flexibility services. It should be well-designed to comply with network's peak nature and customers' preferences.

Thus, flexibility mechanisms following a market-based approach are required, to enable the system to access its available physical flexibility, and when existing flexibility is insufficient, efficiently invest in additional flexibility. This is further discussed in the proposed local flexibility mechanisms in Chapter 7.

7 LOCAL FLEXIBILITY MECHANISMS

This chapter presents the proposed local flexibility mechanisms (LFMs) aligned with the DN charge design in Chapter 5, performing a complementary role to overcome its implementation concerns providing distribution-level coordination. Through market-based approaches, LFMs aim to unlock flexibility in the distribution level by incentivizing customers to reveal their preferences and willingness to pay in order to reach optimal investment decisions that increase the economic efficiency of the whole system. Two LFMs are proposed: short and long term. Short-term LFM is designed to extract available flexibility capabilities within the distribution-level through efficient utilization of existing network assets and DERs. Then, when this flexibility is insufficient and network upgrades are required, long-term LFM is designed to efficiently procure flexibility services to replace network investments through a cost-efficient manner in distribution planning.

Figure 7.1 shows how the proposed LFMs and the DN charge design are implemented following the traffic light concept discussed in section 6.3. When the network operates in the normal state, with no network constraints, only fixed network charges are applied. If the network's utilization level is expected to increase requiring network upgrades, this would lead the network to the alert state. Within the alert state PCNC is applied along with the fixed charges. Short-term LFM is introduced within the alert phase to allow customers to hedge against high PCNC while providing flexibility services. It aims to reduce the uncertainty of peak hours and avoid the creation of new unexpected peak hours through dynamic auctions (further explained in section 7.1). Since PCNC is applied based on a pre-defined capacity threshold (as discussed in sections 5.1-5.2), it is unlikely that the network will be driven into the emergency state. However, in case of emergency state, DSO interventions through energy withdrawal/injection curtailment will be expected to maintain the network's stability. Then, during network planning, if the utilized short-term customer flexibility is insufficient to alleviate the need for network reinforcements, Long-term LFM is implemented to procure additional firm capacity through DERs, promoting efficient DER network integration. Long-term LFM operates through Request for Proposals (RFP). RFP is issued to coordinate and incorporate DER investments in the long-term distribution planning allowing DSOs to mix between network investments and other solutions efficiently. Selected customers through the RFP sign contracts with the DSO to provide flexibility services during network's yellow and red states. Both short- and long- term LFMs are further explained in Sections 7.1-7.4 and 7.5 respectively.

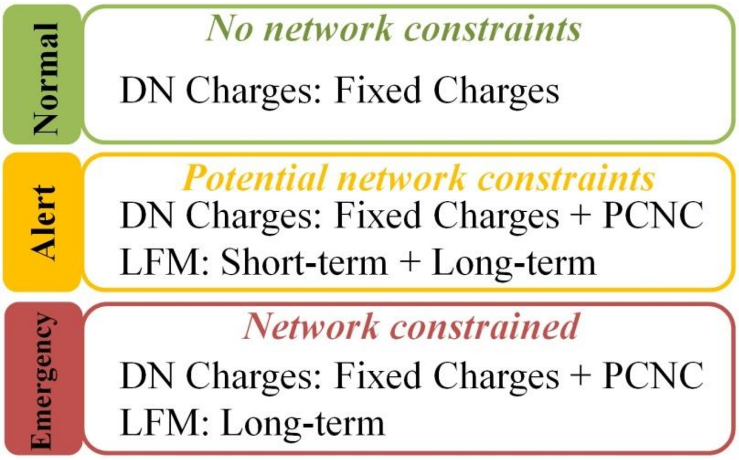


Figure 7.1 Mapping Distribution Network Charges and LFM to the Traffic Light Concept

Section 7.1 presents the proposed short-term LFM that aligns with the economic signals established through the DN charges based on PCNC and fixed charges discussed in Chapter 5. Sections 7.2 – 7.4 presents two proposed approaches to implement short-term LFM and compares them: Simultaneous Ascending Auction (SAA) and Simultaneous Ascending Clock Auctions (SACA). Section 7.5 presents the proposed long-term LFM. Finally, chapter remarks conclude in section 7.6.

7.1 Short-term LFM: customers' coordination through auctions

Short-term LFM aims to ensure that flexibility services are provided efficiently through competitive market mechanisms. Hence, it should be structured to properly incentivize and utilize responsive customers directly or through intermediaries to provide their flexibility in a way that does not distort economic signals already established through the DN charges. The objective of short-term LFM is to engage customers' flexibility to dynamically compensate network peaks economically as well as to avoid the creation of unexpected peaks. Simultaneous Ascending Auction (SAA) and Simultaneous Ascending Clock Auction (SACA) are two proposed approaches that work as a tool to retrieve information regarding future network usage. The auctions are held to offer customers network capacity during potentially network scarce situations, i.e. allocating distribution network capacity.

For the auctions to succeed in attaining its objective, two main factors are required: (i) the auction design that fits well to serve the objective, and (ii) a sufficient number of customers involved, well informed, and willing to participate. The second factor depends on per case basis, whether the network to be considered serves sufficient customers or not. This section deals with the first factor, proposing a flexibility mechanism through decentralized market-based approaches that would be held at the distribution level, carried out by the DSO.

7.1.1 Design parameters of the proposed short-term LFM:

(i) **Local DN identification:** The DSO indicates the local area and hours where the short-term LFM will be held based on the network assets affected by the yellow alert (i.e. emerging network constraint, following the traffic light concept) and the associated customers. Depending on the network, this could take place frequently or occasionally.

(ii) **Notification period:** Customers affecting the local DN are warned 24 hours in advance.

(iii) **Network capacity allocation process:** Short-term LFM is held during yellow alert hours (peak and borderline peak hours). During these hours, local network customers may reserve their network capacity in advance. The process of booking and allocating network capacity is explained in section 7.1.2.

(iv) **Real-time commitment:** During real time, yellow alert hours may or may not evolve into a network peak hour, depending on the level of network utilization. If the network's threshold is exceeded (following the DN charge design in Chapter 5), it will then be considered a peak hour. In this case, customers that exceed their booked network capacities will be exposed to PCNC.

7.1.2 Network capacity reservation

Since the price signals customers receive are the PCNC during peak hours, which account for future required network investments, auctions are designed to align with these signals and coordinate customers to reduce their network usage during these hours or shift it to other non-peak hours. The auctions are held to allocate network scarce capacity that is not yet absolute, to reveal customer preferences whether the local network should be upgraded to accommodate extra capacity, or other more economical solutions could be held from the customers' side (such as load shifting or DG dispatching). Dynamic auctions with simultaneous rounds are the most suitable to attain these objectives. They are designed for auctioning multiple units (network capacity) of different products (hours) that act substitutes for each other simultaneously. Hence, customers are encouraged to shift part of their load or injections to hours that are more economic. Moreover, clock auctions which requires pre-defined prices, would also allow price discovery.

The product to be auctioned is the network's capacity during peak hours, which are established by a pre-defined network utilization threshold (as mentioned in Chapter 5), and during borderline peak hours, defined by relaxing the threshold to include also hours with some potential to become peak hours, as shown in Figure 7.2. The relaxed threshold should be set to guarantee an adequate level of security. The auction is held to offer network capacity for customers to book it in advance. The auctions are held locally; hence, only customers that affect the utilization level of peaking assets will be able to contribute to the auction. Moreover, auctions will be held simultaneously for all peak and borderline peak hours on daily basis, as in the day-ahead energy market, and the DSO is the auctioneer. The auctions take place on a day, where peak hours are expected on the following day. It aims to signalize customers that withdrawals/injections should be shifted away from these hours.

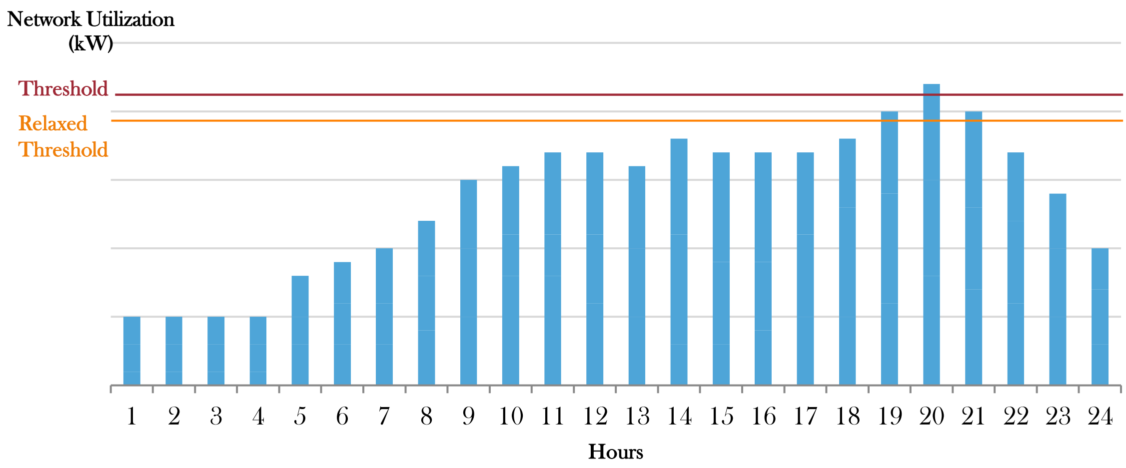


Figure 7.2 Forecasted Peak and Borderline Peak Hours Identification

Two schemes of distribution-level auctions serving as short-term LFM are proposed. The first one is based on Simultaneous Ascending Clock Auction (SACA), where the DSO as an auctioneer sets the price for each round, which is based on the total booked capacity of the previous rounds. The second scheme is based on Simultaneous Ascending Auction (SAA), which is similar to the first scheme in many aspects, but instead of the DSO setting the price, customers bid both price and capacity. The clearing price is then set based on the marginal accepted bid. Both schemes are further explained and discussed below.

7.2 Short-term LFM Design: Simultaneous Ascending Clock Auction (SACA)

SACA is implemented during peak and borderline peak hours. For the example shown in Figure 7.2, the auction will be held the day-ahead for hours 19, 20 and 21. The auction is held to offer the network's capacity for reservation during these hours. Through simultaneous rounds, the price for each auctioned interval of network capacity (kW) is set by the DSO, based on the total booked capacity of the previous rounds, and according to the curve linking network capacity with auction prices as illustrated in Figure 7.3. The curve proposed in Figure 7.3 is composed of two parts, although other variants are also possible. The first part consists on an exponential relationship for network capacities booked below the threshold. It aims to value the network's capacity progressively, signalizing customers as the threshold is being approached. The second part follows a linear relationship for those capacities exceeding the threshold, based on the PCNC calculation method presented in Chapter 5.

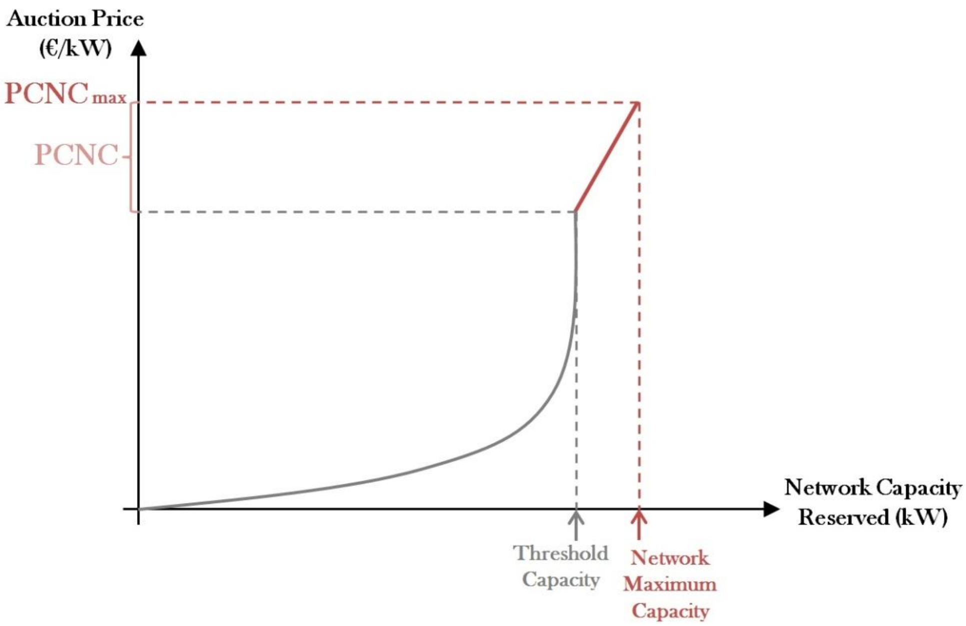


Figure 7.3 Computing Auction Price based on Booked Network Capacity

The auction follows the following steps:

- **Step 1**, ex-ante the auction, a quantity of the network's capacity is booked by the DSO referred to as the Minimum Service Capacity (MSC). MSC is an amount of electricity expected to be required by customers to serve their basic requirements. The main difficulty here is how to distribute MSC between customers. MSC calculation is based on forecasts and its allocation between customers could be based on different proxies. For example, it could be equivalent to a percentage of their average hourly consumption. The concept of MCS considers a social aspect, providing customers with the minimum capacity required to perform their daily activities with respect to the fixed network charges they pay.
- **Step 2**, the auction is held day-ahead, simultaneously for all peak and borderline peak hours. For each of these hours, the price for the first round is set based on the amount of capacity booked by the DSO as MSC, as shown in Figure 7.4. For each auctioned hour, customers bid the quantities of the network capacity above their MSC share they are willing to book at the price set for round 1. Then, again based on the total amount of capacity booked (MSC + capacity booked through round 1), the price for second round is set, as shown in Figure 7.4. The rounds would proceed until the total booked capacity is equal to the network's capacity threshold, or until gate closure. If the total booked capacity exceeds the threshold, as in Figure 7.4 for the fourth round, then this hour would be recognized as a peak hour. Customers pay according to their reserved capacity as in (7.1), where customer's payment (CP) for reserved capacity (RC) is the sum of reserved network capacity quantities (Q_r) in each round (r) multiplied by the price (P_r) of that round.

$$\boldsymbol{CP_{RC_i} = \sum_{r=1}^{R} P_r \times Q_{r_i}} \tag{7.1}$$

It should be noted that the capacity allowed for reservation by each customer in each round should be limited during the first couple of rounds, to avoid over booking. The allowable booking quantities per round could be set as a percentage of each customer's average consumption, or other proxies could be implemented. The number of rounds with restricting bidding capacity may be limited to a pre-defined total reserved network capacity.

- **Step 3**, during real time, customers are exposed to different charges based on their reaction during peak hours. During a peak hour, PCNC will be allocated to customers that did not book their capacity, or by the quantities that exceed their booked capacity. An exemption equivalent to their share of MSC will be discounted from their total unreserved capacity. On one hand, customer that booked capacity in advance through the SACA, are expected to fulfil their commitment by not using more than the capacity they booked. If they finally use more, then they would be allocated a PCNC according to the actual network's utilization level. The customer payment during peak hour (PH) is as in (7.2), where AC is the actual used capacity, and BC is his total booked capacity as in (7.3).

$$CP_{PH_i} = PCNC \times (AC_i - BC_i - MSC_i) \tag{7.2}$$

$$BC_i = \sum_{r=1}^{R} Q_{r_i} \tag{7.3}$$

However, if customers use less than their booked capacity, neither PCNC will be allocated, nor reimbursement of the unused capacity will be paid. On the other hand, if customers decide not to book their capacity in advance, they will be exposed to a charge as in (7.4).

$$CP_{PH_i} = PCNC \times (AC_i - MSC_i) \tag{7.4}$$

Customers' payments through the auctions and during peak hours are used to recover network costs. They are deducted from the total network cost, and the remaining network costs are recovered through fixed charges, as explained in Chapter 5. Thus, although participation in the auction is not mandatory, it is beneficial for customers to bid for their required capacities in advance to hedge against high network prices (PCNC) during peak hours. As shown in Figure 7.4, during this peak hour PCNC will range between price of round 5 and $PCNC_{max}$, depending on the actual utilized network capacity during that peak hour.

Customers are exposed to the risk whether an hour may or may not evolve into a peak one. Depending on their flexibility, customers may be able to shift part of most of their loads to non-auctioned hours. For their unshiftable load, through the auctions, they have the opportunity to insure themselves against high network charges of the PCNC. Section 7.2.1 discusses how customers' flexibility and participation in the auction affect their payments, and section 7.2.2 demonstrates how customers with DERs may bid their injection capacities as a source of flexibility.

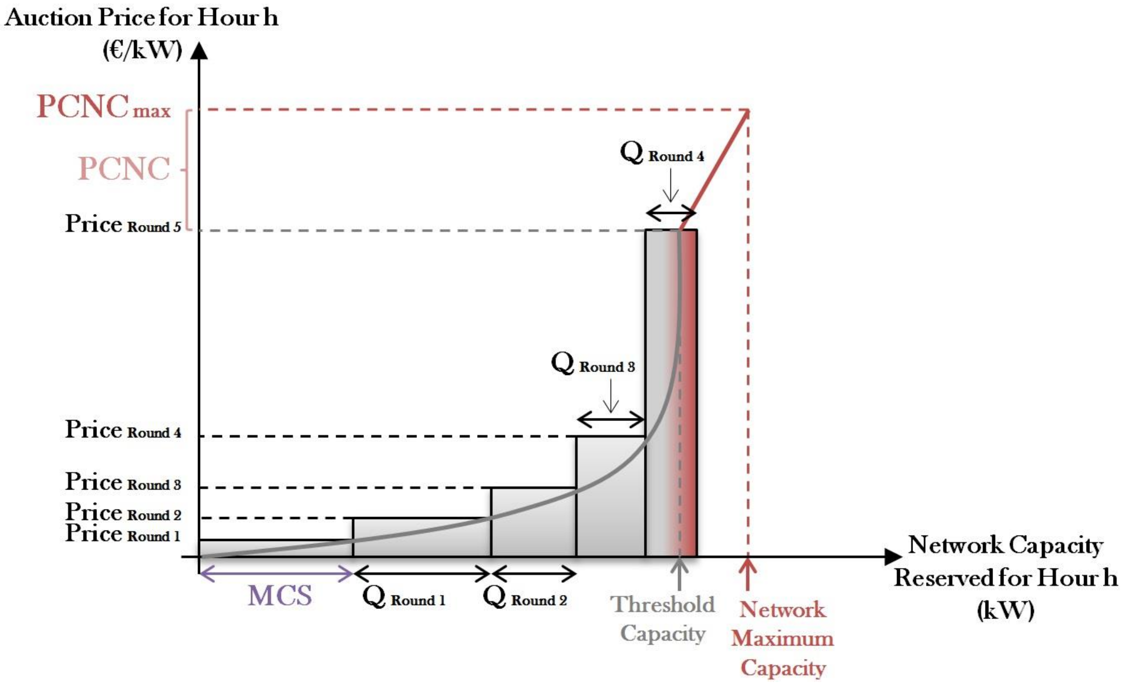


Figure 7.4 Computing Auction Price for each Round

7.2.1 Participation of customers in the auction affects their payments

If customers are flexible, and willing to participate in the auction, then they will bid capacities above their MSC that they require during the auction hours. Assume that the network peak is due to high load consumption, and the load curve provided in Figure 7.2 consists of three customers with equal individual peak loads, and that each one has a different hourly profile, as illustrated in Figure 7.5. Each one of the three customers will shift part of their load, depending on their flexibility, during hours 19, 20 and 21 to other off-peak hours. During the rounds, each customer will bid only for their unshiftable load. Figure 7.6 shows customers' actual load profile during real-time, where all loads are below the threshold. Hence, customers have avoided high PCNC by booking their capacity needs through the auction. However, avoidance of PCNC would not be guaranteed if customers decide to shift their load, but do not participate in the auctions.

If customers are flexible, but do not value their flexibility by bidding in the auctions, they might end up with higher bills. However, if they are lucky, they might not be exposed to PCNC during real-time. This risk is subject to the network's actual utilization level. For example, if customers shift their load during peak and border peak hours, but not enough, and do not book their capacity in advance, while the network's actual utilization level exceeds the threshold in real-time, then they will be allocated network charges following the curve in Figure 7.3. Thus, their flexibility is not valued, and higher payments are allocated to them. On the contrary, if the customers instead had bid for their capacities and the network's utilization level exceed the threshold, they will not be allocated PCNC.

Since not all customers are flexible to the same extend, and some are inflexible, SACA aims to ensure flexible customers are not jeopardized. Figure 7.6 shows different reactions of the three customers based on their flexibility level. Comparing Figure 7.6 to Figure 7.5, it can be observed that C1 is inflexible, C2 is semi-flexible, and C3 is very flexible. C1 decides neither to shift his load nor to bid in the auction. C2 shifts his load slightly, but decides to bid in the auction, and C3 shifts more load than C2, and decides to bid in the auction. According to Figure 7.7, hour 20 remains as a peak hour and hours 19 and 21 are no longer borderline peak hours. Hence, PCNC is allocated to customers using capacity that has not been booked in advance during the SACA. Thus, the allocation of PCNC during hour 20 only affects C1, since he decided not to bid in the SACA, and C2 and C3 did not exceed their booked capacities. Consequently, C1 is allocated a charge (CP_{PH_20}) as in (7.5), where $PCNC_{20}$ is equivalent to the price corresponding the network's utilization level for hour 20 following Figure 7.3. Whereas for C2 and C3, they would only pay for their booked capacities determined during the day-ahead auction, which would be lower than PCNC.

$$CP_{PH\_20_i} = PCNC_{20} \times (AC_i - MSC_i) \tag{7.5}$$

If all customers are inflexible, they will book their capacity ex-ante and some of them will pay almost PCNC. Then, in real-time only the last ones in the auction that were not matched will pay actual PCNC. This is an incentive for inflexible customers to declare their capacities in advance, allowing DSOs to obtain accurate data regarding network flows.

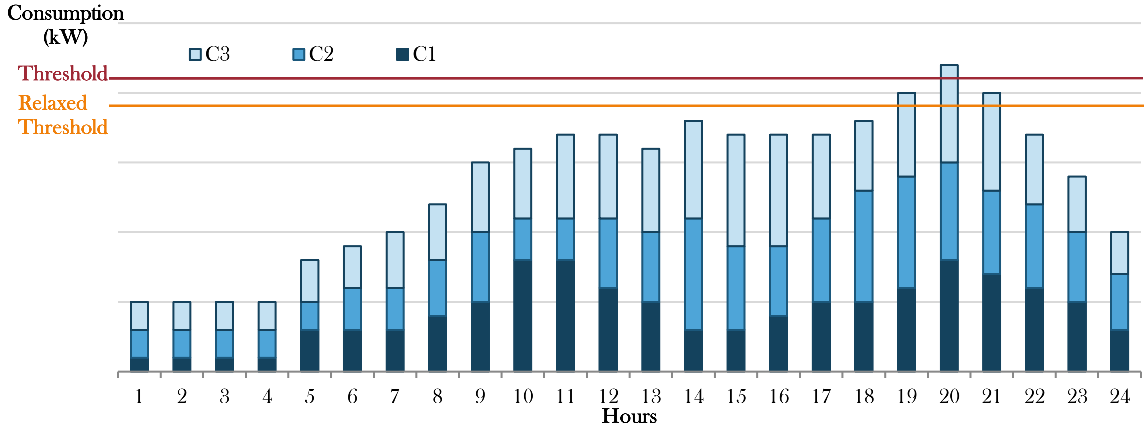


Figure 7.5 Illustrative Example of Forecasted Customers' Load over 24 hrs

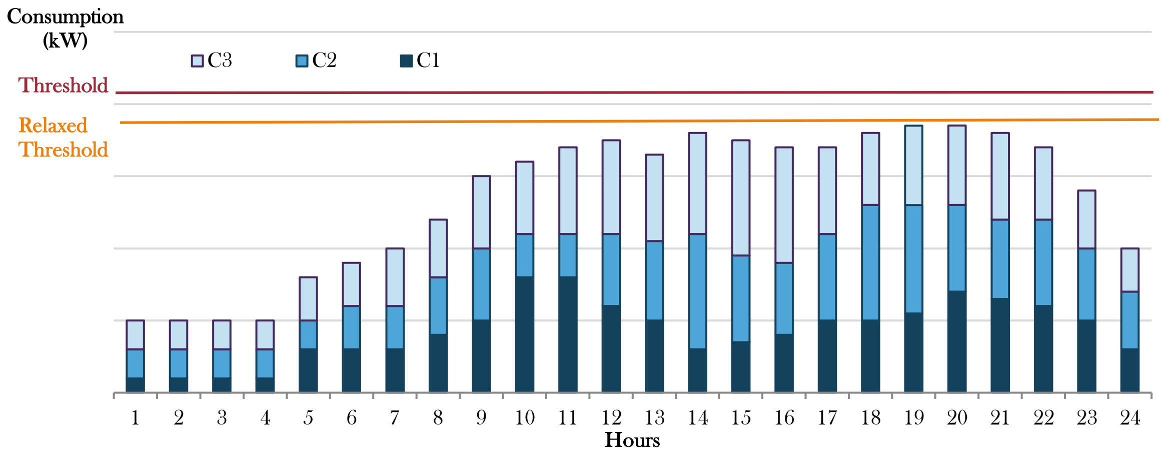


Figure 7.6 Flexible Customers' Load over 24 hrs

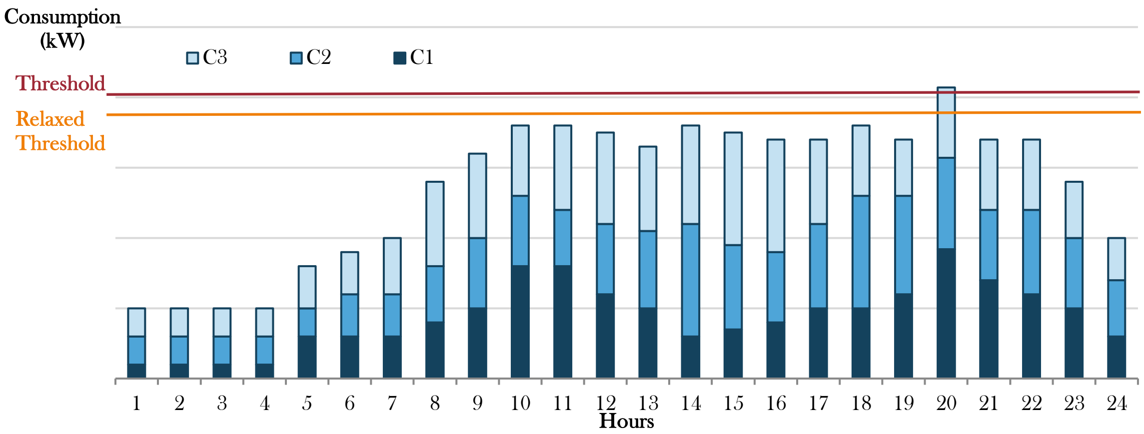


Figure 7.7 Comparing different Customers' Flexibility Levels

7.2.2 Injections as a source of flexibility

Utilizing customers' flexibility to reduce network's utilization level during peak hours could also be achieved through energy injections. DGs and storage units may also bid with injection quantities that they could provide corresponding the round's price they are bidding in. For example, as shown in Figure 7.8, during the second round customers would bid to book network capacity (Q_l round 2) or bid to provide network capacity through injections (Q_g round 2). The resultant of the two quantities is then used to indicate the price of the third round. It should be noted that since SACA is based on ascending prices, if Q_g is higher than Q_l, the difference is transferred to the following round, which would auction network capacity at the same price as the current round.

There are several advantages regarding the implementation of SACA. First, the DSO sets the prices, which are aligned with the network's utilization level. This avoids customers or intermediaries from predicting prices, since they are not experienced nor have complete information. Secondly, as the auction is carried out simultaneously for all peak and borderline peak hours, it allows customers to consider other options (i.e. other hours) that are cheaper, or without PCNC. Flexible customers will have options to shift their load. They will shift their load during peak and borderline peak hours to hours without PCNC. Meanwhile, less flexible and inflexible customers will bid during the first rounds of peak and borderline peak hours to guarantee lower prices. Customers that do not book their capacity through the auction, or exceed their booked capacity, will be riskily exposed to PCNC. Hence, it provides price discovery and ensures customers' commitment. Thus, lead to retrieving earlier accurate forecasted information of the flows of peak and borderline peak hours upon which could be relied on.

There are two main concerns regarding the implementation of SACA: firstly, MCS should be well defined, calculated and distributed among customers required to participate in the auctions. Secondly, the capacity allowed for reservation for each customer should be limited during the first couple of rounds, to avoid over booking. Implementing these constraints is not difficult given the increasing sophisticated advances in technology and platforms. However, the basis on which the capacity limitation will be introduced needs further investigation. Moreover, another common concern regarding distribution-level auctions is the level of participation of customers.

Although it is not expected that auctions will be held frequently, as peak hours may occur rarely per year, yet it would be a burden for customers. However, customers could transfer this burden to intermediaries, such as traditional retailers or third party aggregators, allowing them to act on their behalf by taking over their bidding task.

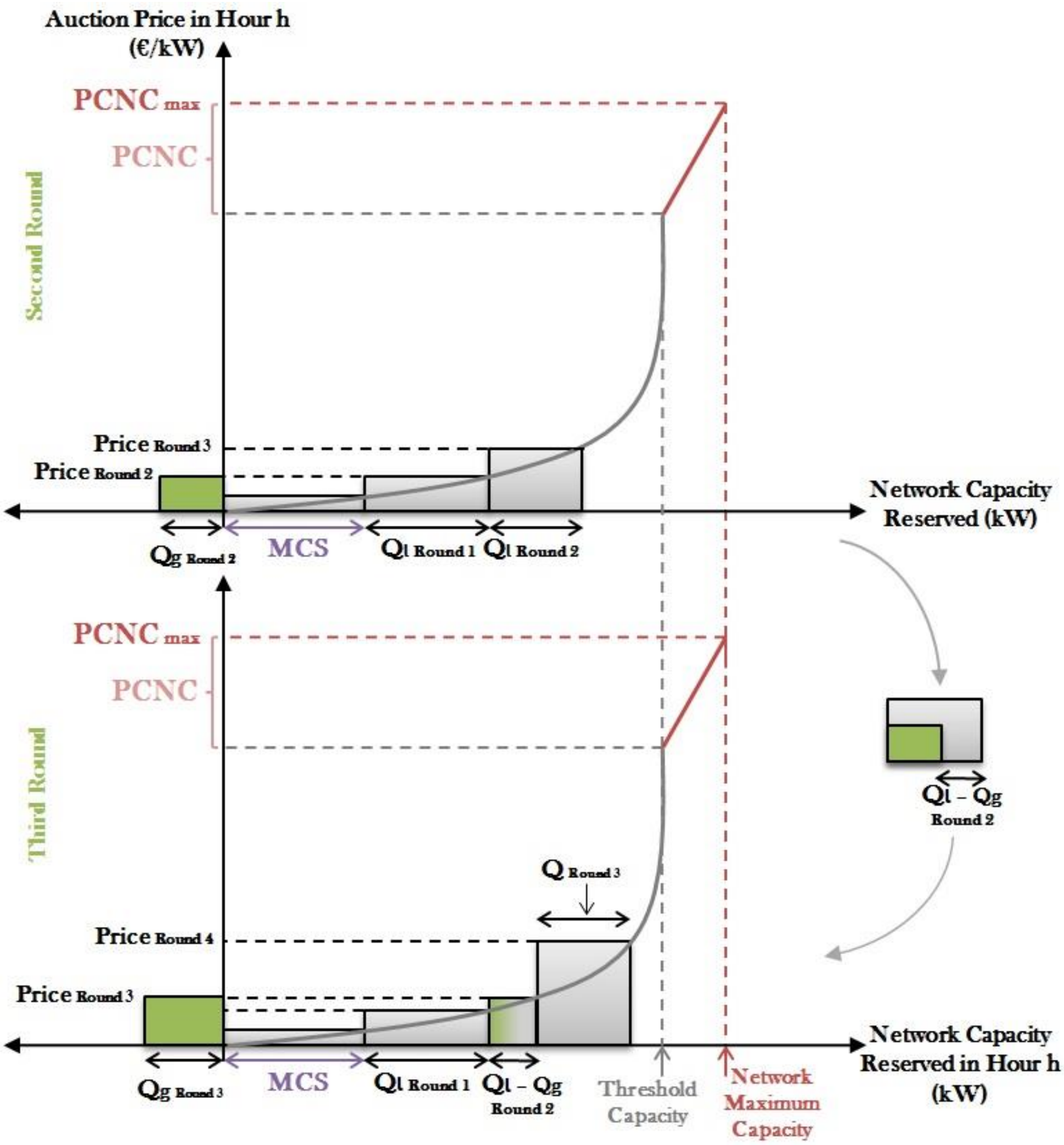


Figure 7.8 Including Injection Bids into SACA

7.3 Short-term LFM Design: Simultaneous Ascending Auction (SAA)

SAA operates differently from SACA. The product of the auction is the network's capacity, but customers bid paired capacity and price, as illustrated in Figure 7.9. There is no MSC held ex-ante, and customers bid according to their flexibility level and the maximum they are willing to pay for network capacity reservation. The auction follows the next steps:

- **Step 1**, the auction is held day-ahead simultaneously for each peak and borderline peak hour. Customers bid a series of paired capacities and prices for each hour they are willing to book capacity in. Bids are then ranked in merit order, with the highest accounting for inflexible demand. It is assumed that either inflexible demand will bid through their retailer, or the DSO has enough knowledge to account for it. The auction follows uniform pricing, where the clearing price is determined by the marginal bid intersecting the price curve, as shown in Figure 7.9.

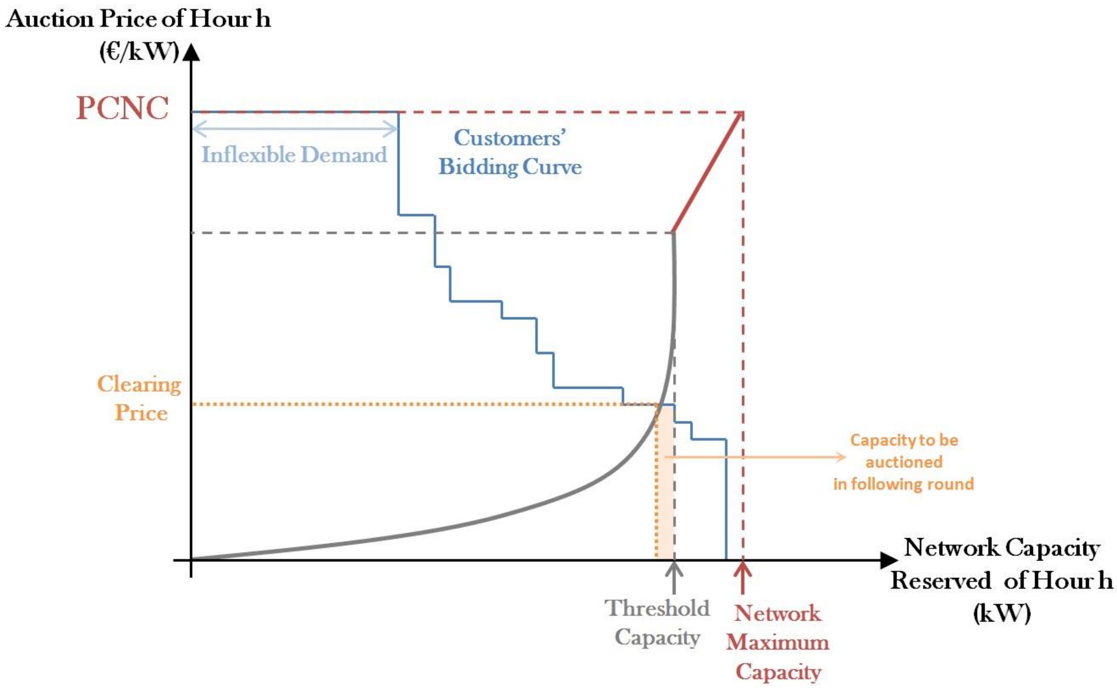


Figure 7.9 Illustration of Simultaneous Ascending Auction

- **Step 2**, for the second round, the remaining capacity to the pre-defined threshold is auctioned. Bids' prices must be higher than the clearing price of the first round. Again, they are ranked according to merit order, and bids adding up to the remaining capacity are accepted at a clearing price equivalent to the new marginal bid. Auctioning the network's capacity through multiple rounds allows customers to benefit from auctions of other hours carried out simultaneously. Within the rounds, customers may shift part of their load to cheaper hours.

- **Step 3**, during real time in the event of a peak hour, customers that used unreserved capacity are exposed to PCNC corresponding to the network's utilization level, similar to that discussed in SACA.

As in SACA, customers may bid with injection quantities at the prices they are willing to provide their flexibility. These quantities are included within the PCNC's price curve, increasing the network capacity at their corresponding prices as shown in Figure 7.10.

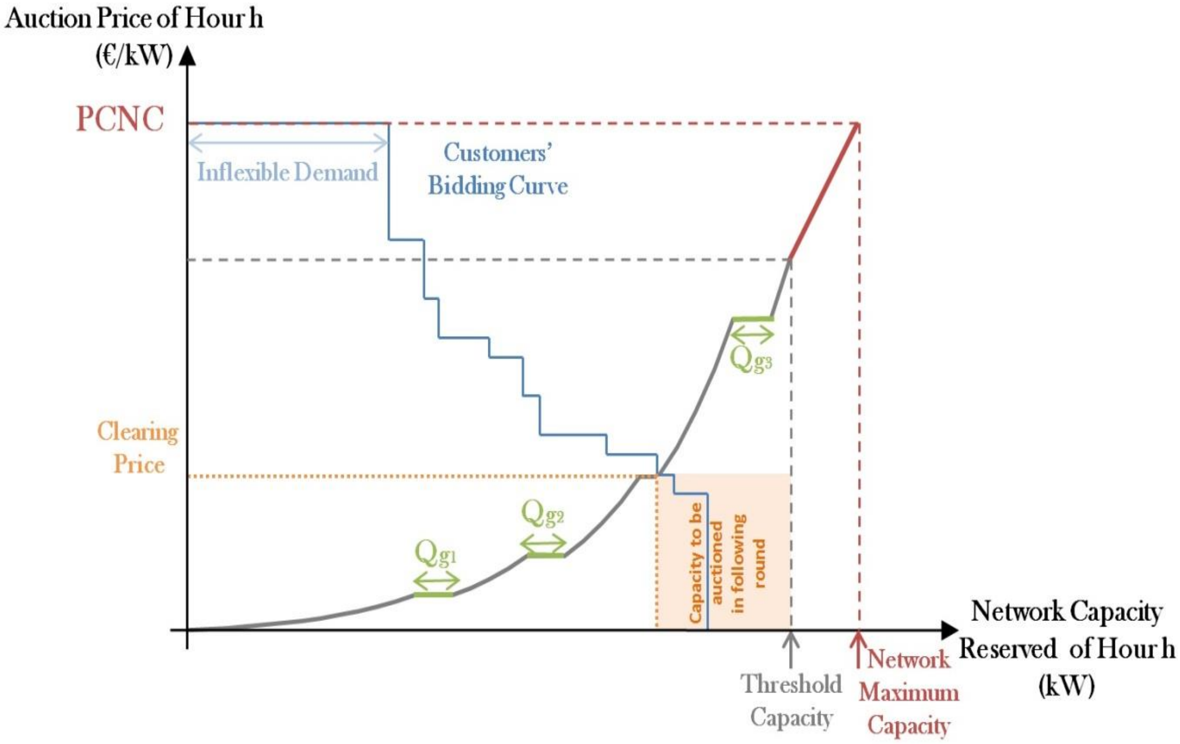


Figure 7.10 Illustration of SAA with Injection Bids

SAA, compared to SACA, is a more straight-forward approach to implement the proposed flexibility mechanisms. However, it requires accurate information regarding inflexible demand, in order to auction the remaining capacity to the threshold. This is not required in SACA as the mechanism does not require anticipating inflexible demand. Moreover, within SAA, the number of rounds is limited, as it is based on the amount of booked capacity during the first round. If during the first round the bids exceed the threshold capacity, with prices greater than the threshold equivalent price, then no more rounds will be required, as shown in Figure 7.11. The clearing price is then determined by the marginal bid corresponding to the threshold capacity. Whereas in the SACA, since the bidding capacity per customer is limited during each round, there is room for price discovery, and for customers to shift their bids between auctioned hours. Furthermore, the aspect of MSC could also be introduced to SAA if required, to offer customers a minimum capacity that satisfies their basic requirements with respect to the fixed charges customers pay. In this case, the threshold capacity would be reduced to account for the MSC. In conclusion, if the clearing price for both SAA and SACA is equal, through SACA customers would pay less. This is because through SACA the customer's total booked capacity is valued at different prices up to the clearing price. Whereas through SAA the whole capacity is valued at the clearing price.

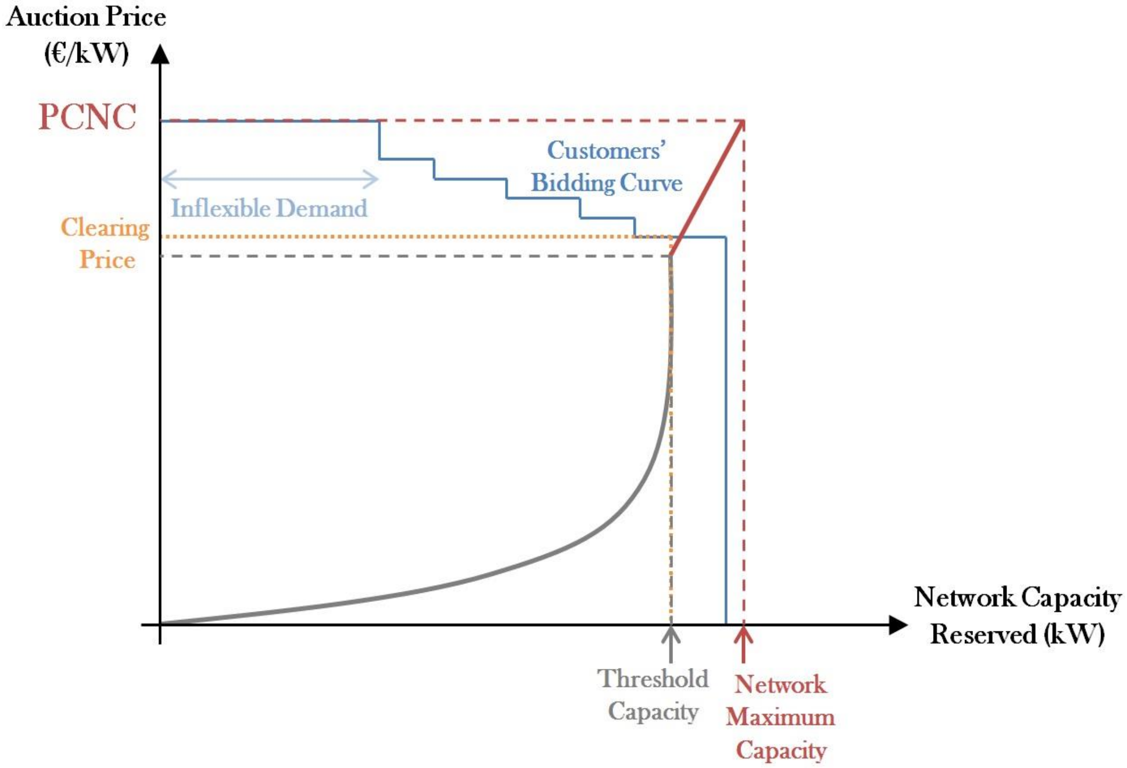


Figure 7.11 Illustration of High Price Bidding in Simultaneous Ascending Auction

7.4 Short-term LFM vs Flexibility Markets in Literature

Short-term LFM is similar to other flexibility markets that have been proposed in the literature, as both aim to extract customers' flexibility through financial incentives to more efficiently operate the network and defer network reinforcements. However, the LFMs proposed in this paper differ in three main aspects, as illustrated in Figure 7.12. Firstly, flexibility markets are designed uncoupled from network charges, whereas LFM is designed to be aligned with dynamic PCNC; hence, it follows the economic signals already established through the cost-reflective tariff. Secondly, the traded commodity in flexibility markets is the customer's flexibility, where as in short-term LFM it is the network's capacity. During expected peak hours or borderline (potentially) peaks hour, customers bid to book network capacity, rather than providing flexibility bids. Thirdly, in the proposed short-term LFM customers are not remunerated for their flexibility services through payments. Instead, customers gain financial benefits by avoiding PCNC.

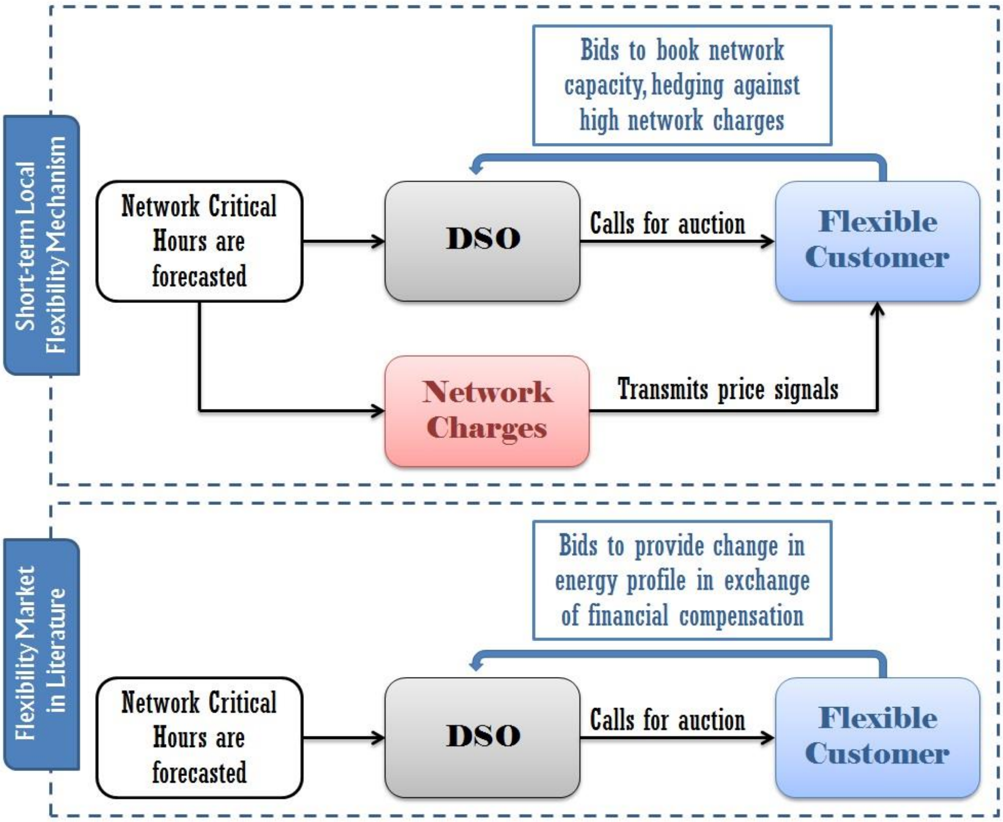


Figure 7.12 Comparison between Short-term LFM and Flexibility Market

7.5 Long-term LFM: Coordination of Customer DER Investments through Request for Proposals According to Network Future Needs

Customers may take inefficient DERs investment decisions mainly as a consequence for being over-or undercompensated for the services that they provide to the network. This may lead to opportunities to deliver cost-efficient network services that may replace costly network upgrades being left untapped. This is due to either inefficient economic signals being sent or inadequate compensations. Consequently resulting in a loss in the system's overall efficiency, where higher unnecessary network costs are accumulated and transferred to customers through network charges. The proposed long-term LFM aims to reveal, efficiently utilize and appropriately compensate the value of flexibility services that DERs and flexible customers can provide.

Long-term LFM aims to procure a portfolio of capacity resources through a competitive mechanism, on a non-discriminatory basis, that would best serve to DSOs as a substitute for traditional network reinforcements. Network reinforcements are commonly carried out by lumpy investments due to its large increments, although the actual required capacity may be much lower. Thus, the cost to deliver a certain additional capacity is higher than the theoretical optimum (Poudineh and Jamasb, 2014). An alternative approach is using DER capabilities to avoid network upgrades, which are able to resolve local network constraints in order to meet the demand during peak network utilization periods. Thus, under DSO unbundling as in Europe, services procurement from DER could be an alternative to substitute network upgrades if it is economically efficient. The procurement of these services should ensure the accommodation of projected demand/ generation increase along with a reserve margin. Besides deferral of network reinforcement, DERs, depending on their capabilities, may also provide other system services, such as energy, spinning reserve, voltage and frequency regulation, as well as compensating the variability of demand and generation side (Zafirakis et al., 2013).

According to (Tierney, 2016), market-based mechanisms lead to greater value to the system and customers, where the DSO can fairly obtain and efficiently pay for the DER services needed at market-based competitive prices. The objective is to design a cost effective DER services procurement model that provides additional network capacity during critical network periods. Different exisiting proposals for procurement models are discussed in section 6.4, which are decoupled from network charges and do not consider inputs from short-term flexibility utilization approaches to optimally procure network flexibility needs.

Therefore, a long-term LFM is proposed to efficiently procure network firm capacity through DERs, in line with the network charges design proposed in Chapter 5, and the short-term LFM proposed in sections 7.1-7.4. The proposal is similar to the approaches discussed in section 6.4, with a main difference that it is linked to the short-term LFM and the network charges to efficiently incentivize customers regarding DER investments and enhance the system's economic efficiency.

7.5.1 Proposed long-term LFM

The proposed long-term LFM aims to provide a competitive procurement mechanism for long-term flexibility products: network firm capacity, voltage control, and power quality support. Depending on the network's needs, calls are issued regarding each of the flexibility products within each local network. Since network firm capacity as a long-term flexibility product is aligned with the network charges and short-term LFM, it is the main focus of this section. Similarly, other flexibility products could follow this proposal.

Long-term LFM provides network firm capacity procurement by DERs through RFPs to serve the DSOs in the network planning. It could be also understood as another scheme to coordinate customers' response regarding DER investments. DERs provide firm capacity at a specific location during specific time to increase the network's hosting capacity. This is done by either injecting power or curtailing load when the network experiences high network consumption events, or by curtailing injections and increasing load during high network injection events. This long-term LFM complements the short-term LFM proposed in sections 7.1-7.4. First, the existing network assets are assessed including existing flexibility provided by the short-term LFM to identify its ability to supply the network given future withdrawal/ injection projections. Then, if the available flexibility is insufficient to cover network needs in the future, sources of additional flexibility will be requested. Based on that planning analysis, a long-term LFM will be implemented. It aims to provide a market-based approach for DER services procurement, providing additional flexibility to the network at a cost lower than network reinforcements. The design of the proposed long-term LFM is shown in Figure 7.13 and discussed below.

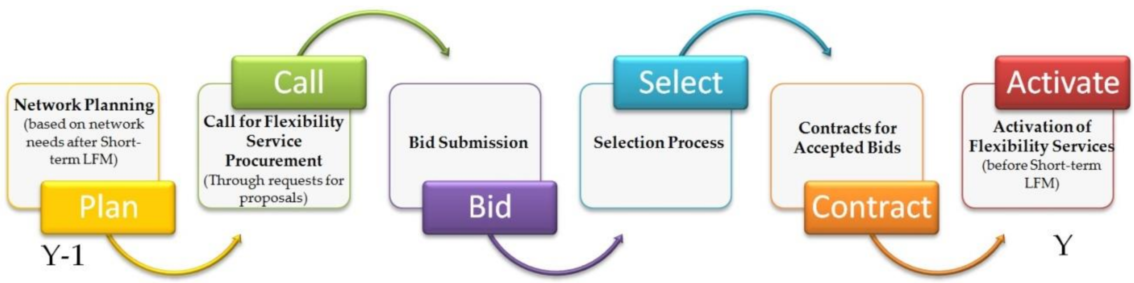


Figure 7.13 Long-term LFM steps

(i) Network Planning

The two proposed LFMs, short-term and long-term, function subsequently as shown in Figure 7.14. First, responses to the short-term LFM are assessed to investigate to which extend network reinforcements could be avoided. Then, the DSO analyzes necessary network reinforcements that remain critical for maintaining network's reliability. Since investments in additional flexibility are costly, thus careful planning is required. This is done through a long-term planning tool (for example a computational tool such as a Reference Network Model (Domingo et al., 2011; Gómez et al., 2013)), where different scenarios considering DERs and network reinforcements are analyzed to find the optimal network capacity required.

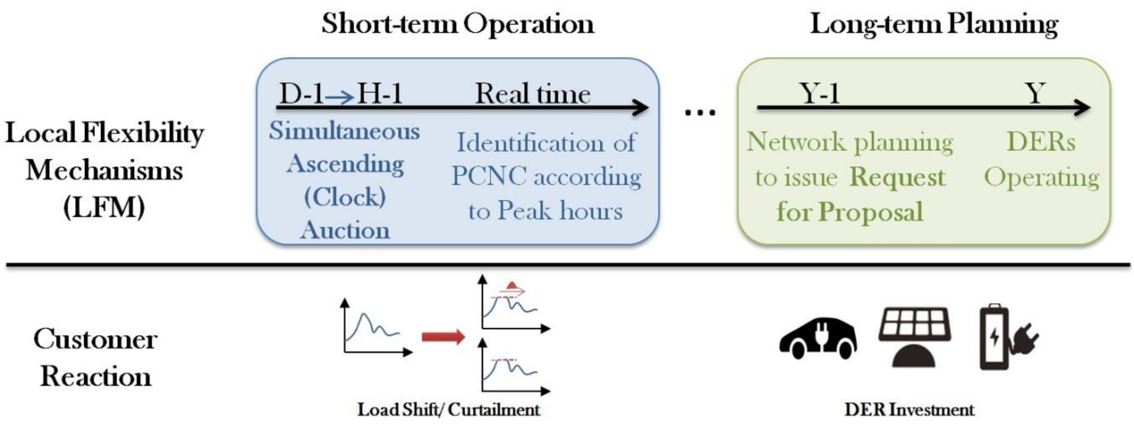


Figure 7.14 Timeline for Proposed Flexibility Mechanisms

(ii) Call for Flexibility Services Procurement

The DSO announces a call for firm capacity procurement through RFP. The RFP call is issued a year in advance, year Y-1, for it to operate in year Y. The call would include technical aspects such as (i) local network customers that affect the network under consideration, and thus may participate in the RFP, (ii) firm capacity required and its nature based on network planning, (iii) expected number of commitment hours (when DERs provide firm capacity) and when, (iv) start date for contract delivery (which is year Y) and length of contract (typically 3-5 years), (v) notification period range (minimum time required by customer to respond to commitment signal) and the firm capacity option. Several RFP may be issued in different areas with capacity shortage concerns. Customers should be aware of their expected availability, so those who are willing may invest in DER types accordingly.

One of the main differences between RFP and auctions is that RFP is subject to a set of price and non-price criteria, while in auctions the selection of bids is mainly driven by prices. Weight is given following both price and non-price criteria (Kreycik et al., 2011). The selection criterion is announced ex-ante within the RFP call. Thus, RFP allows the DSO the option to include other factors other than the price in the selection process, such as the DER location, which may be more useful for network operation as it may reduce losses.

Depending on the type of event the network is expected to experience, high network withdrawals or high network injections, the nature of firm capacity required is identified. There are two options customers may select from to provide a forward commitment of future network firm capacity upon being called. First option is based on restricting their injections/ withdrawals to a pre-defined firm capacity. During network critical events, customers will be called with a day-ahead notification period to comply with the pre-defined firm capacity. Second option is based on allowing DSO intervention and physically restricting customer’s withdrawals or injections up to a pre-defined capacity with a short notification period (usually minutes). The second option mainly serves real-time network critical events.

A third option remunerates customer’s flexibility based on the real-time change in consumption/ injection with respect to the latest energy schedule. This requires a previous commitment with settlement implications of the individual schedule of consumption/ injection level based on the position in the wholesale market.

(iii) Bids Submission

In response to the call issued by the DSO, customers of the local network may submit their bids. Customers’ bid should include: DER’s location, firm capacity willing to provide, the price, the firm capacity option (whether they would restrict their withdrawals/ injections, or allowing DSO interventions) and the notification period. Customers should bid the firm capacity they are willing to comply with during network peak hours.

(iv) Selection Process

DSO compares the received customers bid along with traditional network upgrades to select most efficient bids. This will put wires and non-wires solutions on an equal footing resulting in the most efficient outcome reducing network costs. Including the location in the selection criteria may reduce the total system’s costs further. Hence, the selection criteria will consider both price and location, and aims to rank bids according to their contribution to reducing total costs. Using network planning tools, qualifying bids are introduced, in terms of technological characteristics, firm capacity and location.

Then, both price and non-price criteria are then considered for the selection of final winners. The DSO runs different scenarios to select the optimal bids that would reduce the network's total cost. A number of researches have tackled and formulated this problem (Esmat et al., 2018; Heussen et al., 2013; Olivella-Rosell et al., 2018; Reihani et al., 2016; Zhang et al., 2014). The inclusion of DERs' location allows DSOs to procure extra flexibility for the network that enhances its operation and management. For example, a DER at a location closer to the load may reduce losses and be favorable than another DER that provides the same required firm capacity but located farther.

The aim through the RFP is to provide a non-discriminatory process that encourages competition within the distribution-level. Through fair and transparent competition, optimal bids are selected that guarantees technical and economic efficiency are achieved.

(v) Contracts for Accepted Bids

Contracts types and designs for demand response were discussed in section 6.6. Customer whose accepted bids are selected will then go into contracts with the DSO. It aims to ensure that DER owners are committed; are obligated to serve sufficiently (the exact contracted firm capacity) during the whole duration of network utilization peak hours. For the firm capacity option where customers will restrict their withdrawals/ injections, a reasonable notification period is stated that is sufficient for customers to be prepared to be available to provide firm capacity. As some customers might not be able to deliver by the due date they have defined, or might not fulfill their commitment, therefore a penalty should be included in the contract terms. The penalty would be equivalent to the cost of alternatives to provide the service, or to the extreme to value of loss load (VOLL) acquired by the DSO due to unserved load. This penalty would lead to more efficient bidding, as customers with intermittent DERs will bid more realistically to avoid penalties. Thus, the contract will state the amount of firm capacity, notification period, remuneration rate, and non-compliance penalties to ensure customers' commitment.

For the firm capacity option where customers (DER owners) will restrict their withdrawals/ injections, customers are compensated for their availability whether their service is used or not. However, they are penalized if insufficient service (capacity or duration) is provided. Following the tariff design discussed in Chapter 5; at the end of the billing period compensations are added to the total network cost, whereas penalties and income from PCNC are deducted. The remaining network cost is then recovered through fixed charges.

(vi) Activation of Flexibility Services

When network peak hours are identified day-ahead, the DSO first dispatches the contracted flexible resources (those DERs under contract through long-term LFM). This is done by sending signals to the DER owners according to their notification period. Based on the expected network utilization level, and the available contracted flexibility, short-term LFM may be implemented if extra network flexibility is required. Thus, long-term LFM contracts are dispatched before short-term LFM goes into action. This sequence is taken for two reasons: first, DERs under contracts provide a more certain network flexibility. Secondly, long-term LFM contracts were implemented to replace network assets, and to reduce network peaks and consequently PCNC. Hence, it should be dispatched first before applying PCNC to customers.

Finally, long-term LFM increases the economic and social benefits of the whole system. Firstly, network costly investments are avoided by cheaper alternatives, which are translated into tariff reductions. Secondly, from DER owners' side (those that were selected during the RFP), they own DERs that they could personally use when not required by the DSO. Through which they may satisfy their own load or provide other system services, hence reducing their energy costs. Thirdly, from customers' side, peak hours are resolved or at least reduced, hence the exposure to PCNC are also reduced. Moreover, since additional flexibility is available within the network, the threshold for PCNC would be adjusted accordingly. Lastly, from the DSOs' side, accurate information regarding available DERs' firm capacity and its location is retrieved, which may be used to assist in network operation and be taken in consideration in network planning.

7.6 Chapter Remarks

The proposed LFMs aim to assist customers and coordinate their responses in a way that would increase system's economic efficiency and maximize social welfare. They aim to encourage the development of network-optimized flexibility services that consequently would reduce network costs for DSOs and customers. Thus, flexibility mechanisms should be well aligned with well-designed network charges, following their pre-established economic signals.

Although the short- and long-term LFMs are complementary and both aim to extract end-users' flexibility through financial incentives to more efficiently operates the network and defer network reinforcements, yet they are different in two main aspects: firstly, opposing to the long-term LFM, in the short-term LFM end-users are not remunerated for their flexibility services through payments. Instead, end-users gain financial benefits by avoiding PCNC. Secondly, the short-term LFM complements cost-reflective network charges that are based on PCNC, whereas the long-term LFM could be implemented by itself without the short-term LFM or with other network charge designs. However, linking it to efficient cost-reflective network charges and the short-term LFM would lead to higher economic efficiency.

Finally, through the two mentioned mechanisms the DSO may efficiently make use of customers' flexibility while providing distribution-level coordination. The implementation of LFMs will lead to a number of benefits for the DN and the system as a whole: i) higher customer participation, revealing their flexibility, ii) deferral of costly network investments, iii) better DN operation and planning with more reliable information, iv) reduction of uncertainty in network peak hours, making cost-reflective dynamic network charges (PCNC) more socially accepted.

8 Conclusion & Future Work

This chapter summarizes the main finding in the thesis, discusses research reflections and identifies future work.

8.1 Concluding Remarks

Designing cost-reflective network charges is challenging and requires trade-offs between different tariff design principles. On one hand, network charges should reflect the costs customers impose on the network. On the other hand, it should be easily understood by customers in order for them to respond to the economic signals they receive. The dilemma is that the more cost-reflective the methodology used for network charges is, the more sophisticated it becomes. Hence, customers' engagement becomes uncertain, which is an essential key to achieve high system's economic efficiency. Therefore, less sophisticated network charges that send clear and easy to comprehend economic signals are more likely to encourage efficient customers' responses. Through the theoretical analysis and the case studies carried out in the thesis, the following remarks were found important to consider:

- Volumetric network charges cannot serve efficiently in a network with active customers, since they are no longer following similar energy profiles. It allows them to avoid part of network charges through self-generation, promoting cross-subsidization between customers.
- Fixed network charges are useful when no response is required from customers. It allows them to use the network freely while ensuring full network cost recovery.
- Demand network charges encourage customers to reduce their peaks. When demand charges are linked to network's peak, they consider the temporal and locational effects and incentivize customers to reduce peaks when the network is

highly utilized to avoid the need for network upgrades. This is different from demand charges based on individual peak, which encourage peak reduction continuously, regardless the network's utilization level. On one hand, constant peak reduction during all times seems more efficient as it leads to flattening the energy curve. On the other hand, it is inefficient as it encourages customers to over-invest in DERs, reducing network usage at times of low network utilization levels and leading to lower system economic efficiency. It should be noted that DN charges with temporal discrimination requires the installation of smart meters to communicate economic signals to customers.

- Network charges should be symmetrical and do not discriminate between consumers, generators or storage units, despite which appliances are installed behind the meter. Those causing an increase in network costs should be allocated higher charges and those contributing to reducing the costs should be rewarded.
- Network charges should transmit both short- and long-term economic signals, where each induces different customers' responses. Short-term signals influence the operational decisions customers take. They are related to planning, shifting and curtailing their injections/withdrawals. Long-term signals influence the investment decisions customers take, for instance investing in DERs.
- Future network costs, due to network reinforcements, are driven by high network utilization levels. These costs should be transmitted to customers potentially causing them to alert them during network peaks. This will allow customers to find alternative solutions and reveal their preferences. Hence, network peaks should be clearly defined by capacity thresholds to avoid over-investments in DERs which would consequently reduce the system's economic efficiency.

8.2 Contributions

This thesis provides three main contributions:

- ***A cost-reflective network charge has been proposed,*** consisting of first a forward-looking locational component based on the network's utilization level, which transmits the long-term incremental cost of network upgrades. Then, a residual cost component that recovers the remaining part of the regulated network revenues is proposed. The objective of the proposed network charge is to increase the system's efficiency by incentivizing efficient short- and long-term customers' reaction while ensuring network cost recovery.
- In order to assess and compare different network charge designs, two methods were proposed and implemented. First an ***optimization model*** that simulates customers' response to the proposed network charge in comparison to other traditional network charge designs. The model considers the operational and DER investment decisions that customers take rationally to minimize their total costs. Secondly, an ***evaluation methodology based on the Analytical Hierarchy Process technique*** is proposed in order to assess and compare different designs

of network charges with respect to four attributes: network cost recovery, deferral of network costs, efficient customer response and recognition of side-effects on customers.

- Cost-reflective network charges are designed to incentivize customers' reaction, but they are insufficient by themselves to guarantee it. In order to stimulate efficient reaction from customers' side, they should be provided with approaches that allow them to reveal their preferences and provide their flexibility services. Hence, besides cost-reflective network charges, distribution-level flexibility mechanisms are required to enhance customers' reaction and utilize their flexibility. ***A framework for Local Flexibility Mechanisms (LFM) is proposed*** in this thesis, complementing the proposed cost-reflective network charge and aligned with its pre-established economic signals. It aims to provide distribution-level coordination to mitigate unintended customer responses to network charges, by allowing customers to reveal their preferences and offer their flexibility services. It consists of a short-term LFM that utilizes customers' flexibility in day-to-day network operation, and a long-term LFM that procures customers' long-term flexibility to replace partially or fully network investments in network planning. The proposed LFMs aim to:

- Establish a more stable, predictable and socially accepted network charges.
- Provide a hedging mechanism for customers to avoid high network charges (PCNC).
- Allow customers to reveal their willingness to pay and preferences.
- Utilize customers' flexibility efficiently in the short and long term.
- Provide better DN operation and planning with more reliable information.
- Provide cost-efficient alternatives to network investments, which consequently will increase the system's economic efficiency.

8.3 Reflections

This section presents some reflections to the research carried out as well as responses to inquires that arouse.

- **Fairness issue: are dynamic charges based on locational differentiation and spiking PCNC acceptable for customers?**

Network costs are generally accused to be unfairly allocated among customers, regardless the methodology used. This is because each methodology is likely to favor a group of customers over the other. Hence, if the methodology on one hand provides predictable and stable economic signals, utilizes customers' flexibility efficiently, provides customers with approaches to hedge against high network charges, promotes effective customers' reaction, as well as ensuring network cost recovery, but on the hand is differentiating customers based on their location, overall it is considered fairly acceptable.

- **Customers may not react to PCNC anticipating that the network investment costs taken will eventually be allocated among more customers (not only the local ones) through fixed charges. Hence, they will be finally**

allocated a slightly higher fixed network charge which is most probably lower than the cost of DER investments.

Given that customers are risk averse, this behavior is unexpected. Customers will be exposed PCNC for at least a year, during which they will be allocated high payments if they do not react. Moreover, investment in DERs may benefit them reducing their energy payments.

- **After investment decisions to accommodate the expected increase in network's utilization level, will PCNC be alleviated?**

No. PCNC cannot be alleviated as it controls the customers' responses, limiting the network's utilization level. When network capacity is increased, the threshold for PCNC is increased as well, but remains applicable. Customers will be less frequently exposed to it or never.

- **Passive customers are benefitting from active customers' responses to PCNC and short-term LFM.**

PCNC and short-term LFM aim to stimulate customers' responses to reach the optimal investment decisions. They are applied for a transition period during which the DSO would reach cost-efficient network investment decisions. If passive customers decide not to react and take the risk of paying high network charges, they are revealing their willingness to pay through their actions. Thus, if insufficient local flexibility is available, then Long-term LFM will be implemented which will provide an optimal mix of DER and network investments. During network peak hours DER owners will be called to provide their flexibility services and be financially compensated. Therefore, passive customers will not be benefitting from active customers' responses.

- **Dynamic energy prices do not necessarily coincide with the DN's utilization level. Conflicting economic signals may confuse customers.**

It is true that customers do not react to the DN charges solely, but to the whole electricity tariff which may include another dynamic component for the energy prices. Tariffs should be additive: energy prices and network charges. Low energy prices may encourage customers to increase their consumption, leading to higher network utilization level. PCNC remains applicable to maintain a reliable DN utilization level. Other approaches should be implemented to make use of the excess available low cost generation.

8.4 Future Work

In the following, some suggestions for improving and further developing the proposed methods in this thesis are as presented:

- **Implementation of proposed cost-reflective DN charges into a large distribution network**

Applying the cost-reflective DN charges proposed in Chapter 5 to a large DN network will highlight new implementation concerns that could be used to further improve the current proposal. The effect of accumulated PCNC of different voltage levels, as well as the density of customers in urban and rural areas may affect customers' reactions, DER investments and consequently the system's future costs.

- **Implementation of short-term LFMs on distribution networks and assessing customers' responses**

The LFMs framework presented in part II of this thesis could be tested on the distribution network. This would require simulating customers' response that considers customers' flexibility and strategic bidding decisions in order to minimize customers' costs without violating their preferences' constraints.

- **Implementation of long-term LFM and investment decision through detailed cost-benefit analysis**

The process through which DSOs undergo to reach an optimal mix of DER and network investments is challenging. It includes running different scenarios and carrying out a detailed cost-benefit analysis that includes factors such as: energy losses, emissions reduction, cost of smart infrastructure (communication and software), etc. Moreover, there is a high uncertainty in customers' long-term engagement that should be taken in consideration when compared to network investments. Besides, the lifetime of network investments, smart infrastructures and DERs vary significantly.

- **Addressing the impact of customers' flexibility on other parts of the system**

As customers provide flexibility services, they deviate from their expected profile which may impact the energy wholesale market. This impact should be considered and well addressed in the energy balancing markets.

- **Extending LFM design to include both DSO and TSO**

The LFMs proposed only consider utilization of customers' flexibility by DSOs to serve distribution-level needs. These flexibility services may also assist the TSO through ancillary services and frequency regulation. This model could be extended to include DSO-TSO coordination.

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APPENDIX

IEEE 34 Node Test Feeder Line (Branch) Data

Branch No.	Bus From	Bus To	R (pu)	X (pu)	B (pu)	Rating (MVA)
1	1	2	0.00221	0.00136	2.32E-09	9.925
2	2	3	0.00148	0.00091	1.55E-09	9.925
3	3	4	0.02757	0.017	2.89E-08	9.925
4	4	5	0.0113	0.00306	4.85E-09	6.050
5	4	6	0.03207	0.01978	3.37E-08	9.925
6	6	7	0.02543	0.01568	2.67E-08	9.925
7	7	8	0.027	0.016	8.64E-12	7.775
8	8	9	0.0004	0.00017	2.68E-10	7.775
9	9	10	0.00333	0.00091	1.43E-09	6.050
10	9	13	0.01318	0.00544	8.82E-09	7.775
11	10	11	0.09377	0.02535	4.02E-08	6.050
12	11	12	0.02676	0.00723	1.15E-08	6.050
13	13	14	0.0059	0.0016	2.53E-09	6.050
14	13	15	0.00108	0.00045	7.26E-10	7.775
15	15	16	0.02638	0.01076	1.77E-08	7.775
16	16	17	0.00067	0.00028	4.49E-10	7.775
17	17	18	0.04543	0.01228	1.95E-08	6.050
18	17	19	0.04753	0.01961	3.18E-08	7.775
19	19	20	0.025	0.015	8.64E-12	7.775
20	20	21	0.095	0.204	0	0.500
21	20	23	0.00632	0.00261	4.23E-09	7.775
22	21	22	0.32359	0.19957	9.48E-09	1.650
23	23	24	0.00315	0.00085	1.35E-09	6.050
24	23	25	0.00752	0.0031	5.04E-09	7.775
25	25	26	0.00036	0.00015	2.42E-10	7.775
26	25	30	0.00261	0.00108	1.75E-09	7.775
27	26	27	0.00174	0.00072	1.16E-09	7.775
28	27	28	0.0047	0.00194	3.14E-09	7.775
29	28	29	0.00068	0.00028	4.58E-10	7.775
30	30	31	0.00346	0.00143	2.32E-09	7.775
31	31	32	0.00111	0.00046	7.43E-10	7.775
32	31	33	0.00036	0.00015	2.42E-10	7.775
33	33	34	0.00627	0.00259	4.06E-09	7.775

IEEE 34 Node Test Feeder Cost Data

Branch No.	Bus From	Bus To	Rating (MVA)	Rating (Amp)	length (ft)	Length (km)	Cost (€/km)	Cost (€)	Annuity (€)	O&M Cost (€)	Total Cost per year (€)	Daily Cost (€)	Total Daily Cost (€)	
1	1	2	9.925	230	2580	0.786	33000	25950.67	1512.36	1297.53	2809.89	7.70	91.06	Including Substation cost
2	2	3	9.925	230	1730	0.527	33000	17401.03	1014.10	870.05	1884.15	5.16	5.16	
3	3	4	9.925	230	32230	9.824	33000	324182.23	18892.74	16209.11	35101.86	96.17	96.17	
4	4	5	6.050	140	5804	1.769	24400	43165.04	2515.58	2158.25	4673.83	12.81	12.81	
5	4	6	9.925	230	37500	11.430	33000	377190.00	21981.94	18859.50	40841.44	111.89	111.89	
6	6	7	9.925	230	29730	9.062	33000	299036.23	17427.28	14951.81	32379.09	88.71	88.71	
7	7	8	7.775	180	10	0.003	28700	87.48	5.10	4.37	9.47	0.03	26.04	including VR1
8	8	9	7.775	180	310	0.094	28700	2711.81	158.04	135.59	293.63	0.80	0.80	
9	9	10	6.050	140	1710	0.521	24400	12717.48	741.15	635.87	1377.02	3.77	3.77	
10	9	13	7.775	180	10210	3.112	28700	89314.63	5205.09	4465.73	9670.82	26.50	26.50	
11	10	11	6.050	140	48150	14.676	24400	358097.33	20869.25	17904.87	38774.12	106.23	106.23	
12	11	12	6.050	140	13740	4.188	24400	102186.03	5955.21	5109.30	11064.52	30.31	30.31	
13	13	14	6.050	140	3030	0.924	24400	22534.47	1313.27	1126.72	2439.99	6.68	6.68	
14	13	15	7.775	180	840	0.256	28700	7348.12	428.23	367.41	795.64	2.18	2.18	
15	15	16	7.775	180	20440	6.230	28700	178804.21	10420.38	8940.21	19360.59	53.04	53.04	
16	16	17	7.775	180	520	0.158	28700	4548.84	265.10	227.44	492.54	1.35	1.35	
17	17	18	6.050	180	23330	7.111	24400	173508.01	10111.73	8675.40	18787.13	51.47	51.47	
18	17	19	7.775	180	36830	11.226	28700	322180.00	18776.06	16109.00	34885.06	95.58	95.58	
19	19	20	7.775	180	10	0.003	28700	87.48	5.10	4.37	9.47	0.03	26.04	including VR2
20	20	21	0.500	Transformer	0	0.000	26400	26400.00	1538.54	1320.00	2858.54	7.83	7.83	
21	20	23	7.775	180	4900	1.494	28700	42864.02	2498.04	2143.20	4641.24	12.72	12.72	
22	21	22	1.650	228	10560	3.219	27000	86904.58	5064.64	4345.23	9409.87	25.78	25.78	
23	23	24	6.050	140	1620	0.494	24400	12048.13	702.14	602.41	1304.55	3.57	3.57	
24	23	25	7.775	180	5830	1.777	28700	50999.44	2972.15	2549.97	5522.13	15.13	15.13	
25	25	26	7.775	180	280	0.085	28700	2449.37	142.74	122.47	265.21	0.73	0.73	
26	25	30	7.775	180	2020	0.616	28700	17670.48	1029.80	883.52	1913.33	5.24	5.24	
27	26	27	7.775	180	1350	0.411	28700	11809.48	688.23	590.47	1278.71	3.50	3.50	
28	27	28	7.775	180	3640	1.109	28700	31841.85	1855.68	1592.09	3447.78	9.45	9.45	
29	28	29	7.775	180	530	0.162	28700	4636.31	270.20	231.82	502.01	1.38	1.38	
30	30	31	7.775	180	2680	0.817	28700	23444.00	1366.27	1172.20	2538.47	6.95	6.95	
31	31	32	7.775	180	860	0.262	28700	7523.07	438.43	376.15	814.58	2.23	2.23	
32	31	33	7.775	180	280	0.085	28700	2449.37	142.74	122.47	265.21	0.73	0.73	
33	33	34	7.775	180	4860	1.481	28700	42514.11	2477.64	2125.71	4603.35	12.61	12.61	
Substation			2					281000	16376.16	14050.00	30426.16	83.36	Total	
VR1								60000	3496.69	6000.00	9496.69	26.02	Daily	943.66
VR2								60000	3496.69	6000.00	9496.69	26.02	Cost (€)	

IEEE 34 Node – 24 hours Active power (P) in MW

Bus No.	Hour																							
	1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**	**18**	**19**	**20**	**21**	**22**	**23**	**24**
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	0	0	0	0	0	0
2	0.0037	0.0056	0.0046	0.0052	0.0068	0.0070	0.0130	0.0189	0.0256	0.0147	0.0123	0.0112	0.0121	0.0220	0.0156	0.0130	0.0194	0.0190	0.0267	0.0275	0.0233	0.0192	0.0197	0.0161
3	0.0076	0.0077	0.0085	0.0074	0.0082	0.0125	0.0156	0.0173	0.0161	0.0152	0.0121	0.0136	0.0136	0.0239	0.0233	0.0172	0.0154	0.0155	0.0153	0.0215	0.0275	0.0199	0.0138	0.0125
4	0.0008	0.0022	0.0006	0.0006	0.0009	0.0009	0.0041	0.0041	0.0022	0.0023	0.0024	0.0030	0.0021	0.0016	0.0034	0.0041	0.0042	0.0024	0.0038	0.0066	0.0080	0.0037	0.0025	0.0008
5	0.0006	0.0005	0.0007	0.0010	0.0013	0.0011	0.0019	0.0030	0.0056	0.0080	0.0053	0.0035	0.0016	0.0015	0.0034	0.0057	0.0021	0.0015	0.0013	0.0020	0.0032	0.0016	0.0013	0.0007
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	0	0	0	0	0	0
9	0.0003	0.0003	0.0003	0.0009	0.0011	0.0007	0.0008	0.0015	0.0015	0.0009	0.0025	0.0020	0.0002	0.0008	0.0008	0.0008	0.0007	0.0008	0.0023	0.0011	0.0007	0.0005	0.0021	0.0017
10	0.0015	0.0015	0.0015	0.0015	0.0015	0.0018	0.0060	0.0065	0.0114	0.0154	0.0093	0.0074	0.0139	0.0138	0.0059	0.0161	0.0066	0.0042	0.0054	0.0175	0.0140	0.0084	0.0058	0.0116
11	0.0195	0.0151	0.0134	0.0164	0.0243	0.0275	0.0522	0.0517	0.0571	0.0412	0.0362	0.0400	0.0457	0.0477	0.0444	0.0400	0.0447	0.0534	0.0700	0.0845	0.0733	0.0551	0.0349	0.0311
12	0.0137	0.0171	0.0154	0.0188	0.0172	0.0221	0.0467	0.0486	0.0564	0.0437	0.0365	0.0428	0.0544	0.0452	0.0450	0.0420	0.0395	0.0530	0.0576	0.0558	0.0675	0.0456	0.0341	0.0205
13	0.0046	0.0038	0.0040	0.0038	0.0045	0.0105	0.0151	0.0177	0.0163	0.0150	0.0144	0.0103	0.0086	0.0219	0.0179	0.0187	0.0163	0.0188	0.0217	0.0158	0.0245	0.0201	0.0102	0.0052
14	0.0033	0.0032	0.0029	0.0040	0.0034	0.0063	0.0200	0.0167	0.0170	0.0172	0.0089	0.0075	0.0112	0.0089	0.0142	0.0112	0.0166	0.0153	0.0102	0.0124	0.0125	0.0175	0.0109	0.0040
15	0.0003	0.0003	0.0003	0.0003	0.0002	0.0003	0.0006	0.0012	0.0023	0.0009	0.0006	0.0009	0.0044	0.0018	0.0013	0.0034	0.0052	0.0008	0.0019	0.0051	0.0055	0.0017	0.0005	0.0003
16	0.0105	0.0082	0.0081	0.0074	0.0095	0.0159	0.0324	0.0377	0.0310	0.0347	0.0259	0.0248	0.0329	0.0370	0.0331	0.0271	0.0291	0.0294	0.0349	0.0480	0.0335	0.0373	0.0263	0.0139
17	0.0001	0.0001	0.0001	0.0001	0.0001	0.0001	0.0003	0.0005	0.0005	0.0004	0.0020	0.0008	0.0005	0.0003	0.0002	0.0002	0.0001	0.0001	0.0001	0.0004	0.0003	0.0002	0.0001	0.0001
18	0.0001	0.0001	0.0001	0.0002	0.0002	0.0001	0.0005	0.0005	0.0008	0.0020	0.0009	0.0009	0.0014	0.0012	0.0009	0.0005	0.0009	0.0005	0.0007	0.0003	0.0003	0.0003	0.0003	0.0004
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	0	0	0	0	0	0
20	0.0007	0.0010	0.0011	0.0011	0.0008	0.0008	0.0029	0.0042	0.0032	0.0017	0.0024	0.0020	0.0022	0.0034	0.0028	0.0029	0.0026	0.0075	0.0051	0.0056	0.0050	0.0033	0.0017	0.0017
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	**0**	0	0	0	0	0	0	0
22	0.1375	0.1375	0.1400	0.1550	0.1550	0.1875	0.2100	0.2150	0.2175	0.2175	0.2175	0.2125	0.2250	0.2350	0.2350	0.2280	0.2500	0.2000	0.1850	0.1575	0.1500	0.1325	0.1350	0.1375
23	0.0041	0.0021	0.0027	0.0029	0.0028	0.0049	0.0065	0.0104	0.0085	0.0130	0.0084	0.0089	0.0173	0.0135	0.0146	0.0192	0.0088	0.0096	0.0173	0.0205	0.0245	0.0096	0.0102	0.0127
24	0.0001	0.0001	0.0001	0.0000	0.0002	0.0001	0.0003	0.0004	0.0002	0.0003	0.0001	0.0001	0.0001	0.0001	0.0001	0.0003	0.0001	0.0001	0.0006	0.0005	0.0010	0.0002	0.0002	0.0001
25	0.0347	0.0216	0.0125	0.0163	0.0189	0.0350	0.0492	0.0554	0.0615	0.0509	0.0400	0.0467	0.0404	0.0520	0.0590	0.0440	0.0463	0.0710	0.0690	0.0890	0.0847	0.0748	0.0584	0.0348
26	0.0007	0.0004	0.0003	0.0003	0.0005	0.0011	0.0045	0.0019	0.0018	0.0011	0.0006	0.0005	0.0013	0.0005	0.0013	0.0011	0.0020	0.0019	0.0019	0.0012	0.0028	0.0010	0.0009	0.0004
27	0.0693	0.0693	0.0693	0.0693	0.0587	0.0747	0.1600	0.2773	0.2773	0.2933	0.3093	0.3200	0.3467	0.3573	0.3787	0.4320	0.4053	0.3200	0.2667	0.2133	0.2027	0.0640	0.0747	0.0693
28	0.0066	0.0043	0.0043	0.0064	0.0069	0.0086	0.0159	0.0187	0.0210	0.0230	0.0133	0.0168	0.0097	0.0153	0.0156	0.0152	0.0159	0.0183	0.0177	0.0340	0.0279	0.0215	0.0134	0.0061
29	0.0182	0.0160	0.0128	0.0134	0.0143	0.0171	0.0433	0.0573	0.0471	0.0511	0.0396	0.0346	0.0448	0.0470	0.0632	0.0530	0.0568	0.0572	0.0526	0.0720	0.0505	0.0381	0.0360	0.0197
30	0.0820	0.0597	0.0597	0.0572	0.0572	0.0820	0.1690	0.1541	0.1293	0.1293	0.1616	0.1641	0.1591	0.1566	0.1268	0.1245	0.1181	0.1566	0.1740	0.1740	0.1491	0.1442	0.1442	0.1516
31	0.0149	0.0117	0.0094	0.0097	0.0143	0.0221	0.0328	0.0409	0.0403	0.0389	0.0301	0.0269	0.0354	0.0344	0.0331	0.0462	0.0313	0.0478	0.0610	0.0589	0.0413	0.0470	0.0296	0.0239
32	0.0117	0.0085	0.0078	0.0073	0.0106	0.0146	0.0272	0.0399	0.0365	0.0299	0.0311	0.0274	0.0275	0.0272	0.0315	0.0282	0.0286	0.0311	0.0362	0.0480	0.0379	0.0341	0.0192	0.0135
33	0.0025	0.0017	0.0024	0.0015	0.0026	0.0032	0.0085	0.0064	0.0091	0.0113	0.0048	0.0063	0.0061	0.0052	0.0057	0.0058	0.0054	0.0079	0.0140	0.0109	0.0125	0.0071	0.0030	0.0030
34	0.0017	0.0017	0.0028	0.0018	0.0016	0.0018	0.0066	0.0074	0.0058	0.0035	0.0082	0.0064	0.0082	0.0139	0.0140	0.0130	0.0053	0.0116	0.0088	0.0115	0.0058	0.0048	0.0063	0.0036
Total	**0.4514**	**0.4010**	**0.3856**	**0.4100**	**0.4235**	**0.5606**	**0.9457**	**1.1150**	**1.1027**	**1.0762**	**1.0363**	**1.0419**	**1.1265**	**1.1889**	**1.1905**	1.2135	**1.1772**	**1.1554**	**1.1616**	**1.1954**	**1.0896**	**0.8135**	**0.6953**	**0.5971**

IEEE 34 Node – 24 hours Reactive Power (Q) in MVar

Bus No.	Hour 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0.0020	0.0029	0.0024	0.0027	0.0036	0.0037	0.0068	0.0100	0.0135	0.0077	0.0065	0.0059	0.0064	0.0116	0.0082	0.0068	0.0102	0.0100	0.0141	0.0145	0.0123	0.0101	0.0104	0.0085
3	0.0040	0.0041	0.0045	0.0039	0.0043	0.0066	0.0082	0.0091	0.0085	0.0080	0.0064	0.0071	0.0072	0.0126	0.0123	0.0091	0.0081	0.0082	0.0080	0.0114	0.0145	0.0105	0.0073	0.0066
4	0.0004	0.0011	0.0003	0.0003	0.0004	0.0005	0.0020	0.0020	0.0011	0.0012	0.0012	0.0015	0.0010	0.0008	0.0017	0.0020	0.0021	0.0012	0.0019	0.0033	0.0040	0.0018	0.0012	0.0004
5	0.0003	0.0002	0.0003	0.0005	0.0006	0.0006	0.0010	0.0015	0.0028	0.0040	0.0027	0.0018	0.0008	0.0008	0.0017	0.0028	0.0011	0.0008	0.0007	0.0010	0.0016	0.0008	0.0006	0.0004
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0.0001	0.0001	0.0001	0.0004	0.0005	0.0003	0.0003	0.0006	0.0006	0.0003	0.0010	0.0008	0.0001	0.0003	0.0003	0.0003	0.0003	0.0003	0.0009	0.0004	0.0003	0.0002	0.0009	0.0007
10	0.0008	0.0008	0.0008	0.0008	0.0008	0.0009	0.0030	0.0032	0.0057	0.0077	0.0046	0.0037	0.0069	0.0069	0.0029	0.0081	0.0033	0.0021	0.0027	0.0088	0.0070	0.0042	0.0029	0.0058
11	0.0101	0.0078	0.0069	0.0084	0.0125	0.0142	0.0269	0.0266	0.0294	0.0212	0.0186	0.0206	0.0235	0.0246	0.0228	0.0206	0.0230	0.0275	0.0361	0.0435	0.0377	0.0284	0.0180	0.0160
12	0.0071	0.0089	0.0080	0.0097	0.0089	0.0115	0.0242	0.0252	0.0292	0.0227	0.0189	0.0222	0.0282	0.0234	0.0233	0.0218	0.0205	0.0275	0.0299	0.0289	0.0350	0.0237	0.0177	0.0106
13	0.0023	0.0019	0.0019	0.0019	0.0022	0.0051	0.0074	0.0087	0.0080	0.0074	0.0071	0.0050	0.0042	0.0107	0.0088	0.0092	0.0080	0.0092	0.0106	0.0077	0.0120	0.0098	0.0050	0.0026
14	0.0017	0.0016	0.0014	0.0020	0.0017	0.0031	0.0100	0.0084	0.0085	0.0086	0.0044	0.0038	0.0056	0.0044	0.0071	0.0056	0.0083	0.0076	0.0051	0.0062	0.0062	0.0088	0.0054	0.0020
15	0.0001	0.0001	0.0001	0.0002	0.0001	0.0001	0.0003	0.0005	0.0011	0.0004	0.0003	0.0004	0.0020	0.0008	0.0006	0.0015	0.0024	0.0003	0.0008	0.0023	0.0025	0.0008	0.0002	0.0001
16	0.0046	0.0036	0.0036	0.0033	0.0042	0.0071	0.0144	0.0167	0.0137	0.0154	0.0115	0.0110	0.0146	0.0164	0.0147	0.0120	0.0129	0.0130	0.0155	0.0213	0.0148	0.0165	0.0117	0.0062
17	0.0000	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0002	0.0003	0.0002	0.0010	0.0004	0.0003	0.0002	0.0001	0.0001	0.0001	0.0000	0.0000	0.0002	0.0001	0.0001	0.0001	0.0000
18	0.0001	0.0000	0.0000	0.0001	0.0001	0.0001	0.0002	0.0003	0.0004	0.0010	0.0004	0.0005	0.0007	0.0006	0.0004	0.0002	0.0005	0.0003	0.0003	0.0002	0.0001	0.0002	0.0002	0.0002
19	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
20	0.0003	0.0004	0.0005	0.0005	0.0004	0.0004	0.0013	0.0019	0.0015	0.0008	0.0011	0.0009	0.0010	0.0016	0.0013	0.0014	0.0012	0.0035	0.0024	0.0026	0.0023	0.0015	0.0008	0.0008
21	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
22	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905	0.0905
23	0.0021	0.0011	0.0014	0.0015	0.0014	0.0025	0.0033	0.0053	0.0043	0.0066	0.0043	0.0046	0.0088	0.0069	0.0074	0.0098	0.0045	0.0049	0.0088	0.0105	0.0125	0.0049	0.0052	0.0065
24	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0001	0.0002	0.0001	0.0001	0.0000	0.0000	0.0000	0.0000	0.0000	0.0001	0.0000	0.0000	0.0003	0.0003	0.0005	0.0001	0.0001	0.0000
25	0.0176	0.0109	0.0063	0.0082	0.0095	0.0177	0.0249	0.0280	0.0311	0.0257	0.0202	0.0236	0.0204	0.0263	0.0299	0.0222	0.0234	0.0359	0.0349	0.0450	0.0428	0.0378	0.0295	0.0176
26	0.0004	0.0002	0.0002	0.0002	0.0003	0.0006	0.0025	0.0011	0.0010	0.0006	0.0003	0.0003	0.0007	0.0003	0.0007	0.0006	0.0011	0.0010	0.0010	0.0007	0.0015	0.0006	0.0005	0.0002
27	0.0528	0.0528	0.0528	0.0528	0.0447	0.0569	0.1219	0.2112	0.2112	0.2234	0.2356	0.2437	0.2640	0.2721	0.2884	0.3290	0.3087	0.2437	0.2031	0.1625	0.1543	0.0487	0.0569	0.0528
28	0.0033	0.0022	0.0022	0.0032	0.0035	0.0043	0.0079	0.0093	0.0105	0.0115	0.0066	0.0084	0.0049	0.0076	0.0078	0.0076	0.0079	0.0092	0.0089	0.0170	0.0139	0.0108	0.0067	0.0030
29	0.0136	0.0119	0.0096	0.0100	0.0107	0.0128	0.0324	0.0429	0.0352	0.0382	0.0296	0.0259	0.0335	0.0351	0.0473	0.0397	0.0425	0.0428	0.0393	0.0539	0.0378	0.0285	0.0270	0.0147
30	0.0500	0.0363	0.0363	0.0348	0.0348	0.0500	0.1030	0.0939	0.0787	0.0787	0.0984	0.0999	0.0969	0.0954	0.0772	0.0758	0.0719	0.0954	0.1060	0.1060	0.0909	0.0878	0.0878	0.0924
31	0.0077	0.0060	0.0049	0.0050	0.0074	0.0114	0.0169	0.0211	0.0208	0.0201	0.0156	0.0139	0.0183	0.0178	0.0171	0.0239	0.0162	0.0247	0.0315	0.0304	0.0213	0.0243	0.0153	0.0124
32	0.0077	0.0056	0.0052	0.0048	0.0070	0.0096	0.0180	0.0263	0.0241	0.0197	0.0205	0.0181	0.0181	0.0179	0.0208	0.0186	0.0188	0.0205	0.0239	0.0317	0.0250	0.0225	0.0127	0.0089
33	0.0013	0.0008	0.0012	0.0008	0.0013	0.0016	0.0042	0.0032	0.0045	0.0057	0.0024	0.0032	0.0030	0.0026	0.0029	0.0029	0.0027	0.0039	0.0070	0.0054	0.0062	0.0036	0.0015	0.0015
34	0.0009	0.0008	0.0014	0.0009	0.0008	0.0009	0.0033	0.0037	0.0029	0.0017	0.0041	0.0032	0.0041	0.0069	0.0070	0.0065	0.0027	0.0058	0.0044	0.0058	0.0029	0.0024	0.0031	0.0018
Total	0.2816	0.2529	0.2429	0.2475	0.2523	0.3130	0.5351	0.6516	0.6392	0.6292	0.6140	0.6208	0.6660	0.6952	0.7032	0.7289	0.6927	0.6900	0.6886	0.7117	0.6508	0.4799	0.4191	0.3633

Energy prices in €/MWh

Hour	Energy prices [€/MWh]
1	39.1
2	37.1
3	26.56
4	22
5	20.1
6	25
7	28.11
8	42.69
9	41.1
10	48.99
11	48.99
12	44.89
13	43.5
14	40.1
15	38.71
16	38.98
17	40
18	42
19	44
20	55.1
21	53.59
22	48.99
23	44.01
24	39.33

Curriculum Vitae

Ibtihal Abdelmotteleb was born in Kuwait City, Kuwait in 1988. She has received her Bachelor and Master degrees in electrical power and control engineering from Arab Academy for Science, Technology and Maritime Transport (AASTMT), Cairo, Egypt in 2009 and 2012. She worked as a teaching assistant in the same university from 2009 to 2014.

In 2014, she was selected as a PhD candidate for the Erasmus Mundus joint doctorate (EMJD) fellowship in Sustainable Energy Technologies and Strategies (SETS) awarded by European Commission; a joint degree program between TU Delft University in Netherlands, KTH Royal Institute of Technology in Sweden, and Comillas Pontifical University in Spain, where she is pursuing her PhD degree.

In 2014, she joined Smart and Sustainable Grid research group in Instituto de Investigación Tecnológica (IIT). She worked closely with her main supervisor Prof. Tomás Gómez and co-supervisor Dr. Javier Reneses focusing on designing efficient distribution network tariffs considering the integration of high penetrations of distributed energy resources. She also participated in two projects: 'Utility of the Future,' funded by MIT and 'Tariff design for Jamaica,' funded by JPS.

She has also visited during her PhD the Faculty of Technology, Policy and Management (TPM) at TU Delft from September 2016 – May 2017, where she focused on demand response and flexibility from the policy, regulatory and economic aspect with Dr. Laurens de Vries.

Her research interests include the regulation and economics of the power and energy industry, renewable energy, distribution networks, and demand response.

List of Publications

Journal Articles:

- I. Abdelmotteleb, T. Gómez, J.P. Chaves, J. Reneses. '**Designing efficient distribution network charges in the context of active customers**.' *Applied Energy*. vol. 210, pp. 815-826, January 2018.
- I. Abdelmotteleb, T. Gómez, J. Reneses. '**Evaluation methodology for tariff design under escalating penetrations of Distributed Energy Resources**.' *Energies*. vol. 10, no. 6, pp. 778-1-778-16, June 2017.

Conference Papers:

- I. Abdelmotteleb, T. Gómez, J.P. Chaves, '**Benefits of PV inverter volt-var control on distribution network operation**,' 12th PowerTech Conference - PowerTech 2017. Manchester, United Kingdom, 18-22 June 2017.
- I. Abdelmotteleb, T. Gómez, J. Reneses, '**Distribution network cost allocation using a locational and temporal cost reflective methodology**,' 19th Power Systems Computation Conference - PSCC 2016. Génova, Italy, 20-24 June 2016.
- I. Abdelmotteleb, T. Gómez, J.P. Chaves, J. Reneses, '**Incentivizing consumer response through cost-reflective distribution network charges**,' CIRED Workshop 2016. Helsinki, Finland, 14-15 June 2016.

Submitted Journal Article:

- I. Abdelmotteleb, T. Gómez, J.P. Chaves, L.J. de Vries, J. Reneses, '**A framework for electricity distribution-level coordination through local flexibility mechanisms**,' Applied Energy, under review.

Submitted Book Chapter:

- I. Abdelmotteleb, T. Gómez, J.P. Chaves, '**New distribution network charges for new integrated network services**.' Consumers, prosumers, prosumagers: How innovation in energy services will lead to stratification of consumers and disrupt traditional utility business paradigm,' under review.

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