DOCTORAL THESIS

Madrid, Spain 2023

Distribution network tariff design under decarbonization, decentralization, and digitalization

Nicolás Morell Dameto

COMILLAS
UNIVERSIDAD PONTIFICIA

Distribution network tariff design under decarbonization, decentralization, and digitalization

Nicolás Morell Dameto

Doctoral Thesis supervisors:

Dr. José Pablo Chaves Ávila	Universidad Pontificia Comillas
Prof. Dr. Tomás Gómez San Román	Universidad Pontificia Comillas

Members of the Examination Committee:

Prof. Dr. Laurens de Vries	Delft University of Technology
Prof. Dr. Yannick Perez	Université Paris-Saclay
Prof. Dr. Leonardo Meeus	European University Institute
Dr. Pablo Dueñas Martínez	Universidad Pontificia Comillas
Dr. Rafael Cossent Arín	Universidad Pontificia Comillas

Acknowledgements

Es un reto para mí transmitir a través de estas líneas el profundo agradecimiento que siento a todas las personas que me han acompañado a lo largo de esta tesis. Me siento muy afortunado por tantas buenas personas que me rodean y que, de una manera u otra, han contribuido a hacer realidad este trabajo.

Empiezo con mis directores de tesis, Tomás Gómez San Román y José Pablo Chaves Ávila, unos guías ejemplares en este camino. Muchas gracias Tomás por enseñarme el rigor científico, a abordar los problemas al detalle y a enfocarme en las cuestiones clave. José Pablo, muchas gracias por tu paciencia y por tu incansable apoyo, esfuerzo y sacrificio. Os agradezco mucho las oportunidades que me habéis brindado. Ha sido un verdadero placer aprender y trabajar con vosotros.

Este trabajo hubiera sido mucho más complicado si no fuera por los compañeros del IIT con quienes he compartido el camino de la investigación. Mis queridos compañeros de la cuarta planta: Timo, Fernando, Pedro C., Leandro, Leslie, Matteo, Morsy, Miguel Ángel, David, Shilpa, Miguel, Eliana y Jesús. También me gustaría agradecer los buenos momentos que hemos pasado en el IIT. Gracias Paulo, David, Teresa, Santos, Sebas, Pedro O., Erik, Rafa y aquellos que no menciono y siempre habéis estado allí. Muchas gracias por acogerme en esta gran familia que es el IIT.

Además, quiero agradecer a todas aquellas personas que me habéis ayudado tanto a la hora de decidirme a empezar la tesis, como a lo largo de su desarrollo: Camila Fernandes, Rafael Cossent, Carlos Mateo, Pablo Frías, Javier García y Pedro Linares.

I would like to thank all the people involved in the Slovenian network tariff reform project, which has been a great source of inspiration for this thesis, especially Andreja Kanduc, Igor Podbelsek and Timotej Kodek, from EIMV; and David Batic and all the team from the Energy Agency. Also, thanks to Fundación Iberdrola, Fundación Naturgy, Endesa, European Commission and ARESEP for making this thesis financially feasible.

During the thesis, I had the opportunity to conduct part my research at MIT, where I found invaluable people. Thank you, Pablo Dueñas and Rob Stoner, for your support and for making this stay possible. A deep thanks to Tim Schittekatte, who helped me to focus on the key questions, who provided the right papers at the right times, and made the MIT stay an unforgettable experience. Thank you for your time and efforts. Also, I would like to thank my colleagues at MIT Energy Initiative: Jim, Amanda, Sydney, Jonte, Tony, Jameson, Rahman, Less, Paul, Graham, and all the friends who made Cambridge an amazing place to live.

Finalmente, me gustaría dedicar mi mayor agradecimiento a mi familia.

A mis padres, Mariano y Dolores, que siempre se han preocupado por mi formación y me han apoyado en todas las decisiones que he tomado. A mi hermano Pedro por haber sido mi *referente académico durante muchos años y por ayudarme en los momentos clave. A tía Pepa por ser un pilar en nuestra familia y acompañarnos siempre que estamos en Mallorca. Moltes grasis!*

A mis hijos, Mariano y Rocío, por ser la ilusión y la alegría de nuestras vidas.

Todo el trabajo de esta tesis se lo dedico a mi mujer, Rocío. No tengo palabras para agradecer tu apoyo, tu esfuerzo y tu cariño. Gracias a ti empecé la tesis y gracias a ti la termino. ¡Quién nos diría hace cuatro años que ahora estaríamos casados, con dos hijos y dos tesis!

Abstract

The electricity network tariffs aim to recover network costs while also adhering to principles of economic efficiency and equity. The majority of existing network tariffs in different countries primarily focus on cost recovery, implicitly assuming customers are not very sensitive to price changes. Despite theoretical proposals for network tariff designs that align better with these principles, their validation is confined to simplified network systems. This thesis formulates a dynamic network tariff with high temporal and geographical granularity and implements it in a real electricity system. The implementation into the actual system is achieved by adapting tariff methodologies to manage large-scale multi-layered networks and complex datasets.

Due to most network costs are sunk costs, the enhanced tariff design focuses on signalling long-term network costs, those that network operators are likely to incur in a future where demand continues to grow, i.e., those that can be reduced or even avoided. On the other hand, long-term costs are usually smaller than sunk costs, hence an additional term, called residual costs, needs to be paid by consumers to achieve the cost recovery objective.

In the context of the entire network, consumers and generators need to be grouped into subsystems based on voltage levels. This grouping allows for the calculation of network utilization levels, a framework known as the cascade model. While long-term costs are recovered through energy charges during peak network utilization hours, which are symmetric for both energy injections and withdrawals, residual costs are recovered through a fixed charge without distorting other economic signals.

This innovative network tariff structure encourages the shifting of flexible loads to periods of lower demand, aligning the economic incentives for individual users with system benefits. As a result, this approach reduces the need for future network investments. Furthermore, the equitable nature of the proposed tariff establishes a level-playing field for distributed resources that offer flexibility services. Illustrated through the example of Slovenia, this thesis provides a framework worthy of consideration by regulators for implementation in real-world electricity systems.

Additionally, this thesis examines the performance of different long-term network tariff designs in a future with many flexible customers who respond to price signals by modifying their consumption patterns. In theory, long-term economic signals balance between flexible consumption and the long-term costs associated with network expansion. Designs of long-term network tariffs with high geographical granularity are studied, which improves the efficiency of cost distribution among users. However, it is observed that when a significant number of users synchronize their responses to ex-ante network charges, the peak-shifting effect occurs, leading to new network peaks that trigger network reinforcements earlier than initially expected.

Thus, this thesis demonstrates that the predictability principle, often associated with fairness, could conflict with the principle of economic efficiency in this context. As a solution, ex-post pricing aligns network charges with the gradual growth of network costs over time. To address the lower predictability for users, this thesis proposes an innovative coordination mechanism for user response. This mechanism involves a local network capacity market where users reserve their expected network capacity usage within a competitive framework. A detailed case study is presented, comparing various network tariffs in this context, showing that the application of ex-post tariffs and the proposed mechanism can prevent greater network reinforcements by coordinating user responses. The complexity of the presented tariff structure places retailers and aggregators as key players in the future electricity system, acting as intermediaries to transform complex tariff structures into products tailored to each user's flexibility and risk tolerance.

Resumen

Las tarifas de la red eléctrica tienen como objetivo recuperar los costes de la red y, a su vez, cumplir con los principios de eficiencia económica y equidad. La mayoría de las tarifas de red existentes en los distintos países se centran principalmente en la recuperación de costes, asumiendo implícitamente clientes poco sensibles a los cambios en los precios. A pesar de que existen propuestas teóricas de diseños de tarifas de red mejor enfocadas a los principios mencionados, su validación se limita a sistemas de red muy simplificados. Esta tesis formula una tarifa de red dinámica con alta granularidad temporal y geográfica y la implementa en un sistema eléctrico real. La implementación al sistema real se consigue adaptando la metodología de tarifas para gestionar redes multicapa a gran escala y conjuntos de datos complejos.

Debido a que la mayoría de los costes de red son costes hundidos, el diseño mejorado de la tarifa se centra en señalar los costes de red de largo plazo, aquellos en los que el operador de red debería incurrir en un futuro en el que la demanda sigue creciendo, y por tanto, aquellos que se pueden reducir e incluso evitar. Por otro lado, los costes de largo plazo suelen ser menores a los costes hundidos, y por tanto, se requiere de un término adicional, llamado costes residuales, que deben satisfacer los consumidores para lograr el objetivo de recuperación de costes

En el contexto de toda la red, los consumidores y los generadores deben agruparse en subsistemas según los niveles de tensión. Esta agrupación permite el cálculo de los niveles de utilización de la red, un marco conocido como el modelo en cascada. Mientras los costes de largo plazo se recuperan a través de cargos de energía en las horas de máxima utilización de la red y que son simétricos para las inyecciones y para los consumos de energía, los costes residuales se recuperan a través de un cargo fijo que no distorsiona el resto de las señales económicas.

Esta innovadora estructura de tarifas de red fomenta el desplazamiento de cargas flexibles a períodos de menor demanda, alineando los incentivos económicos que reciben los usuarios individuales con los beneficios del sistema. Como resultado, este enfoque reduce la necesidad de inversiones futuras en la red. Además, la naturaleza equitativa de la tarifa propuesta establece una plataforma justa para los recursos distribuidos que ofrecen servicios de flexibilidad. Ilustrado a través del ejemplo de Eslovenia, esta tesis ofrece un marco que merece ser considerado por los organismos reguladores para su implementación en sistemas eléctricos del mundo real.

Adicionalmente, esta tesis analiza el rendimiento de diferentes diseños de tarifas de red de largo plazo en un futuro con muchos clientes flexibles que responden a las señales de precio modificando sus patrones de consumo. En teoría, las señales de largo plazo establecen un equilibrio entre el consumo flexible y los costes de largo plazo relacionados con la expansión de la red. Se examinan diseños de tarifas de red de largo plazo con alta granularidad geográfica, lo que mejora la eficiencia en la distribución de los costes entre usuarios. Sin embargo, se observa que cuando un número significativo de usuarios sincronizan sus respuestas a cargos de red

establecidos ex-ante se produce el efecto *peak-shifting*, por el que se generan nuevos picos de red que conllevan refuerzos en la red más tempranos de lo inicialmente previsto.

Con ello, esta tesis muestra que el principio de previsibilidad, normalmente asociado a la equidad, podría estar en conflicto con el principio de eficiencia económica en dicho contexto. Como solución, la fijación de precios ex-post alinea los cargos de red con el crecimiento gradual de los costes de la red en el tiempo. Para solventar la menor previsibilidad para los usuarios, esta tesis ofrece un innovador mecanismo de coordinación de la respuesta de los usuarios de red. Este mecanismo consiste en un mercado local de capacidad de red donde los usuarios reservan el uso que esperan hacer de la capacidad de red dentro mediante un marco competitivo. Se presenta un caso de estudio detallado en el que se comparan varias tarifas de red en dicho contexto, demostrando que la aplicación de las tarifas ex-post y el mecanismo propuesto son capaces de evitar mayores refuerzos en la red mediante la coordinación de la respuesta de los usuarios de red. La complejidad de la estructura tarifaria presentada erige a los comercializadores y agregadores como piezas clave en el sistema eléctrico del futuro como intermediarios, transformando estructuras de tarifas complejas en productos adaptados a la flexibilidad y la tolerancia al riesgo de cada usuario.

Content

List of figures

List of tables

Abbreviations and acronyms

ACER	Agency for the Cooperation of Energy Regulators
ANEEL	Agência Nacional de Energia Elétrica (Brazilian regulator)
CEER	Council of European Energy Regulators
CNMC	Comisión Nacional de los Mercados y la Competencia (Spanish regulator)
CPP	Critical Peak Price
DER	Distributed Energy Resources
DG	Distributed Generation
DSO	Distribution System Operator
EV	Electric Vehicle
HPUC	Hawaii Public Utility Commission (Hawaiian regulator)
HV	High Voltage
ICT	Information and Communication Technology
LMPs	Locational Marginal Prices
LTIC	Long-Term Incremental Cost
LTMC	Long-Term Marginal Cost
LV	Low Voltage
MV	Medium Voltage
NRA	National Regulatory Authority
PCNC	Peak Coincident Network Charge
PTDF	Power Transfer Distribution Factor
PTR	Peak Time Rebates
PV	Photovoltaic solar installation
RTP	Real Time Price
STMC	Short-Term Marginal Cost
ToU	Time-of-Use

TSO	Transmission System Operator
VPP	Variable Peak Price

Notation

Sets

J	Customer groups
NE_v	Network elements in each voltage level v
P	Time periods
U	Network users
V	Voltage levels
X_v	Network areas in each voltage level v

Indexes

e	Network element, such as lines, transformers, or substations, *e* ϵ NE_v
h	Hour h ϵ (0, 8760)
j	Customer group *j* ϵ *J*
p	Time period *p* ϵ *P*
u	Network user *u* ϵ *U*
v, w	Voltage level *v, w* ϵ *V*
x, y	Network areas *x, y* ϵ X_v

Parameters

$A_{v,x}$	Network area *x* in voltage level *v*
C_e	Network costs of element *e* (€/year).
C_v	Network costs of voltage level *v* (€/year)
$C_{v,x}$	Total network costs in area $A_{v,x}$ (€/year)
ΔC_v	Annual growth of network costs for voltage level *v* (p.u.)
$\Delta C_{v,x}$	Annual growth of total network costs in area $A_{v,x}$ (p.u.)
CAP_u	Physical capacity for network user *u* (kW)

CAP_j Aggregated physical capacity of customer group *j* (kW)

$CC_{u,p}$ Contracted capacity of network user *u* in time period *p* (kW)

ΔD_v Annual growth of network peak demand at voltage level *v* (p.u.)

$\Delta D_{v,x}$ Expected annual growth of the network peak demand in area $A_{v,x}$ (p.u.)

EC_v Aggregated consumption of network users connected to voltage level *v* (kWh).

$EC_{u,p}$ Aggregated consumption of network user *u* in time period *p* (kWh)

$EC_{v,h}$ Aggregated energy consumption at voltage level *v* in hour *h* (MWh)

$EC_{v,x,h}$ Aggregated energy consumption in area $A_{v,x}$ in hour *h* (MWh)

$G_{v,h}$ Aggregated energy generation at voltage level *v* in hour *h* (MWh)

$G_{v,x,h}$ Aggregated energy generation in area $A_{v,x}$ and hour *h* (MWh)

H Number of hours with maximum energy flows

L_v Energy losses coefficient at voltage level *v* (p.u.)

LC Energy losses costs (€/year)

Y Years of the planning horizon

Z Number of largest values of hourly network usage to signal forward-looking network reinforcements.

Variables

α_w^v Cost sharing factor for capacity charges based on the electricity flow from voltage level *v* to voltage level *w* (p.u.)

$\alpha_{w,p}^v$ Cost sharing factor based on the electricity flow from voltage level *v* to voltage level *w*, for the time period *p*, applied to costs recovered by capacity charges (p.u.)

αe_w^v Cost sharing factor for energy charges based on the electricity flow from voltage level *v* to voltage level *w* (p.u.)

$\alpha e_{w,p}^v$ Cost sharing factor based on the electricity flow from voltage level *v* to voltage level *w*, for the time period *p*, applied to costs recovered by energy charges (p.u.)

c_v^C Network costs of voltage level *v* to be recovered by capacity charges (€/year)

$c_{v,p}^C$ Network costs of voltage level *v* allocated to time period *p*, to be recovered by capacity charges (€/year)

$c_{v,p}^{C,w}$ Costs of voltage level *v* that will be allocated to users of voltage level *w*, at time period *p*, to be recovered by capacity charges (€/year)

c_v^E Costs of voltage level *v* that are allocated to energy charges (€/year)

$c_{v,p}^{E}$	Network costs of voltage level *v* allocated to time period *p*, to be recovered by energy charges (€/year)
$c_{v,p}^{E,w}$	Costs of voltage level *v* that will be allocated to users of voltage level *w*, at time period *p*, to be recovered by energy charges (€/year)
c_{v}^{w}	Costs of voltage level *v* that are allocated to users connected at voltage level *w* (€/year)
$cp_{v,x,h}$	Local capacity market clearing price in hour *h*, and area $A_{v,x}$ (€/kW)
$f_{v,h}$	Aggregated energy flow from voltage level *v* to voltage level *v*-1 in hour h (MWh)
h_{e}	Number of hours when network usage of element *e* $(nu_{e,h})$ surpasses the 60% of the network element physical capacity
$h_{v,p}$	Number of hours of time period *p* included in the *H* for voltage level *v*;
$ibc_{v,x,h}$	Individual booked capacity in hour *h*, and area $A_{v,x}$ (kW)
$ied_{v,x,h}$	Individual energy deviation in hour *h*, and area $A_{v,x}$ (kWh)
$inu_{v,x,h}$	Individual network utilisation in hour *h*, and area $A_{v,x}$ (kWh)
$ip_{v,x,h}$	Individual payment in hour *h*, and area $A_{v,x}$ (€)
ic_{e}	Long-term incremental network costs associated to network element *e* (€)
$ic_{e,h}$	Long-term incremental network costs associated to network element *e* to be recovered in hour *h* (€)
ic_{v}	Incremental network costs for voltage level *v* along the considered planning horizon (€/year)
$ic_{v,h}$	Incremental network costs associated with voltage level *v* and hour *h* (€/kWh)
$ic_{v,x}$	Incremental network costs in area $A_{v,x}$ (€/year)
$ic_{v,x,h}$	Incremental network costs of area $A_{v,x}$ allocated to hour h (€)
$ic_{v,h}^{j}$	Incremental energy cost associated with voltage level *v*, and hour *h*, for customer group *j* (€/kWh)
$it_{u,e,h}$	Long-term incremental network term that network user *u* pays for the usage of network element *e* in hour *h* (€/kWh)
it_{h}^{j}	Forward-looking peak coincident energy charge for customer group *j* at hour *h* (€/kWh)
$it_{v,x,h}$	Long-term incremental network term that customers face as users of area $A_{v,x}$ in hour *h* (€/kWh)
it_{h}^{y}	Forward-looking peak coincident energy charge that customers located in area A_{y} face in hour *h* (€/kWh)
$l_{v,h}$	Energy losses at voltage level *v* at hour *h* (MWh)

$lc_{v,h}$	Energy losses costs associated with voltage level *v*, and hour *h* (€/kWh)
$lc_{v,h}^{j}$	Energy losses charge associated with voltage level *v*, and hour *h*, for customer group *j* (€/kWh)
lt_{h}^{j}	Losses energy charge for customer group *j* at hour *h* (€/kWh)
$net_{v,h}$	Difference between consumption and generation for a voltage level *v*, at hour *h* (MWh)
$net_{v,x,h}$	Net hourly consumption in area $A_{v,x}$ and hour *h* (MWh)
$nu_{e,h}$	Network usage of element *e* in hour *h* (kWh)
$nu_{v,h}$	Network usage for voltage level *v* at hour *h* (MWh)
$nu_{v,x,h}$	Network usage in area $A_{v,x}$ and hour *h* (MWh)
$nu_{v,h}^{Y}$	Projected network usage at hour *h* in year *Y* for voltage level *v* (MWh)
$\overline{nu}_{v}$	Network usage threshold above which network reinforcements will be required in the future assuming a growing network usage for voltage level *v* (MW)
$\overline{nu}_{v,x}$	Network usage threshold above which network reinforcements will be required in the future assuming a growing network usage in area $A_{v,x}$ (MWh)
$pcnc_{v,x,h}$	Peak coincident network charge in hour *h*, and area $A_{v,x}$ (€/kWh)
$ptdf_{u}^{e}$	Power transfer distribution factor that corresponds to the incremental flow through network element *e*, due to an incremental withdrawal of network user *u* (p.u.)
$ptdf_{v}^{j}$	Power transfer distribution factor that corresponds to the incremental flow through voltage level *v*, due to an incremental withdrawal of customer group *j* (p.u.)
$ptdf_{v,x}^{v-1,x+1}$	Power transfer distribution factor that corresponds to the incremental flow through area $A_{v,x}$, due to an incremental withdrawal of area $A_{v-1,x-1}$ (p.u.)
rc_{e}	Residual network costs associated to network element *e* (€)
rc_{v}	Residual network costs for voltage level *v* (€/year)
$rc_{v,x}$	Residual network costs in area $A_{v,x}$ (€/year)
rc_{v}^{j}	Residual network costs associated with voltage level *v* to be recovered by customer group *j* (€/year)
$rt_{e,u}$	Residual term that network user *u* pays for the usage of network element *e*, based on individual contracted capacity (€/kW)
rt^{j}	Residual charge for customers connected to customer group *j* (€/kW year)
t_{w}^{E}	Network energy term for consumers connected to voltage level *w* (€/kWh)

$t_{w,p}^{E}$ Network energy term for consumers connected to voltage level *w*, for time period *p* (€/kWh)

$t_{w,p}^{C}$ Network capacity term for consumers connected to voltage level *w*, for time period *p* (€/kW)

Chapter 1.
Introduction

1.1. Motivation

Modern societies depend on robust energy systems powering their vital functions, from homes to industries, facilitating transportation, and enabling communications. The electricity grid is therefore a crucial connective tissue, transmitting electricity from power plants to end consumers, while network tariffs enable electricity transmission and distribution companies to recover the costs associated with building, operating, and maintaining the intricate grid infrastructure. The design of electricity network tariffs usually corresponds to independent National Regulatory Authorities (NRAs), and represents a critical and dynamic interplay within the energy industry, harmonizing the objectives of cost recovery for network operators and promoting an equitable and efficient allocation of these costs among customer segments.

In the last decades, Decarbonization, Decentralization, and Digitalization (3 Ds) are three major trends that are presenting many challenges and opportunities for network tariff design.

First, under decarbonization, the increasing uptake of renewable energy sources such as solar panels and wind turbines has disrupted traditional patterns of electricity generation. On the demand side, decarbonization objectives lead to the electrification of transport and heating, through electric vehicles (EVs) and heat pumps, along with the adoption of distributed renewable generation (IEA, 2023, 2022). This change in generation and load patterns will require network operators to invest in new infrastructure and adjust network tariff structures (IEA, 2021). For example, Eurelectric and E.DSO (2021) estimate that 375-425 billion of investments in distribution grids in the EU27+UK are needed between 2020-2030 to make them fit-for-purpose.

Second, the decentralization of the energy system places consumers at the core of the ongoing transformation. With the availability of new technologies connected at the premises of end-users, there is a shift in how energy is consumed, self-produced, and stored. These technologies include thermostatically controlled loads, distributed renewable generation, energy storage, EVs, smart meters, and information and communication technology (ICT). The decentralization approach empowers end-users to actively participate in the electricity market, increasing the value of having consumers coordinate their electricity usage with the wider power system (Dondi et al., 2002; Lopes et al., 2007; Pérez-Arriaga, 2016). For example, ACER and CEER (2022) report that in the case of Germany, 63,000 photovoltaic solar installations (PVs) with a rated capacity under ten kW were installed in the first half of 2020, or a year-on-year growth rate of 56%. During the same period, the number of newly installed household electricity storage reached 46,000 units, a year-on-year growth rate of 59%. 87% of household electricity storage systems are installed together with a PV system.

Third, digitalization presents a range of opportunities for improving the efficiency and responsiveness of electricity network tariffs, as noted by Pérez-Arriaga (2016). A report by European Commission (2020) estimates that in 2020 the number of electricity smart meters totals 123 million in the EU-27 + UK, which corresponds to a 43% penetration rate. Smart meters deployment, automatized energy management systems and energy storage facilities enable customers to react to the economic signals they receive from the electricity bills (Rossetto and Reif, 2021). One key benefit of digitalization is the creation of new business models for aggregators that allow them to cluster the responses of thousands of consumers in order to provide system services to network operators, either reacting to network tariffs, or through DSO local markets. This could enable small customers to contribute to the provision of flexibility services to transmission and distribution system operators, as noted by Glachant and Rossetto (2018) and Prettico et al. (2019).

These three advances undermined old and existing network tariff methodologies, which were thought for static and inflexible network users, producing inefficient cross-subsidies among active customers, i.e., those installing Distributed Energy Resources (DERs) and responding to price signals, and passive customers. As an example, net-metering tariffs along with volumetric charges have over incentivized PV deployment, reducing network charges for early PV adopters, while network costs were not reduced alike. As a consequence, in recent years, network tariff design has become a hot topic, not only in the European Union (Hoarau and Perez, 2019; Manuel de Villena et al., 2021; Pérez-Arriaga, 2016; Schittekatte et al., 2018) but also in the United States (Brown et al., 2018; Wood et al., 2016), Australia (Passey et al., 2017; Young et al., 2019), and elsewhere (Hendam et al., 2022). It is crucial to design electricity network tariffs adapted to the changing needs of the electricity grid, avoiding inefficient network investments, and promoting a fair distribution of costs among customers.

This thesis focuses on revisiting the network tariff design in the context of decarbonization, decentralization and digitalization. Note that network tariffs are just a piece of a bigger puzzle. End-customers face network tariffs as part of the electricity bill, which also includes electricity market prices, policy-related charges, and taxes. It is essential that all costs faced by customers in the electricity bill are efficiently allocated, not only network costs, since customers' reaction depend on the aggregated price signal.

ACER (2023) segments network tariff design in a three-step process. First, the recognized or allowed revenues of the network operators are determined. Second, the tariff structure is defined, which can differ among countries according to the cost allocation method or according to diverse network tariff settings such as temporal and geographical differentiation of network charges. Third, the costs are allocated to each tariff structure item, obtaining the network charges to be paid by users. This thesis deepens into the second and the third abovementioned network tariff design steps, taking as input the outcome from the first step, i.e., the allowed revenue for network operators to be recovered by network tariffs.

According to literature, network tariffs should fulfil some principles, besides the recovery of network costs, which can be summarized in two: economic efficiency and equity (Burger et al., 2019a; Pérez-Arriaga, 2016). This thesis deals with the allocation of network costs to customers focusing on the achievement of both economic efficiency and equity, which are usually considered as competing principles, meaning that an increase in economic efficiency could lead to a reduction in equity, and vice versa.

From a theoretical point of view, if network tariffs were optimally designed, network costs would be allocated to customers in a way that the maximum social welfare is achieved. In this context, network tariffs would perfectly reflect the underlying network costs; and since network costs are time and location dependent, network charges would be calculated in a customer-by-customer basis and would have very fine granularity (Pérez-Arriaga, 2016). Under these optimal conditions, the emergence of new developments, or technologies, such as EVs, self-generation, or energy management systems, would not have a severe impact on network tariff structures since price signals would be truly cost-reflective. Obviously, real network tariffs are not like this and that is why the 3 Ds have a significant effect in terms of cross subsidies among customers.

Current network tariff designs are far from the first-best solution. The main reason is that such a fine granularity requires a massive amount of data which was not available until smart meters were deployed. As a consequence, regulators and utilities could not increase temporal and locational granularity of network tariffs, and thus their cost-reflectivity. This situation led to network charges that were flat and energy based. Derived from this lack of economic signals, end-customers were passive, since moving their consumption to off-peak hours did not mean reducing their network payments.

In the last years, some countries advocate for increasing the share of capacity-based network charges, which are more related to the main network cost driver, the network peak usage, than energy-based charges. According to ACER (2021), 13 of the 27 member states of the European Union had capacity charges in place in 2021. Under capacity charges, payments depend on either the maximum individual network usage within a time period, or a subscribed capacity.

A more recent trend regarding the cost allocation method is provided by CEER (2020) and some avant-garde countries moving towards forward-looking methodologies instead of the historical accounting approach. This is motivated by all the demonstrated cross-subsidies that are caused by ill-designed network tariffs, such as the aforementioned PV death spiral effect under flat volumetric tariffs and net-metering approaches in Australia, or the peak shifting effect in specific network locations where many flexible customers are connected. ACER (2023) recommends NRAs to analyse the advantages and disadvantages of forward-looking and incremental cost allocation methods within the next 4 years.

Forward-looking network tariffs have been theoretically proposed by Pérez-Arriaga (2016) and Abdelmotteleb et al. (2018), among other authors. They consist of the segmentation of network costs among long-term network costs, accounting for the expected reinforcement costs in the future, and residual costs, accounting for all sunk costs that are not recovered through the allocation of long-term costs. Forward-looking charges reflect the costs of future network reinforcements, providing a level playing field for customers to decide whether to modify their network usage behaviour or, on the contrary, to face network reinforcement costs, only in the case that their network usage patterns will produce them. In this sense, forward-looking have demonstrated their superior performance with respect to other cost allocation methodologies. However, there is a gap in its practical implementation in real-world systems. This thesis aims to contribute to filling this gap, by proposing a mathematical formulation for the forward-looking incremental network charges applied to real-world systems. This thesis provides regulators a tool for testing whether the network under their jurisdiction satisfies the requirements for the implementation of forward-looking network tariff designs. Furthermore, this thesis contributes to the comparison of different network tariff designs implemented in real-world systems, which can serve regulators as a basis for the analysis of the advantages and disadvantages of forward-looking and incremental cost allocation methods. Within the umbrella of the 3 Ds, this thesis focuses on the effect of the different network tariff designs on active customers, i.e., those adopting PV or electric vehicles, or those participating in DSO local markets.

Many authors propose DSO local markets to coordinate customer responses, which help to lower network congestions and therefore future network reinforcements (Anaya and Pollitt, 2015; Poudineh and Jamasb, 2014). However, there is a lack of analysis on how DSO local markets and network tariffs interact with each other. In fact, if as abovementioned network tariffs aim to reduce future network reinforcements, there is a risk of providing customers the same incentives for reducing network congestions through two different mechanisms, i.e., network tariffs and DSO local markets, which could lead to an inefficient overreaction of customer responses if they are not well designed.

Finally, this thesis deepens on the impacts that could arise in a future electricity grid with many flexible customers. Specifically, network tariffs would not reflect long-term network costs if charges were set ex-ante and customers shifted a large amount of their network usage to off-peak hours, creating new and increased peaks in those hours that were previously considered as off-peak hours. This effect is known as peak-shifting effect or rebound-peak effect (Muratori and Rizzoni, 2016; Steen et al., 2016). In this sense, there is a lack of literature dealing with the peak-shifting effect under different network tariff designs, concretely under forward-looking incremental network charges.

This thesis contributes to the discussion of the possible solutions to the peak shifting effect problem by proposing an ex-post implementation of the forward-looking incremental charges and an innovative customer response coordination mechanism in the form of a local network capacity market, in which customers can book in advance the amount of network capacity they are willing to use during those days when network congestions are expected.

1.2. Objectives

The aforementioned challenges, posed by decarbonization, decentralization, and digitalization, lead to one broad research question: how to formulate forward-looking network tariffs applied to real-world systems that maximize social welfare, i.e., establishing a network tariff where long-term network costs are signalled to customers, enabling customers to avoid increasing network costs through an efficient network usage derived from the opportunities provided by the 3 Ds.

This question can be decomposed in three objectives, focusing on:

1. How 3 Ds interact with different network tariff designs, in each of its steps, i.e., 1) the balance between economic efficiency and equity principles, 2) how to segment network costs that must be recovered via network tariffs, and 3) which are the selected tariff settings for the network cost allocation among network users to align tariff principles.
2. How would be theoretically formulated a forward-looking network tariff design, and how could it be implemented in a real-world system?
3. Which are the potential solutions for network tariff designs for the challenges that networks will face in a future with a high number of flexible customers responding to

economic signals, synchronizing their network usage, and creating the peak-shifting effect?

This thesis sets out to provide answers to these three questions. To that end, different aspects of these questions are addressed in four separate chapters.

1.3. Scientific contributions

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

C1- Providing a state-of-the-art review, focusing on the impact of Decarbonization, Decentralization and Digitalization on the network tariff design, discussing upon three topics: 1) definition of network tariff principles, mainly economic efficiency and equity, 2) network cost recognition and segmentation, and 3) cost allocation among customers.

C2- Proposing a theoretical forward-looking network tariff design following a long-term incremental cost method in which network costs are divided among forward-looking and residual costs, and calculating forward-looking network charges follow economic efficiency principles, while residual charges follow equity principles. The proposed tariff design is compared to other two network tariffs in a simplified network model.

C3- Implementing the Long-term incremental cost method to a real-world system through a network model in which customers are divided among voltage levels, and forward-looking network charges are symmetrically applied to injections and withdrawals following economic efficiency principles. The mathematical formulation to calculate the forward-looking incremental charges is provided, and the required inputs for the methodology are described. In addition, a case study compares the effect of the proposed network tariff design with other two current network tariffs in a real-world system when they are applied to different types of active customers.

C4 – Proposing and formulating an advanced network tariff design consisting on an ex-post implementation of the long-term incremental cost method with high granularity in order to improve the cost-reflectivity of forward-looking charges. It aims to mitigate the peak shifting effect that could occur in an environment of many flexible customers responding to network tariffs, and synchronizing their network usage when facing ex-ante price signals.

C5 – Proposing a customer response coordination mechanism that complements cost-reflective ex-post network tariff charges. It aims to reduce the low predictability of ex-post charges by allowing customers, through their retailers or aggregators, to book in advance the network capacity they are willing to use for a certain critical period. The mechanism is a DSO local market, in which the booking capacity prices are linked to the network congestion at each specific zone, implicitly incentivizing customers to using less network during congested times, thus, coordinating their responses, and avoiding future network reinforcements.

Objective	Contribution	Chapter	Publication
1	C1	2	(Morell Dameto et al., 2020)
2	C2	3	(Morell Dameto et al., 2020) (Morell Dameto et al., 2021)
2	C3	4	(Morell-Dameto et al., 2023a)
3	C4 & C5	5	(Morell-Dameto et al., 2023b)

Table 1.1. Link among objectives, contributions, chapters and publications in the thesis

1.4. Thesis structure

The rest of the thesis is organized in 6 chapters as detailed below.

Chapter 2 provides a state-of-the-art review on the network tariff design, discussing three topics: principles definition, cost recognition and segmentation, and cost allocation to customers. Finally, theoretical network tariff proposals are contrasted with current network tariff designs in the real-world. Some essential gaps are found that lead to sub-optimal network tariff designs, especially in real-world systems.

Chapter 3 discusses the theoretical network tariff design following the aforementioned three-step process. Briefly, this chapter proposes a long-term incremental cost methodology for the network tariff design to signal those network elements in the moments when they are close to being congested in the future. These economic signals are sent to customers in the form of forward-looking peak-coincident network charges which are calculated on a customer-by-customer basis, depending on the specific network components they use. In addition, to comply with the cost recovery objective, residual network costs are recovered through a non-distortive fixed charge. The proposed methodology is applied in a simplified network composed of 9 customers and compared to other two tariff structures.

Chapter 4 deals with the implementation of the proposed long-term incremental cost methodology to real-world systems. The required inputs and the mathematical formulation of the proposed network tariff design are provided, and it is computed for the Slovenian case using data provided by the Slovenian Energy Agency. The resulting forward-looking network charges are compared with other two network tariff alternatives, one being the Slovenian network tariff in 2019 and another very similar to the planned one to be implemented in 2024. Concretely, the effects of the three tariffs are analysed in terms of the economic signals that active customers installing PV, EVs, or participating in DSO local markets receive.

Chapter 5 advances on the implementation of the forward-looking network tariff design, by increasing the locational granularity and proposing the ex-post calculation of network charges to increase cost-reflectivity, specifically when peak-shifting effect occurs. With the aim to mitigate the low predictability of ex-post network charges, a complementary customer response coordination mechanism is proposed in the form of a local network capacity market. Through this auction-based market, network users can book in advance the amount of network they are willing to use during critical days set by the DSO for the specific congested networks. The coordination mechanism is mathematically formulated and tested in a 10,000-customer network in which up to 20% of customers adopt heat pumps and respond to network charges through an optimal customer response model. The required network reinforcements are then calculated using the reference network model (RNM). Results are compared to two other long-term based tariff structures applied ex-ante, showing the benefits of the proposed tariff in terms of lower network reinforcements.

Finally, chapter 6 concludes and provides the main contributions, and recommendations for future research.

Chapter 2. Literature review on network tariff design

Ever since electricity started to spread over modern societies, network tariff design has been a recurrent topic in academic circles and also among utilities and national regulators, who are usually responsible for their practical implementation. Section 2.1 offers a historical perspective and highlights the importance of an efficient network tariff design by exploring frequent discussions on the issue. By acknowledging the facts that led us to the current network tariff designs, experts and regulators may better assess how future tariffs should look like.

The rest of the chapter presents a comprehensive review of the various network tariff design approaches, from an academic perspective, while also considering their practical implementation and the challenges faced by regulators when proposing network tariff reforms for real-world systems.

A tariff structure is composed of a set of charges allocated to different customer categories designed to collect the allowed regulated network costs for using the transmission and distribution networks that deliver electricity from power plants to homes or businesses. Thus, the network tariff design takes as input the network costs to be recovered and produces as output the network charges that each customer category should satisfy. Section 2.2 outlines the fundamental principles that underpin network tariffs, mainly economic efficiency and equity, including how these principles interact with one another.

Then, a systematic methodology is presented for the network tariff design, following the structure presented by ACER (2023), as shown in Figure 2.1. The second and the third ACER steps (definition of tariff structure and allocation of costs to tariff structure items) are joined as a single step called allocation of costs to customers through different tariff settings.

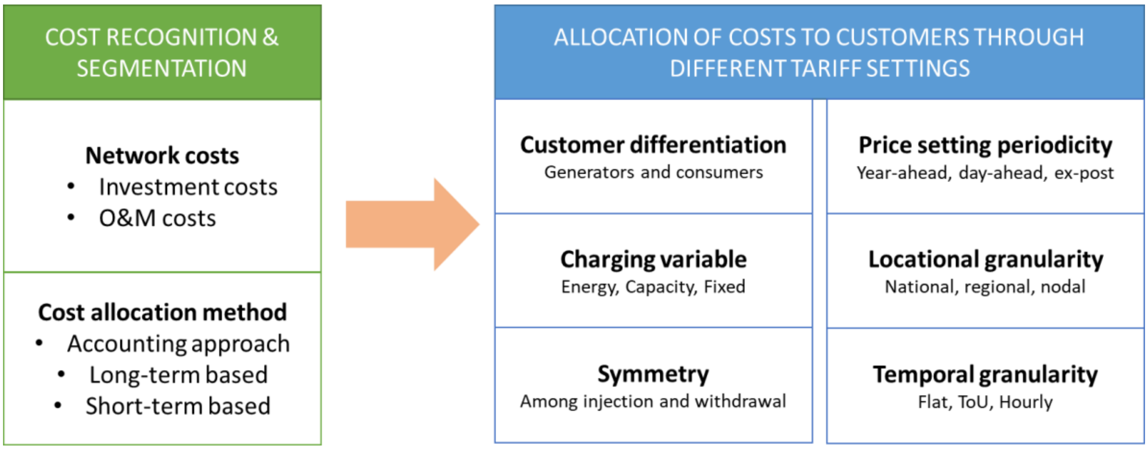

Figure 2.1. Network tariff design

1) **Cost recognition and cost segmentation** (section 2.3). The first step when designing network tariffs is to define the boundaries of the network, and the allowed remuneration for the network operators. This means recognising which are the network costs that need to be recovered. According to ACER (2023), network costs include investment, operation and maintenance costs of network assets, and also energy losses and system operation services costs. This thesis only focuses on the allocation of investment, operation and maintenance costs of network assets, except in chapter 4, in which energy losses costs are also considered in the network tariff design for a real-world system. In addition, network costs are not exclusively recovered via regular network tariffs (also called use-of-system tariffs), but also by other mechanisms such as connection charges. The analysis performed in this thesis only deals with the formulation of use-of-system charges, although interactions with other mechanisms are acknowledged in section 2.3.

   Once network costs to be recovered by network tariffs are known, it is common to define a network model in which the network is segmented, usually by voltage levels. Network costs are differentiated according to the network model, e.g., high voltage (HV) network costs, medium voltage (MV) network costs and low voltage (LV) network costs. Furthermore, network costs can be divided according to their cost-driver, i.e., the magnitudes related to network users that contribute to increasing the amount of costs, for instance, the peak consumption, the energy consumed or injected in the network, or the new connection of a network user. As further explained in section 2.3, depending on how the economic efficiency principle is understood, cost segmentation can vary among accounting approaches, long-term based approaches or short-term based approaches.

2) **Allocation of costs to customers through different tariff settings** (section 2.4). Once network cost segments have been identified, the next step is to allocate them to customer groups. Following the selected network model, users are divided among the network segment where they are connected, i.e., HV, MV, or LV. In addition, network users can be broadly categorized into two main groups: power-generating facilities and customers. Power-generating facilities, as defined by the European Union regulation, refer to facilities that convert primary energy into electrical energy and are connected to the network (EU Regulation, 2019). On the other hand, customers are users who purchase electricity for their own consumption or for the purpose of reselling it within or outside the system where they are located. According to the European Union's legislation, prosumers are considered part

of the customers' group and are categorized as active customers (EU Directive, 2019). This classification acknowledges the role of prosumers who both consume and produce electricity, often through the use of renewable energy sources. In most countries, generators do not face network charges, although with the increase of variable renewable generation in the last years they are starting to create network congestions. Whether and how should generators face network charges remain as an open question.

Cost allocation among network users is determined by the available types of charges, which typically can be energy-based charges, capacity-based charges, fixed charges per customer, or a mix of them. In addition to the charging variable, tariff structure design involves selecting an appropriate level of locational and temporal granularity for the chosen type of charges, as well as the periodicity of charges calculation and publication. Section 2.4 further details the different network tariff settings focusing on the need for revisiting some of the aspects of electricity tariff design due to the new challenges presented by the 3 Ds transformation (Decarbonization, Decentralization, and Digitalization).

From an economic efficiency perspective, the ideal solution would call for designing highly dynamic charges with individualized pricing based on the specific location in the grid. This would require a very fine temporal and locational granularity, where users would be charged for the electricity that they withdraw from or inject to the network at each connection point and at every moment. However, implementing such a solution in practice would be extremely challenging and complex, making it expensive and difficult for consumers to understand and accept.

Furthermore, equity considerations come into play, particularly in the context of rural and urban users. Applying individualized charges with high granularity could result in rural users facing significantly higher charges compared to urban users. This is due to lower load density and higher customer dispersion in rural areas. Such a scenario could create inequitable outcomes, as rural users may bear a disproportionate burden of network costs compared to their urban counterparts.

In practice, the network tariff design can vary significantly across countries, depending on a range of factors such as national energy policies, and regulatory frameworks such as whether they have liberalized or monopolistic market structures. In the case of Europe, however, there are some commonalities in the approach to network tariff design, which are influenced by the European Union (EU) regulations and policies. So, section 2.5 deepens in the gap between the theoretically most advanced network tariff designs and the real-world implemented tariffs, along with the main reasons that create this gap. Finally, section 2.6 concludes.

2.1. Historical perspective of electricity network tariff design

Electricity has been known since ancient times, with the Greeks and Romans having some knowledge of static electricity. However, the modern era of electricity began in the 19th century with the invention of the first practical electric generator by Michael Faraday in 1831 (Berkson, 1974).

Faraday's work on electromagnetic induction laid the foundation for the development of electric power generation, and by the late 19th century, electrical power systems were being developed in cities and towns (Hughes, 1993). Thomas Edison's invention of the incandescent light bulb in 1879 and the establishment of the first electric power station in New York City in 1882 marked the beginning of the widespread use of electricity for lighting and other purposes. Over the next few decades, electric utilities began to expand rapidly, with new power stations being built in cities and towns across the United States and Europe. By that time, most electric utilities charged their customers a flat rate based on the amount of electricity consumed, regardless of when or how it was used. As electric power systems became more complex and larger in scale, utilities noticed a sharp peak in demand, as electricity was used almost entirely for lighting (Byatt, 1963).

Hopkinson (1892) is recognized as the classic reference acknowledging that much of the cost of electric supply is fixed, since generators and conductors must be ready to give a supply at any moment no matter the number of hours during which the supply is used. In order to provide a cost-reflective economic signal to consumers, he proposed an individual maximum capacity charge linked to fixed costs, and a flat energy charge to recover operating costs, mainly coal consumption costs to produce electricity. By that time, individual peak usage was almost coincidental with system peak usage, since all consumers turned the lights on during the same time periods. The aim of the electricity tariff proposed by Hopkinson was to incentivize consumers to increase their individual load factor.

However, it was soon pointed out that the peak hours of consumers did not coincide, concretely when electricity was used for power. (Clark, 1911), and lately further elaborated by (Lewis, 1941), proposed that consumers would have to pay according to their share on the system peak, rather than based on their individual peaks. The implementation of such a tariff required a consumer's meter that automatically adjusted to accommodate different time-blocks in a day to differentiate system peak and off-peak periods. The high cost of the controlled meters and the unreliability of their measures, along with the scepticism of most electrical engineers were presumably the cause of the little adoption of time-of-use (ToU) tariffs (Byatt, 1963).

Lately, in the mid-20th century, (Boiteux, 1949), and (Houthakker, 1951) proposed the marginal cost theory for electricity pricing. Briefly, marginal cost theory states that customers should pay according to the change in costs produced by a marginal increase in demand. In terms of the resulting charges, marginal pricing means that tariffs should be set to the system marginal running cost in off-peak periods, and to the long run marginal cost in peak periods, which includes the generation capacity reinforcement and the network reinforcement costs. They proposed this methodology for rather inelastic customer response, and acknowledged that their proposal needed to be revisited if the peak-shifting effect occurred, i.e., customers reacting to prices moving the system peak to cheaper hours.

Steiner (1957) further investigated the peak-shifting effect. His main concerns resided in the impossibility of knowing ex-ante when system peak hours will occur in the scenario of non-firm peaks, i.e., consumers adjusting their demand according to prices. Thus, his theoretical proposal was an ex-post network charge in which customers pay according to their participation on actual peak consumption periods. In addition, he also acknowledged that to reach the optimal customer response, it is required that customers recognize the interdependence of their responses, and they have mutual striving for joint optimization. However, he considered his proposal not applicable in practice due to the lack of information and the difficulty of coordinating small customer responses.

In parallel to the advances on the theoretical optimum tariff design, (Bonbright, 1961) focused on the view of the electricity as a basic need, emphasizing on various essential aspects of rate design principles, other than economic efficiency, such as ensuring that rates are understandable and acceptable to customers, tariff changes are made thoughtfully, and that there is no discrimination between different end users or end uses. By that time, electric companies were vertically integrated, owning generation, transmission and distribution assets, and thus, acting like territorial monopolies. The varied interpretation of Bonbright's principles led to a huge variety of electricity tariff designs, including both generation and network costs, across the globe which are still present nowadays (see, for example, (ACER, 2021)).

In the latter half of the 20th century, many countries began to deregulate electric utilities (F. Steiner, 2000). Electric companies were split among generation, transmission, distribution and retail businesses. Generation and retail businesses were liberalized, while networks remained as a regulated natural monopoly.

On the one hand, electricity markets were created to increase competition among generators and consumers, treating the electricity as a commodity. Both generators and consumers receive/pay the marginal clearing price in which the marginal generator meets the demand curve. Over the world, electricity markets converged into similar designs, enabling international energy trading by market coupling in order to gain economic efficiency.

On the other hand, the network cost allocation problem was responsibility of regulators, since networks are considered a natural monopoly due to the inefficiency of building parallel lines, economies of scale, and the nature of electricity as a basic good. Since energy markets are fully driven by economic principles, network tariffs remained one of the tools for regulators and politicians to ensure equity principles. The different balance between economic efficiency and equity principles led again to a huge variety of network tariff designs across countries.

Finally, in the early 21st century, smart meter deployments, along with the increasing decarbonization and decentralization, have opened new opportunities for electric utilities to manage their networks more efficiently, and for customers to react to economic signals. This new environment is challenging traditional network tariffs that need to be revisited with the aim of continuing to promote technical and economic efficiency for the system and achieving a fair and equitable share of network costs allocated to customers.

2.2. Principles of network tariff design

The network tariff design is a complex and multifaceted process involving several key principles. By carefully balancing these principles, regulators can design tariffs that provide appropriate incentives for investment and efficiency, while also ensuring that the costs of the network are fully recovered.

The main principle guiding any tariff design is cost recovery. However, tariff design aims not only to ensure cost recovery but also to enhance the system's technical and economic efficiency, promoting customers' efficient usage of the electricity system in both the short and long term. Additionally, charges should be fair and equitable among customer categories and non-discriminatory between customers who use the network in the same way. There is a general consensus in the literature that electricity tariffs should follow economic efficiency, equity, and transparency principles (Rodríguez Ortega et al., 2008; OECD, 2011; Burger et al., 2019).

In addition to principles, some authors have identified measurable objectives that can be used to quantify how principles are explicitly formulated or fulfilled. These objectives are identified for the aforementioned principles.

Economic efficiency refers to the principle that goods or services should be consumed by individuals or entities who derive the greatest benefit from them (Reneses et al., 2013). The underlying objective of this principle is to maximize social welfare, with a primary focus on minimizing the overall costs incurred by the system. This objective encompasses both short-term and long-term system costs, emphasizing the need to optimize resource allocation over time.

In order to promote the minimization of total system costs, it is important to employ effective measures that encourage users within the network to adopt efficient usage patterns (Batlle, 2011). One such approach involves the implementation of economic signals that incentivize network users to modify their behaviour in ways that contribute to more efficient network utilization. By employing this strategy, network costs, particularly those related to infrastructure, can be effectively managed and reduced. Within the framework of economic efficiency, several objectives can be derived in tariff design:

- **Cost reflectivity**: Network tariffs should accurately reflect the costs associated with delivering the service, considering variations in time, location, and supplied quality of electricity (Pollitt, 2018a). In addition to cost reflectivity, there are other objectives closely related to economic efficiency that contribute to achieving cost reflectivity:
  - **Cost additivity**: Tariffs should be structured in a way that combines different cost categories or items to accurately reflect the total system costs. By aggregating these costs, the tariffs can provide a comprehensive representation of the expenses involved in delivering electricity services.
  - **Symmetry**: Costs that are influenced by the consumption and injection of energy or power should be charged or rewarded using the same methodology, considering the chosen locational and time granularity. This objective ensures fairness and consistency in how costs are attributed to consumers based on their energy usage and generation patterns.
  - **Robustness against customer aggregation**: Costs that remain constant regardless of whether consumption/generation is aggregated or individualized for each customer should not be charged differently when considering aggregated customer groups compared to individual customers. This objective promotes fairness and equitable treatment of customers, regardless of their aggregation status.
- **Predictability**: In the short term, it is important for consumers to have a clear understanding of the expected charges in advance. Tariffs should be designed in a way that allows consumers to estimate, with reasonable accuracy, the amount they will be charged for their electricity consumption. In the long term, predictability of tariffs and the methods used to calculate them provide regulatory certainty to users, ensuring stability and transparency in the electricity pricing system.
- **Technology neutrality**: Tariffs should be independent of the specific activities for which electricity is used by network users, as well as the technology employed to withdraw or inject energy into the grid. This objective promotes a level playing field for both centralized and decentralized energy resources, sending efficient economic signals to invest in the most beneficial technology for the system, regardless of size or use (Barrera, 2019). By adopting a technology-neutral approach, tariffs can adapt to changes in technology and market dynamics, encouraging innovation and competition (Reneses et al., 2013).
- **Minimization of cross-subsidies**: This objective aims to prevent one consumer's actions from negatively impacting the charges of other consumers. Tariffs should be designed in a way that ensures a fair distribution of costs among all electricity users, without

placing an undue burden on specific groups. Minimizing cross-subsidies helps to maintain economic efficiency and fairness within the electricity pricing system, promoting cost-reflective tariffs and preventing cost shifting between different consumer segments.

Equity is a principle that has multiple sub-principles, including allocative equity, distributional equity, and transitional equity (Burger et al., 2019a):

- **Allocative equity**: Under this sub-principle, comparable network usage patterns, regardless of payer nature, energy final usage, or appliances behind the meter, should be charged equally (Burger et al., 2019a; Reneses et al., 2013). While allocative equity is considered an aspect of the equity principle, its implications align completely with the principle of economic efficiency. For instance, as per (Burger et al., 2019a), marginal consumption/production should be charged/paid according to the marginal cost/value it creates, which is synonymous with cost reflectivity and can lead to a more efficient system.
- **Distributional equity**: This sub-principle suggests that charges should be proportional to the economic ability of each user. It is crucial when allocating residual costs to vulnerable consumers (Burger et al., 2019a; Strielkowski et al., 2017). Residual costs refer to costs that lack a cost driver and cannot be recovered using economically efficient signals, as explained in Chapter 3. There are trade-offs between this sub-principle and the principle of economic efficiency.
- **Transitional equity**: Under this sub-principle, the transition from an old to a new tariff scheme should be gradually implemented.

Transparency and simplicity are crucial aspects of tariff design. They emphasize the importance of publishing and explaining the methodology used in tariff design. This mechanism serves as the means to verify the extent to which the other principles and objectives are being fulfilled.

By providing detailed information on how tariffs are formulated, stakeholders can assess the compliance of the tariff structure with the established principles and objectives. This transparency and simplicity support a more informed and engaged consumer base while fostering acceptance and confidence in the electricity pricing system. Digitalization can improve the traceability and transparency of information, allowing for more detailed signals about the different charges associated with electricity consumption. This can be achieved through the use of apps that display market prices and signal system operation conditions, enabling active customers to modify their consumption patterns, either manually or through automatic devices, in ways that enhance overall system efficiency.

Simplicity further enhances transparency by promoting clear and straightforward tariff structures. Simplified tariffs facilitate consumer comprehension, making it easier for them to understand and evaluate the charges associated with their electricity usage.

It is widely recognized that achieving all principles and objectives simultaneously in a single tariff design can be challenging due to inherent conflicts between principles. In fact, the equity principle may impose limitations on economic efficiency, creating a trade-off between the two (Batlle, 2011; Reneses et al., 2013). For example, the implementation of the economic efficiency principle could result in too-high network charges, creating issues related to distributional equity, i.e., affordability, particularly for low-income households or those with high energy usage.

Another example of conflicting principles concerns simplicity against economic efficiency. Traditionally, regulators have preferred simple charges to allocate power system costs to electricity customers. However, this approach may no longer be sufficient with the increasing penetration of active customers with DERs and flexible demand. Simple methods lack temporal or spatial granularity, resulting in tariffs that bundle costs of all the value customers receive. Consequently, tariffs may over or undercompensate active customers for the system value they provide, which could lead to investment in DERs that maximize individual profit but are inefficient for the system. Inadequate compensation also reduces the efficiency of the system since it leaves innovative opportunities to provide additional services for operating the system untapped (Pérez-Arriaga, 2016).

The improvements in digital data collection, computing power, and data transfer have enabled the development of more cost-reflective and granular tariffs with higher levels of locational and temporal discrimination. This would allow for a more complex tariff structure with multiple components. However, it is important to ensure that the final customer bills are kept simple and easily understood, particularly for consumers who may have limited capacity to engage with the energy market. Retailers would find value in offering residential or small consumers the option to hedge against price volatility by creating simplified bills. At the same time, more sophisticated price and tariff structures could be offered to active customers who respond to price signals.

Smart meter data can provide deeper insights into customer consumption patterns, which can be used to develop more efficient and equitable tariff structures. A better understanding of the relationship between consumption patterns and customer metrics, such as wealth or income, could enable more accurate segmentation of customers and the development of more targeted tariff structures. By leveraging the power of digitalization to enhance the efficiency and responsiveness of tariff design, it may be possible to create a more equitable and sustainable energy system for all stakeholders.

To address these challenges and find a balanced approach, some authors, such as Abdelmotteleb et al. (2017) and Schittekatte et al. (2018), have developed quantitative models to compare different tariff designs in terms of economic efficiency and equity. By employing a quantitative approach, these models provide a framework for evaluating and comparing different tariff designs based on the diverse objectives and principles.

In summary, while the principles of network tariff design may seem straightforward, there are often challenges and trade-offs that arise when trying to balance these principles. This thesis aims to contribute to the analysis on how principles are fulfilled by different network tariff structures following the aforementioned network tariff design steps: 1) cost recognition and segmentation, and 2) cost allocation to customers through different tariff settings. By carefully considering these issues and seeking input from a variety of stakeholders, policymakers can design tariffs that provide appropriate incentives for investment and efficiency, while also ensuring that energy remains affordable, reliable, and sustainable for all customers.

2.3. Network costs recognition and segmentation

The aim of this chapter is to establish the concepts of network cost recognition and network cost segmentation within the scope of this thesis. Network cost recognition usually refers to defining the allowed revenues for the network operators. Although network tariffs are the main tool for the recovery of network costs, other charges also recover part of the network costs, such as connection charges, exit fees, or DSO local markets. In this thesis, the concept of cost recognition is narrowed to the network costs that have to be recovered through network tariffs (or use-of-system tariffs), excluding those network costs that are recovered via other mechanisms. On the other hand, cost segmentation refers to the methodology used to divide those network costs that must be recovered through network tariffs by locations, voltage levels, or other segmentations based on cost-drivers etc.

Cost recognition

Networks can be categorized into two main types: transmission and distribution.

- Transmission costs are the costs associated with transporting electricity from where it is generated to distribution systems. These costs include the cost of building and maintaining high-voltage transmission lines and substations, as well as the cost associated to energy losses, system services, and quality-of-service requirements incurred during the transmission process.
- Distribution costs are the costs associated with delivering electricity to end-users. These costs include the cost of building and maintaining high (in some jurisdictions), medium and low-voltage distribution lines and transformers, the cost of energy losses and quality-of-service requirements, as well as the cost of metering, billing, and customer service.

Network costs mainly consist of capital expenditures (CAPEX) associated with network infrastructure investment with long depreciation periods, and operation and maintenance costs related to this infrastructure (OPEX). Therefore, if energy losses costs are excluded, the electricity network is a capital-intensive business.

In order to extract out of the total network costs those that must be recovered through network tariffs, those costs that are recovered (or signalled) through the following mechanisms should be subtracted from the total network costs to avoid overlapping economic signals:

1. **Connection charges**: A connection charge is a one-off payment that new customers or those requesting a higher network connection capacity must face due to needed network reinforcements. In order to clearly recognise the network costs to be recovered by network tariffs, regulators should consider the potential overlaps with the connection charging approach because both charges could attempt to reflect the same network costs that individual network users cause. The degree to which connection charges fully reflect the cost of providing a user with a new or upgraded connection to the network depends on the type of connection charge (Schittekatte and Meeus, 2018). In general, three types of connection charges can be distinguished: super-shallow, shallow and deep connection charges (ENTSO-E, 2020).

    a. **Super-shallow** connection charges: customers basically do not face charges for the new or extended connection.
    b. **Shallow,** or also named shallowish, charges only consider the new extension from the existing grid to the connection point of the requesting user.
    c. **Deep** connection charges additionally include all the network reinforcements in the existing network required to accommodate the power flows from the new connection.
2. **DSO local markets**: An additional economic signal that could be overlapped with the network tariff signal comes from local flexibility mechanisms. Briefly, flexibility mechanisms aim to extract the inherent flexibility of network users to avoid network

reinforcements through extra payments to flexibility service providers, either through auctions, bilateral contracts, markets or regulated payments. Thus, local flexibility mechanisms and cost-reflective peak-coincident charges can have the same objective, i.e., reducing future network costs. A rigorous analysis on the economic signals sent by all connection charges, network tariffs, exit fees, and DSO local markets should be performed to avoid signalling the same network costs through two or more mechanisms.

Active customers with PV, demand response, batteries, and/or EVs are referred to as flexibility providers to the grid, improving grid efficiency (Abdelmotteleb et al., 2018; Bergaentzlé et al., 2019; Pérez-Arriaga, 2016). Distributed generation could improve system reliability, as system failures can be mitigated with local resources. As a result, the procurement of flexibility services by network operators is becoming increasingly relevant, leading to the creation of DSO local markets (Abdelmotteleb et al., 2018). Tariff design should not become an obstacle for active customers to provide these flexibility services, ensuring that active customers with energy storage facilities are not subject to double charging, including network charges, when providing flexibility services to network operators (EU Directive, 2019).

3. **Exit fees**: when a customer completely disconnects from the grid and self-provides energy needs through alternative sources, it is known as grid defection. In this case, the electricity system or the rest of the customers should not bear the residual costs that remain in the system and were covered by the defected customer. This issue raises a discussion about the potential application of exit fees or alternative tariff designs to recover these residual costs when defections occur (Burger et al., 2019a; Haapaniemi et al., 2019). Exit fees, i.e., charges for customer who completely defect from the grid, are an additional income for DSOs and TSOs reflecting network sunk costs. Following the same reasoning as with connection charges, network costs that are recovered (or signalled) through network tariffs should not be again charged through exit fees to avoid overcharging.

Cost segmentation

Once the network costs to be recovered by network tariffs are recognized, these costs can be treated as a whole, or they can be segmented. The most common cost segmentation is the voltage level differentiation according to a network model. The network model defines the levels in which the network is split, and also stablishes the cascading relation between them, i.e., how costs in a voltage level are apportioned among customers of the same and the rest of voltage levels. ACER (2023) reports that the principle of cost-cascading is embedded into the network tariff design in all analysed countries (EU member states and Norway), reflecting the electricity flow from transmission to distribution. It is remarked that if reverse flows (from distribution to transmission) become relevant in the future, a review of the cost-cascading would be necessary. Italy and Portugal are considering it for the future.

Furthermore, under each voltage level, network costs can be segmented depending on how the economic efficiency principle is understood. It is very common that economic efficiency is understood as segmenting network costs based on cost-causality principles, ultimately searching for each user's responsibility for each network cost component, even though most of network costs have no responsibility other than historical decisions. Alternatively, the economic efficiency principle can be understood as the search for the maximization of the global welfare, in this case, the utility of the network users (Pérez-Arriaga, 2016). As introduced in section 2.1, several authors propose the marginal pricing as the cost allocation methodology to reach the maximum global welfare. In this sense, there is still a discussion on whether long-term or short-term marginal cost allocation methodologies are optimal. Thus, network cost segmentation and allocation can be based on the following strategies.

a) **Accounting approach** also named cost causality methods or average cost methods. Most countries apply the same allocation methodology to the sum of all network costs with no distinction between costs. Network tariffs are determined by dividing the recognised costs, or allowed revenue, by the forecasted demand. This cost model is backward-looking as it considers costs that have already been incurred in the past. Although it is a simple approach, and ensures the cost recovery objective, the cost distribution criterion is not optimal, which reduces the efficiency of the economic signals sent to customers (Reneses et al., 2013).

b) **Long-term marginal cost approach** or forward-looking approach: the economic efficiency principle is understood as the search for the most efficient development of the existing network in the long-term. Thus, the main signal to be transmitted to network users should aim at minimizing the long-term incremental network costs. Under LTMC methods, dating back to (Boiteux and Stasi, 1964), customers are charged according to their marginal contribution to long-term network costs. Theoretically, LTMC methods can improve efficiency compared to more static cost-causality methods; they send economic signals that maximize social welfare (Reneses and Rodríguez Ortega, 2014). In practice, LTMCs applied to networks are calculated as long-term incremental costs (LTICs). Some academic examples of LTIC applied to network costs are Lima et al. (2002) and Li and Tolley (2007), a summary is provided by Meeus et al. (2020).

   Long-term incremental costs are associated with the network reinforcements needed in the future, and additional investments that will occur if the network usage continues to grow during the peak demand periods (Bonbright, 1961). In addition, in underutilized systems, i.e. practically all systems, this signal is not enough to recover the required network revenues. The remaining cost segment to ensure full cost recovery is defined as residual network costs (Pérez-Arriaga, 2016).

c) **Short-term marginal cost approach**: STMC approach is currently only applied at the transmission level in certain power systems, e.g., in the US in the form of Locational Marginal Prices. The STMC has the potential to generate congestion rents, as price differences among locations, that could partially offset the total network costs. However, practical experience with this methodology in transmission grids has resulted in total network cost recovery rates of less than 20%. Thus, in power systems where STMC has been implemented, an additional method for network cost recovery must be employed (Reneses et al., 2013).

   The cost recovery issue is even higher in the application of STMCs to distribution networks. In addition, STMC based network charges would depend on the location of customers with respect to the substation or transformer. Since the grid planning is exogenous to customers, the resulting STMC based network tariffs would be arbitrary and influenced by new network deployment or network reconfiguration. Consequently, such economic signals, although being economically efficient, could be unpredictable and unequitable.

Although, in theory, the LTMC method is a more cost-reflective approach to signal the true cost of using the network, LTMC approaches are not widely used, and usually ill-designed. Only 6 European countries (Estonia, Croatia, France, Norway, Portugal and Sweden) out of the 28 analysed by ACER (2023) apply LTMC methods, while 22 countries apply average cost methods, as shown in Figure 2.2. In addition to these countries, the UK has also implemented a LTMC method for the network tariff design which differentiates between long-term incremental network costs and residual costs (Ofgem, 2019b). As a consequence of the low adoption rate of LTMC approaches in Europe, and its presumably better performance, ACER (2023) recommends NRAs to evaluate the advantages of applying incremental and long-term cost models within the following 4 years.

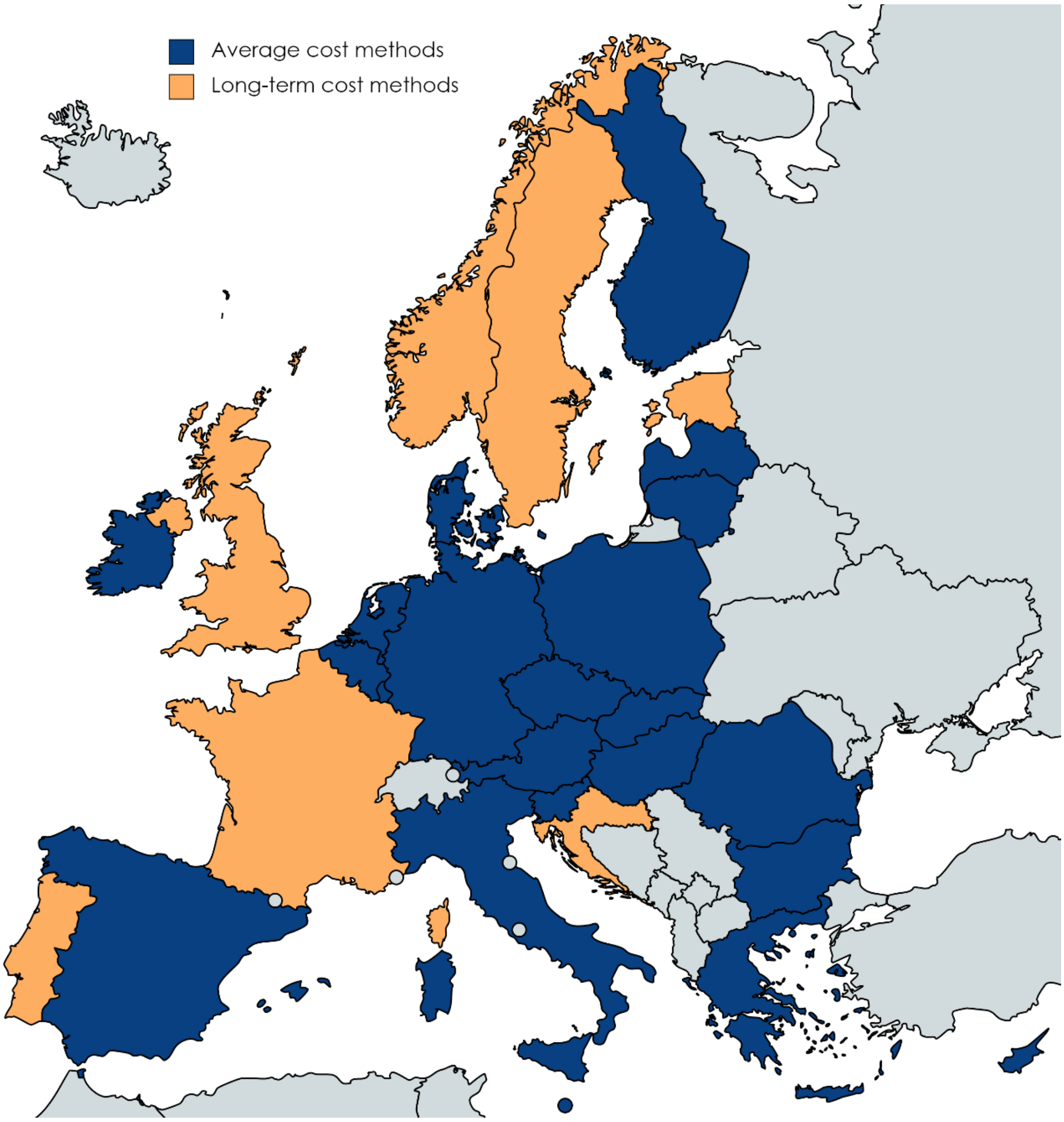

Figure 2.2. Cost segmentation and allocation in European countries. Source: ACER (2023)

For the case of countries applying LTMC methods, there are no similar strategies on their implementation. Estonia uses of a forward-looking cost model to account for costs that are changing during the application of network charges, (e.g., additional costs resulting from a new legal obligation imposed on the network operator) and LTMCs are recovered through energy-based charges. Croatia and France use a combination of energy and capacity-based charges, while Sweden and Norway use a capacity-based charge to recover LTMCs. Finally, Portugal uses a power-based charge, except for LV customers, in which case energy charges are used, as capacity charges do not exist for LV users. For the countries applying LTMC methods, it becomes necessary to define the allocation of residual costs resulting in the tariff-setting process, except for Estonia, where any additive or multiplicative adjustment is not allowed to reconcile the difference between allowed revenues of the network operator and the revenues obtained from the incremental unit price, but the network operator has the right to submit a request for new network charges to cover new network costs.

Again, there is not a consensus on how residual costs are allocated to customers, which in theory should be allocated in a non-distortive way. France and Portugal apply a multiplicative adjustment of the unit charges to account for the residual costs. Norway recovers the residual costs through fixed and capacity charges and Sweden applies a fixed charge to recover residual costs.

Although being a more cost-reflective approach, there is a gap of research on how forward-looking methods should be applied in real systems, and specifically under the effect of the 3 Ds transformation. This thesis aims to contribute to fill this gap, deepening in the practical implementation questions and the future issues that may arise when developing forward-looking methods.

2.4. Network costs allocation: tariff settings

Each network cost segment is allocated to customers through different tariff settings, which vary depending on the following dimensions, which can differ among countries.

1. **Customer differentiation.** In addition to the network model segmentation, network tariffs can be differentiated depending on the customer type (industrial, commercial, residential), the appliances (electric vehicles, solar generation, etc.), or the manner of organization (e.g., energy communities). Although the principle of allocative equity and technology neutrality support no differentiation of network charges among customer types, it is still very common to find EV specific tariffs for both private and public charging points, feed-in tariffs or exemptions for PVs and other types of self-consumption, differentiation among industrial, commercial and residential tariffs (ACER, 2023).

2. **Symmetry.** Network charges are usually applied only to withdrawn energy, although some countries apply injections charges, usually negative (ACER, 2023). However, from the point of view of the network, a reduction in demand is equivalent to an increase in generation. Therefore, symmetric network tariffs for energy withdrawals and injections, i.e., the same charge but with the opposite sign, could make sense to better reflect the underlying network costs. In addition, energy withdrawals and injections can have different network charges, such as feed-in tariffs. Symmetric network charges for injection and withdrawals are not adopted in any country, and it has only been considered in the UK's Distribution Use of System charges significant code review (Ofgem, 2019a), although Germany applies a negative injection charge for the avoided network costs (ACER, 2021).

   Finally, a very extended practice is net-metering, by which energy generated and consumed in a certain period of time are compensated, and neither charged nor rewarded. Net-metering tariffs have led to increased installation of distributed renewable generation, mainly solar photovoltaics (PVs). However, active customers who install PVs partially avoid paying regulated costs, while the rest of the customers cross-subsidize them by bearing these costs (Strielkowski et al., 2017). As a consequence, CEER (2017) recommended avoiding net-metering practices, indicating that it reduces customers' time-value sensibility to volatile prices and undermines efforts to enhance flexibility and to develop a wider demand-side response.

3. **Locational granularity**. The cost of supplying electricity varies across the network. These differences arise from the network congestions that limit energy flows between locations, and also due to the proportionality of energy losses with the length of lines. The implementation of locational differentiation in network charges require a deeper knowledge of the network topology, network costs by location, and energy flows among them. In practice, many countries apply homogeneous network tariffs for all the territory following the principle of not discriminating customers (ACER, 2023). In Europe for example, regional or zonal differentiation is only applied in four countries: Austria, Norway, Sweden and UK; while other few countries, such as Germany, have different network charges according to the specific DSO where customers are connected (ACER, 2023).

   However, as renewable energy generation becomes more distributed, a higher locational granularity in network charges is needed to ensure cost-reflectivity and efficiency in the use of existing network infrastructure. This can be achieved by designing tariffs that account for the specific location of energy generation and consumption, allowing for a more equitable distribution of network costs. Thus, network tariffs can be:
   a. System-wide: the same network tariff is applied to the entire country.
   b. Zonal: the system is divided among differentiated zones with independent network tariffs, based on the network costs in each zone. This is the case for example of UK, Norway, etc.
   c. Nodal: network charges are different at each point of connection. However, in practice, nodal network tariffs are not applied yet in distribution in any country.

4. **Temporal granularity of charges.** The cost of electricity also varies with time as a consequence of changes in load and generation patterns, which produce network congestions in some times and idle network capacity in others. In order to be economically efficient, network tariffs should reflect the temporal aspect of network costs. However, increasing temporal granularity requires detailed data on load and generation, and thus is limited by the temporal granularity of measurements. In addition, increasing temporal granularity could have some side-effects such as a higher complexity, which can reduce customer engagement and thus, tariff effectiveness. The temporal granularity of charges can be:
   a. Yearly: network charges are flat throughout the year
   b. Daily: network charges are flat throughout the day, but they differ from one day to another, for example seasonal tariffs.
   c. Time-block: network tariffs differ according to predefined time-blocks in a day. Usually, days are divided among two or three time-blocks and also time-blocks can change by seasons, usually peak and off-peak season, leading to six different time-blocks along the year. Time-of-Use tariffs are a very extended example of it.
   d. Hourly or shorter: network tariffs differ by hours. Some examples can be Critical Peak Pricing in which charges are higher only in the specific hours when network congestion is expected; or Real Time Pricing in which network charges can vary as much as the network congestion status. CPP and RTP are used in countries where electricity prices are bundled, and network costs are jointly recovered with electricity generation costs (e.g., France); while it has never been applied to network charges alone (CEER, 2020).

5. **Price setting periodicity.** This parameter measures how close to delivery time network charges are re-calculated. The closer to the delivery time, the better network charges will reflect the actual grid state and the risk of congestion (Eurelectric, 2016). Network charges can be calculated:
    a. Year ahead (static): network charges are calculated once per year based on annual load forecasts. In this case, seasonal patterns and working/leisure times can be reflected in the network tariff, but the accuracy of these signals is low.
    b. Day ahead (dynamic). Network charges are calculated the day ahead based on the predicted network usage of the following day. A higher price setting periodicity enables a higher accuracy of signals, but it reduces predictability for customers. The most advanced type of dynamic tariffs is real-time pricing (RTP), in which the charge would vary hourly or even by minutes, reflecting network utilization levels – similar to wholesale electricity market prices. In the case of critical peak pricing (CPP), the customer pays a higher price at specific times during the day, or on days during the year when network usage is very high, or the grid is exceptionally constrained. Peak time rebates (PTR) reward the customer for reducing the load (Bhagwat and Hadush, 2020). Another kind of dynamic tariff is the Variable Peak Price (VPP), where consumers know peak time blocks in advance, but tariffs charged during those peak hours are indicated only a few hours before peak events.
    c. Ex-post. Network charges are computed once network usage is known according to each user's share of the actual peak or collection of the actual highest peaks (Pérez-Arriaga, 2016). The only way to fully reflect network costs in the network congested hours is by knowing which are the true hours contributing to network congestion. All ex-ante approaches are susceptible to forecast errors.

In most cases, network tariff methodologies are set for a fixed period of time, typically 4 or 5 years, while the tariff values are updated on a yearly basis (ACER, 2023). In addition, some sort of critical peak pricing, which is triggered the day-ahead and jointly applied to electricity generation and network costs, has been adopted in some countries such as France, and plans to introduce CPP can be found in Slovenia, China, USA and Japan (CEER, 2020). In addition, some sort of ex-post pricing is applied in UK to transmission network consumers in the form of triads, intended to avoid the three yearly critical peaks of demand on the system (CEER, 2020).

6. **Charging variable**. The selection of the charging variable depends on the cost driver of the selected cost item. Network costs can be trespassed to network users through:
    a. Fixed charge (€/customer) which provides network tariff stability and no incentives to modify network usage patterns.
    b. Capacity charge (€/kW), also named power-based charge, or demand charge which can vary according to basis used for charging:
        i. Measured capacity: the maximum network capacity used in a certain period of time. The aim of this charge is to increase the individual load factor following the idea that networks are built to satisfy peak demands. Measured capacity is calculated ex-post.
        ii. Contracted capacity: customers book ex-ante the amount of capacity they are willing to use in a certain period of time, and penalties are applied if the actual network usage surpasses the contracted capacity.
        iii. Physical capacity: which only depends on the available installation at each connection point, and usually refers to the connection's technical maximum power that can be delivered. This charging variable does not produce incentives to modify network usage patterns.

c. Energy charge (€/kWh) based on the actual energy consumption. It provides incentives to modify network usage if applied with temporal granularity.

In the vast majority of countries, the transmission and distribution tariffs for withdrawal have a combined tariff basis (i.e., an energy-based component and a power-based or lump sum component). For distribution, energy-based charges have a significantly higher weight in the cost recovery in most countries. For transmission, the weight of the energy- and power-based charges are more balanced. Lump sum plays a relatively small role in European countries (ACER, 2023).

As it has been previously mentioned, flat volumetric energy charges used to recover network costs can over-incentivize customers to install self-generation, leading to lower network payments by active customers, while other customers bear the costs. This effect reduces total network payments but does not equally reduce total network system costs, meaning regulators would need to increase energy charges to fully recover network costs for the next tariff settlement period. As a result, customers who did not install self-generation would face higher rates for the same electricity consumption, further encouraging them to invest in self-generation. Experts suggest that tariff structures should be redesigned to counteract these effects (Brown and Sappington, 2018; Pérez-Arriaga, 2016; Siano, 2014).

A mix of the previous charges with different settings is commonly used. For example, it is common to find countries where customers face at the same time energy charges, capacity charges and fixed charges. Another example are null energy charges until a certain limit is reached, which can be an individual limit (kW of individual capacity), or a collective limit (% of substation capacity), and then an increasing energy charge, as proposed in this thesis. Another example would be progressive energy tariffs, by which energy charges increase when energy consumption surpasses some thresholds, as in Italy some few years ago in the retail electricity price (which included network charges).

As a summary, current electricity tariff designs have not kept pace with decentralization changes, leading to distortions in system efficiency and creating distributional and inequitable effects on certain categories of end-users.

2.5. Gaps between theoretical and practical network tariff designs

This section shows current network tariff designs in different countries, the main trends in last network tariff reforms, and the barriers to the development of more efficient tariff designs.

One of the aims of network tariffs is to send economic signals to customers so they can use their flexibility to reduce network investments. Although, in practice, customers not only react to network tariffs, but also to the rest of economic signals they face in the electricity bill, mainly energy market prices, policy-related charges, retail charges, and taxes.

The first gap between theoretical and practical network tariff designs is related to transparency. While network tariffs in the majority of American countries are bundled with the rest of electricity bill components; in most European countries, network tariffs are differentiated (unbundled) from other economic signals since the liberalization of the electricity sector, starting in 1996, and regulators follow a specific network cost allocation method. Unbundling of electricity sector costs in Europe produced an increased transparency allowing a clear breakdown of costs, more efficient pricing mechanisms for each cost segment, and a higher competition for non-regulated costs, such as generation and retail. Therefore, a first barrier for developing more cost-reflective network tariffs is the lack of transparency in the differentiation of network costs from other costs, which lowers economic efficiency of price signals and the consequent customer responses.

Although transparency in Europe has been increased after liberalization, and now customers can know exactly how much they pay for each cost segment of their electricity bill, there are some non-electricity-related costs that are still recovered through electricity bills. In Europe, for example, ACER/CEER (2022) compares the share of each cost component in the final electricity bill for households in capital cities. As shown in Figure 2.3, the portion of network charges in the final electricity bill presents huge variations (from 13% in Cyprus to 45% in Hungary) which depends on the electricity generation mix, the network topology of each country, and the amount of policy and taxes levied on the electricity bill.

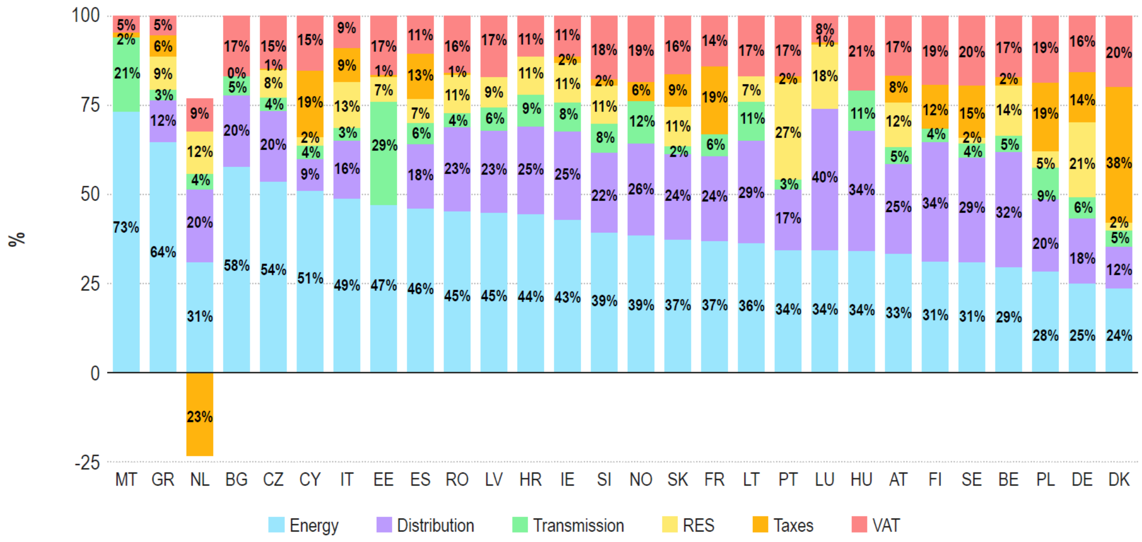

Figure 2.3. Composition of electricity bill for households in capital cities. Source: (ACER/CEER, 2022)

While electricity market prices send economic signals to optimally allocate a scarce product through competitive markets, policy charges respond to ambitious decarbonization policies and high penetration targets for renewable generation, which cannot be reached relying solely on market prices (Gerres et al., 2019). As a result, support mechanisms are usually included in the electricity tariff structure to cover the extra cost of RES investments.

Thus, in many countries, e.g., Germany, United Kingdom, Italy and Spain, a consequence of decarbonization objectives is an important increase of subsidies given to renewable generators that are recovered through policy charges in the final electricity bill, usually distorting the economic signal sent by electricity market prices and network charges. It is important to note that many of these policy charges were built on 20th century assumptions, when customers were rather price inelastic (Pérez-Arriaga, 2016). Nowadays, incorporating these support mechanisms to recover policy costs into final electricity bills can create distributional effects between passive and active customers (Mastropietro, 2019), leading to higher electricity bills for customers, thereby impacting their ability to efficiently respond to the economic signals sent by both network tariffs and energy markets. Providing hidden incentives through tariff design to decentralized technologies can impact on network cost recovery. Thus, network tariffs may need to rise, negatively affecting stability and predictability (Nijhuis et al., 2017). This jeopardizes decarbonization through electrification by reducing electricity competitiveness especially considering that electricity competes with other energy fuels used in heating and transport sectors. A clear and transparent tariff structure will help to send the correct economic signals to customers so the decarbonization objectives are fulfilled at the lowest cost. This thesis focuses concretely on increasing network tariff design transparency, although some of the conclusions regarding non distortive residual network charges are also applicable to non-electricity-related policy charges.

A second gap between theory and practice on network tariff design is related to cost segmentation. While in theory, LTMC methodologies perform better than accounting approaches, as mentioned in section 2.3, the majority of countries still opt for the latter. The main reason behind this fact is the institutional inertia of leaving network tariff methodologies untouched. In fact, any network tariff reform has some political cost for the responsible administration since network cost recovery is a zero-sum game, at least in the short term, in which any tariff modification produces winners and losers among network users. However, the 3 Ds are challenging old network tariff designs, producing evident cross-subsidies among customers, and making the revision of network tariff design mandatory for the next years. Although some countries, such as UK and Norway (CEER, 2020), are pushing towards LTMC methods, there is still a long path to efficiently implement LTMC methods in real-world systems, and to demonstrate their actual performance. This thesis, by comparing LTMC against account-based approaches implemented in real-world systems, aims to support regulators' decisions on more economically efficient and equitable network tariff designs that in the long run will lead to system-wide cost savings.

The third gap between theory and practice is related to the network cost allocation through different tariff settings. As previously mentioned, in theory, the optimal network tariff structure would be very granular in terms of time and space, and very dynamic in order to capture variations in the network conditions. In practice, there is no one-size-fits-all methodology (CEER, 2020), and countries have to balance between principles leading to a huge variety of network tariff structures (see for example ACER (2023) report). The main barrier to the reduced temporal granularity, locational granularity, and price-setting periodicity was the low price-elasticity of customer responses, which was translated into a low granularity of measurements. The deployment of smart meters in many European countries during the last decade is creating new opportunities to design more granular network tariffs that increase cost-reflectiveness for potentially price responsive active customers. Many countries are moving towards higher temporal granularity by introducing or improving time-of-use charges. In France, new network tariffs were introduced in 2014 for low voltage network users, with five time-block energy charges. One of the time periods, the annual peak period, being defined by the DSO to signal peak demand periods at the local level, while continuing the daily peak shaving through ToU energy charges (CEER, 2020). In 2021, a new methodology was adopted in Spain for small customers, with a higher time granularity. It consists of 2 differentiated time blocks for the contracted capacity charge and 6 time-blocks (3 daily time-blocks with seasonal differentiation) for the energy charge (CNMC, 2020). In Germany, since LV household smart meters are not deployed, temporal granularity on electricity tariffs cannot be implemented yet (EUniversal, 2020). Other solutions, such as time-varying network tariffs via interfaces, combined with intelligent energy management of consumers with flexible assets were considered in a pilot operated by Mitnetz Strom.

At the same time, countries that had mostly energy-based charges have recently moved to capacity-based charges. For example, in Italy, a gradual tariff reform took place between 2015 and 2017. Network tariffs were modified from progressive volumetric energy charges, i.e. the charge per kWh of consumed electricity increased with the growing amount of total electricity consumed during the billing period, to a three-component structure tariff based on a fixed charge, a contracted capacity charge, and a non-progressive energy charge (CEER, 2020; Regalini, 2019). In Belgium, a planned reform aims to add a capacity charge in the network tariff for small consumers and businesses, currently facing ToU energy charges to recover network costs (EUniversal, 2020). Figure 2.4 shows the percentage split of withdrawal charges among fixed, capacity and energy charges in most European countries.

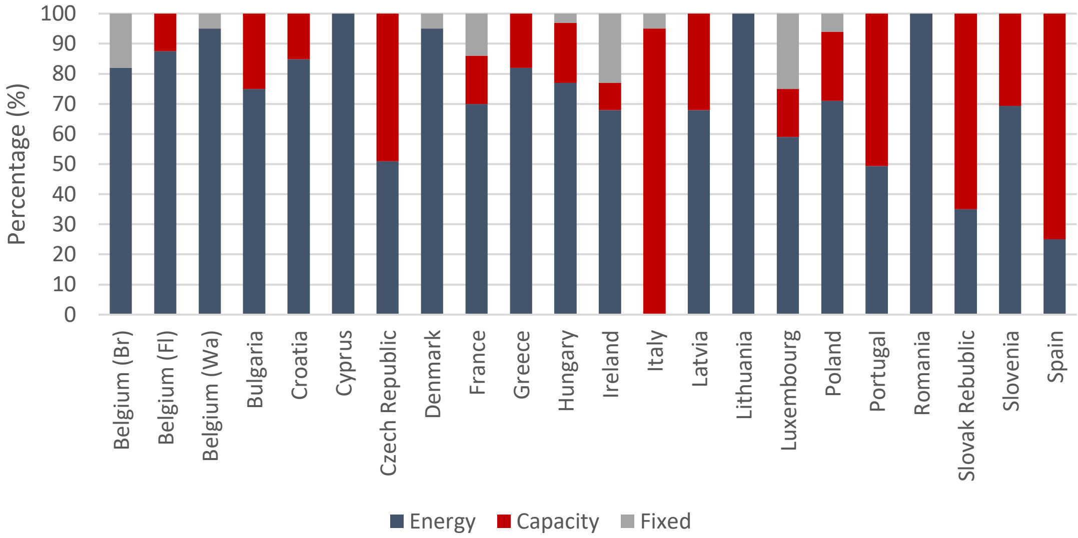

Figure 2.4. Percentage split of withdrawal charges among energy, capacity and fixed charges in European countries. Source: ACER (2021)

Some countries, such as Portugal, are also proposing locational charges among customers, and some other countries such as Germany and the UK are already applying locational differentiation because tariffs are not national and differ by DSO. However, Ofgem, the UK regulator, is currently reviewing the tariff design in order to make tariffs more cost reflective. Some of the issues under review are improving locational accuracy of distribution charges, analysing other design options for distribution and transmission charges, and linking electricity network tariffs with the procurement of flexibility services from customers to DSOs (Ofgem, 2018).

A still standing barrier in some countries is the conception of customers as passive price-takers, driven by institutional inertia, leading to an overweight of simplicity principle against economic efficiency. As a consequence, network tariffs are homogeneous for large regions, such as in Spain (CNMC, 2020) and/or with low temporal differentiation (ACER, 2023).

A special mention is required for net-metering, which aims to get the advantages of symmetry of charges for injections and withdrawals, although net-metering can vary from rewarding injections with the full retail price to just rewarding them with the wholesale energy market price, and from receiving credits for the rest of the year to just netting generation and demand in the same hour. Some examples are found in the US, Brazil, Australia, Belgium, and Italy, among others. However, in many cases, net-metering is coarsely applied by netting injections and withdrawals in different places and time-periods, leading to a cost-reflectivity loss and to cross-subsidies among customers (Eid et al., 2014). In fact, some countries identified the perverse economic incentives of net-metering and have limited its implementation, and CEER recommended avoiding net-metering practices (CEER, 2017). For example, in 2012 ANEEL (the Brazilian regulator) established a net-metering scheme for small-scale distributed generation. After a first general review in 2015, which demonstrated a cost recovery gap for DSOs, which would lead to increasing distribution charges, ANEEL decided to move away from net-metering once the national installed capacity of distributed generation had reached 1.25 GW. (De Albuquerque et al., 2019). Similarly, in Australia, flat volumetric tariffs added to generous feed-in-tariffs led to a huge increase of PV installation, which increased tariffs for all non-solar customers because network costs were not recovered (Azuatalam, 2019; Passey et al., 2017; Simshauser, 2016). Similarly, in 2015, Hawaii Public Utility Company substituted the previous net-metering approach by two mechanisms, 1) customer self-supply, in which injections to the grid are not allowed and 2) customer grid supply, in which customers receive up to 75% of retail prices for the injected energy (HPUC, 2015, 2019). As observed, the implementation of symmetric electricity charges, including both energy and network components, misses the fact that network costs are mainly sunk costs. Therefore, symmetry of network charges is exclusively applicable to those truly cost-reflective charges, as it is the case of forward-looking charges reflecting long-term network costs. The lack of transparency and cost-reflectivity in the network tariff design has led to important cross-subsidies among customers, which require to revisit them.

2.6. Concluding remarks

Three main gaps are found in the literature review between theoretical and practical network tariff designs. The first gap is related to a lack of transparency in the network tariff design in many countries. The second gap is related to the selected cost segmentation, while theory leads to LTMC methodologies, most countries apply accounting approaches. The third gap is related to the low cost-reflectivity of the selected tariff settings which lead to sub-optimal network tariff designs.

With the aim to contribute to fill the aforementioned gaps, the following chapters of this thesis show the theoretical benefits of LTMC methodologies (Chapter 3) and propose a mathematical formulation for the practical implementation in real-world systems (Chapter 4). The first gap is addressed through a detailed mathematical formulation which leads to an increased transparency of the network tariff design. The second and the third gap are addressed by the network cost segmentation between long-term incremental costs and residual costs, and the long-term incremental cost recovery through highly granular forward-looking energy charges. Furthermore, Chapter 5 contributes to the third gap by proposing advanced ex-post network charges and a customer response coordination mechanism, which can solve the peak-shifting effect in the case of systems with many flexible customers synchronizing their network usage.

This thesis aims to support regulators on their way to more efficient network tariff designs, without producing cross-subsidies among customers, and leading to the optimal network development considering the potential flexibility of end-customers investing in new technologies. In a future with a significant share of decentralized energy resources actively participating in the electricity systems, sub-optimal network pricing will lead to evident cross subsidies among network users. Most avid customers will soon take advantage of cross-subsidies by taking decisions which will not benefit the system, making profits at the expense of the rest of customers. This will reveal the need for revisiting the network tariff design, but a too-late revision could produce regulatory uncertainty for early DER adopters. Therefore, the sooner regulators tackle with the 3D's network tariff design revision, the more optimal and stable outcomes it will produce.

Chapter 3. Theoretical network tariff design in the context of decarbonization, decentralization, and digitalization

This chapter proposes, and demonstrates in a simplified case study, a methodology for the implementation of forward-looking incremental network tariff in an ideal world of complete information regarding network flows, injections and withdrawals. The proposed methodology follows the two sequential steps presented in the network tariff design process in section Chapter 2: consisting of three sequential steps: (1) cost recognition and segmentation and, (2) cost allocation to customer categories and charging variables. The analysis and case study carried out in this chapter were published in Morell Dameto et al. (2020) and Morell Dameto et al. (2021).

The main contributions of this chapter are:

- Section 3.1 proposes a new methodology for the allocation of network costs, which divides network costs into incremental and residual costs (for the allocation of incremental network costs, highly granular - both temporal and locational - charges are applied).
- Section 3.2 demonstrates the benefits of the proposed network cost allocation methodology in a case study consisting of a simplified network model comparing the proposed with other often-used tariff structures in two scenarios: 1) economic signals under network congestion issues, and 2) economic signals when customers adopt distributed generation.

Finally, concluding remarks of this chapter are presented in Section 3.3.

3.1. Methodology: forward-looking incremental network charges and residual network charges

Following the network tariff design process presented in section Chapter 2, a step-by-step methodology to produce the proposed network cost allocation is presented in Figure 3.1.

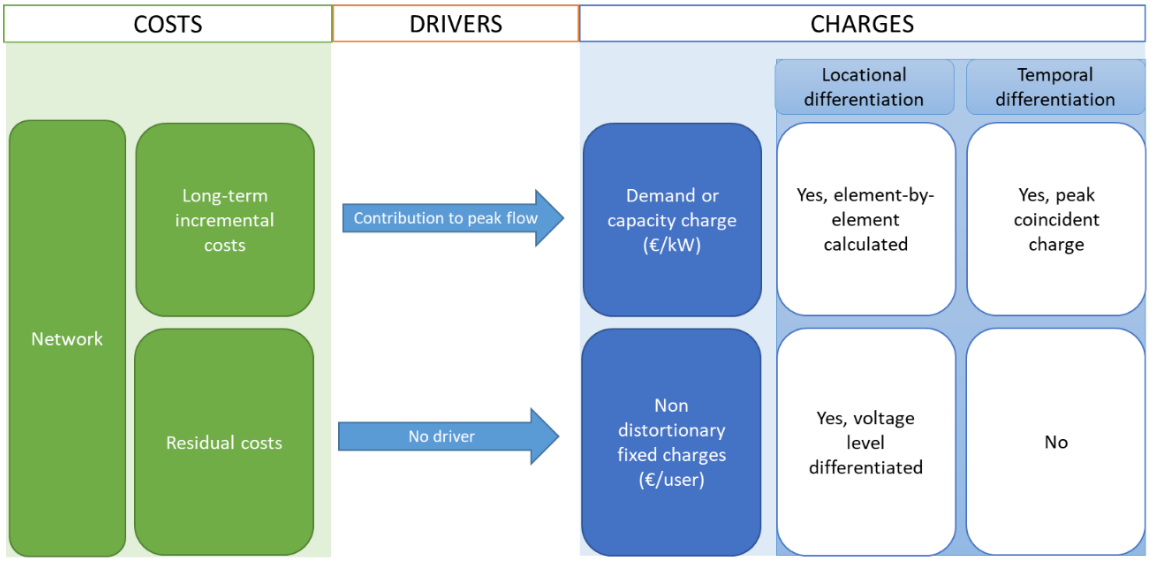

Figure 3.1. Forward-looking network cost allocation methodology. Source: (Morell Dameto et al., 2020)

3.1.1. Cost recognition and segmentation

Since past investments are sunk costs, the economic efficiency principle leads to design tariffs that mainly are addressed to minimize long-term network expansion costs. For this purpose, some authors, like (Pérez-Arriaga, 2016), agree that network costs should be segmented between long-term and residual costs, following the LTMC method.

Long-term costs are those future costs that DSOs and TSOs will face to maintain system integrity and quality of service given an increasing electricity demand. Therefore, long-term costs correspond to the expected costs of the network expansion planning. Investments in network assets are discrete and irreversible, and they are performed every few years – note that the lifespan of these assets is 40 years and beyond.

Long-term network costs can be calculated using a generation-demand network expansion model, considering different scenarios to characterize the evolution patterns of network users. Incremental demand changes also differ over time. In order to compute long-term incremental costs, it is necessary to bring future costs caused by incremental demands to present value, to signal current customers their potential impact on the future grid. This approach is similar to the one expected to be developed by Ofgem in the UK under the Forward-Looking Charging reform (Ofgem, 2019c).

After network cost recognition and segmentation, cost drivers should be identified for each cost segment, in this case, long-term and residual network costs. The main trigger for future network investments is the maximum peak usage of each network element, i.e., the maximum amount of energy that flows through the element due to the aggregation of all the generation and demand. Therefore, for long-term incremental costs, the main cost driver is the maximum network flow in each network component (Abdelmotteleb et al., 2018). For residual costs there is no driver, as this cost is calculated as the remaining part of the total recognized regulated cost.

Interaction between network tariffs, connection charges, exit fees and DSO local flexibility markets

Regardless of the network cost allocation methodology, network charges should avoid reflecting the same costs that are sent by other economic signals. In the case of a LTMC based method, the potential overlaps of long-term network costs with other economic signals deserve special attention. Those costs extracted from connection charges, exit fees, and DSO local markets should be considered to reduce either long-term network costs or residual network costs, depending on whether they are sending a long-term signal or they are just recovering sunk costs.

In the case of connection charges, the degree to which connection charges fully reflect the incremental cost of providing a user with a new or upgraded connection to the network depends on the type of connection charge. The simultaneous application of deep connection charges and forward-looking charges could be conflicting, because the same network costs could be signalled twice. On the other hand, super-shallow connection agreements would be fully compatible with forward-looking peak-coincident charges.

In the case of exit fees, if a customer defects from the grid, a significant amount of foreseeable recovered costs would not be recovered, causing a future increment in network charges for the remaining consumers to satisfy cost recovery objectives. If the network used to deliver electricity to the defected consumer is not already depreciated and the rest of consumers will not use it, the defected consumer should bear with the depreciated network investment cost via an exit fee. Therefore, in the case of an application of an exit fee, its purpose would be the allocation of a residual network cost with no effect on long-term network costs.

Finally, in the case of DSO local flexibility markets, depending on their structure and the network tariff structure, they could overlap, or complement each other. Network tariffs are usually designed for large systems. Local flexibility mechanisms, though, are designed ad-hoc for dealing with congestion problems or network deferral strategies that mainly affect specific network components located within those larger areas. Local flexibility markets' structure can vary among many parameters such as the service provided, time-frame, contract length, location, etc., (see Valarezo et al. 2021). In this respect, both mechanisms could coexist but since flexibility from network users can defer or reduce network costs, and if so, they should be considered as part of the long-term incremental cost calculation. The interactions of network charges and local flexibility markets should be studied in detail in future research.

3.1.2. Tariff setting for long term incremental costs

After identifying cost segments and cost drivers, costs should be allocated among system users, i.e., generators and customers, through the available charging variables, to guide them towards an optimal usage of the electricity network.

According to the economic efficiency principle and the cost reflectivity and symmetry criteria to allocate long-term network costs, generators and customers should be treated equally. Furthermore, active customers highlight the need for this symmetry because, additionally to consuming power from the grid, they can also inject power in other periods.

Charging variables

The main problem in selecting the charging variables to allocate costs derives from the difficulty of simultaneously meeting both efficiency and equity principles. Traditionally, regulators have assumed that low-income customers consume less energy than the richer ones. For this reason, volumetric tariffs (energy-based) have been and currently are widely used to allocate network costs among network users, so the former ended paying less network costs than the latter. However, new developments, mainly PV panels, break this assumption since richer customers are able to avoid high-energy charges by reducing their consumption through PV adoption.

These avoided charges are reallocated to the rest of the customers through higher volumetric charges, further incentivizing PV installation. Several authors refer to this problem (Borenstein, 2017; Hoarau and Perez, 2019; Pérez-Arriaga, 2016; Schittekatte and Meeus, 2017; Simshauser, 2016; Trabish, 2016) as the death spiral (direct feedback between volumetric tariffs and DER deployment). Furthermore, theoretically, only energy losses costs and a part of the quality of service costs are proportional to energy consumption, and, according to the principle of economic efficiency and cost reflectivity, should be charged through volumetric energy charges, as stated at (González, 2014).

A practical solution to the death spiral problem, or the equity issues among customers installing or not PV panels, consists of introducing either measured or contracted capacity charges (€/kW) to allocate part of the network costs, while reducing the flat energy-based charges. Capacity charges also increase the cost reflectivity of the tariffs, since the main driver of network costs is the peak energy flow, which determines the necessary network installed capacity (Prettico et al., 2019; Van Langen, 2019). The application of capacity charges would also incentivize, in the future, the implementation of storage technologies, as several papers foresee (BP Energy Outlook 2019, 2019; Eero, 2018; Hayward and Graham, 2017; Ioannis et al., 2018); and customers would be incentivized to move part of their consumption from peak hours to off-peak ones (Burger et al., 2019a; Simshauser, 2016). Note that in the case of time blocks as short as one hour, energy charges and capacity charges would provide very similar economic incentives in practice. For the case of capacity charges, it is common to measure capacity as an average of the highest peaks within the time period. If instead, instantaneous demand was considered for capacity charges, although it is not usual, economic signals would differ from those provided by energy charges.

Following the economic efficiency principle, the proposed approach for collecting long-term network costs would be to implement peak-coincident forward-looking charges (either capacity or energy based) that measure the contributions of network users to the peak network flows in the periods of maximum utilization. This economic signal would incentivize user responses to reduce network peak flows and delay future grid investments.

Time Granularity

Long-term incremental costs are driven by the maximum peak usage of the network. So, those customers contributing to maximum peak usage in each particular network component or network zone should face higher network costs since they would be responsible for the future network investments. Following the economic efficiency principle, peak-coincident network charges should vary with time since they send an economic signal related to reinforcement costs, which are required to satisfy peak network usage.

For example, if a line is congested or close to being congested in the near future, those network users who contribute to this congestion should be signalled the cost of not-shifting their consumption, because if they continue or increase their peak consumption at these hours, new investments would be triggered. In case their willingness to use the network is higher than the peak-coincident charge, these users will pay the elevated peak coincident network charges and the reinforcement will happen. Otherwise, the reinforcement will be avoided (and thus overall network costs reduced compared to a counterfactual) and users shifting their network usage save out significant network charges.

Under a purely theoretical approach with perfect knowledge about the future network characteristics, it would be possible to know the peak hours of each network element. This means that customers could be charged according to their actual contribution to peak usage in each network element. However, in practice, and when smart meters are deployed, a common methodology is to select ex-ante those hours on which the network is expected to be more used, defining those time blocks as peak hours and the rest as off-peak hours.

Ideally, the more temporally differentiated a tariff signal is, the higher the level of efficiency that can be achieved. Additionally, a shorter price setting period may provide more efficient responses from customers. However, implementation costs of such granular and dynamic tariffs – not only due to the technical development of smart meters and markets, but also customer awareness and engagement – must be compared to the potential benefits in terms of long-term system costs and efficiency.

Smart-metering deployment is key enabling network charges with higher time discrimination, such as peak-coincident network charges (Abdelmotteleb et al., 2018; Passey et al., 2017; Pérez-Arriaga, 2016), by which customers are charged proportionally to their network usage when the grid is congested.

An Illustrative Example for Determining Time Granularity

Assuming a low-voltage feeder that supplies 425 real consumers and is connected through a 100-kW distribution transformer to the rest of the distribution network. The actual usage of this transformer is shown in Figure 3.2 as the blue histogram. Note that this usage is, in all hours, below the transformer capacity (100 kW). In addition, a demand growth for this group of users of 1.15 over the next 40 years is assumed. Network usage would increase as the orange histogram shows. This increasing demand would trigger a new investment in the network, since the transformer will be overloaded in specific hours when the network usage is above 100 kW.

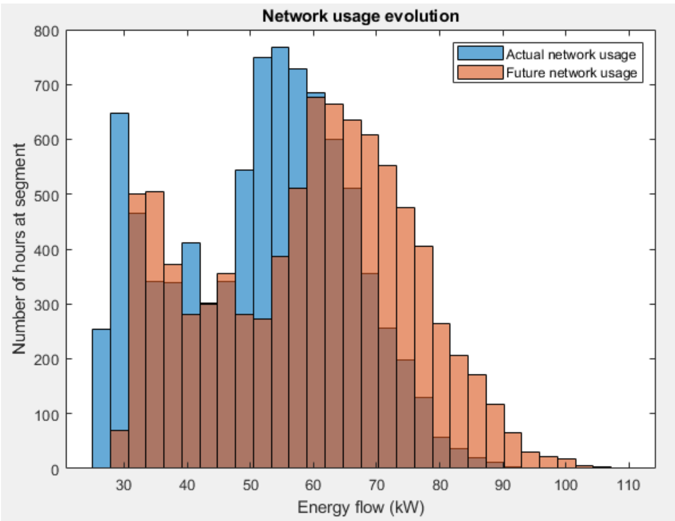

Figure 3.2. Network usage evolution. Actual network usage in blue and future network usage in orange. Source: (Morell Dameto et al., 2020)

Following efficient economic signals, the users should respond to peak-coincident charges through load shifting or load reductions and, in this way, delay network investments if the cost of such actions is a more efficient than the network reinforcement alternative, i.e., lower total costs.

A key decision is to identify the periods of time that should be signalled by the cost-reflective charge. A straightforward decision would be to select those hours in which the future network usage is above the rated network capacity. However, if only those hours are chosen, the intrinsic uncertainty related to demand forecast may, in the end, lead to congestion in hours close to the selected period where charges would be smaller. Therefore, it is recommended to extend the number of hours when peak-coincident charges are applied to hours that are close to peak periods (Abdelmotteleb et al., 2018). In practice, a lower threshold or security margin should be defined to determine the periods when peak-coincident charges are applied, e.g., those hours when the energy flow exceeds 60% of the rated capacity.

Locational Granularity

Once more, the principle of economic efficiency leads us to design peak-coincident network charges with a high level of locational granularity to incentivize efficient network user responses depending on the particular network components that are expected to be congested. However, some countries, following the equity principle, do not permit differentiation among customers' location to recover network costs, which leads to a customer differentiation based on the network model, i.e., customer categories are equivalent to voltage levels (CNMC, 2019).

Theoretically, peak-coincident network charges should be calculated for each network user depending on its connection point to the grid. The considered network should be divided into as many elements as it is composed of, e.g., lines, transformers, substations, etc. Then, for each element, the number of hours in which its expected flows exceed the threshold according to the security margin selected are considered, as shown in Figure 3.2. All network users contributing to peak usage of network component are charged proportionally and according to the potential future investment or incremental cost associated with the expansion of this network component.

As it happened with dynamic charges with high temporal granularity, the potential benefits produced by network charges with high locational differentiation should be compared with its implementation costs, including data availability. Highly granular tariffs would require data about grid components and forecast usage which may not be available, and computation capabilities may also be a challenge. Therefore, in practice, network tariffs are usually computed at aggregated level.

Computation of forward-looking incremental charges

In an ideal world, network tariff design would require complete information regarding costs of each network element, network flows, injections and withdrawals with high time granularity, e.g., hourly. In this chapter, a simplified version of the ideal LTMC based methodology is formulated, assuming complete information, in order to identify the main differences with other network tariff designs that will be presented in the case study.

The forward-looking tariff consist of two terms: 1) a peak coincident network charge applied on an hourly and user-to-user basis and 2) a residual fixed charge. The highly granular peak coincident charge reflects the long-term network costs sending an economic signal to network users who contribute to the flow of network elements that can be potentially congested in the future. In this case, the risk of congestion is defined for each network element e at hours (h_e) when network element flow ($nu_{e,h}$) surpasses the 60% of the network element physical capacity. The long-term incremental cost of each element (ic_e) is calculated as the annualized future reinforcement cost. Long-term incremental network costs are uniformly allocated to those hours under risk of congestion, as shown in Eq. 1. If the settled threshold is not surpassed in any of the hours, long-term incremental network costs are null.

$$ic_{e,h} = \frac{ic_e}{h_e} \quad (1)$$

The contribution of each user *u* to the network flow of each element is calculated as the Power Transfer Distribution Factor (Sauer, 1981) $ptdf_u^e$, which reflects the increase of network flow (in kW) through the network element *e* when there is an increase of consumption of 1 kW from network user *u*. Although *ptdf* values could change hourly due to different network operational conditions, for simplicity $ptdf_u^e$ is considered a fixed value calculated yearly. In a future with hours with reverse power flows and network reconfigurations *ptdf* values could be calculated at each time-step in order to signal the time-dependent impact of each withdrawal or injection in the rest of the network components. Incremental costs associated to network element *e* and hour *h* are allocated to network user *u* through the corresponding $ptdf_u^e$, as shown in Eq. 2, considering that incremental costs are apportioned among total network usage of element *e* $(nu_{e,h})$. The resulting value is the long-term incremental term that network user *u* faces for the usage of network element *e* in hour *h.* Network user *u* faces the sum of all terms $(it_{u,e,h})$ associated to all network elements *e* in which $ptdf_u^e$ is not null. Note that both generation and demand face symmetrical charges, i.e., equal but in the opposite direction.

$$it_{u,e,h} = \frac{ic_{e,h} * ptdf_u^e}{nu_{e,h}} \quad (2)$$

3.1.3. Tariff setting for residual network costs

Residual network costs do not have cost-drivers. Thus, charging generation plants with these costs would mean that generators would translate them into higher energy offers in the market, passing them to final customers. To avoid this, residual charges should be solely allocated to customers.

Residual costs are calculated as the remaining network costs that are not recovered through peak-coincident charges. Since there is no cost driver for residual network costs, their allocation to customers should not follow any other economic efficiency principle than not distorting the economic signals sent by other charges such as the peak coincident charge or the energy market prices. Therefore, temporal granularity should be avoided for the allocation of residual network costs. Any temporal differentiation of charges would provide economic signals for customers to reduce their electricity bills by modifying their network usage, while the network would not benefit from it. Alternatively, allocative equity criteria could lead regulators to differentiate residual network charges by customer categories depending on the voltage level where they are connected, following the selected network model.

Charging variable alternatives

Several options to recover residual network costs have been discussed in the literature (Borenstein, 2016; Brown and Sappington, 2018; Pollitt, 2018; Ofgem, 2019b; Batlle et al., 2020). The main proposed approach is a fixed charge (periodical payment in euro per connection) that does not distort the economic signals. Recovering residual network costs with a flat energy rate per kWh consumed, regardless of the time or the location of this consumption, can result in a significant distortion to the rest of economic signals. This approach invites network users to net out their demand for electricity by installing system-wide inefficient self-generation behind the meter. By cancelling electricity demand with embedded generation, those customers would avoid paying residual costs, which would have to be reallocated to other customers. Moreover, since the rest of customers face higher flat energy rates, they are more incentivized to adopt self-generation, thus exacerbating the utility ‘death spiral’ effect (Simshauser, 2016).

Besides, a capacity charge (proportional to peak demand) could produce inefficient incentives for customers to install batteries or incentivize them to change their consumption patterns (Schittekatte et al., 2018). Therefore, experts agree that a fixed charge is more efficient, but at the same time, they recognize the difficult task of leveraging the fixed charge to satisfy also the equity principle, understood in this context as treating identical customers equally (Batlle et al., 2020; Burger et al., 2020).

It is recommended to select fixed charges per customer (€/customer), which should not impact other efficient price signals, and network users should not be able to avoid this payment by modifying their network usage patterns. Any kind of load shedding, load shifting and defection from the grid are considered as modification of consumption patterns. In fact, decentralization would allow some customers to disconnect from the grid. If residual network charges were high enough, grid defection would be an extreme case of flexible customer response, by which customers would avoid residual network charges. However, this would also reduce the network costs recovered by the DSOs and could become an issue for the economic sustainability of the tariff system because many customers defecting from the grid would mean a raise in the remaining customer network payments, further incentivizing grid defection. Thus, some measures could be establishing residual network charges for those defecting during a limited time period, or even receiving some payments if, for instance, by disconnecting from the grid, they contribute to the deferral of network investments (Pérez-Arriaga, 2016). However, for a high range of fixed charges, connection benefits are greater than the fixed charges for most customers (Burger et al., 2019b).

An additional advantage of fixed charges is that they allow addressing equity issues depending on how they are leveraged among customer categories. The British regulator is moving into this direction. In the UK, there is a proposal to recover residual network costs through a fixed charge for domestic customers depending on the aggregated net consumption of the customer category where they are classified—equal payment for customers classified under the same category (Ofgem, 2019d).

However, there are some additional equity implications: Should all network users pay the same charge, irrespective of their energy consumption or their peak or contracted power? Residential customers that consume more energy are likely to be wealthier than customers that consume less energy. An equal fixed charge for all customers would disproportionately affect low-income customers, which would be socially unacceptable. This discussion can be extended to commercial or industrial customers. Although an annual charge not directly linked to electricity consumption is an efficient instrument, further considerations on how to allocate this sum to customers is required.

Fixed charges can be a postage-stamp rate, i.e., a uniform charge for all customers under the same consumption customer group, or they can vary based on different individual customer parameters: income, historical consumption, or physical capacity (Borenstein et al., 2021). On the one hand, flat or postage-stamp rates could be seen as inequitable among vulnerable and non-vulnerable customers. On the other hand, income-based fixed charges meet the equity principle, and are independent of the level of consumption, but the practical implementation of these charges would be very difficult due to legal barriers and availability of data. Fixed charges based on historical consumption could provide inefficient economic signals to customers, since they are dependent on the customer's demand, even though selecting a sufficiently large number of years could smooth the economic signal. Finally, another option is physical capacity, defined as the maximum supply capacity depending on the customer electrical installation based on technical standards, which cannot be modified by customers either by changing their peak demand or by changing their contracted capacity agreements.

As a qualitative assessment, three different types of charges are compared, mainly for residential customers, perform considering the equity principle, along with their robustness against new developments such as self-generation, storage, customer aggregation.

1. Fixed charge based on the income level or the real estate tax

The allocation of residual costs according to the income level of residential customers allows progressive charges with respect to consumers' income. The real estate tax could also be a proxy for the income level of the owner. This fixed progressive charge would meet equity criteria, as well as being independent of the level of consumption.

This fixed charge would be independent from the consumption or contracted power of the consumer, or whether the consumer decides to install self-generation or storage units. The collected amount would also not change if several consumers were aggregated as a cluster with a single connection point to the system, forming, for instance, a citizen energy community. Finally, this charge would easily be applicable to new consumers requesting connection to the grid.

On the other hand, the practical implementation of this type of charge would be complex due to access to the information, which is not relevant for the operation of the electricity system but required for its implementation. Both income data and real estate taxes are traditionally not available to utilities. In addition, substantial regulatory changes for their implementation would be needed with respect to current practices.

2. Contracted or installed capacity charge

A less radical approach compared to the current situation, in countries where network capacity is contracted, is to use the contracted capacity or the installed capacity, i.e., the maximum allowed capacity for a consumer installation based on technical standards, to allocate residual costs. This approach is currently used for the allocation of other regulated costs in some jurisdictions. However, any charge related to the size of the customer connection can introduce barriers to electrification. To avoid this, the application of this charge could be exempted in off-peak periods. The charge would be fixed for the whole year, proportional to the maximum capacity contracted for peak time-blocks. In this way, no extra costs would be added to consumption or generation during off-peak hours, and therefore no barriers would be created, for instance, to electric vehicle recharging during periods of low network utilization.

Contracted capacity and installed capacity can be modified by the customer, but only to a certain extent, because a customer must contract or install capacity which corresponds to his maximum consumption. In addition, these charges are basically not avoidable for customers with photovoltaic self-generation installations, since they are not controllable, and thereby not able to reduce their contracted capacity.

This proposal, however, is not robust against cross-subsidies that could arise, for example due to the installation of storage systems which would allow contracted or installed capacity to be reduced, or due to supply point aggregation which would enable all consumers to reduce contracted or installed capacity, since the aggregated maximum capacity would be less than the sum of the individual maximum capacities. Contracted or installed capacity, as charging variables, are directly applicable to new consumers requesting connection to the grid. Finally, this allocation method is also easily applicable to commercial or industrial consumers.

3. Fixed charge based on historical consumption

The central idea of this last alternative is to seek the "historical" responsibility of each customer for the stranded residual costs. For example, historical energy consumption could be considered a reasonable indicator of the costs associated with past policy costs, i.e., historical costs of support mechanisms for renewable energy. The calculation by which the fixed charge to each consumer is determined takes its annual historical consumption as a reference.

The relationship between historical consumption and income level is not so clear. It is presumed that consumers with higher incomes have more household appliances and therefore higher consumption. But low-income consumers have less efficient appliances or poorly thermally insulated homes. By defining a fixed charge on historical consumption that would not be updated, consumers could not change their payments by changing their actual consumption patterns.

The transition from current tariff designs to this alternative would not be difficult because utilities already know the required data. The associated fixed charges could not be avoided by customers installing self-generation and storage technologies. Despite this, it presents some problems of applicability to new consumer connections where historical consumption data would not be available. To resolve this, default charges could be set taking as a reference consumers with similar characteristics (Batlle et al., 2020).

As mentioned, there is no one-size-fits-all solution, and the application of one method or another will be up to national regulators, based on the applicable laws, data accessibility, network technical development, and customer engagement.

Computation of residual network charges through capacity charges

The residual fixed charge by customer is intended to recover the remaining network element costs (rc_e) that are not recovered through incremental network charges, as shown in Eq. 3.

$$rc_e = C_e - ic_e \tag{3}$$

Following the allocative equity principle, network users are responsible for the residual costs of all the network elements they use. However, differently from long-term incremental network charges, an unmodifiable capacity charge is selected as the charging variable to not distort the efficient economic signal sent by peak coincident network charges. Physical capacity is selected as a proxy of network users' size.

Residual costs associated to network element *e* are apportioned among those users making use of it through the corresponding $ptdf_u^e$. The residual term ($rt_{e,u}$) that each network user *u* faces is applied to the individual capacity (CAP_u), as shown in Eq. 4.

$$rt_{e,u} = rc_e \frac{ptdf_{e,u}}{\sum_u (CAP_u * ptdf_u^e)} \tag{4}$$

3.2. Case study: network tariff comparison in a simplified network model

The case study presented in this section compares the effects of the application of three network tariffs (a Flat energy tariff, a ToU Energy and Capacity tariff currently applied in Spain, and the Forward-looking tariff) in a simplified and detailed network composed by 9 customers where one LV customer installs PV generation. For simplicity, tariffs are calculated and applied for one representative day (24 h). Note that this case study does not analyse the end-consumer tariff, but only the network tariffs, so generation and other regulated costs are not included in the economic signal.

3.2.1. Network Model Description

The simplified network consists of three voltage levels (High voltage - HV, Medium voltage – MV, and Low voltage - LV) with transformers between them. There are two generators (one in the HV network, which is the slack bus, and another in the MV network) and nine consumers (2 in HV, 2 in MV, and 5 in LV), as shown in Figure 3.3. Consumer load curves are shown in Figure 3.4. Individual capacity (CAP_u) is calculated as the maximum hourly energy consumption for each network user.

The annual maintenance costs and the annualized investment costs to be recovered through the tariffs are known for each network element. All three tariffs recover the same total network costs.

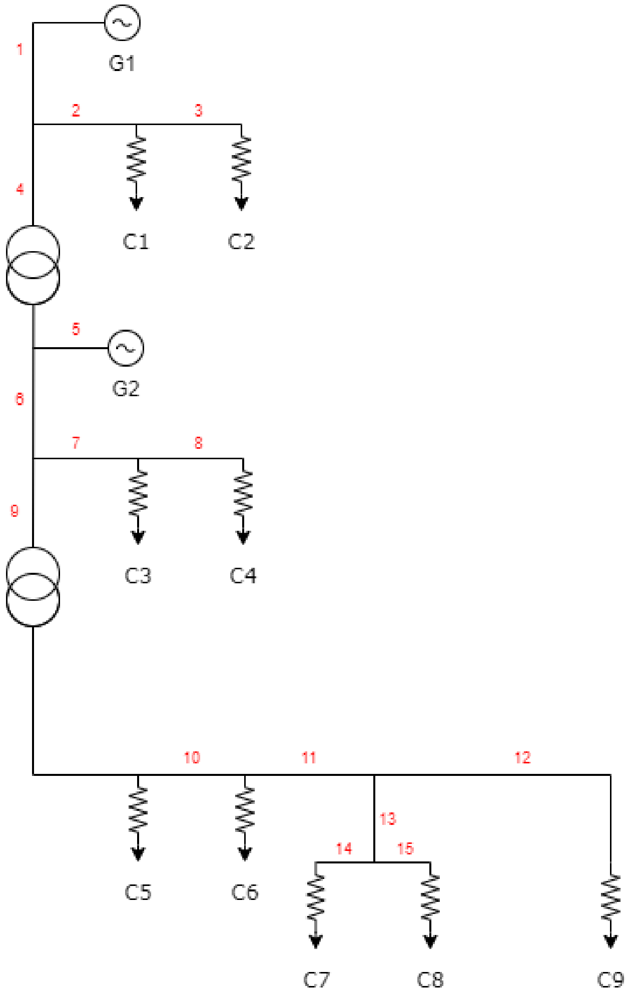

Figure 3.3. Simplified network model. Gs and Cs represent generators and consumers' locations, respectively, and red numbers represent the electricity network lines. Source: (Morell Dameto et al., 2020)

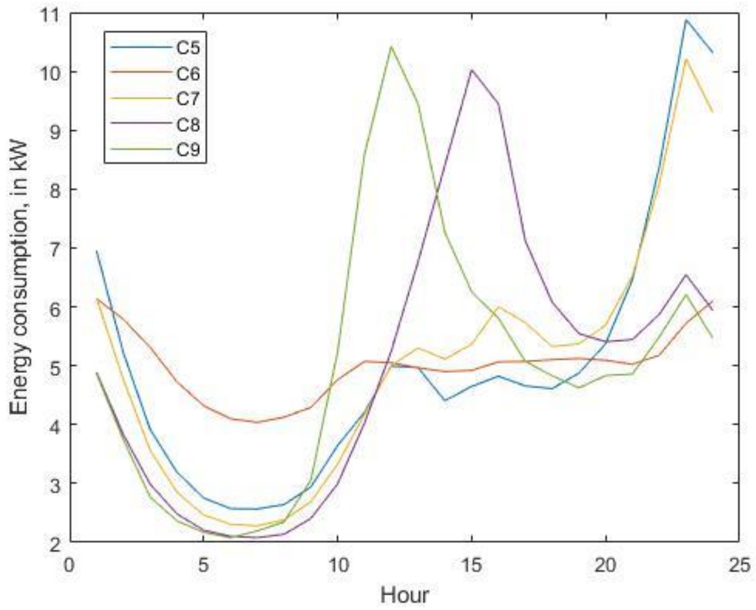

Figure 3.4. Load curves of low-voltage consumers. Source: (Morell Dameto et al., 2020)

3.2.2. Alternative network tariff description

While the forward-looking tariff was described in section 3.1, this section describes the two alternative network tariff designs applied in the case study, both following and accounting approach but with different weights among charging variables: 1) Flat energy tariff, and 2) ToU energy and capacity tariff, currently used in Spain.

Flat energy tariff

The flat energy tariff consists of a volumetric charge equal for all hours. In this case, network tariff design follows an accounting approach. Network costs are grouped by voltage levels (C_v) and allocated among network users according to a cascade network model, explained in the ToU energy and capacity tariff, by which customers connected to lower voltage levels are responsible for the costs of the network where they are connected and those from upper voltage levels. In practice, the volumetric tariff is the same for customers connected to the same voltage level.

Network costs per voltage level (C_v) are apportioned among the same and lower voltage levels according to a cost sharing factor (αe_j^i) as shown in Eq. 5. The cost sharing factor is calculated in the ToU Energy and capacity tariff section.

$$c_v^w = C_v * \alpha e_w^v \qquad (5)$$

Further, the sum of network costs that customers connected to voltage level w must face ($\sum_v c_v^w$) is apportioned among all the energy consumed in that voltage level (EC_w), resulting in the volumetric network tariff for customers connected to voltage level w (t_w^E), as shown in Eq. 6.

$$t_w^E = \frac{\sum_v c_v^w}{EC_w} \qquad (6)$$

ToU energy and capacity tariff

The ToU energy and capacity tariff consists of two charges: (1) a contracted capacity charge in €/kW-year, and (2) a volumetric charge in €/kWh. Both charges are different by voltage levels and have temporal differentiation by time periods, which are calculated according to the peak consumption hours at each voltage level. Time differentiation consist of three time periods (peak, shoulder, and off-peak) for all network users, and the differentiation among voltage levels has been maintained. Hours belonging to each period are: P1: h9 to h13 and h18 to h21; P2: h8, h14 to h17 and h22 to h24; and P3: h1 to h7. Note that, in this case, contracted capacity is used instead of physical capacity. Although contracted capacity is usually higher than physical capacity, for simplicity in this case study, contracted capacity and physical capacity are equivalent.

The network tariff calculation process is the following:

1. The recognised network costs for each network voltage level are allocated to the two charging variables so that the capacity charges are responsible for recovering 100% of the HV network costs and 75% of the MV costs and LV costs, while energy charges collect 25% of MV and 25% of LV costs.

2. Network costs associated to each voltage level and charging variable (C_v^C for capacity network costs and C_v^E for energy network costs) are allocated to time periods *p* according to the proportion of peak hours found at each time period ($\frac{h_{v,p}}{H}$), as shown in Eq. 7 and Eq. 8, being H the total number of hours with maximum energy flows, and $h_{i,p}$ the number of hours of time period *p* with maximum energy flows. For example, if period 1 contains 50% of the total peak hours, 50% of costs will be allocated to that period. In this case study, it has been considered that the peak hours are the 8 hours of highest consumption at each voltage level.

$$c_{v,p}^{C} = c_v^{C} * \frac{h_{v,p}}{H} \quad (7)$$

$$c_{v,p}^{E} = c_v^{E} * \frac{h_{v,p}}{H} \quad (8)$$

3. The cascade network model is applied, following the assumption that responsibility for the costs of a voltage level lays on users connected to that voltage level and users connected at lower voltage levels (Reneses et al., 2011). The cost of a voltage level and period to be recovered through capacity charges is allocated to the same and lower voltage levels according to a cost-sharing factor, as shown in Eq. 9 and Eq. 10. The cost sharing factor is calculated for each time period as the contribution of each voltage level to the voltage level network flow at peak hours. This calculation is made for each voltage level, for each time period and for each type of charge (energy or capacity). In the case of energy charges, the aggregated energy consumed in each period and each voltage level is used instead of the peak flow.

$$c_{v,p}^{C,\mathrm{w}} = c_{v,p}^{C} * \alpha_{w,p}^{v} \quad (9)$$

$$c_{v,p}^{E,\mathrm{w}} = c_{v,p}^{E} * \alpha e_{w,p}^{v} \quad (10)$$

4. The energy tariff that network users connected to voltage level *w* face for each time period is calculated as the sum of the energy related costs that must be recovered at that voltage level divided by the aggregated energy consumption at that time period and voltage level.

$$t_{w,p}^{E} = \frac{\sum_v c_{v,p}^{E,w}}{\sum_{u \in w} EC_{u,p}} \quad (11)$$

5. The capacity network tariff that network users connected to voltage level *w* face for each time period is calculated as the sum of the capacity related costs that must be recovered at that voltage level divided by the sum of all customers' contracted capacities at that time period and voltage level.

$$t_{w,p}^{C} = \frac{\sum_{v} C_{v,p}^{C,\mathrm{w}}}{\sum_{u \in w} CC_{u,p}} \qquad (12)$$

3.2.3. First scenario: economic signals when network is close to congestion

The objective of this first case study is to show the differences that appear in charges faced by network users under the three tariffs when the usage of some network elements exceeds the selected operational security margin (60%) in some hours. In this case, the LV transformer usage is above 60% of its capacity in h1 and from h10 to h24, and the line 12 usage surpasses the 60% of its capacity limit from h11 to h14. Instead, if congestions were not expected, all three tariffs would send similar charges to all network users.

Figure 3.5 shows charges faced by consumers 6 and 9 under the three tariff structures. Figure 3.5 (left) shows charges applied to consumer 6, who does not use line 12, while Figure 3.5 (right) shows charges applied to consumer 9, who uses line 12 for electricity supply. The Flat energy tariff (yellow) consists of a flat energy charge equally applied to all LV consumers. The ToU Energy and Capacity tariff (orange) consists of a volumetric charge and a contracted capacity charge, that is the same for both consumers because they are both connected to the LV network. Finally, the Forward-looking tariff (blue) consists of a peak-coincident capacity charge and a fixed charge; in this case, both are different for consumers 6 and 9. This difference is due to the fact that consumer 9 is responsible for line 12 peak flow. Therefore, consumer 9 faces higher peak-coincident capacity charges than consumer 6. If consumer 9 consumed less in those hours when line 12 surpasses the threshold, for instance by installing a PV panel, or reducing demand, consumer 9 would face lower rates and the need for future network reinforcements would be reduced. On the other hand, consumer 6 is not able to relieve the line 12 peak flow and, consequently, does not receive peak-coincident charges related to line 12. Similarly, the peak-coincident charges observed for consumer 6, and some part of peak-coincident charges for consumer 9, are due to their contribution to the peak flow of the LV transformer, which is also congested in some hours.

Notice that peak-coincident network charges could result in negative payments, which means incomes for network users who contribute to reducing peak flows. For instance, this would be the case for consumers increasing demand in areas with high generation where network peak flows are due to power flowing to upstream voltage levels.

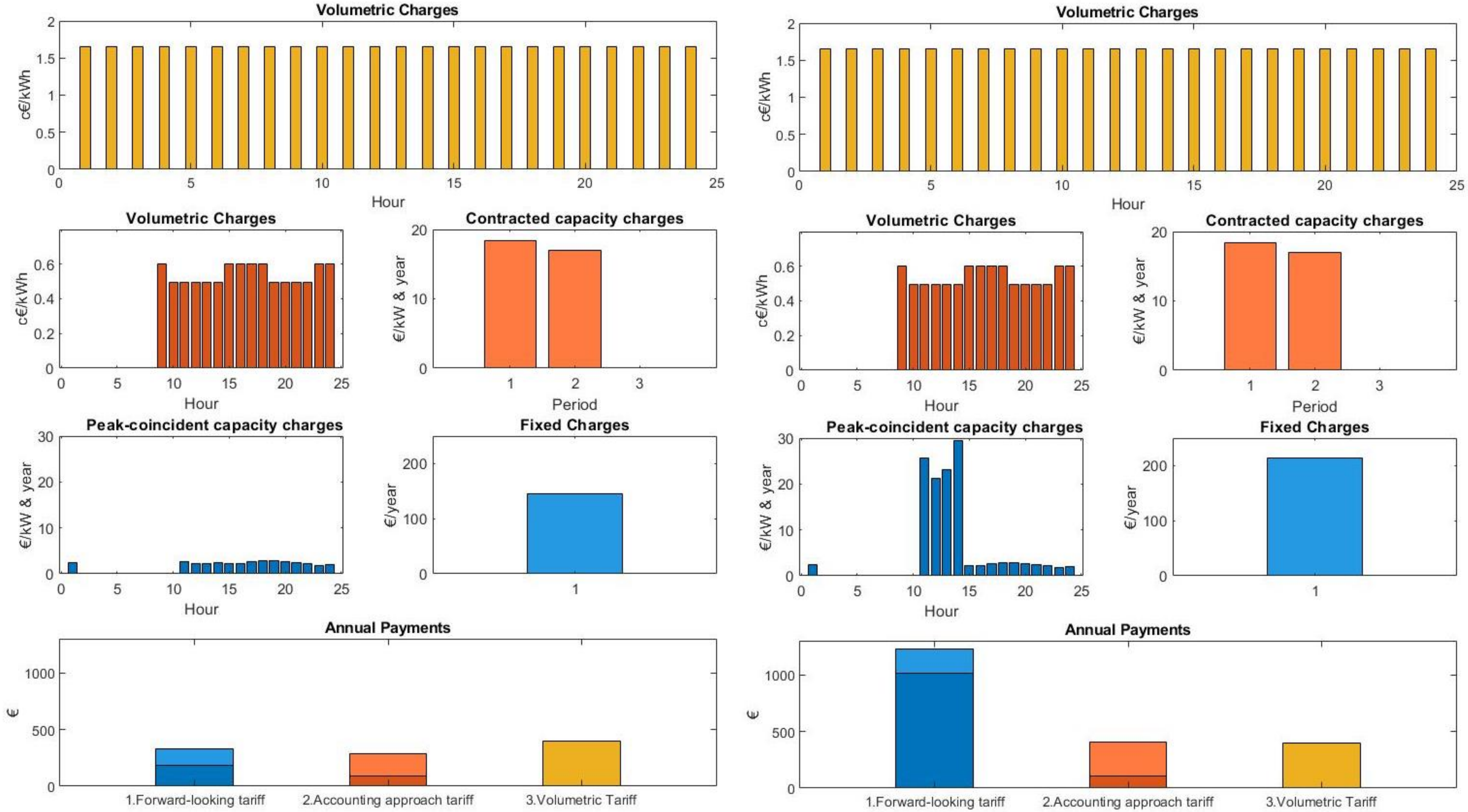

Figure 3.5. (left) Charges applied to consumer 6. (right) Charges applied to consumer 9. Flat energy tariff in yellow, ToU Energy and Capacity tariff in orange, and Forward-looking tariff in blue. Source: (Morell Dameto et al., 2020)

3.2.4. Second scenario: economic signals when a customer adopts self-generation

The second scenario presents the effect of one LV consumer installing PV panels for self-generation on each tariff structure. It is assumed that consumer 6 is installing a 5-kW PV panel installation, reducing the net demand from the grid. In this second case, charges are calculated for a new tariff period, i.e., several years later, so long-term effects are highlighted. Note that, in this case study, one LV consumer installing PV technology would be equivalent to a 20% of LV consumers adopting this technology in an entire system, which is a realistic situation for many countries).

Figure 3.6 shows the charges applied in the next tariff period, after including in the tariff calculation the effect produced by the new net load pattern of consumer 6, once PV generation is installed.

By comparing Figure 3.5 (left) and Figure 3.6, economic incentives received by consumer 6 are highlighted. Volumetric tariffs are slightly increased for all consumers because of the net demand reduction due to the PV installation. In the case of the accounting approach tariff, volumetric and contracted capacity charge periods are modified, since, in this new tariff period, off-peak hours are now accounted for in the first 8 hours of maximum utilization of the LV network. Likewise, as in the volumetric tariff, the overall charges are slightly increased because of the net demand reduction. Regarding the Forward-looking tariff, peak-coincident charges are allocated to those hours in which the transformer usage is above 60%. Peak-coincident charges are higher in this second case because transformer reinforcement costs are divided among a lower number of close-to-congestion hours. On the other hand, residual charges are not modified.

As a conclusion, under the ToU Energy and Capacity tariff, and the Volumetric tariff, consumers receive incentives to install distributed generation technologies, such as PV panels, by obtaining reduced network payments which do not correspond to actual or future network cost savings. Looking to the annual payments, consumer 6 would obtain different savings from the PV installation depending on which tariff is applied: Flat Energy tariff (105 €/year), ToU Energy and capacity tariff (13 €/year) or Forward-looking tariff (3 €/year).

The obtained results show that volumetric tariffs are particularly harmful in this situation since consumers are highly incentivized to self-generate. This means that the rest of the consumers will have to bear the burden of the costs avoided by this consumer. This situation leads to the so-called death spiral problem, which is both inefficient and inequitable.

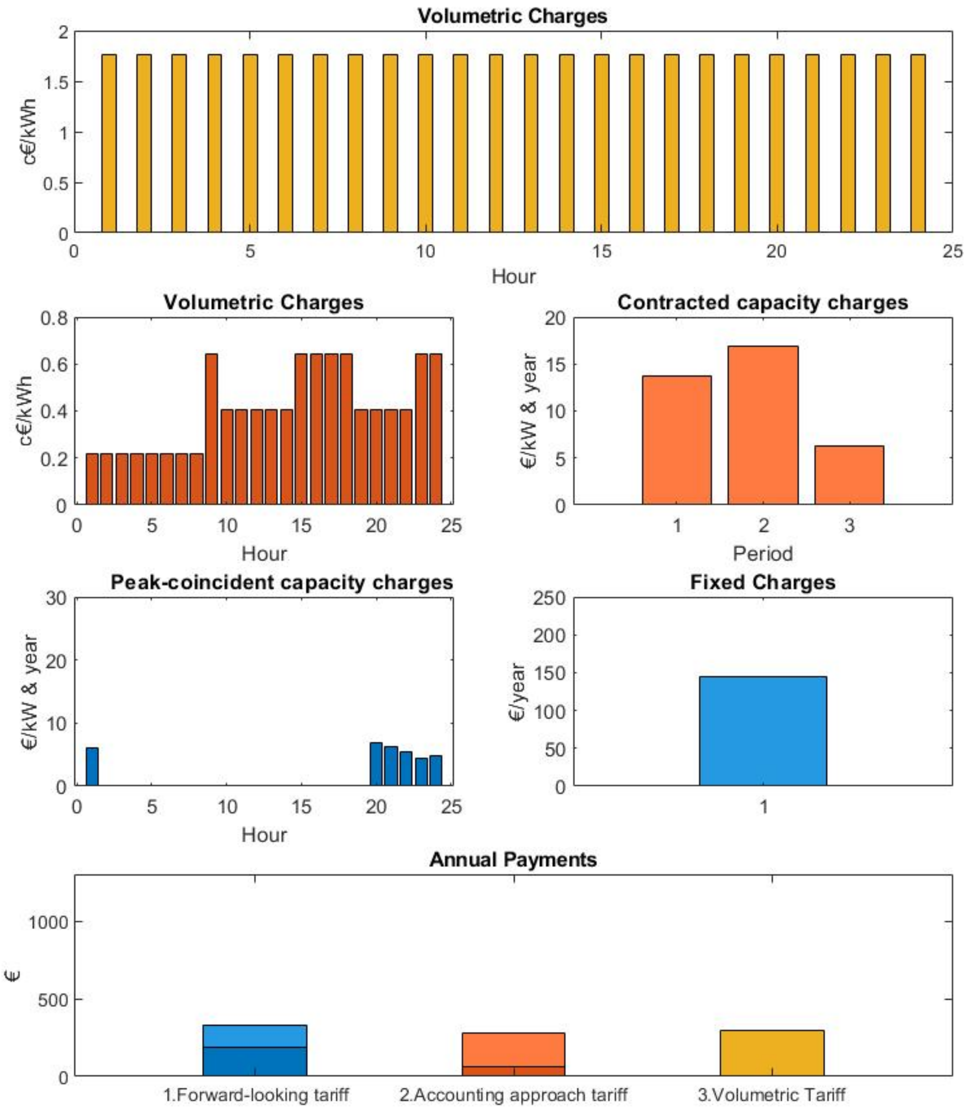

Figure 3.6. Charges applied to consumer 6 in the next tariff period. Flat energy tariff in yellow, ToU Energy and Capacity tariff in orange, and Forward-looking tariff in blue. Source: (Morell Dameto et al., 2020)

3.3. Conclusions

Electricity tariffs are being reviewed all over the world. The deployment of smart meters and other digital technologies, electrification of transport and building sectors, and decentralized DER massively connected to distribution networks make it indispensable to change the allocation of electricity system costs among users. The traditional guiding network tariffs principles are economic efficiency, equity, and transparency. However, as it was described in section 2.2, decarbonization, decentralization and digitalization have a significant impact on tariff principles, and thus, on how network tariffs should be designed.

Following the network tariff design explained in chapter 2, this chapter discusses how principles should be translated into the allocation of network costs. The proposed methodology aims to be a first-best theoretical approach, in which network charges are user-by-user and hourly calculated. Following the idea that Long-term incremental cost methods provide more efficient economic signals than standard accounting approaches, the proposed methodology segregates total network costs into long-term incremental costs and residual costs. To avoid double-charging effects, costs that are recovered through other economic signals such as connection charges, exit fees, or local flexibility markets, are subtracted from the recognised costs to be recovered through network charges.

Once costs to be recovered are known, long-term costs are allocated to customers considering their individual network usage at maximum network utilization hours at each element, i.e. peak-coincident charges, and residual costs are computed as non-distortive fixed charges. Peak-coincident charges are designed to ensure that network users receive signals that reflect the costs, in terms of future network reinforcements, of their network usage and encourage them to behave in a way that the social welfare is maximized. On the other hand, residual charges are designed to recover all system costs not recovered through peak-coincident charges. Residual charges do not send any economic signal that distorts efficient consumer responses to cost-reflective charges and energy prices.

Peak-coincident network charges with high locational and time granularity provide efficient signals to incentive price-responsive customers, but, in many jurisdictions, there are legal impediments for the implementation of locational tariffs. Socialization of tariffs between different geographical areas or regions is a current practice. While, for residual network charges, several options are discussed in the literature, fixed charges following equity principles discriminating between users by size, wealth, or other similar proxies are the preferred options.

Finally, the case study provides evidence of the benefits of applying the proposed forward-looking methodology in comparison to other current tariff designs based on an accounting approach: a Flat energy tariff and a ToU Energy and Capacity tariff. The three network tariffs are applied to a simplified network of 9 customers in which network flows, sunk costs and reinforcement costs are known for each network element. The results of the case study show the benefits of a location-differentiated network tariff, which allows for an optimal cost-reflectivity of network charges, especially when some network elements are expected to be congested in the future. In addition, the case study shows that the accounting approach tariffs provide over-incentives to customers to install self-generation to reduce their network payments, while network costs are not equally reduced. As a consequence of the lower network payments from self-generating consumers, network tariffs should be raised to ensure cost recovery, which further incentivize customers to adopt self-generation, producing the so-called death spiral problem.

The proposed forward-looking methodology solves the cost-reflectivity issue of the accounting approach tariffs, by reducing network payments only to those customers contributing to lower future network reinforcement costs, while ensuring cost recovery through the residual fixed charge. Although this study supports that economic efficiency is the leading principle in a network tariff design, equity principle cannot be forgotten. For example, what would happen if vulnerable consumers were located at the end of the feeder and thus face higher network costs. In this case, a levelized weighting of residual charges could alleviate equity issues, e.g., by reducing residual network payments for vulnerable consumers. However, further discussions are required to translate this theoretical proposal, both forward-looking and residual charges, into a tariff design to be practically implemented in real systems.

Chapter 4.
Forward-looking network tariff design for real-world systems

In the previous chapter, the formulation of a forward-looking dynamic peak-coincident network tariff is proposed and tested in a small feeder. Forward-looking or long-term costs were calculated for each network element according to the network utilization levels in an hourly basis, and network charges were calculated on a customer-by-customer basis. However, the applicability of this tariff formulation to real-world electricity systems, consisting of sublayers of different voltage levels, and containing thousands of network components with millions of customers is a challenge, which is a recurrent issue in practical tariff design (Manuel de Villena et al., 2019; Schittekatte and Meeus, 2020).

This chapter adapts the formulation of the forward-looking peak coincident network tariff to be applied to real-world electricity systems. In particular, the formulation is applied to the case of the Slovenian system, considering a whole year of data with hourly resolution. To deal with this challenge, a two-step approach is introduced:

1. The system-wide network is divided into subsystems, by voltage levels, under a cascade network model, where consumers and generators are clustered into those subsystems and treated symmetrically.
2. Then, like Ofgem's task forces organization, network costs are divided among forward-looking costs, energy losses costs, and residual costs (Ofgem, 2019b, 2022).
    a. Long-term incremental network costs calculated for each subsystem are allocated to the hours in which the maximum network usage is close to its maximum capacity limit, and then allocated to all downstream subsystems.
    b. Energy losses costs are allocated to energy charges calculated as the contribution of each customer group to the energy flow in each network voltage level.
    c. Residual costs, as the required revenue reconciliation after applying the proposed cost-reflective charges, are allocated to non-distortive fixed charges.

An additional contribution with respect to previous formulations of peak coincident network charges is to propose dynamic energy charges (€/kWh) instead of using dynamic capacity charges (€/kW). Energy charges, by sending economic signals at all relevant times within peak periods, avoid the lack of incentives to efficiently manage consumption that capacity charges would produce for a customer experiencing an unanticipated high consumption episode at the beginning of a billing period during which the maximum capacity is measured. Further details on this are provided in section 4.1.2. In addition, energy and capacity charges provide similar economic signals if they are hourly differentiated, as explained in section 3.1.2, being the former a simpler and easily understandable alternative.

The proposed network tariff design is applied to a system-wide case study, the Slovenian system, and its implications on active customers adopting PVs, EVs, or providing flexibility services, are compared to other two commonly used system-wide tariff designs. From the point of view of policy makers and regulators, the added value of the presented analysis lies in the system-wide scalability. Therefore, the economic implications for the analysed customers can be generalized to every customer in the system adopting these technologies. This is different from the results presented in small test feeders, which cannot be easily scaled up, because, in these cases, tariffs are calculated to recover only the test feeder's costs.

As shown in the case study, the proposed method could be applied to any electricity system with a significant number of customers with smart meters. The conditions that should be fulfilled to implement the proposed network tariff design are accurate information about time granular (hourly) energy consumption and generation at each voltage level, energy flows among voltage levels, and network costs of each voltage level. In addition, expected peak consumption and network cost growth by voltage level are required. Furthermore, the proposed solution could also be implemented in countries that are still in the way of full smart-meter deployment. In this case, customers with smart meters would face the cost-reflective network charge, while those customers without smart meters would face a weighted average of the same cost-reflective network charge, considering the aggregated hourly load profile of all customers without smart meters.

As theoretically expected, results show that the proposed method implemented in a real-world system increases economic efficiency by better aligning forward-looking network costs with individual network charges. However, higher economic efficiency would only be achieved if customers actually react to price signals. It is implicitly assumed that customers subject to the proposed network tariff design will, at least to some extent, adapt their grid usage to minimize their electricity bill. This is not an unreasonable assumption when thinking about the inherent flexibility of, especially, EV charging. In the existing literature, Jessoe and Rapson (2014) show that well-informed customers could reduce their electricity usage up to 22%, compared to 0% to 7% for the case of non-informed customers under the same economic signals. Therefore, it is critical to engage customers by showing them the benefits of reacting to price signals. Batalla-Bejerano et al. (2020) provide a thorough review of information strategies, such as social marketing and smart meter feedback, that can be an effective complement to price-based policies. A deeper analysis of how customers react to the different network tariff designs is left for future developments, as it requires considering a large range of factors such as individual price risk, education, loss of autonomy, privacy, etc. Regulators should consider the applicability of the proposed methodology, balancing the implementation costs, mainly driven by smart meter deployment and communication infrastructure, and the benefits derived from a higher efficiency on network tariffs, considering the customer engagement levels in each jurisdiction. The methodology and case study were published in (Morell-Dameto et al., 2023a).

The chapter continues as follows. Section 4.1 introduces the proposed network tariff design and its mathematical formulation for a real-world electricity system. Section 4.2 presents the Slovenian case study, showing the required input data, and the resulting network charges. Section 4.3 presents the implications of the proposed tariff in comparison to other two alternative tariff structures when active customers adopt EV, PV, or provide flexibility services. Finally, Section 4.4 concludes.

4.1. Formulation of system-wide forward-looking peak coincident network charges

In this section, system-wide forward-looking charges and residual charges are formulated for a time span of one year. This section is divided in four parts, which follow the network tariff design process presented in chapter 2, first segmenting network costs, and then setting the network charges for each of the identified cost segments, in this case three: forward-looking, energy losses and residual costs.

First, in subsection 4.1.1 the considered electricity system is schematically represented through a system-wide cascade network divided into voltage levels where both generation and demand are connected. Network users are classified according to customer groups depending on the voltage level at which they are connected, and whether they are generators or consumers. Then, network costs are divided among forward-looking costs, energy losses costs, and residual costs.

In subsection 4.1.2, forward-looking costs are allocated to peak-coincident energy charges in those hours of maximum usage of each network voltage level. In subsection 4.1.3, energy losses costs are allocated to energy charges calculated as the contribution of each customer group to the energy flow in each network voltage level. Finally, in subsection 4.1.4, residual costs are recovered through fixed charges based on the physical capacity of each customers' connection. Figure 4.1 shows the structure of section 4.1, as well as the summary of the proposed network costs allocation.

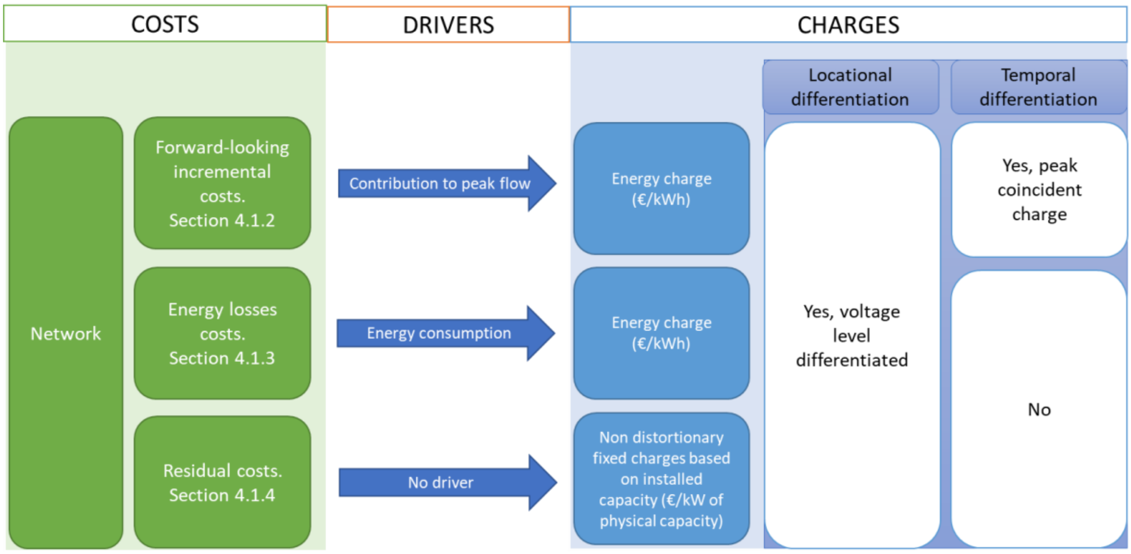

Figure 4.1. Summary of network costs allocation. Source: (Morell-Dameto et al., 2023a)

4.1.1. Network model and customer groups: cascade model and locational granularity

The adopted network model is a schematic representation of the considered system-wide network through a cascade model of hierarchically connected subsystems, one for each voltage level. Network users connected to each voltage level are classified under customer groups.

In each voltage level, two customer groups are differentiated: 1) generation, including generators and standalone storage installations, and 2) consumption, including both regular and active customers. The reason for this separation is that the final network tariffs are different depending on the customer group. While forward-looking charges are applied symmetrically to both customer groups, generation and consumption, residual charges are only applied to the consumption customer group. Figure 4.2 illustrates the adopted network model, in which each voltage level takes as inputs, the flow from the generation customer group connected at that voltage level and the flow coming from the upper voltage level, and as outputs, the flow to the consumption customer group connected to that voltage level, and the flow going to the lower voltage level.

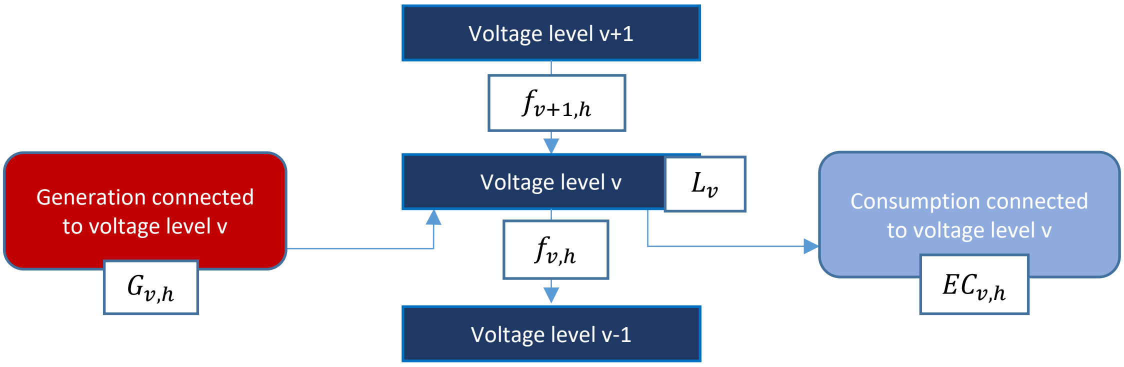

Figure 4.2. Network model. Source: (Morell-Dameto et al., 2023a)

The adopted network model allows calculating the impact of a customer group increasing its generation/consumption at a certain voltage level on the network flow of another voltage level. For example, assuming that all generation is connected to the HV network, the customer group connected at LV increasing 1 kWh its consumption would produce an increment of network flows at the HV network equal to 1 kWh multiplied by the applicable energy losses coefficients at each network voltage level connecting consumption (LV) and generation (HV).

The incoming energy flow from an upper voltage level ($f_{v+1,h}$) is calculated as the outgoing energy flow equal to consumption ($EC_{v,h}$) and flows to lower voltage levels ($f_{v,h}$) subtracting generation ($G_{v,h}$), and applying the voltage level's energy losses coefficient ($1 + L_v$), as shown in Eq. 13. Considering LV as the lowest voltage level (for LV, $v = 0$), this calculation is made upwards, starting from LV, where there are no flows to lower voltage levels ($f_{0,h} = 0$).

$$f_{v+1,h} = (1 + L_v) * (f_{v,h} + EC_{v,h} - G_{v,h}) \tag{13}$$

Under the proposed network model, voltage levels are considered black boxes in a cascade with inputs, outputs, and internal losses. In each voltage level, generation and consumption are both located at the lower (or downstream) side of the voltage level. As a consequence, under this network model, a marginal increase of energy injection produces the same energy flows and energy losses in the system than a marginal decrease of energy consumption in the same voltage level, which complies with the symmetry criterion for economic signals to both injection and withdrawals. Only in the case of the HV network, generation is located in the upper side of the voltage level, since it is considered as the slack bus, and therefore it is neither charged nor rewarded for the use of the network[1].

First, the calculation of the forward-looking peak coincident energy charges is explained. Second, the per-kWh charge for the energy losses costs. Third, the residual charge to fulfil the cost recovery objective.

4.1.2. Incremental network costs allocation

This section presents the mathematical formulation to calculate the long-term incremental network costs by voltage levels, in this case High Voltage, High Voltage/Medium Voltage, Medium Voltage, Medium Voltage/Low Voltage, and Low Voltage, as detailed in the case study (Section 4.2), and their allocation to peak-coincident energy charges for each customer group. The required inputs are the recognized network costs, the expected growth of network costs, the expected growth of peak demands of each voltage level, and the current hourly load profiles and generation profiles of each customer group for the calculation period, in this case, one year.

Cost segmentation by voltage levels

As an input for the methodology, it is required to breakdown the recognized network costs, including capital expenditures (CAPEX) and operating expenses (OPEX), by voltage levels (C_v). Moreover, an estimation of the annual growth of the network costs by voltage level (ΔC_v) coming from network expansion plans should be available. Costs per voltage level at the national level are considered; although further cost segmentation could be developed if zonal differentiation within the system-wide network were applied, which would provide more adjusted economic signals only to the specific congested zones. However, this would require a more detailed network model and data on current and future network costs divided by regions and voltage levels. The current lack of data, in most countries, on network topology and on differentiated network costs by zones is a barrier to further locational differentiation of network charges. This chapter, focused on the implementation of forward-looking network charges to real-world systems, acknowledges this barrier and proposes a voltage level differentiation of network costs and customers, and therefore, of network charges.

Determination of long-term incremental costs and residual costs

As discussed in section 3.1.1, cost minimization leads to tariff designs that are mainly addressed to minimize long-term network expansion costs. Thus, network costs are segmented between incremental and residual costs.

The incremental cost is obtained as the network expansion cost from the current situation to the long-term considered future. Incremental network costs per voltage level (ic_v) are calculated as the expected growth for network costs (ΔC_v) in the next Y years, as shown in Eq. 14. As it has been mentioned, in general, incremental network costs would be lower than recognized network costs (C_v), and residual network costs (rc_v) would be required to ensure cost recovery. So, in this case, residual network costs are calculated per voltage level as the remaining part of the recognized network costs (energy losses costs are neither considered)

[1] Should reverse flows become more relevant in the future, the selection of the slack bus will be a key topic for the cost-reflectivity of the network model. For now, by assuming HV generation as the slack bus, it is assumed that a marginal increase in demand in any node of the network will be compensated by an increase of HV generation. However, this may not hold true if decentralized generation is massively deployed.

after subtracting the incremental network costs recovered in that voltage level, as shown in Eq. 15. Subsection 4.1.4 comes back to the allocation of residual costs.

$$ic_v = C_v * [(1 + \Delta C_v)^Y - 1] \tag{14}$$

$$rc_v = C_v - ic_v \tag{15}$$

Allocation of incremental costs to peak-coincident energy charges

Under the adopted network model, the maximum flows through each voltage level would be considered as the driver of the long-term incremental costs. Following the economic efficiency principle, long-term network costs are recovered through peak-coincident forward-looking charges that measure the contribution of network users to the peak flows of each voltage level.

Peak coincident network charges should vary in time as the network peak usage only occurs at certain times of the year. Therefore, network costs are allocated to the hours in which the maximum usage of each voltage level is close enough to its maximum capacity limit, and therefore if the load would continue growing in the future, the forward-looking long-term incremental cost would be different from zero.

Once peak periods have been identified, it should be decided whether peak usage should be signalled through energy (€/kWh) or capacity (€/kW) charges. Capacity charges are commonly used to signal network costs since they account for the individual peak usage in a certain period, incentivising flat load profiles within the period of calculation. However, under capacity charges, a customer experiencing an unanticipated high consumption at the beginning of a metering period does not receive any incentive to efficiently manage consumption for the rest of the time within that metering period. Such randomness of sporadic short high consumption, or injection, situations can be avoided through energy charges, which incentivize optimal network usage at all relevant times within the peak periods. In addition, capacity charges make sense for time-block differentiated charges, in which only the highest peak consumption in each time-block is considered for the network tariff calculation. However, under hourly differentiated charges, capacity charges and energy charges produce similar economic signals, being energy charges simpler and more understandable.[2] Therefore, in the following, peak-coincident energy charges (€/kWh) are calculated.

Peak hours are identified as those hours when the estimated network usage in the future will be higher than a network capacity limit. Current network usage ($nu_{v,h}$) is calculated aggregating consumption ($EC_{v,h}$), flows to the lower voltage level ($f_{v,h}$), and subtracting generation ($G_{v,h}$), as shown in Eq. 16. The estimated network usage in the future horizon year Y ($nu_{v,h}^{Y}$) is calculated in Eq. 17 as the current network usage ($nu_{v,h}$) incremented by the annual expected growth of the network peak demand (ΔD_v) in the following Y years. On the other hand, the network capacity limit ($\overline{nu}_v$) is defined as the network usage threshold, above which, network reinforcements are required. This limit is calculated as the average of the *Z* largest hourly energy flows at the considered network voltage level Eq. 18. Figure 4.3 shows, for the sake of

[2] The concern that under capacity charges a consumer might lack the incentive to reduce its load during peak hours due to an unanticipated high consumption event early in the billing period could be addressed by not only considering the maximum demand during a billing period for the calculation of the forward-looking network charges but also the 2nd, the 3rd, etc., peak-coincident demand values. In the extreme case, assuming hourly differentiation of charges, all hourly demand values in a considered peak period could be considered for network charging purposes, which would lead to the same incentives as under hourly peak coincident energy charges. For simplicity, peak coincident energy charges are recommended.

illustration, an annual Load-Duration Curve (LDC) of the network flow ($nu_{v,h}$), which means that the load is ordered from high to low values, the LDC of the estimated network flow in the future year Y, $nu^{Y}_{v,h}$, and the network capacity limit $\overline{nu}_{v}$ for a LV network.

$$nu_{v,h} = \begin{cases} EC_{v,h} + f_{v,h} & if\ v = HV \\ EC_{v,h} + f_{v,h} - G_{v,h} & if\ v \neq HV \end{cases} \quad (16)$$

$$nu^{Y}_{v,h} = nu_{v,h} * (1 + \Delta D_{v})^{Y} \quad (17)$$

$$\overline{nu}_{v} = \frac{\sum_{h=1}^{Z} max\ (nu_{v,h})}{Z} \quad (18)$$

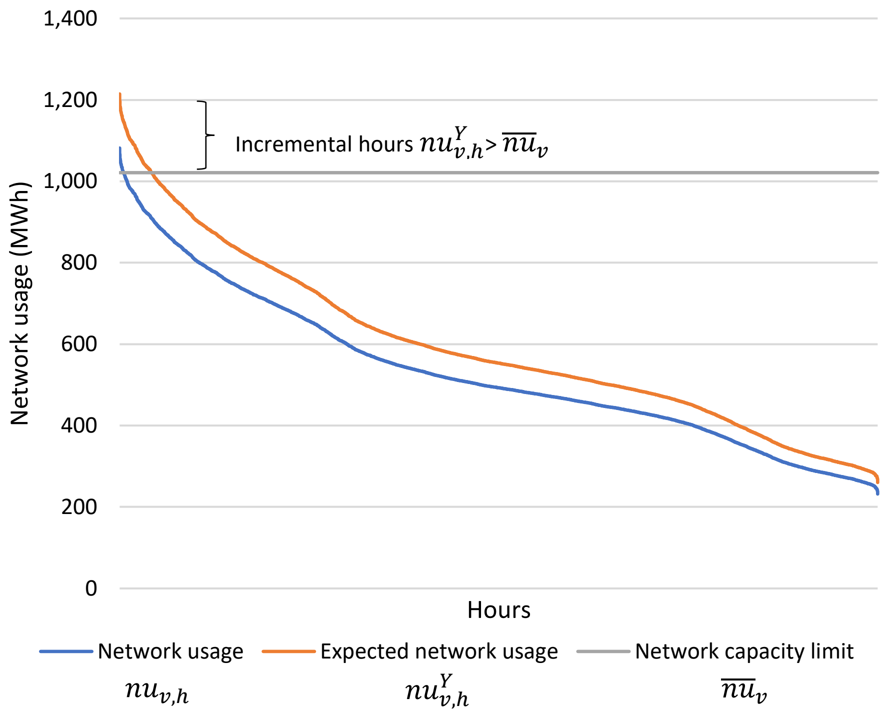

Figure 4.3. Load-duration curve of network usage, expected network usage, and network capacity limit. Source: (Morell-Dameto et al., 2023a)

The long-term incremental costs to be recovered at each voltage level (ic_{v}) are allocated to those hours in which $nu^{Y}_{v,h} > \overline{nu}_{v}$. The share of incremental costs allocated to each hour ($ic_{v,h}$) is proportional to the difference between the estimated network usage ($nu^{Y}_{v,h}$), and the network capacity limit ($\overline{nu}_{v}$) as shown in Eq. 19.

$$ic_{v,h} = \begin{cases} ic_{v} * \frac{nu^{Y}_{v,h} - \overline{nu}_{v}}{\sum_{h\,\epsilon\, nu^{Y}_{v,h} > \overline{nu}_{v}} (nu^{Y}_{v,h} - \overline{nu}_{v})} & if\ nu^{Y}_{v,h} > \overline{nu}_{v} \\ 0 & if\ nu^{Y}_{v,h} < \overline{nu}_{v} \end{cases} \quad (19)$$

Calculation of peak-coincident energy charges per customer groups

In the case of peak-coincident charges, cost-reflectivity and symmetry are the guiding criteria. Therefore, as theoretically proposed in section 3.1.2, both customer groups, generation and consumption, should be treated equally, since an increment in withdrawal has the same effect as a decrease in injection in terms of network usage. This might sound like a straightforward idea, but it is often not applied in practice (see e.g., the review provided by ACER (2021). The same peak-coincident charges are calculated for injections (-) and withdrawals (+). Assuming that peak-coincident charges are positive in a demand-driven congested network zone, generators, storage facilities and active customers when injecting energy into the grid would be rewarded at the same price as would be paid by regular or active consumers when withdrawing energy from the grid. The opposite would happen if peak-coincident charges are negative in a generation-driven congested zone.

For the calculation of peak-coincident charges, it is required to calculate the incremental flow through each voltage level due to an increase of demand or decrease of generation at any node represented in the network model, which is the PTDF (Power Transfer Distribution Factor). Note that in this case, $ptdf_v^j$ represents the incremental flow through the voltage level *v*, due to an incremental withdrawal of customer group *j*, who groups all network users connected to voltage level *w*, being $w \leq v$, instead of being a relation between a network element and a network user, as it was proposed in the previous chapter. $ptdf_v^j$ is calculated as the multiplication of the applicable energy losses coefficients of all crossed networks between voltage levels *w* and *v*, as shown in Eq. 20.

$$ptdf_v^j = \prod_{w \leq v} (1 + L_w) \tag{20}$$

Incremental network costs associated with each voltage level *v* ($ic_{v,h}$) are allocated to each customer group *j*, connected to voltage level *v* ($ic_{v,h}^j$), proportionally to the $ptdf_v^j$ multiplied by the energy withdrawn or injected by the customers connected to voltage level *v* ($net_{v,h}$), following Eq. 21.

$$ic_{v,h}^j = ic_{v,h} * \frac{ptdf_v^j}{\sum_{j \leq v} \left(ptdf_v^j * net_{v,h} \right)} \tag{21}$$

Where ($net_{v,h}$) is the net energy consumption at voltage level *u*, calculated in Eq. 22. As stated before, the HV generation is considered the slack bus.

$$net_{v,h} = \begin{cases} EC_{v,h} & if\ v = HV \\ EC_{v,h} - G_{v,h} & if\ v \neq HV \end{cases} \tag{22}$$

The peak-coincident energy charges for customer group *j* at hour *h* (it_h^j), are calculated as the sum of costs allocated to that customer group, coming from the same and upper voltage levels according to the cascade network model, as shown in Eq. 23.

$$it_h^j = \sum_{v \geq j} ic_{v,h}^j \tag{23}$$

4.1.3. Energy losses costs allocation

It is assumed that the allowed annual energy losses costs (LC) are allocated to customer groups as a network charge. Energy losses per voltage level *v* at each hour *h* ($l_{v,h}$) are calculated as in Eq. 24. Although a portion of energy losses is independent of the load on the network, mainly those related to energizing network transformers, known as core or iron losses, this formulation assumes that the main cost-driver of energy losses is energy consumption, which is responsible for three-quarters of energy losses (Western Power Distribution, 2022). Therefore, energy losses costs ($lc_{v,h}$) are allocated among voltage levels and hours of the year proportionally to the energy losses at each voltage level and hour, as shown in Eq. 25. Implicitly it is assumed that a higher temporal disaggregation of energy losses costs is not available.

$$l_{v,h} = L_v * (f_{v,h} + EC_{v,h} - G_{v,h}) \tag{24}$$

$$lc_{v,h} = LC * \frac{l_{v,h}}{\sum_{v,h} l_{v,h}} \tag{25}$$

The energy losses costs associated to each voltage level ($lc_{v,h}$) are allocated to each customer group *j*, proportionally to the corresponding PTDF multiplied by the energy withdrawn or injected by the customer group, following Eq. 26 and 27. According to their withdrawals and injections into the network, customers are charged/rewarded through losses energy charges, symmetrically, as in the case of peak-coincident energy charges. Although temporal differentiation is used for the calculation of energy losses charges, the high correlation between energy losses and net consumption leads to flat energy losses charges, as in Table 4.4.

$$lc_{v,h}^{j} = lc_{v,h} * \frac{ptdf_v^j}{\sum_{j \le v} \left(ptdf_v^j * net_{v,h}\right)} \tag{26}$$

$$lt_h^j = \sum_{v \ge j} lc_{v,h}^j \tag{27}$$

4.1.4. Residual network costs allocation

Residual network costs are recovered through residual charges, which are not meant to incentivize specific responses from network users (Ofgem, 2019d). Like taxes (except Pigouvian taxes), the basic objective for the allocation of residual costs is to minimize distortions to the already defined economically efficient charges and prices (Pérez-Arriaga, 2016). As it was discussed in section 3.1.3, charging generation or storage facilities with residual charges would distort their competition in the market. They would internalize those residual charges into their market offers, distorting the competition among them, and ending final customers paying them within the final energy price. Therefore, residual costs are solely allocated to the consumption customer groups, including both regular and active customers.

First residual network costs must be allocated to the different customer groups. Residual network costs have no driver, but the main cost-drivers when the legacy network investment was made were the energy consumption and the peak demand ("backward cost-causality"). Therefore, residual network costs are allocated to customer groups following the adopted cascade network model in which each consumption customer group is responsible for the residual network costs according to the network flows it produces at the same and upper voltage levels, as shown in Eq. 28-30. In Eq. 28, residual costs for each voltage level *v* (rc_v) are allocated to each consumption customer group *j* (rc_v^j) based on a coefficient (α_w^v) that is calculated as the participation of the consumption customer group *j*, which represents all consumption customers connected to voltage level *w*, over the flow in voltage level *v*. For the case of the LV (*v*=0), customers connected to this voltage level (*w*=0) are the only ones participating in the flow of that voltage level, and therefore $\alpha_0^0 = 1$, as in Eq. 29. In the case of higher voltage levels, the coefficient (α_w^v) is proportional to the annual energy consumption at voltage level *v* ($\sum_h EC_{v,h}$) over the annual energy flowing downward through the voltage level *v* ($\sum_h f_{v,h}$), as shown in Eq. 30.

$$rc_v^j = rc_v * \alpha_w^v \tag{28}$$

$$\alpha_0^0 = 1 \tag{29}$$

$$\alpha_w^v = \begin{cases} \frac{\sum_h f_{v,h}}{\sum_h EC_{v,h} + \sum_h f_{v,h}} \alpha_w^{v-1} & if\ v > w \\ \frac{\sum_h EC_{v,h}}{\sum_h EC_{v,h} + \sum_h f_{v,h}} & if\ v = w \neq 0 \\ 0 & if\ v < w \end{cases} \tag{30}$$

As mentioned in section 3.1.3, fixed charges can be a postage-stamp rate, an income-based charge, a capacity-based charge, or based on historical consumption. Considering the data availability requirements of all alternatives, a capacity-based charge is the most easily implementable for a current real-world system. Physical capacity is the most unmodifiable charging variable out of the three types of capacity charges (contracted, measured or physical). Therefore, physical capacity of users' connection is the variable for calculating individual fixed charges for each consumption customer group, as shown in Eq. 31. Residual network charge (in €/kW) for customers in the consumption customer group *j* (rt^j) is calculated as the sum of the residual costs allocated to customer group *j* (rc_v^j) of each voltage level divided by the aggregated physical capacity of customers included in the consumption customer group *j* (CAP_j).

$$rt^j = \frac{1}{CAP_j} \sum_v (rc_v^j) \tag{31}$$

4.2. Case study

The numerical application of the proposed tariff formulation to the Slovenian electricity system is presented with 2019 data. The total electricity consumption of the Slovenian system was 12,748 GWh, with a peak demand of 2,193 MW. The total number of customers was almost 950,000, and the smart meters roll-out was above 75%. By the end of 2021, the smart meter roll-out reached 88% (ACER/CEER, 2022), and it is expected to increase to 100% by 2025, according to their National Energy Climate Plan (NECP) (European Commission, 2018).

In the case of Slovenia, the cascade network model is composed of the following five voltage levels: high voltage networks ($v = 4$), HV/MV substations ($v = 3$), medium voltage networks ($v = 2$), MV/LV transformers ($v = 1$), low voltage networks ($v = 0$). Differentiating substations and transformers from MV and LV networks is case dependent, and the reason behind that is the historical network model applied in previous regulatory periods. According to that, generation and consumption customer groups, follow the same logic, are represented as:

- Customer group 4 – HV customers, connected to 400, 220, or 110 kV.
- Customer group 3 – MV customers connected to MV bus bar of HV/MV substation.
- Customer group 2 – MV customers connected to 35, 20, or 10 kV.
- Customer group 1 – LV customers connected on the LV bus bar of MV/LV transformers.
- Customer group 0 – LV customers connected to 400/230 V.

4.2.1. Data

Data used for the case study were the recognized network costs by the regulator and other inputs provided by the Energy Agency of Slovenia: the annual network and energy losses costs, the annual growth of network costs, and the annual growth of peak demand for each customer group, the energy losses coefficients, and the aggregated hourly energy consumption, generation, contracted capacity by each voltage level. The number of years for the planning horizon, Y, was 10, and the number of hours in the year with the largest network usage that would induce network reinforcements in the future, Z, was 100[3].

Table 4.1 shows the network costs of the Slovenian system divided by voltage level used to apply the proposed methodology. Table 4.2 shows the energy consumption, generation of each customer category, as well as energy losses, network capacity limit and the annual growth of peak demand values for each voltage level. The expected growth of costs and peak consumption are based on the NECP and considering the electricity consumption recovery after economic stagnation due to COVID-19 (European Commission, 2018).

Voltage level	Network costs (€/year) – C_v	Annual growth of network costs (%) - ΔC_v	Energy losses costs (€/year) – cl_v	Energy losses coefficients (p.u.) – L_v	Network capacity limit (MW) – $\overline{nu}_v$
4	69,120,218	3.29%	16,071,036	0.016	2,089
3	33,813,964	4.32%	852,957	0.002	1,863
2	72,203,762	4.43%	9,192,931	0.025	1,685
1	39,756,524	2.56%	1,127,785	0.005	1,143
0	85,068,056	1.48%	9,811,401	0.050	1,022

Table 4.1. Network costs, annual growth of network costs, energy losses costs, energy losses and network capacity limit for each voltage level in the Slovenian system. Source: (Morell-Dameto et al., 2023a)

Customer group	Energy consumption (MWh) – ec_v	Generation (MWh) - $\sum_h G_{v,h}$	Physical capacity (kW) – CAP_j	Annual growth of peak demand (%) - ΔD_v
4	2,122,660	12,365,438	371,971	0.62%
3	1,243,188	68,621	148,538	0.97%
2	3,960,406	618,526	883,482	0.97%
1	483,366	20,881	137,659	1.32%
0	4,937,972	288,188	8,146,559	1.32%

Table 4.2. Input data for each customer group in the Slovenian system. Source: (Morell-Dameto et al., 2023a)

4.2.2. Network charges

Results for the peak-coincident network charges are first presented. After, the results for the losses, and finally, the residual charges are discussed.

Peak-coincident network charges

Figure 4.4 shows the symmetrical peak-coincident forward-looking energy charges for the different customer groups connected at each voltage level, each block representing one voltage level. From left to right, HV, HV/MV, MV, MV/LV, and LV are represented. Only the relevant months are displayed, from January to March, and December since peak-coincident energy

[3] Note that Z represents the number of hours in which a higher network usage could produce network reinforcements in the future. If Z is lower, few hours would have high network charges, while if Z is higher, many hours would provide economic signals to customers, the same long-term network costs would be distributed among more hours, and hourly charges would therefore be lower. For a system in which network peaks are not expected to move between hours, as in the current Slovenian case, a lower value of Z better reflects those few hours that are really contributing to network reinforcements. However, as it will be observed in chapter Chapter 5, a system with a high share of customers responding to economic signals would require a higher Z, up to 1000 to 1500 hours, to avoid customer response synchronization and the peak-shifting effect.

charges are only non-zero during these months. For the rest of the months, peak-coincident energy charges are null in all voltage levels. Three observations are made.

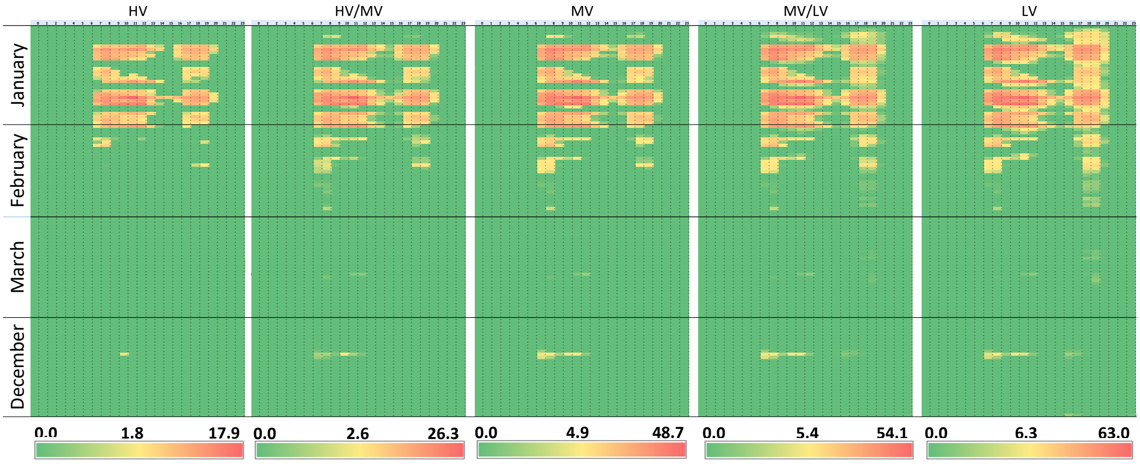

Figure 4.4. Peak-coincident energy charges in c€/kWh for January-March and December 2019. From left to right: HV, HV/MV, MV, MV/LV, and LV. The 24 hours are presented in the columns and days in the rows. Source: (Morell-Dameto et al., 2023a)

First, only during a few winter months the peak-coincident charges are non-zero. This occurs as the network costs are driven by peak demand and Slovenia is a largely winter peaking country. In other seasons, there are no long-run cost associated with network usages as usage remains significantly under the winter peak. Second, the lower the voltage-level the higher and more spread the peak-coincident charge. This can be explained by the fact that electricity still mainly flows from higher to lower voltage level, i.e., lower voltage levels pay for costs associated to their own voltage level and all voltage levels above. In the end, the lowest voltage level observes a coincident peak charge that is an aggregate of all the coincident peak-charges of all voltage levels (including its own). Third, within the winter days there are also significant changes of the peak-coincident charge. That makes sense as electricity usage varies significantly within the day. Figure 4.5 presents more detail on the obtained symmetrical hourly peak-coincident energy charges (in €/MWh) for each generation/consumption customer group for two representative days: winter weekday, winter weekend.

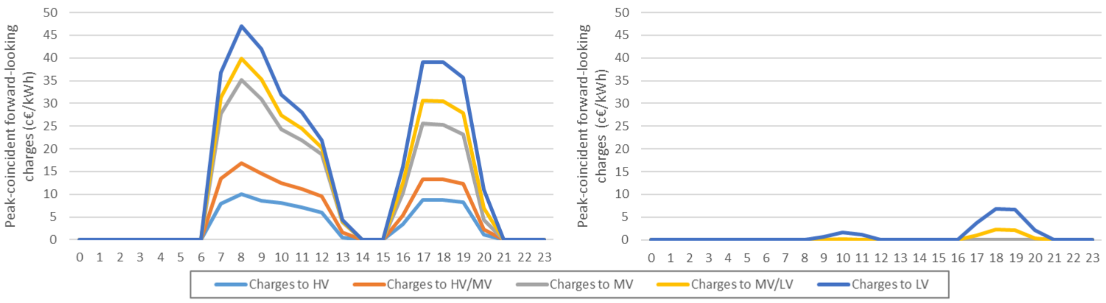

Figure 4.5. Example of peak-coincident network charges for: left- winter weekday (09/01/2019) and, right- a winter weekend (20/01/2019). Source: (Morell-Dameto et al., 2023a)

Energy losses charge

In the case of energy losses charges, the obtained results are a flat energy charge for all hours that differs per customer group. Table 4.3 shows the energy losses charges, and the portion of this charge associated with each voltage level. Similar as with the discussion above, as electricity still mainly flows from the highest to the lowest voltage levels, customers connected to the lower voltage levels pay/receive more than customers connected to the highest voltage levels.

Customer group	VL0	VL1	VL2	VL3	VL4	Total
0	0.187	0.020	0.099	0.008	0.163	0.477
1		0.019	0.094	0.008	0.156	0.276
2			0.093	0.008	0.155	0.256
3				0.007	0.151	0.159
4					0.151	0.151

Table 4.3: Energy losses charges for each customer group. Units c€/kWh. Source: (Morell-Dameto et al., 2023a)

Residual network charge

Finally, residual network charges under the proposed formulation for consumption customer groups are presented in Table 4.4. The residual network charges are a fixed charge based on the physical capacity of users' connection (kW). Different from the peak-coincident charges and the energy losses charges, the LV customers pay the lowest per unit residual network charge. The explanation for this is that the LV customers usually have oversized physical capacities (see Physical capacity vs Energy consumption in Table 4.2), meaning that they use much less than the available supply capacity.

Voltage level	Residual charge (€/kW month)
4	1.657
3	3.517
2	3.125
1	3.995
0	1.414

Table 4.4: Residual network charges for each consumption customer group. Source: (Morell-Dameto et al., 2023a)

4.3. Implications of alternative tariffs on active customers

Regulators and policy makers face the task of enabling the most efficient participation of distributed resources in real-world electricity networks. The aim of this section is to discuss the beneficial impact of implementing the proposed network tariff design in a context of an increasing number of customers adopting flexible loads such as EVs, on-site generation such as PVs, and increasingly providing flexibility services. Concretely, the economic signals provided by the proposed tariff are compared to two other conventional network tariff designs. The following of this section consists of three parts. First, the two alternative network tariff designs are introduced. Second, the impact of the different network tariff designs on active customers with PV and EVs is analysed. Third, the interaction of tariffs with DSO local markets, and the provision of system services is discussed.

4.3.1.Alternative tariff designs

The two selected conventional alternatives are: i) the current network tariff applied in Slovenia (Mohar et al., 2005), and ii) a more cost-reflective energy and capacity-based tariff, both with time-of-use (ToU) differentiation, based on the current network tariff applied in Spain (CNMC, 2020), which was explained in detail in section 3.2.2. To allow for a fair comparison among network tariff designs, all are enforced to recover the same total recognized network costs (considering the entire power system). For simplicity, comparisons are focused on the impact on household active customers connected to the low voltage level.

Current network tariff applied in Slovenia

The actual network charges in Slovenia are based on energy charges and a charge based on the physical capacity, thus not modifiable and time independent. The energy charges differ for peak (weekdays from 6am to 10pm) and off-peak (weekdays from 10pm to 6am and weekends) hours. Table 4.5 shows network charges for 2019.

Voltage level	Customer group	Energy charge (c€/kWh)		Physical capacity charge (€/kW-month)
		Day tariff	Night Tariff	
0	households	4.077	3.135	0.75872

Table 4.5. Current network charges for 2019. Source: (Morell-Dameto et al., 2023a)

ToU energy and capacity tariff (currently applied in Spain)

A ToU energy and capacity tariff is currently applied in Spain. Under this tariff, network costs associated with each voltage level are broken-down in energy and capacity driven costs and allocated to energy charges (€/kWh), and contracted capacity charges (€/kW-month), respectively. Remembering section 3.2.2, around 75% of total network costs are considered capacity driven, and the rest, 25% of total network costs, are considered energy driven.

Then, network costs are allocated to predefined time-blocks according to the contribution of the load at each time-block to the system load peak, so that network usage in off-peak periods is more incentivized than in peak periods, through ToU energy and capacity charges. Hours of the whole year are classified under time-blocks according to electrical seasons based on the system load curve (High season goes from December to March, and Low season from April to November), weekdays or weekends, and different intraday time-blocks, as shown in Table 4.6.

	Time block 1	Time block 2	Time block 3	Time block 4	Time block 5
High season Weekday	From 7 to 14, and from 17 to 20	From 6 to 7, and from 14 to 17, and from 20 to 22		From 0 to 6 and from 22 to 0	
Low season Weekday			From 7 to 20	From 6 to 7 and from 20 to 23	From 0 to 6 and from 23 to 0
High season Weekends and holidays			From 8 to 14 and from 17 to 21	From 7 to 8, from 14 to 17 and from 21 to 22	From 0 to 7 and from 22 to 0
Low season Weekends and holidays				From 9 to 14	From 0 to 9 and from 14 to 0

Table 4.6. Resulting hours in each time-block under the ToU energy and capacity tariff. Source: (Morell-Dameto et al., 2023a)

Finally, charges associated with one voltage level and a time-block are divided among lower voltage levels, based on their proportional network usage of each voltage level. Table 4.7 presents the resulting ToU Energy and Capacity network charges for LV customers for Slovenia in 2019.

Voltage level	Time-block	Capacity charge (€/kW month)		Energy charge (c€/kWh)	
		High season	Low season	High season	Low season
0	1	2.89936		1.355	
	2	1.20590		1.360	
	3	0.45751	0.45751	1.243	1.243
	4	0.08053	0.08053	1.282	1.282
	5	0.00397	0.00397	1.215	1.215

Table 4.7. Network charges under the ToU energy and capacity tariff. Source: (Morell-Dameto et al., 2023a)

4.3.2.Active customers with PV and EVs

On-site generation and flexible loads such as EVs provide customers the ability to react to the network tariff, as well as to the rest of the electricity bill. As the case study of chapter Chapter 3 demonstrates, PV generation only decreases long-term network costs if the generated energy is injected into the network during peak hours. Following the same reasoning, EV charging at peak periods should pay the true (future) costs they cause, while EV charging at off-peak should be stimulated as it does not entail additional future costs.

To quantify the implications of the three network tariffs on active customers, a representative Slovenian household with a physical capacity of 11kW and an annual consumption of 8 MWh/year is modelled when adopting solar generation (PVs) or electric vehicles (EVs) in an illustrative example. Four cases are considered, one for a household customer adopting a 3.5 kW-peak PV installation (annual generation of 4.88 MWh); and three EV cases (annual consumption of 4 MWh) with different charging strategies: slow charging during off-peak periods, slow charging during peak periods and fast charging during peak periods.

Figure 4.6 shows the average individual consumption under the four proposed cases in the 100 hours of highest network usage, compared to the original load profile (OP). The 100 hours of the highest load (see the LDC in Figure 4.3) are used as a proxy for the contribution of individual network usage to the network costs. Fast EV charging at peak hours is mostly coincidental with hours of higher network usage, while slow EV charging at off-peak hours does not increase the network usage when is already high. PV generation reduces the individual consumption in many hours of the year, but in the hours of highest network usage, usually winter days, this reduction is small. Note that in Figure 4.6, PV case shows the net load profile obtained as the original load profile minus the PV generation, i.e., the electricity withdrawn from the grid.[4]

[4] Note that the energy generated by the PV installation is used for self-consumption in a net-billing approach for each 15 min profile data, meaning that the energy is not netted among different 15-min intervals. When the generated energy is higher than the consumed energy in a 15-min interval, the net energy is injected into the grid, and when it is lower, the net energy is consumed from the grid.

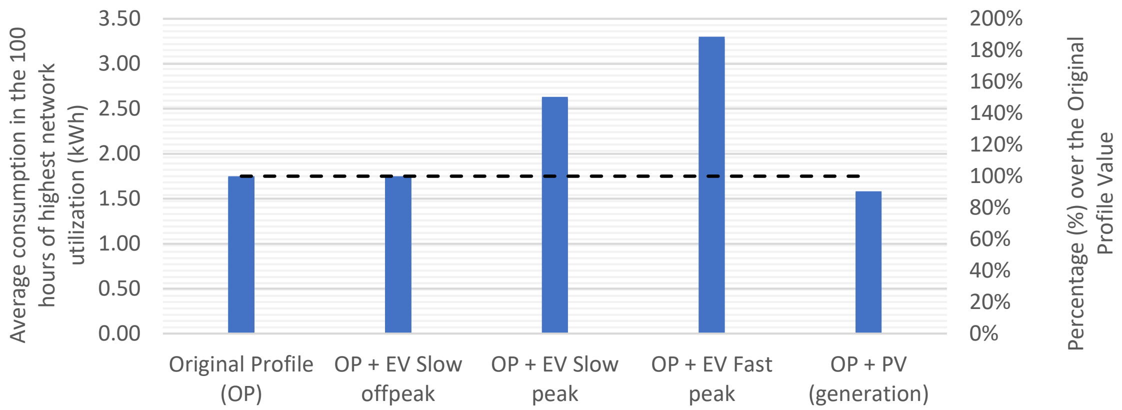

Figure 4.6. Contribution of PV and EV charging cases to the 100 hours of highest network utilization. Source: (Morell-Dameto et al., 2023a)

Figure 4.7 shows the annual payment of the customer under each network tariff design. Annual payments are grouped from April to November, and from December to March (winter) to show the differences between months with and without intensive use of the network. Under the current Slovenian tariff and the ToU energy and capacity tariff, injected energy into the grid is neither paying, nor being remunerated by network charges. While under the proposed tariff, a symmetric forward-looking network charge is applied, i.e., injections are remunerated. The benefits of PV when reducing energy purchases or selling energy surpluses to the market are not considered, only the effect of network tariffs is discussed. For the case of the current Slovenian tariff and the ToU energy and capacity tariff, energy losses payments are implicitly allocated to the general energy charges. While for the forward-looking tariff, energy losses payments (yellow) are unbundled from forward-looking payments (orange).

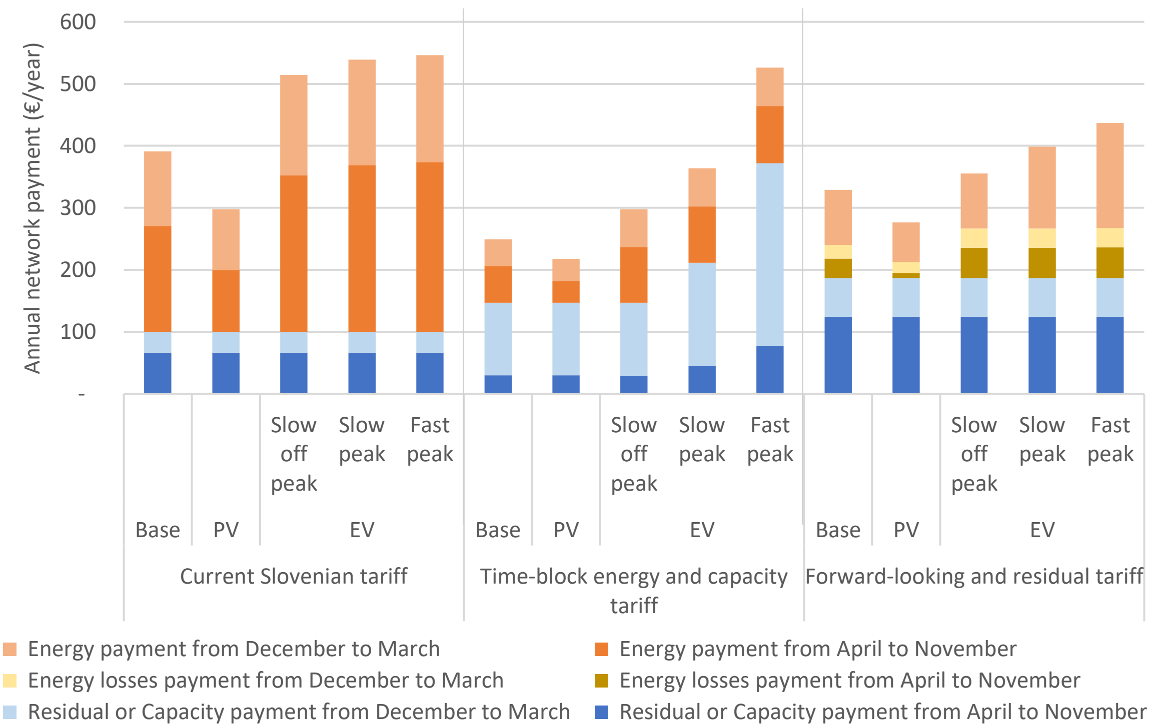

Figure 4.7. Network payments (€/year) for a representative LV customer household under each tariff design after installing PV or EV following three strategies: slow off-peak, slow peak, and fast peak. Source: (Morell-Dameto et al., 2023a)

First, the network charges for the base case (low voltage connected household without PV or EV) across the three different network tariff designs is not the same. Besides the exact network tariff design, the main driver behind this difference is the allocation of the network charges across the voltage levels. In the current Slovenian network tariff methodology, a larger share of costs is allocated to the lowest voltage-level compared to the network tariff applied in Spain and the proposed network tariff. The latter more cost-reflective approaches allocate more network costs to higher voltage levels and thus to commercial and industrial consumers.

Second, when looking at the relative network cost differences between the different users per network tariff it can be seen that all three network tariffs at least respect the ranking indicated by Figure 4.6, i.e., the consumer contributing the least to the cost driver pays the lower network charges and vice versa. However, the relative differences in network charges paid per consumer are significantly different per network tariff design. Each network tariff design is discussed individually.

The current Slovenian approach shows the disadvantages of a network tariff with a high share of energy charges and low temporal differentiation. The relative benefit from PV adoption is the highest for this network tariff design with a reduction of about -25% of network charges paid compared to the base case. Such reduction overstates the network cost savings of the adoption of PV. At the same time, EV charging during peak times is nearly equally valued as EV charging in-off peak periods, which does not reflect the actual network cost savings of one strategy versus the other and thus does not sufficiently incentivize off-peak charging. From Figure 4.6 it can be seen that the impact differences between off-peak and peak charging are substantial, basically no additional stress is put on the network under off-peak charging, while the contribution to the network peak nearly doubles under fast peak charging.

Under the ToU energy and capacity tariff, for the case of PV adoption, the contracted capacity cannot be reduced as the PV production is not aligned with the individual peak consumption. The observed savings in network charges under PV are due to the lower net energy consumption in almost all time-blocks, and thus failing to incentivize PV adoption when it is able to reduce long-term network costs (e.g., by pairing it with storage and inject during peak periods). In the case of EV adoption, strong incentives are provided to move from fast to slow charging, but assuming that a significant portion of network costs is residual (“sunk costs”), this network tariff design tends to over-penalize a capacity increase due to EV charging, implying, in the end, raising the barrier for transport electrification. For example, fast charging is more expensive than slow charging during April to November when there would be no issue in accommodating this load.

Finally, the proposed forward-looking tariff succeeds in reducing the energy payment of a customer installing a PV when the generation profile is aligned with peak-coincident hours in winter season. In the case of EV adoption, slow off-peak charging is highly incentivized since the increment in peak network flows is almost negligible when compared to the base case in Figure 4.7, the minor increase in network charges is driven by the increase in losses due to the higher volume of total electricity withdrawn from the network. Importantly, fast charging is penalized only during network peak hours in the winter. Figure 4.8 summarizes the previous discussion showing the relation between the contribution to the 100 hours of highest network usage and the increment in network payments under each tariff subtracting the residual and energy losses payments. Note that both contribution to peak and network payment values are divided by the corresponding original profile (OP) values to allow a comprehensive comparison. The ideal network tariff design is the one where network charges increase proportionally with the increased contribution to the network cost driver (see also Passey et al. (2017) doing a similar analysis for Australia).

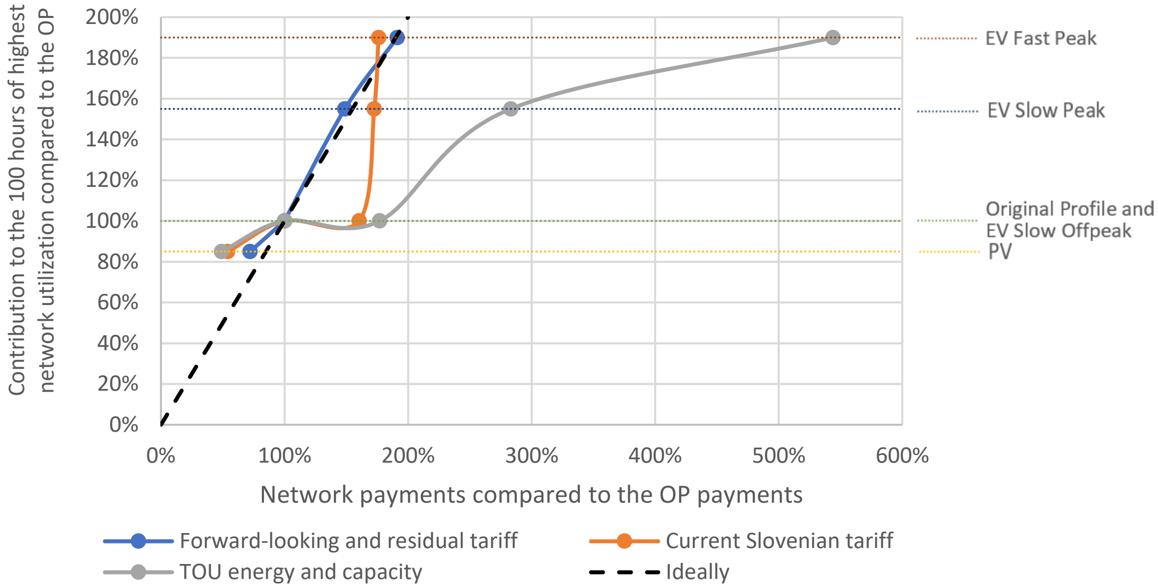

Figure 4.8. Relation between contribution to 100 hours of highest network utilization and incremental network payments (excl. residual network costs and energy losses costs) under the three tariff structures. Source: (Morell-Dameto et al., 2023a)

4.3.3. Active customers providing flexibility services and the role for symmetric network charges

The flexibility provision is understood as intended energy deviations (upward and/or downward) under DSO local markets or services (e.g., balancing, congestion management), which can be provided by any network user able to modify its baseline demand/generation profile with respect to previous commitments to support the system. Historically, generators provided flexibility services, however, today and even more so in the future, standalone storage and active customers are expected to also provide these services. The objective of a regulator is to settle a level playing field for fair competition and enable the participation of all service providers in order to minimize the total costs of these services which are finally levied from all consumers.

From the point of view of the network tariff design, under the current Slovenian tariff or the ToU energy and capacity tariff, active customers or storage units providing flexibility services by increasing their consumption with respect to the baseline profile are subject to additional network capacity and energy charges, while generators reducing their injections would not face any initial or additional network charge, since network injections are neither charged nor rewarded in terms of network usage, as seen in Figure 4.9. With regards to impacts on the grid, increasing consumption or reducing generation at the same connection point are equivalent. Therefore, both commented ''non-symmetric network tariff designs'' imply an unequal treatment for active customers or storage installations providing flexibility services with respect to generators.

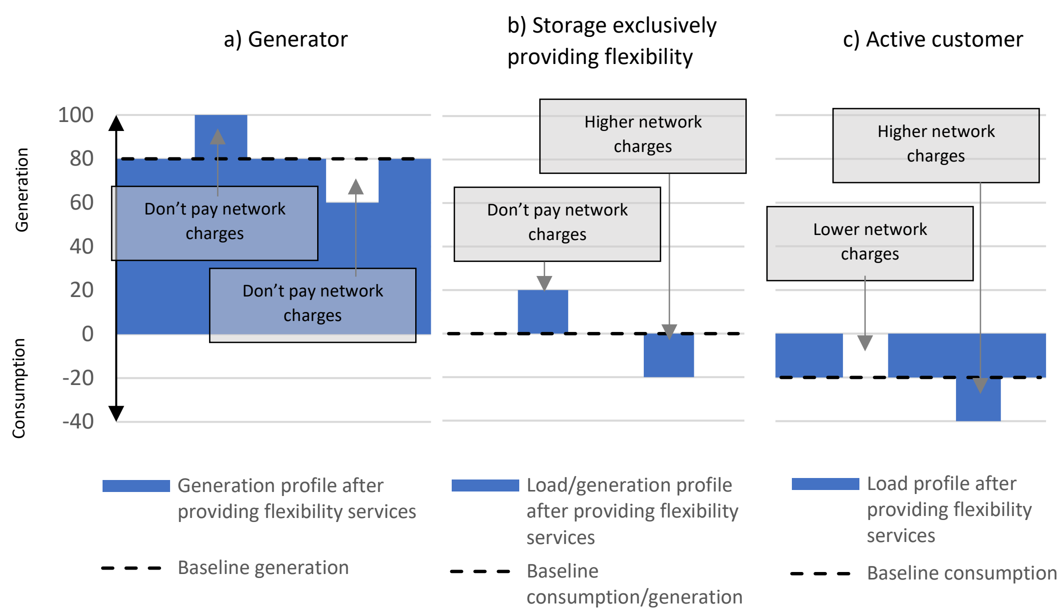

Figure 4.9. Network charges increase/decrease after providing upward or downward flexibility services under non-symmetric network tariffs for a) generator, b) storage exclusively providing flexibility services, and c) active customers. Source: (Morell-Dameto et al., 2023a)

To avoid this undesired effect, in some jurisdictions, regulators exempt those grid users of network charges when they provide flexibility services, as it happens in Spain under a ToU tariff design with stand-alone storage installations (CNMC, 2020). Such solution might work in case the action of the flexibility provider has no impact or even improves local network conditions. This might be the case when for example flexibility is delivered to the distribution system operator (DSO) to solve local network constraints, i.e., in a local flexibility market. However, in case the flexibility provider sells balancing energy to the transmission system operator (TSO), the activations from the flexibility provider are completely decoupled from the local network situation. In such case, exempting the flexibility provider from the network tariff could be unjustified and increase network stress.

In contrast, under the forward-looking peak coincident tariff, flexibility providers would be charged/rewarded by the final net consumption/injection profile once flexibility services have been provided. Due to the symmetry of peak-coincident energy charges, each flexibility service provider would internalize in their flexibility offers the involved network charges, resulting in the aforementioned level playing field and incentivizing them to account for network usage.

4.4. Conclusions

The aggregated impact on the grid of technologies related to the transition to a more decarbonized economy, like solar PV panels, energy storage systems, heat pumps and electric vehicles is expected to be massive in the near future. Regulatory authorities are responsible for promoting a more efficient, decarbonized, and equitable power system coordinating the actions of increasingly active consumers and the network by revisiting the network tariff design.

This chapter presents a step forward in the implementation of LTIC-based methods in real-world systems. In the previous chapter, the LTIC-based method was applied to a single feeder, resulting in customer-by-customer charges, which is impractical for real-world cases. The solution proposed in this chapter to the real-world complexities is the division of the network via a cascade model in which energy injections and withdrawals are classified according to their voltage level connection and treated symmetrically. After, network costs are determined per voltage-level, and then, voltage-level specific forward-looking peak-coincident charges, charges for energy losses, and non-distortive residual network charges are calculated. The residual network charge complies with the cost recovery objective; considering equity principles and the limited data availability in real-world systems, a fixed charge based on the physical capacity of user´s connection is proposed. The physical capacity of a user's connection is dependent on the customer electrical installation and can typically not be modified by customers.

The current Slovenian tariff and a ToU energy and capacity network tariff are used to demonstrate the benefits of the proposed forward-looking network tariff design applied to different types of active customers. The proposed tariff incentivizes the efficient use of flexible loads, for instance, slow versus fast EV charging, and EV charging in off-peak versus peak hours, while still promoting the electrification of transport. In the case of customers adopting PV installations for self-consumption, the proposed tariff provides less of a discount compared to the current tariffs, aligning better individual customer benefits with expected system benefits, reducing, in the end, long-term network costs. Moreover, it is illustrated that when active customers provide flexibility services, the symmetric nature of the proposed tariff enables a level playing field in which any exemptions of network charges are not required, as it would happen with the other two compared alternatives. Under the forward-looking tariff, customers are exposed to variable peak coincident network charges with the associated risks. However, it is important to note that customers can select the retailer and electricity supply contracts that better fits their risk management strategy and the desired complexity. Thus, retailers are expected to play a key role in translating network charges into electricity bills, by offering diverse products, from pass-through contracts to fixed prices with the associated premiums. Moving towards a more complex network tariff design could encounter objectors since the right balance between principles is not equally perceived by all stakeholders involved. In fact, any network tariff reform has some political cost for the responsible administration since network cost recovery is a zero-sum game, at least in the short term, in which any tariff modification produces winners and losers among network users. This chapter, by comparing different network tariff designs, aims to support regulators' decisions on more economically efficient and equitable network tariff designs that in the long run will lead to system-wide cost savings.

Future implementations of cost-reflective advanced tariff designs would require higher locational and temporal granularity. Regarding locational granularity, more detailed network models differentiating areas depending on topologies, rural, urban, and semi-urban, and considering actual and future levels of penetration of distributed energy technologies, would be required. Regarding temporal granularity, hourly and even 15-min tariffs are required, provided by smart meters, to discriminate the actual use of the network and the responsibility of network injections and withdrawals on those flows. Regarding the anticipation to set dynamic tariffs, the tendency is moving from one year in advance to a more dynamic price setting, with monthly, weekly, or even daily tariff updates, as it happens with dynamic energy prices indexed to wholesale electricity markets.

The proposed tariff formulation can be easily adapted to include both discussed higher granularities, and therefore it stands out as a good option for regulators and policymakers to gradually improve future network tariff designs. While this chapter demonstrates that a forward-looking network tariff can be applied to any real-world electricity system with the sufficient level of smart metering deployment, the following chapter Chapter 5 deepens in the potential future advances and challenges of its practical implementation in a context of many customers adopting distributed energy resources and responding to network tariff economic signals.

Chapter 5.
Future-proof network tariff design

In previous chapters, a theoretical discussion and a mathematical formulation for the implementation of forward-looking incremental network charges have been presented, first for a simplified network and then for a real-world system. This chapter moves one step further and analyses how the proposed forward-looking network tariff design would perform in an environment of many flexible customers reacting to price signals, what challenges could encounter in that plausible future, and what solutions would improve the network tariff design in terms of the principles of economic efficiency, equity and transparency.

The proposed environment of many flexible customers responding to price signals derives from the ongoing and further expected electrification of transport and heating, and the deployment of smart meters and other smart devices, such as automatic thermostats or, smart EV charging, among other home energy management systems that will help customers to reduce their electricity bills by modifying their consumption patterns automatically, i.e., without manual intervention other than pre-setting conditions such as in-house thermal comfort, or the state of EV battery in the morning. The EU had an initial goal of deploying at least 1.5 million energy saving smart thermostats in 2022 (European Commission, 2023a), along with a strategy for the adoption of additional 30 million heat pumps by 2030 compared to 2020 (European Commission, 2023b). Some commercial examples of smart EV chargers and thermostats currently available in the market are (*Ecobee*, 2023; *Nest*, 2023; *Tado*, 2023; *Tesla*, 2023; *Wallbox*, 2023).

If the network price signals that automatic devices receive are not cost-reflective, customer responses could not lead to the social maximum welfare, i.e., they would lead to inefficient network reinforcements that could be avoided. As discussed in section 4.4, increasing temporal and locational differentiation of network charges would definitely improve their cost-reflectivity. Network conditions can rapidly change from one location to another, and thus forward-looking network charges require high locational and temporal differentiation to be effective and incentivise efficient customer response at the right place and time. See also discussions in Perez-Arriaga et al. (2017) and Pollitt (2018).

Furthermore, if customers have the ability to react to price signals, static network tariffs could lead to the so-called peak-shifting effect (CEER, 2017; CEER, 2020; Steen et al., 2016) or rebound peak effect (Muratori and Rizzoni, 2016). This effect creates new local peaks due to the synchronisation of customer responses when they are subject to the same static network charges with temporal differentiation. An example can be a wealthy neighbourhood with a significant penetration of EVs that jointly start charging at the start of an off-peak price period. These new peaks would eventually require local network reinforcements and increase overall network costs. Thus, system-wide forward-looking network tariffs, even with relatively high temporal granularity, would fail in their primary objective of signalling long-term network costs and maximising social welfare.

In short, this chapter has three significant contributions. As a first contribution, this chapter discusses and formulates forward-looking peak-coincident incremental network charges with high locational differentiation instead of the system-wide approach presented in chapter Chapter 4. The objective is to estimate whether significant efficiency gains are sacrificed by having a more uniform network tariff design across regions, often seen as more “politically acceptable”.

As a second contribution, this chapter analyses in depth efficiency gains that can be made by having more dynamic network tariffs, in combination with locationally differentiated network charges. While time differentiation is already a key element in tariff design across the EU (ACER, 2021), i.e., seasonal, day/night and peak/off-peak differentiation of network charges are quite common, network charges are usually set one year or more in advance (static). The reasons for such static tariffs are predictability for customers and simplicity, which can encourage a higher level of responses by creating habits. However, decentralisation, digitalisation, and automation, together with increasing electrification of space heating and mobility, lead to an increased potential to respond more quickly to changing price signals, often automatically rather than manually, eventually leading to the peak-shifting effect. All ex-ante approaches, static or dynamic, are susceptible to forecast errors. The only way to truly reflect network costs in the network congested hours is by knowing which are the true hours contributing to network congestions.

As Steiner (1957) stated, ex-post pricing stands out as the solution that can grant the alignment of network charges with long-term incremental network costs, and avoid the peak shifting effect, which can could occur even if the price-setting periodicity is as short as one day ahead. This chapter discusses and formulates the ex-post computation of forward-looking peak-coincident incremental network charges. Under ex-post pricing, customers are economically responsible for the creation of new peaks caused by their synchronised response and, therefore, they have the incentive to de-synchronise their consumption without creating new peaks.

The main concerns against ex-post pricing are the low predictability of network charges for customers, since the charges that customers face do not only depend on their individual network usage, but also on the rest of customers’ network usage. To increase predictability, Dupont et al. (2014) propose that ex-post pricing schemes can be coupled with information and automation services. Predicted prices would be sent to network users the day ahead, although afterwards, they would be charged based on the actual network situation. Although this scenario could increase bill predictability, customers’ network charges would still depend on how the rest of customers sharing the same networks use them.

The third contribution of this chapter consists of an alternative coordination mechanism that complements locational differentiated and dynamic network tariffs. The coordination mechanism is formulated as a local network capacity market in which customers can book in advance their expected usage of network capacity. This booking would be performed through price-capacity bids in a transparent and competitive market where the DSO offers the scarce product, i.e., the network capacity, at a cost linked to the long-term incremental network costs. The added value of this mechanism is an improved coordinated customer response, avoiding response synchronisation and the peak-shifting effect. This mechanism adds predictability to the total network charges paid by customers compared to solely ex-post-priced network charges. Importantly, by linking an efficient network tariff formulation to a customer response coordination mechanism as a hedging tool for customers, potential distortions created due to hard-to-avoid interactions of a local flexibility mechanism and network charges are avoided.

Finally, a detailed case study compares the proposed network tariff designs in a 10,000-customer network with actual data, in which an increasing number of customers adopt heat pumps as an example of flexible devices. Customer responses to network charges are analysed by optimising the heat pump operation while maintaining the comfort house temperature within a specific range. This chapter corresponds to publication (Morell-Dameto et al., 2023b).

The rest of the chapter is organised as follows. Section 5.1 is focused on the mathematical formulation of the proposal, which is built upon the formulation presented in section 4.1. Section 5.1.1 presents the formulation of the forward-looking peak-coincident incremental network charges with locational granularity. Section 5.1.2 discusses the ex-post computation of forward-looking peak-coincident incremental network charges. Section 5.2 discusses the design of the customer response coordination mechanism based on a local network capacity market. Section 5.3 presents the case study. Section 5.4 shows the results of the case study and discusses its regulatory implications. Finally, section 5.5 concludes.

5.1. Formulation of locationally differentiated and dynamic forward-looking incremental network charges

This section formulates the forward-looking peak-coincident incremental network tariff methodology considering locational granularity and ex-post pricing to increase dynamism. This formulation builds upon the system-wide forward-looking peak-coincident incremental network tariff presented in section 4.1. Section 5.1.1 focuses on locational granularity, while section 5.1.2 deals with the ex-post pricing of network charges.

5.1.1.High locational granularity

As discussed in section 3.1, in theory, economically optimal network charges would be as granular as a customer-by-customer differentiation, linking each customer’s network usage with its effect on each network item (Schittekatte and Meeus, 2018). In practice, such fine granularity is impossible due to implementation costs and customer acceptability. Some degree of customer clustering is required. In most cases, networks are divided among High Voltage (HV), Medium Voltage (MV) and Low Voltage (LV) subnetworks, hierarchically connected in cascade. In some cases, the HV network is also divided by geographical boundaries to separate areas where network peaks are driven by demand and those where peaks are driven by generation, such as in UK or Norway. In some other cases, such as in Slovenia, as seen in section 4.2, HV/MV substations and MV/LV transformers form two separate subnetwork areas, including all customers (generators, storage, and consumers) directly connected to them.

Different customers and network topologies make region sizing a very case-dependent problem (Cohen et al., 2016; Passey et al., 2017). In order to further increase locational granularity of network charges, some lessons could be extracted from other geographical network differentiations, such as Locational Marginal Pricing (LMPs) applied in wholesale electricity markets in US (Energy KnowledgeBase, 2019; PJM, 2023), or the recent local flexibility markets implemented in Europe (GOPACS, 2022; Piclo Flex, 2019). LMPs are calculated at network nodes where power plant substations are connected to transmission lines, where two transmission systems connect in a transmission substation, or where transmission systems connect to distribution systems in a distribution substation. While in local flexibility markets, DSOs define the concerned network areas and the flexibility requirements within each area.

Network model and customer groups

In this chapter, assuming a hierarchical structure, locational granularity is increased from the previous formulation presented in section 4.1 delimiting network areas by the HV/MV substations and the MV/LV transformers. Thus, the LV network boundaries are defined by the MV/LV transformers to which the LV networks are connected. The MV network boundaries are the HV/MV substation and the MV/LV transformers. The HV network boundaries are the transmission substations and the HV/MV substations. The different network areas are connected among them according to the hierarchical cascade network model, as presented in Figure 5.1. The highest voltage level refers to the HV network, and the lowest ($v = 0$) refers to the LV networks. Within each voltage level, x network areas are defined by the local DSOs attending to the network topology and the network usage patterns in each area. Similarly, to previous chapters, two customer groups are identified for each network area: generation and consumers.

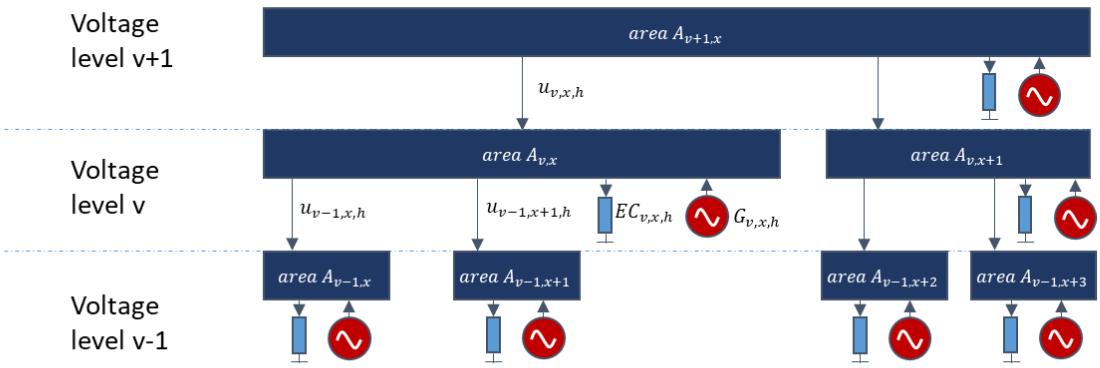

Figure 5.1. Schematic view of the cascade network model. Source: (Morell-Dameto et al. 2023b)

The net hourly energy consumption in area $A_{v,x}$ ($net_{v,x,h}$) is calculated as the hourly energy consumption ($EC_{v,x,h}$) minus the hourly energy generation ($G_{v,x,h}$) of customers located in area $A_{v,x}$, as in Eq. 32.

$$net_{v,x,h} = \begin{cases} EC_{v,x,h} & if\ v \in HV \\ EC_{v,x,h} - G_{v,x,h} & if\ v \notin HV \end{cases} \quad (32)$$

As explained in section 3.1, the Power Transfer Distribution Factor ($ptdf_{v,x}^{v-1,x+1}$) determines the increase in network flows in area $A_{v,x}$ ($nu_{v,x,h}$) due to an increase in the injection/withdrawal of energy from customers located in area $A_{v-1,x+1}$ ($net_{v-1,x+1}$). Thus, following the PTDF nomenclature, areas act as branches, while customers act as nodes. The network utilisation level in area $A_{v,x}$ ($nu_{v,x,h}$) is calculated as the net hourly energy consumption in all areas A_y contributing to the network flow of area $A_{v,x}$ ($net_{y,h}$) multiplied by the $ptdf_{v,x}^{y}$, as shown in Eq. 33. A subgroup of areas $R_{v,x}$ is defined as those areas contributing to the network usage of $A_{v,x}$, including the same $A_{v,x}$. Under the proposed cascade model, $R_{v,x}$

includes the area $A_{v,x}$ itself and the relevant areas connected downstream. For example, in Figure 5.1, $R_{v,x}$ includes $A_{v,x}$, $A_{v-1,x}$ and $A_{v-1,x-1}$. Like in the formulation presented in section 4.1.1, the HV is considered the slack bus, and thus HV generation is not considered for the net consumption calculation.

$$nu_{v,x,h} = \sum_{y \in R_{v,x}} (net_{y,h} * ptdf_{v,x}^{y}) \tag{33}$$

Cost segmentation by area

$C_{v,x}$ is defined as the total network costs in a specific area $A_{v,x}$, which are paid by customers connected to $A_{v,x}$, and also by customers connected to regions contributing to the network usage of $A_{v,x}$.

As an input for the methodology, it is required to breakdown the recognised network costs allowed to be recovered by the tariffs, including capital expenditures (CAPEX) and operating expenses (OPEX), by areas, $C_{v,x}$. Moreover, an estimation of the annual growth of the network costs by area ($\Delta C_{v,x}$) derived from DSO network expansion plans should be available. Examples of distribution network expansion plans with high locational granularity are already available (SP Energy Networks, 2022).

Determination of long-term incremental costs and residual costs

The incremental network costs are obtained as the network expansion cost from the current situation to the long-term considered future. Incremental network costs in area $A_{v,x}$ ($ic_{v,x}$) are calculated as the expected growth for network costs in area $A_{v,x}$ ($\Delta C_{v,x}$) in the next *Y* years, as in Eq. 34. Residual network costs in area $A_{v,x}$ ($rc_{v,x}$) are calculated as the remaining part of the recognised network costs after subtracting the previously calculated incremental network costs per area, as in Eq. 35.

$$ic_{v,x} = C_{v,x} * \left[(1 + \Delta C_{v,x})^{Y} - 1\right] \tag{34}$$

$$rc_{v,x} = C_{v,x} - ic_{v,x} \tag{35}$$

This chapter is devoted to the efficient allocation of incremental network costs, and their effect on customer responses. Regarding residual costs, an increase of locational granularity of residual charges should not affect the price signals sent by incremental charges because their main objective is to not distort them. Therefore, the allocation of residual charges follows the one presented in section 4.1.4 via fixed charges (€/kW of connection), possibly set at different levels conditional upon a proxy of income to deal with the distributional equity issues that may arise with incremental network charges differentiated by location.

Allocation of incremental costs to peak-coincident energy charges

Incremental network costs ($ic_{v,x}$) are allocated to the hours of maximum network utilisation as the driver of future network costs. The hours of maximum network utilisation are identified as those hours when network flows in the area ($nu_{v,x,h}$) are higher than a calculated threshold ($\overline{nu}_{v,x}$). In this case, the network usage threshold ($\overline{nu}_{v,x}$) is calculated as the average of the *Z* largest hourly energy flows at the considered area $A_{v,x}$ ($nu_{v,x,h}$), reduced by a factor proportional to the expected growth of the network peak demand in area $A_{v,x}$ ($\Delta D_{v,x}$) in order to consider the long-term effects of the incremental demand, as shown in Eq. 36. The objective of parameter Z is to separate non-peak and peak hours, i.e., those hours that will trigger network reinforcements, so it depends on the shape of the Load Duration Curve of the aggregated network usage in the area, and the expected flexibility of customer responses. The selected Z value is between 1000 and 1500 hours, since an intense customer response to price signals is expected in the future.

$$\overline{nu}_{v,x} = \frac{\sum_{h=1}^{Z} \max\left(nu_{v,x,h}\right)}{Z} * \frac{1}{(1+\Delta D_{v,x})^{Y}} \tag{36}$$

The share of incremental costs allocated to each hour ($ic_{v,x,h}$) is calculated as the difference between the network usage ($nu_{v,x,h}$), and the network usage threshold ($\overline{nu}_{v,x}$), divided by the aggregation of the annual network usage surpassing the threshold, ensuring that total incremental costs ($ic_{v,x}$) are recovered throughout the year and proportionally allocated to those hours with higher network usage.

$$ic_{v,x,h} = ic_{v,x} \frac{\max\left(0, nu_{v,x,h} - \overline{nu}_{v,x}\right)}{\sum_{h \in nu_{v,x,h} > \overline{nu}_{v,x}} \left(nu_{v,x,h} - \overline{nu}_{v,x}\right)} \tag{37}$$

Peak-coincident energy charge per customer group

The peak coincident incremental network charge in area $A_{v,x}$ ($it_{v,x,h}$) is calculated as the incremental network cost allocated to hour *h* divided by the network usage in hour h, as in Eq. 38. As in the previous formulations, it is symmetrical for generation and consumer groups.

$$it_{v,x,h} = \frac{ic_{v,x,h}}{nu_{v,x,h}} \tag{38}$$

Customers located in other areas contributing to the network usage of area $A_{v,x}$ face the corresponding network charge ($it_{v,x,h}$) incremented by the $ptdf_{v,x}^{y}$. The total peak-coincident energy charges in hour h for a customer located in area A_y (it_h^y), are calculated as the sum of all charges allocated to that area, coming from the same A_y and from areas ($A_{v,x}$) where customers located in A_y contribute to network usage, i.e., where $ptdf_{v,x}^{y} \neq 0$.

$$it_h^y = \sum_{v,x} \left(it_{v,x,h} * ptdf_{v,x}^{y}\right) \tag{39}$$

5.1.2. Ex-post pricing

The network tariff formulation presented in section 5.1.1 is ex-ante calculated, as well as those presented in sections 3.1 and 4.1, meaning that charges are calculated before customers use the network. Ex-ante methodologies, either static or dynamic, set those hours with higher network charges through an estimation of the network usage based on historical data. Thus, ex-ante methodologies do not guarantee an accurate identification of network peaks since they rely upon the similarities between historical and actual network usage. In a region of non-responsive customers, network usage predictions can be precise enough. Inefficiencies derived from a low accuracy on the network peaks identification could be acceptable for the sake of simplicity and predictability of tariffs. However, in an environment with highly responsive customers and changing network peaks, regulators should consider whether the simplicity principle is still relevant enough to offset the economic efficiency loss.

As seen in section 2.5, most countries apply static network charges. A first step to increase network peak identification accuracy of static network charges is moving to more dynamic practices, i.e., postponing network charge calculation to a shorter notice. For example, in France, MV customers can opt for variable peak network tariffs, triggered by the TSO one day ahead (CEER, 2020). Although this alternative improves the identification of network congested days, it does not avoid the peak-shifting effect (Steen, 2016; CEER, 2017) since customers know ex-ante (one day before using the network) the network charges they will face, and thus they are incentivised to synchronise their behaviour in day-ahead off-peak hours and it may create actual new network peaks in the initially predicted off-peak hours. This could be the case of smart thermostats or smart EV chargers.

A step forward is to apply ex-post pricing in the calculation of network charges. Under ex-post pricing, customers pay network charges according to the actual network usage, without knowing the final applicable network charges before the delivery time. Ex-post charges are calculated considering actual network utilisation levels and the exact hours when peaks occur. Therefore, ex-post pricing becomes a more cost-reflective solution, although it can increase complexity, reduce understandability and predictability of the tariffs, which may reduce customer response. For example, the UK experience with Triads (ex-post high charges on the three half-hour periods with the highest system demand) shows that it has been effective at encouraging customers to reduce their demand during critical peak periods, but they add uncertainty for customers (Ofgem, 2019a).

Considering the proposed formulation in the previous section, implementing ex-post pricing under forward-looking peak-coincident network charges is straightforward. Under ex-post pricing, $nu_{v,x,h}$ refers to the actual network usage, which is known after the delivery time, instead of being an ex-ante estimated value. Other variables, such as the network usage threshold ($\overline{nu}_{v,x}$), or the amount of energy surpassing the threshold ($\sum_{h \in nu_{v,x,h} > \overline{nu}_{v,x}} (nu_{v,x,h} - \overline{nu}_{v,x})$) are ex-ante calculated, as in section 5.1.1.

The tariff formulation with ex-post pricing produces two benefits compared to ex-ante pricing: 1) identifies the exact hours when the network is congested, and 2) network charges are proportional to the difference between actual network usage and the threshold; both increasing network charges' economic efficiency.

One of the main drawbacks of ex-post pricing is the low customer response due to the low predictability of network charges. Under this scheme, customers' network charges depend not only on their own network usage but also on the rest of customers' usage.

To coordinate customer responses and increase the predictability of network charges, a customer response coordination in the form of a local network capacity market is proposed, where all customers, directly or through their retailers or aggregators, in the critical days predefined by the DSO, reveal ex-ante their willingness to use the network and reserve the network capacity they plan to use in a competitive and transparent market.

5.2. Customer response coordination mechanism

This section describes the proposed customer response coordination mechanism. The objectives of the local network capacity market are: 1) coordination of customer responses avoiding response synchronisation and the peak-shifting effect, 2) non-distortion of economic signals sent by ex-post network charges, and 3) provision of price predictability for customers. The discussion is divided into three steps: 1) design of the market, including product, temporal horizon, activation, and participants; 2) functioning of the market, describing the bidding process and the market clearing mechanism; and 3) settlement of the market, describing the relation between the proposed mechanism with ex-post network charges. Finally, section 5.2.4 briefly compares the proposed market to other alternative coordination mechanisms.

5.2.1. Local network capacity market design

Like other local flexibility markets, the design of a local network capacity market requires deciding on different market attributes (Valarezo et al., 2021). The first one is the market product, which in this case, is the individual hourly network capacity reserved in the selected network area. The objective of the market in the proposed mechanism is to coordinate the customer response while adding predictability. As such, the price of the individual hourly network capacity reserved in a network area should be linked with its actual value, given by the ex-post forward-looking network charges.

The market participants are first the DSO operating the selected network area, who acts as a single seller, and auctions the available network capacity at each hour; and second; the customers that need to reserve capacity in the network area and act as buyers. Note that the proposed approach differs from most common local flexibility markets (Valarezo et al., 2021), in which customers are offering flexibility as an explicit service to reduce their network usage with respect a baseline in exchange for some reward, and the DSO is the buyer of the service, who uses network curtailments to avoid future network investment costs. Contrary to those flexibility market designs, the proposed local capacity market does not require a baseline calculation which is challenging to define and controversial (CoordiNet, 2021).

The local network capacity market does not have to run every day for every network area. Only in the case that a critical day is identified by the DSO, for example, when the expected network usage ($nu_{v,x,h}$) in area $A_{v,x}$ surpasses the predefined network usage threshold ($\overline{nu}_{v,x}$) in one or several hours, the local capacity market is activated. The local capacity market opens one day before the critical day, and capacity at all hours is auctioned off. DSOs could fail in their identification of critical days, for example due to an unexpected event. In that case, in order to allow a closer trade to the physical delivery time, intraday markets could be designed by the DSO, as in European wholesale energy markets. In any case, customers would face the ex-post network charges, no matter if local network capacity is triggered or not, which sends the efficient economic signal linked to long-term network costs and incentivises customers to change their profile during critical periods.

5.2.2. Local network capacity market functioning

Flexibility utilisation approaches are generally based on auctions, as they allow for pooling, ranking, and jointly clearing all offers for a scarce good in a welfare-maximising manner (Maurer and Barroso, 2011). Concretely, the local network capacity market takes the form of an ascending clock auction, or a sealed-bid auction, as defined by Maurer and Barroso (2011).

Customers, directly or through their retailers or aggregators, bid their offers in the form of pairs of hourly capacity (kW) and price (€/kW) for each hour *h* of the next critical day, and their capacity bids are multiplied by the corresponding $ptdf_{v,x}^{y}$ of the area A_y where they are connected. A certain amount of the demand curve is expected to be hosted by non-flexible customers, who would be willing to pay the maximum price for the use of the network. For simplicity, in this formulation, the booked capacity in an hour *h* is assumed to be coincident with the energy consumption in the same hour. Depending on the offers from customers and the total network capacity per hour, three situations can occur, as shown in Figure 5.2.

1. The total volume of capacity requested for an hour is between 0 kW and the network usage threshold ($\overline{nu}_{v,x}$). In this case, the selling price is settled by the DSO at 0 €/kW, since any increment in network usage ($nu_{v,x,h}$) below the threshold do not produce any increment in future network costs.

2. The total volume of capacity requested for an hour is between the threshold and the network capacity limit, defined as the maximum network usage that can be satisfied in area $A_{v,x}$. In this case, the selling price linearly increases with the actual network usage ($nu_{v,x,h}$), as shown in Eq. 40.

$$pcnc_{v,x,h} = ic_{v,x} * \frac{(nu_{v,x,h} - \overline{nu}_{v,x})}{\sum_{h \in nu_{v,x,h} > \overline{nu}_{v,x}} (nu_{v,x,h} - \overline{nu}_{v,x}) * \overline{nu}_{v,x}} \quad (40)$$

   With $pcnc_{v,x,h}$ being the DSO selling price, calculated as a peak coincident network charge (PCNC), in €/kWh, in area $A_{v,x}$ where the network capacity market is required. $PCNC_{max}$ is the maximum value of $pcnc_{v,x,h}$, calculated as the *pcnc* when the network usage ($nu_{v,x,h}$) is equal to the network capacity limit. Note that the formulation of the peak coincident network charge derives from Eq. 37

3. The total volume of capacity requested for an hour is higher than the network capacity limit. In that case, there are a certain number of customers that cannot be granted capacity. The amount of non-matched capacity is equally apportioned among clearing price offers according to the offer bid size. The matched capacity faces the price at the intersection between the demand curve and the network capacity limit (point C in Figure 5.2).

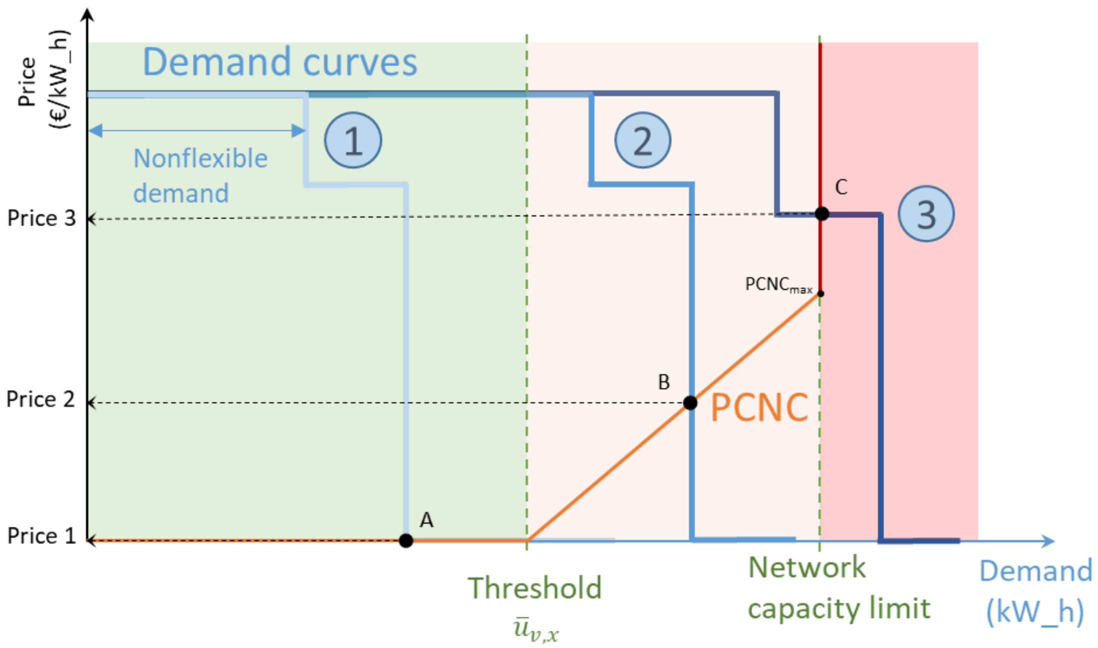

Figure 5.2. Hourly local network capacity market. Example of three clearing prices depending on the total network capacity requested. Source: (Morell-Dameto et al. 2023b)

As a result of the market, customers acquire the right to use the individual booked capacity ($ibc_{v,x,h}$), with no exposure to the volatile ex-post network charges. Note that the actual booked capacity for customers located in other areas A_y is the individual booked capacity in area $A_{v,x}$ lowered by the $ptdf_{v,x}^{y}$.

For the case of a local generation willing to participate in the local capacity market, they make a selling bid, which is joined with the DSO selling bid — assuming that peak network flows in the area are consumption driven. In this case, the matched local generation provides additional capacity, which is beneficial for all customers and the DSO, because more capacity can be matched at no cost for the DSO. The matched local generation should ensure that the energy injected in each period is equal to or higher than their booked capacity. Otherwise, they would reduce the available capacity for the network and should face an energy curtailment or financial penalty.

In the case of network areas with generation-driven congestions, injection bids would form the buying curve (blue), and withdrawal bids would be added to the DSO offer curve.

5.2.3. Local network capacity market settlement

After the delivery time, all customers' network usage is known, as well as the booked capacity in the day-ahead local network capacity market. This section describes how deviations, between the booked capacity in the local network capacity market and the actual network usage, are settled at ex-post network charges $it_{v,x,h}$, calculated in section 5.1.2 (see Eq. 41 and Eq. 42). There are again three possible situations according to the actual network usage ($nu_{v,x,h}$).

$$ied_{v,x,h} = inu_{v,x,h} - ibc_{v,x,h} \tag{41}$$

$$ip_{v,x,h}(€) = ibc_{v,x,h} * cp_{v,x,h} + ied_{v,x,h} * it_{v,x,h} \tag{42}$$

1) If the actual network usage at hour h ($nu_{v,x,h}$) is lower than the network usage threshold, the ex-post network charge is 0 €/kWh ($it_{v,x,h} = 0$), deviations ($inu_{v,x,h}$) from booked capacity ($ibc_{v,x,h}$) are neither rewarded nor penalised. Thus, the final customer payments ($ip_{v,x,h}$) are equal to the price paid for its booked capacity in the local day-ahead network capacity market ($cp_{v,x,h}$) times its booked capacity ($ibc_{v,x,h}$).

2) If the actual network usage is higher than the threshold and lower than the network capacity limit, the ex-post network charge is $it_{v,x,h} > 0$. Deviations ($ied_{v,x,h}$) of the individual network usage ($inu_{v,x,h}$) with respect to their booked capacity ($ibc_{v,x,h}$) can be either network beneficial or detrimental. If the network peak usage is consumption driven, network-beneficial deviations, i.e., consumers withdrawing less than their booked capacity, and generators injecting more than their booked capacity, are rewarded with the corresponding $it_{v,x,h}$. In this case, the energy deviation for a customer is negative $\left(inu_{v,x,h} < ibc_{v,x,h}\right)$. On the contrary, network-detrimental deviations, i.e., consumers withdrawing more energy than their booked capacity, and generators injecting less than their booked capacity, are penalised with the corresponding $it_{v,x,h}$. If the network peak usage is driven by production, higher consumptions/lower injections than booked capacity are rewarded with $it_{v,x,h}$, and lower consumption/higher injection than booked capacity are penalised with the same price.

3) If the actual network usage surpasses the network capacity limit, there would be some energy curtailment until the network usage is within the network capacity limit. The ex-post network charge ($it_{v,x,h}$) are equal to the maximum between $PCNC_{max}$ and the

clearing price that resulted in the local network capacity market ($cp_{v,x,h}$), to avoid, only for this situation, deviation prices lower than booked capacity prices. Individual customers with network usage surpassing their booked capacity would be curtailed up to the booked capacity (easily implementable via smart meters). Individuals with network-beneficial deviations would create an amount of non-used capacity that could be apportioned among those customers with network-detrimental deviations, who could use the network more than their booked capacity. The non-curtailed energy would face the ex-post network charge.

Note that ex-post network charges would be applied for all days, although the threshold would not be reached during non-critical days, and network charges would be 0 €/kWh.

There is a natural incentive for customers to participate in the local network capacity market, since if a set of customers do not participate, the resulting market prices would be lower than ex-post network charges. In the case that all customers participate, either directly or through a retailer or aggregator, the demand curve for the local network capacity market in Figure 5.2 and the actual network usage would intersect the selling curve at the same point, so local network capacity market prices would tend to be coincident with ex-post network charges.

5.2.4. Alternative market designs

Other authors propose mechanisms by which distributed energy resources (DER) can reduce future network investment costs. For example, Anaya and Pollitt (2015) propose interruptible connections for distributed generation to avoid reinforcement costs. Trebolle et al. (2010) propose a market-based approach called reliability options for distributed generation (DG) in which the DG firm capacity procurement is based on a sealed bid auction. Poudineh and Jamasb (2014) propose another market-based approach in which DG, storage, demand response, and energy efficiency compete in a descending clock auction as an alternative for network investment.

However, an uncoordinated application of 1) network tariffs and 2) explicit mechanisms to extract the potential of DERs to reduce network investment costs can lead to inefficient customer responses due to two overlapping economic signals with the same objective. Our proposal, by linking an efficient network tariff formulation to a customer response coordination mechanism as a hedging tool for customers, reduces any distortion that other potential local market mechanisms could create when they are added to the efficient economic signal sent by ex-post network tariffs.

5.3. Case study

The case study implements the proposed forward-looking methodology in a 10,000-customer LV network area within the Slovenian system to recover network costs for one year using annual time series with hourly granularity. The aim of the case study is to compare the efficiency associated with the tariff designs discussed in previous sections in a future environment of many flexible customers reacting to network tariffs. For that, a comparison is made of the network reinforcements that would be required when a varying number of customers (from 5 to 20% of the customers in the area) install heat pumps, as a form of flexible demand, under i) a system-wide forward-looking network tariff, ii) a forward-looking network tariff with locational differentiation, and iii) a forward-looking network tariff with locational differentiation applied with ex-post pricing and implementing the proposed day-ahead coordination mechanism.

As presented in Figure 5.3, first, network tariffs are calculated for one year with hourly granularity and are applied to customers in the selected area. Then, the optimal response of customers installing heat pumps to each network tariff is calculated through a demand response model. Customers who do not install heat pumps remain with the same initial load profile. Finally, a network expansion model is applied to the resulting new load profiles after customers' responses to calculate the required network reinforcements to satisfy the increasing demand due to the installation of heat pumps under optimal automated control.

The input data, the model specifications, and the considered scenarios are described in the following sections.

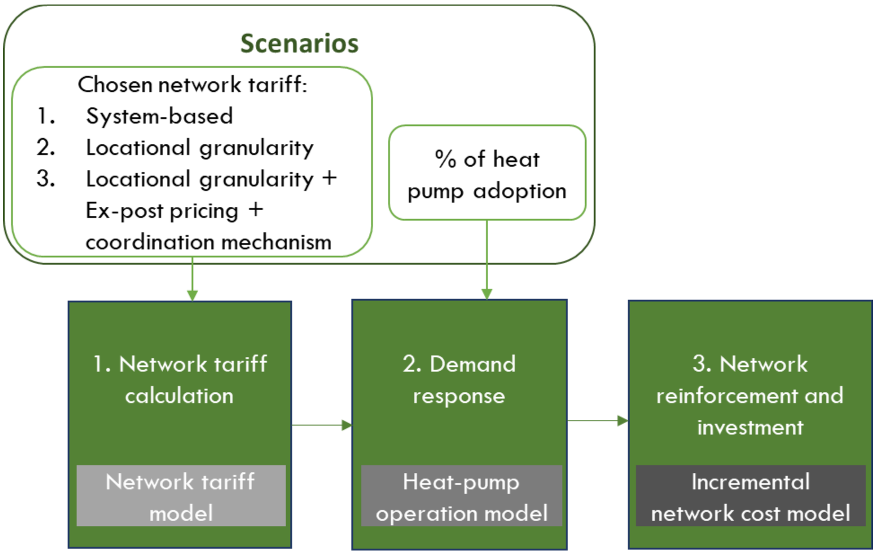

Figure 5.3. Network tariff assessment framework. Source: (Morell-Dameto et al. 2023b)

5.3.1. Network tariff calculation

Network charges are calculated for all three tariff designs for a whole year considering the same inputs, i.e., network costs and annual time series of customer consumption/generation, with the aim of ensuring network cost recovery for all three cases.

Input data required to calculate the network tariff was provided by the Energy Agency of Slovenia, consisting of the annual network costs $C_{v,x}$, the annual growth of network costs $\Delta C_{v,x}$, the annual growth of peak demand, the aggregated hourly energy consumption $EC_{v,x,h}$, and generation $G_{v,x,h}$, and the annual growth of peak demand $\Delta D_{v,x}$, all differentiated by $A_{v,x}$. The number of years for the planning horizon, Y, is 10, and the number of hours in the year with the largest network usage that induce the expected network reinforcements in the future, Z, is set to 1200.

The individual load profiles ($EC_{v,x,h}$) of customers located in the selected area were synthetically created through a Montecarlo simulation using anonymised individual load profiles as inputs. The obtained synthetic individual profiles were validated against real individual measured data used in the previous chapter, showing similar average consumption and standard deviations.

The calculated network charges applied to the network users in the selected network area consist of an hourly peak-coincident energy charge (it_h^y) in €/kWh, and a fixed residual charge in the three considered tariffs.

Table 5.1 shows the main parameters for the system-wide network tariff calculation. For the computation of network charges with higher locational granularity, the specific parameters of the analysed LV network area are provided in the last row of the table.

Voltage level	Network costs (€/year) – $C_{v,x}$	Annual growth of network costs (%) - $\Delta C_{v,x}$	Network usage threshold (MW) – $\overline{nu}_{v,x}$	Annual energy consumption (MWh) – $\sum_h EC_{v,x,h}$	Generation (MWh) - $\sum_h G_{v,x,h}$	Annual growth of peak demand (%) - $\Delta D_{v,x}$
HV network	69,120,218	3.29%	1,725	2,122,660	12,365,438	0,62%
HV/MV substations	33,813,964	4.32%	1,466	1,243,188	68,621	0,97%
MV network	72,203,762	4.43%	1,313	3,960,406	618,526	0,97%
MV/LV transformers	39,756,524	2.56%	858	483,366	20,881	1,32%
LV network	85,068,056	1.48%	764	4,937,972	288,188	1,32%
LV network area	945.200	1.48%	5.8	38,358	-	1,32%

Table 5.1. Network costs, annual growth of network costs, energy losses costs, energy losses and network capacity limit for each voltage level in the Slovenian system and in the analysed LV network area. Source: (Morell-Dameto et al. 2023b)

5.3.2. Customer response

Customer response to network charges is calculated with an optimisation model of the heat pump operation, already used in other research works (Dancker et al., 2023; Yee, 2017). The objective of the optimisation model is to simulate an optimal automated control that minimises the individual heat pump operation costs while maintaining the house temperature within a comfortable range.

As input parameters, for each customer, the optimization model requires the individual customer load profile before installing the heat pump, the expected electricity prices including retail energy price plus network charges, the hourly outside temperature, the building characteristics (Location, Dimensions, Construction materials, Internal heat gains, Irradiance), and the heat pump characteristics (Coefficient of Performance, and Maximum and Minimum heating/cooling capacity).

The retail energy price is set to a constant value throughout the year. The reason for not having a variable retail energy price is to minimize other effects, apart from the considered network tariff designs, in the optimal customer response. The outside temperature is the Ljubljana hourly temperature in 2019 (*Renewables.ninja*, 2019).

The house thermal balance is modelled through a Resistance-Capacitance (RC) model composed of 5 resistances and 3 capacitors, as shown in Figure 5.4, similar to other published models (Bastida et al., 2019; Martín-Martínez et al., 2017) . For the sake of simplicity, house buildings and heat pump parameters are the same for all customers.

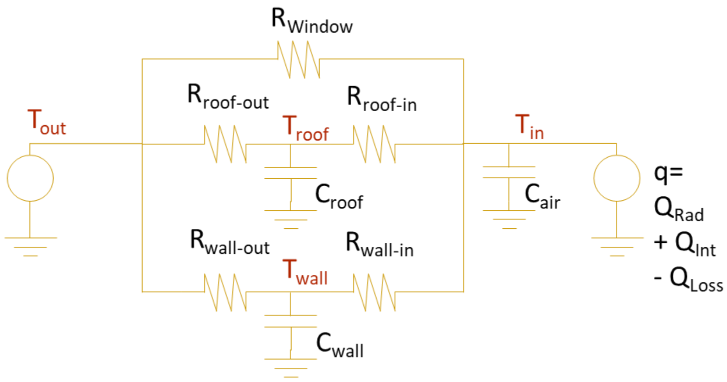

Figure 5.4. House thermal balance model. Source: (Morell-Dameto et al. 2023b)

Being T_{out}, T_{in}, T_{roof}, T_{wall} the outside, inside, roof, and wall temperatures, respectively; R_{window}, $R_{roof-out}$, $R_{roof-in}$, $R_{wall-out}$, $R_{wall-in}$ the window, out-to-roof, roof-to-in, out-to wall, and wall-to-in resistances, respectively; C_{roof}, C_{wall}, C_{air} the roof, wall and air capacitors, and q the heat gain, which is calculated as the heat gain from i) heat pump, ii) radiation dependent on house location, iii) equipment, iv) people, and v) losses such as ventilation, among other energy losses.

The model output is the new hourly load profile of customers installing a heat pump after reacting to electricity prices. Table 5.2 shows the main building and heat pump parameters for the operational model.

Building parameters	Value	Heat Pump parameters	Value
Altitude	295	Type of HP	HVAC
Latitude - Longitude	46.05 14.51	Maximum thermal heating capacity	12 kW
House area	105 m2	Maximum thermal cooling capacity	42 kW
Facade material (area, thickness, conductivity, specific heat)	48x3 m2 25 cm 0.3 W/m°C 1600 J/kg-°K	Heating efficiency Cooling efficiency	1.8 2.9
Windows (area, thickness, conductivity)	12 m2 1 cm 0.8 W/m°C	Internal heat gains per person	0.1 kW
Internal wall and furniture (volume, density, specific heat)	10 m3 720 kg/m3 1200 J/kg-°K	Internal heat gains per light and equipment (%)	0.1 kW per kW used for lighting 0.5 kW per kW used for equipment

Table 5.2. Main parameters of the heat pump operation model. Source: (Morell-Dameto et al. 2023b)

5.3.3. Required reinforcement costs in the selected network area

The economic efficiency principle of network tariff design seeks the right balance between long-term network expansion costs and the potential of end users to optimise their usage of the network. The achievement of this principle would reduce network costs ($C_{v,x}$) in future regulatory periods, and consequently, network charges would also be reduced. Therefore, the objective is to supply demand at the optimum long-term network cost. In the previous section, the new electricity demand based on heat pumps reacted to network tariffs. In this step, the required network reinforcement costs to supply the new demand, i.e., the Long-Term

Incremental Costs, are calculated by using a Reference Network Model (RNM) to compare the three network tariff designs.

The RNM is an electricity distribution network planning model that calculates the optimal distribution network required to supply electricity to the customers in an area. The network is built including the necessary electrical wires, transformers, and other grid equipment. The RNM has been widely used and validated, see Krishnan et al. (2020) and Mateo et al. (2011).

The required input data are the GPS location and the peak demand of customers. The RNM uses a detailed library for standard network facilities for all voltage levels and for each item of equipment: cables, overhead lines, distribution transformers, substation components, and protection devices. Finally, RNM requires as input data a set of general parameters such as the duration of the planning study, load growth, loss factors or simultaneity factors; economic parameters like the weighted average cost of capital (WACC) or the cost of energy losses; and technical parameters such as voltage limits and continuity of supply requirements.

In this case study, there is no data available about the network topology, and therefore the existing grid must be synthetically calculated by a greenfield RNM, which builds a distribution network from scratch taking as input the satellite image of an existing area. Customers location is statistically calculated, and their peak demand is calculated as the maximum consumption of the individual load profiles previously calculated. RNM has served to synthetically build many networks across Europe (Prettico et al., 2021). Then, a brownfield RNM calculates the required network reinforcements to satisfy the load profiles of customers after installing heat pumps and reacting to electricity prices.

The brownfield model outputs are the required network reinforcement costs to supply the aggregated demand of heat pumps. As an illustrative example, Figure 5.5 shows the resulting synthetic network, as a proxy of the existing network (which data is not available), before (Greenfield) and after 20% of customers install heat pumps (Brownfield) and respond to system-wide forward-looking network charges. In the figure, red colour represents those lines requiring reinforcements to satisfy the increasing demand.

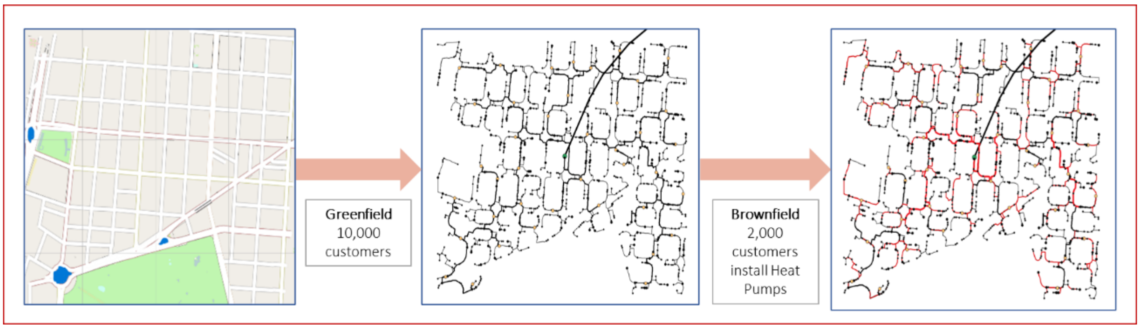

Figure 5.5. Reference Network model results before and after 20% of customers install heat pumps. Source: (Morell-Dameto et al. 2023b)

5.3.4. Scenarios

Scenarios are defined according to each network tariff design and the heat pump penetration rate. The three analysed network tariffs are summarised in Table 5.3:

Network tariff acronym	Locational granularity	Price setting periodicity	Mathematical formulation
SW	System-wide	Ex-ante	Section 5.1.1. One area in each voltage level
L	Per network area	Ex-ante	Section 5.1.1. Several areas in each voltage level
LC	Per network area	Ex-post including coordination mechanism	Section 5.1.2 + Section 5.2

Table 5.3. Summary of analysed network tariffs. Source: (Morell-Dameto et al. 2023b)

i) System-wide forward-looking network charges (SW). The system-wide network tariff design is a simplification of the presented network tariff design with locational granularity in which each voltage level only has one area. Therefore, equations presented in Section 5.1.1 are applicable. The resulting forward-looking peak-coincident incremental energy network charges for LV customers are applied to the customers in the analysed LV network area.

ii) Forward-looking network charges with locational differentiation (L), following the formulation presented in Section 5.1.1. In this case study, there is a lack information on network costs by area ($C_{v,x}$), so network costs in the selected LV network area are prorated according to the number of customers within the area with respect to the total number of LV customers. However, network costs data by area could be available (SP Energy Networks, 2022).

iii) Ex-post forward-looking network charges with locational differentiation with a customer response coordination mechanism (LC). The calculation of network charges follows the formulation presented in Section 5.1.2, and customers are able to book network capacity through the coordination mechanism described in Section 5.2. As a result of the coordinated customer response, individual network payments will differ from those under tariff L. Under the proposed coordination mechanism, customers should place a bidding offer to the local network capacity market for the network capacity they are willing to use and the price they are willing to pay. This decision depends on factors that are beyond the scope of this research work, such as awareness, responsiveness, wealth, etc. (Faruqui and Sergici, 2010). For modelling simplicity, all customers installing heat pumps have the same willingness to pay for booked capacity. Therefore, the hourly network capacity that each individual customer books ($ibc_{v,x,h}$) in the local network capacity market is calculated as the local network usage threshold ($\overline{nu}_{v,x}$) less the inflexible demand, divided by the number of customers installing heat pumps. The inflexible demand is calculated as the initial energy consumption in the area before installing any heat pump ($EC_{v,x,h}$).

Network tariffs are modelled whereby 5% or 20% of households install heat pumps, based on plausible future penetrations. The current penetration of heat pumps in the EU is approximately 2%. It has been forecasted that 20% of households will have heat pumps by 2040, and up to 40% of households may have heat pumps by 2050 (HPA, 2019; McKinsey, 2020).

Scenarios are named according to the tariff design (SW, L, or LC) and the heat pump penetration rate (5% or 20%). For example, scenario SW-5% refers to system-wide network tariffs and 5% of customers adopting heat pumps. For each scenario, results are shown as: (i) the Load Duration Curve of the selected area before and after heat pumps are installed, and optimally respond to electricity prices; (ii) the difference between the new network peak and the initial network peak, i.e., before HP installation; and (iii) the required network reinforcement costs to supply the additional demand based on heat pumps.

5.4. Results and discussion

This section discusses the case study results. Network reinforcement costs are required if the network usage surpasses a threshold related to the network capacity limit. Therefore, as a proxy of network usage, the Load Duration Curve (LDC) of the customers in the selected area before and after the installation of heat pumps is shown, including their response to network tariffs.

5.4.1. System-wide network charges

Figure 5.6 (left) shows the LDC under scenario SW-5%. In the left figure, demand response for a whole year is shown on top of the base load duration curve to illustrate how heat pumps respond to network charges. Figure 5.6 (right) shows the two LDCs, before and after heat pump installation and customer response, but now both curves are not synchronised; both are ordered from highest to lowest values. Only the 300 hours of maximum network usage are shown.

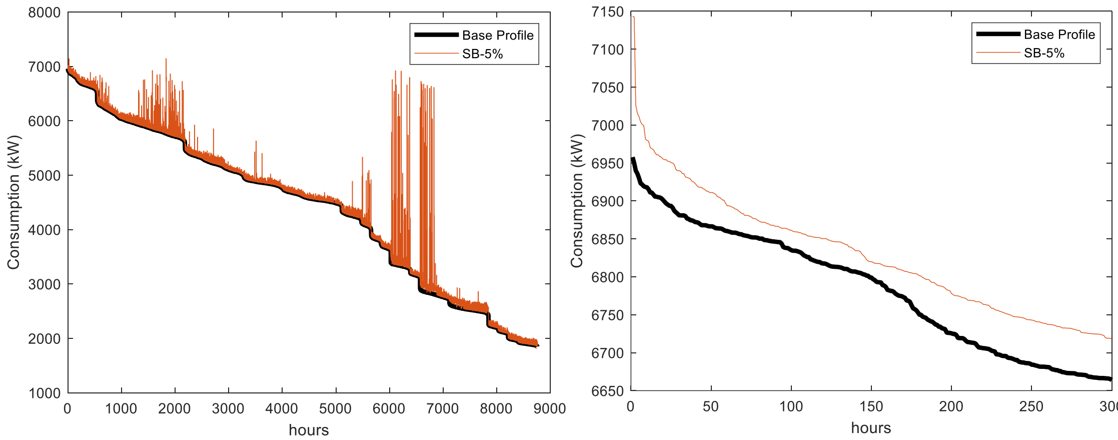

Figure 5.6. Load duration curve when 5% of customers install heat pumps and respond to system-wide forward-looking network charges (scenario SW-5%). Left: full year, right: zoom of the 300 hours with the highest network use. Source: (Morell-Dameto et al. 2023b)

Two effects are observed that increase network peak usage. First, system-wide network charges do not prevent increasing peak network usage in hours 0 to 1200 (Figure 5.6 left), since system network peaks are not time-coincident with local network peaks. Second, temporal discrimination in energy charges leads to the synchronisation of customer responses during off-peak hours with low network charges. See, for example, the increase in consumption from hours 6000 to 7000 on the left side of Figure 5.6. Those hours, before customer responses, were considered off-peak hours, and after that, they raised up to the level of network peak usage, becoming newly created peaks.

5.4.2. Locational granularity

If system-wide network charges are replaced by charges with locational granularity (scenario L-5%), network charges are aligned with the specific LV network peak periods in the concerned network area. Figure 5.7 (right) shows the new response where heat pump consumption avoids local network peak periods. The new network peak usage is equal to the initial one. Locationally differentiated network charges are aligned with the local network peak periods, so flexible customers avoid using the network during those periods, and the initial network peak is not surpassed. The tariff with locational granularity (L-5%) avoided an increase of 2.9% in the network peak when compared to the system-wide network charge methodology (SW-5%) (Figure 5.6), although no network reinforcements were required in any of these scenarios according to the RNM results.

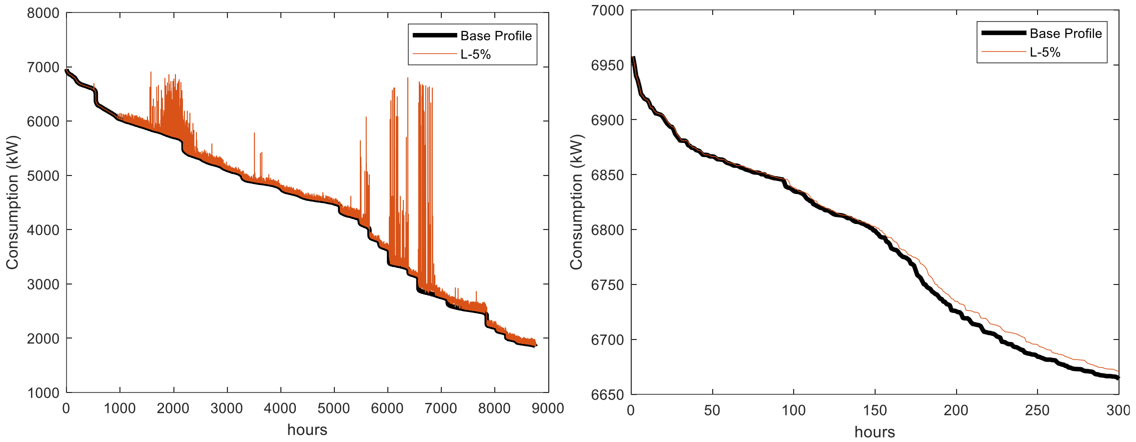

Figure 5.7. Load duration curve when 5% of customers install heat pumps and respond to forward-looking charges with locational granularity without a coordination mechanism (scenario L-5%). Left: full year, right: zoom of the 300 hours with the highest network use. Source: (Morell-Dameto et al. 2023b)

The misalignment between system and local network peak hours is avoided by increasing locational granularity in tariff calculations. Otherwise, customer response synchronisation is not solved. In the case of 5% of customers installing heat pumps, the misalignment effect was the dominating effect. However, if the number of customers adopting heat pumps is increased, as expected to be in the future, the dominating effect could be the customer response synchronisation, and thus additional solutions, such as the proposed customer response coordination mechanism, are required. Figure 5.8 shows the LDCs under scenario L-20%.

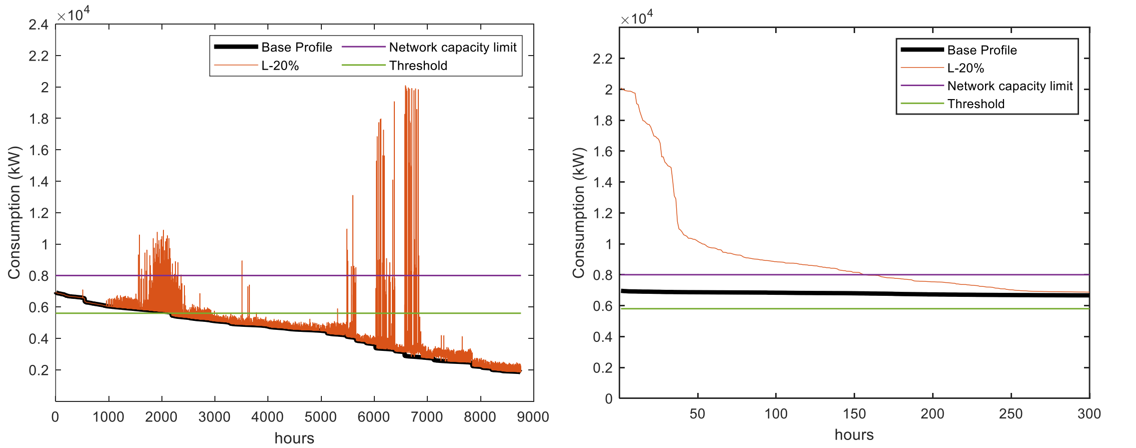

Figure 5.8. Load duration curve when 20% of customers install heat pumps and respond to forward-looking charges with locational granularity without a coordination mechanism (scenario L-20%). Left: full year, right: zoom of the 300 hours with the highest network use. Source: (Morell-Dameto et al. 2023b)

In this case, the synchronised customer response creates new peaks in hours that were not considered peak hours when tariffs were published (hours from 1500 to 2500 and from 6000 to 7000 in the left figure). The required LV network reinforcements to satisfy the new peak demand, calculated using the RNM brownfield model, were equal to 20% of the initial network costs in the analysed LV network area.

5.4.3. Customer response with the proposed coordination mechanism

Figure 5.9 shows LDCs under scenario LC-20%. Note that Figure 5.9 (right) shows the highest 3000 hours, instead of 300, to show customers' behaviour during hours that are close to the threshold.

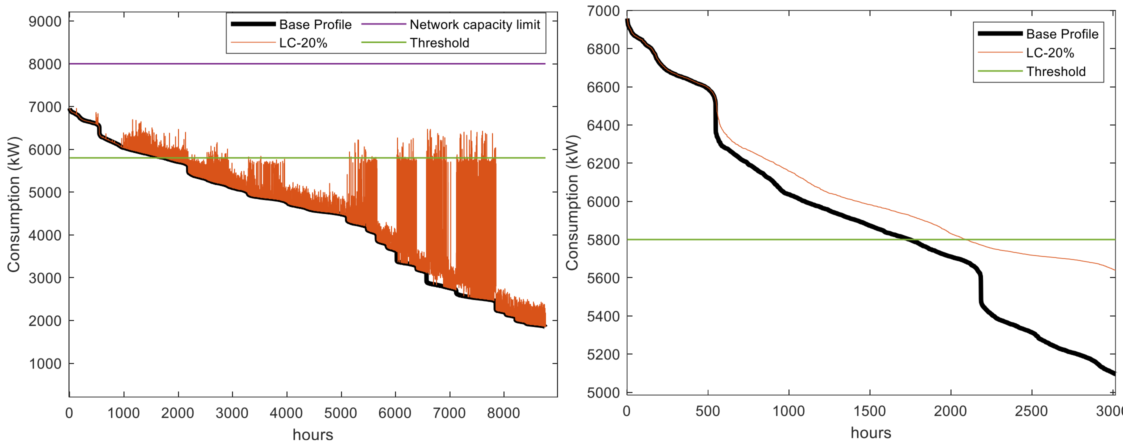

Figure 5.9. Load duration curve when 20% of customers install heat pumps and respond to ex-post forward-looking charges with locational granularity with the proposed coordination mechanism (scenario LC-20%). Left: full year, right: zoom of the 3000 hours with the highest network use. Source: (Morell-Dameto et al. 2023b)

Figure 5.9 (left) shows a consumption increase during off-peak hours until the network utilisation threshold is reached, and a moderate consumption increase during hours close to peak hours, those between hour 1000 and 4000. Under scenario LC-20%, ex-post network charges increase when network usage trespass the threshold. Individual customers face ex-post network charges when their network usage surpasses their booked capacity. Consequently, customers are incentivized to collectively use the network below the threshold. Although the total energy consumed in scenarios LC-20% and L-20% is very similar (around 41,2 GWh), the number of hours surpassing the network capacity limit is 0 in scenario LC-20% compared to 155 hours in L-20% (Figure 5.8 right), which lead to earlier network reinforcements in L-20%.

The number of hours surpassing the threshold is 2090 with respect to 1745 hours in the base profile (Figure 5.9 right), and thus, the resulting ex-post network charges in scenario LC-20% show an average increase of 14 % with respect to scenario L-20%. The amount of network costs recovered through incremental charges increase by 14 % and, therefore, residual network costs are reduced in this case by 2.5 %, ensuring that the same total network costs are recovered under each scenario. Thus, final payments of customers with or without heat pumps are similar for scenarios L-20% and LC-20%, since the increase of incremental charges is compensated by a reduction of residual charges. So, in the short run, both tariff designs are cost-neutral from a customer's perspective. However, in the long run, the total network costs, for both heat pump and not heat pump owners, would be lower under the proposed tariff design.

5.4.4. Model Limitations

The limitations of the presented case study must be acknowledged. Analysis considering different areas, i.e., rural or urban, could deliver different results. Regarding the network tariff calculation, future network cost projections are based on the regulator's estimations, while it does not consider the different heat pump deployment scenarios that are modelled. In the simulations presented, the scenario of applying ex-post network charges, without the coordination mechanism, has not been included, but it would be an intermediate case between the scenario of ex-ante locational differentiated tariff with peak-shifting effect, and the most beneficial one when the coordination market is successfully implemented. Concerning the customer response model, customers adopting heat pumps are all considered responsive to network charges, although nowadays, customers are quite far from being price responsive. Distinct building parameters, thermal requirements, or thermal models would produce different outcomes. Nevertheless, the aim of the case study is to qualitatively demonstrate the effect of three different network tariffs in a highly automated customer-responsive environment and to illustrate the benefits of the proposed solution. In addition, the case study only considers responses from customers installing heat pumps, even though the peak-shifting effect could be created by any flexible device, such as electric vehicles or storage systems, therefore making customer response coordination a fundamental requisite in the future to come.

5.5. Conclusion and Policy Implications

Decarbonisation, decentralisation and digitalisation are reshaping how electricity is traded among customers and how electricity networks are planned and operated. Increasing electrification of transport and heating, the adoption of distributed generation, and energy storage systems will lead to an important economic effort in future electricity networks. At the same time, digitalisation allows distribution utilities to benefit from the smart management of decentralised assets to defer network investments.

Network tariffs are in the spotlight as the tool to reflect network costs into individual network charges through an economically efficient and equitable design. This chapter proposes increasing the economic efficiency of forward-looking incremental network charges through a higher locational granularity, ex-post pricing, and a customer response coordination mechanism in the form of a local network capacity market.

A higher locational granularity allows a better alignment between network charges and long-term network costs of the specific networks that customers use. Ex-post pricing guarantees an accurate identification of network peak hours, which can only be known after the delivery time. The customer response coordination mechanism serves as a platform where customers, directly or through retailers or aggregators, compete in critical days for the scarce product, i.e., the reserved network capacity, enabling an efficiently ordered customer response which avoids the creation of new network peaks due to a synchronised response.

The case study presented in this chapter quantitatively compares three network tariff designs: i) a system-wide forward-looking network tariff, ii) a forward-looking network tariff with locational differentiation, and iii) a forward-looking network tariff with locational differentiation complemented by a customer response coordination mechanism. Different levels of flexible consumption penetration are modelled.

Results show that an increase of locational granularity in network tariffs can reduce network peaks and thus network reinforcement costs. Additionally, even under moderate heat pump penetration levels of 20 %, peak shifting is demonstrated to be a potential issue in the near future. In this case, the presented ex-post network charges and the coordination mechanism show several benefits for all stakeholders (customers, DSOs and regulators):

1. Customers can better predict ex-post network charges since they tend to be similar to the resulting prices of the local network capacity market, and they have the possibility to hedge against volatile ex-post network charges by booking their expected network capacity.

2. DSOs can benefit from the information extracted from the local network capacity market, such as the customers' willingness to pay for the network capacity, to make the optimal network investment decisions and to improve their network expansion plans. Besides, the volume of capacity traded and the number of participating customers, can serve as a basis to define the minimum size of network areas.
3. Regulators, in their role of setting network tariffs, fulfil the economic efficiency principle by sending the optimal economic signals through the ex-post forward-looking peak-coincident network charges producing a level playing field for all customers, i.e., agnostic to the appliances that customers may have behind the meter such as PV panels, EV, storage, etc. A more efficient network cost allocation will allow a larger accommodation of flexible customers with lower network reinforcement costs. At the same time, regulators could address equity concerns, which can be diverse among different jurisdictions, through the allocation of residual network charges without distorting the efficient signal sent by ex-post network charges. For example, vulnerable (or low-income) customers could have a reduced, or even null, residual payment. So, vulnerable customers could avoid an important share of the electricity bill without distorting the efficient economic signal sent by forward-looking charges. Regulators could even move further in the case the aforementioned discount is not enough, and the equity principle prevails over the economic efficiency principle, by guaranteeing a certain amount of network capacity during critical days for vulnerable customers at a lower than market-based price. This guaranteed network capacity would be subtracted from the DSO offer curve, so reducing the available network capacity for the rest of customers. If applied, regulators should acknowledge the loss in overall economic efficiency.

The complexity of the presented ex-post network charges and the customer response coordination mechanism in terms of a higher locational granularity of network charges may pose practical difficulties for network operators, customers and regulatory authorities. In addition, acceptability issues may arise in some customer segments that would not want to be exposed to such complexity.

Regarding the higher locational granularity, the network in some regions or locations is usually more congested than in others. This provides the opportunity to test the proposed solution in some of those specific locations, and then gradually expand the solution to the rest of congested networks. Further research on the practical implementation of zonal, or even nodal approaches, and how to improve the definition of network areas is recommended. Regarding customer acceptability, not implementing the proposed charges would reduce the potential flexibility from customers who are willing to provide it and overall come at a cost of higher than optimal network investment. This environment suggests the key role of aggregators and retailers in the future as: 1) intermediaries between complex tariff structures (including complex network charges) and customers, by offering diverse products according to customers' risk aversion and flexibility, such as simpler energy and capacity charges with some time-block differentiation, while the retailer would assume the risk of exposure to the ex-post network charges and the coordination mechanism in exchange for a premium; and 2) facilitators for customers' active participation in electricity markets, including, for example, in the proposed local network capacity market. This would imply an extension of the responsibility of retailers – who already represent customers in wholesale electricity markets which include complex activities such as energy imbalance management.

Chapter 6.
Conclusions, contributions, and future developments

6.1. Conclusions

Over the last decades, the electricity system has experienced a revolution driven by three major forces: Decarbonization, Decentralization, and Digitalization. Electricity networks are the backbone of the electricity system, connecting generation and consumption, and network tariffs are meant to recover network costs while, at the same time, fulfilling the principles of economic efficiency, equity, and transparency. These principles are often seen as interfering with each other. For example, economic efficiency leads to highly differentiated network charges in terms of time and location, producing complex tariff structures, and reducing understandability for end-customers, which is often considered a measure for the equity principle. On the other hand, simpler network tariff structures, such as energy-based charges with no temporal differentiation, provide wrong and economically inefficient incentives for active customers to adopt self-generation, who avoid paying network charges while network costs are not reduced, and thus creating cross-subsidies between customers.

This thesis follows a conceptual framework for the network tariff design consisting of two steps: 1) cost recognition and segmentation, and 2) cost allocation to customers through different tariff settings.

In the literature review several gaps were found between theoretical first-best network tariff designs and current network tariff designs implemented in real-world systems. Regarding cost recognition and segmentation, the main gaps are:

- A lack of transparency in the overall tariff design, and the recovery of some non-electricity-related costs through the electricity bill, which distorts the efficient economic signals that should be provided by network tariffs and electricity market prices.
- While long-term marginal cost-based approaches theoretically perform better in terms of cost reflectivity than accounting-based approaches, the latter are still predominant in real-world implementations of network tariffs.

Regarding the network cost allocation to customers through different tariff settings, six variables are identified in the tariff structure: customer differentiation, symmetry, temporal granularity, locational granularity, price setting periodicity, and the charging variable. The main gaps are:

- While the economic efficiency principle advocates for network charges that are agnostic to the final usage of the electricity, many countries differentiate network charges for different electricity uses such as customers with electric vehicles, self-generation, etc. The main cause of this situation is a historical network tariff structure that produces cross-subsidies among customers, usually disfavoring passive customers, that is then "solved" through patches in the form of specific network tariffs for specific end-uses, rather than reviewing the overall tariff structure.
- Ill-designed symmetric network charges (for injections and withdrawals) within the rest of electricity bill leads, such as net-metering approaches, do not consider time and space variability of network conditions.
- Although many countries are making huge efforts to improve, location differentiation, temporal granularity, and price-setting periodicity are still far from the theoretical optimum. In the past, the lack of data was the main barrier to achieve a higher cost-reflectivity, but now, with the smart-meters deployment, the main cause is an overweight of simplicity principle at expenses of economic efficiency.
- In a future with many flexible customers reacting to network charges, the peak shifting effect, i.e., customers synchronizing network usage during off-peak hours and creating new and increased network peaks, is considered a major issue.

The research shown in this thesis aims to contribute to the understanding of the effects of Decentralization, Decarbonization and Digitalization to the network cost allocation problem, how real-world systems can move towards more cost-reflective and equitable network tariff designs, which challenges tariff-makers may find in this way, and some proposed solutions to deal with them.

6.2. Contributions

The main contributions of this thesis are:

- Following the same network tariff design structure of 1) cost recognition and segmentation, and 2) cost allocation to customers through tariff settings, this thesis proposes and tests a long-term marginal cost-based methodology and compares it to other network tariff designs. Under the proposed methodology, network costs are split between long-term incremental costs and residual costs. Long-term incremental costs are allocated to customers through peak-coincident charges considering their individual network usage at maximum network utilization hours at each network element, and residual costs are computed as non-distortive fixed charges. Peak-coincident charges are designed to send economic signals that reflect future network reinforcements to network users, incentivizing them to behave in a way that the social welfare is maximized. On the other hand, residual charges recover all system costs that are not recovered through peak-coincident charges without distorting the economic signals sent by peak-coincident charges and the electricity market prices. The preferred alternative for the residual charges design follows the equity principle, e.g., discriminating customers by size, wealth, or similar proxies. Furthermore, the same residual approach could be used for non-electricity-related costs such as for allocating renewable support costs.

- The long-term marginal cost formulation is implemented in a real-world system, the Slovenian electricity system. The complexities found in the practical implementation, like allocation of costs from different voltage levels, are solved by segmenting the network via a cascade model in which energy injections and withdrawals are classified according to their voltage level connection and treated symmetrically. Network costs are determined per voltage-level, and then, voltage-level specific forward-looking peak-coincident charges, charges for energy losses, and non-distortive residual network charges are calculated. In this case, peak coincident charges are hourly energy charges and residual charges are related to the connection physical capacity, as the least-distortive charging variable related to customers' size, due to the impossibility to get income or wealth related data.
- Network tariff design can achieve both economic efficiency and equity, although at the expense of the simplicity principle. This thesis has demonstrated that economic efficiency can be reached through long-term incremental cost allocation, while residual cost allocation deals with those equity issues that can arise after the implementation of the long-term incremental cost approach without distorting the efficient economic signal.
- The proposed formulation in a real-world system is compared to other current network tariff designs (the Spanish and the former Slovenian) focusing on active customers adopting electric vehicles, self-generation, or providing flexibility services. The proposed tariff incentivizes the efficient response of flexible loads, for instance, slow versus fast EV charging, and EV charging in off-peak versus peak hours, while still promoting the electrification of transport. In the case of customers adopting PV installations for self-consumption, the proposed tariff provides less of a discount compared to the current tariffs, aligning better individual customer benefits with expected system benefits, reducing, in the end, long-term network costs. The symmetric nature of the proposed tariff enables a level playing field in which no exemptions of network charges are required for customers providing flexibility services, while they would with the other two compared tariff alternatives.
- Moving towards a more advanced implementation of the proposed long-term based methodology, this thesis provides the mathematical formulation for increasing locational granularity and price-setting periodicity of network charges through ex-post pricing. A higher locational granularity allows a better alignment between network charges and long-term network costs of the specific network elements that customers use. Ex-post pricing guarantees an accurate identification of network peak hours, which can only be known after the delivery time, and trespasses the cost responsibility of newly created peaks to customers, which eventually avoids the peak-shifting effect.
- To overcome the side-effects created by ex-post pricing, such as the low predictability of network charges for customers, this thesis proposes a customer response coordination mechanism. This mechanism takes the form of a local network capacity market where customers, directly or through retailers or aggregators, compete in critical days for the scarce product, i.e., the reserved network capacity, enabling an efficiently ordered customer response and a higher predictability for end-customers, while the efficient economic signals sent by ex-post peak coincident charges are preserved.
- Finally, the proposed highly granular and ex-post network tariff design with the coordination mechanism is tested and compared to other two forward-looking tariffs in a detailed case study. The case study is formed by a network supplying 10,000 customers when a 5% or a 20% of customers adopt heat pumps as a flexible consumption and

reacting to price signals. The case study demonstrates that the combined implementation of the proposed network tariff and the coordination mechanism leads to significant network investment savings in a long-term perspective.

By comparing different network tariff designs, and their interactions, this thesis aims to support regulators' decisions on more economically efficient and equitable network tariff designs that in the long run will lead to system-wide cost savings.

A major part of the work presented in this thesis has been published in the following journal papers and in a book chapter:

- Chapters 2 and 3 have been extracted from the following Energies paper and the book chapter:

> Morell Dameto, N., Chaves-Ávila, J. P., & Gómez San Román, T., 2020. Revisiting Electricity Network Tariffs in a Context of Decarbonization, Digitalization, and Decentralization. *Energies*, *13*(12), Article 12.
>
> https://doi.org/10.3390/en13123111.

> Morell Dameto, N., Chaves Ávila, J. P., & Gómez San Román, T., 2021. Electricity Tariff Design in the Context of an Ambitious Green Transition. In *Energy Regulation in the Green Transition: An Anthology* (Vol. 1, pp. 48-64).
>
> https://forsyningstilsynet.dk/aktuelt/publikationer/danish-utility-regulators-anthology-project-series-on-better-regulation-in-the-energy-sector/vol-1-energy-regulation-in-the-green-transition.

- Chapter 4 has been extracted from the following Energy Economics paper:

> Morell-Dameto, N., Chaves-Ávila, J. P., Gómez San Román, T., & Schittekatte, T., 2023. Forward-looking dynamic network charges for real-world electricity systems: A Slovenian case study. *Energy Economics*, *125*, 106866.
>
> https://doi.org/10.1016/j.eneco.2023.106866.

- Chapter 5 has been extracted from the following paper submitted to Energy Policy journal:

> Morell-Dameto, N., Chaves-Ávila, J. P., Gómez San Román, T., Dueñas-Martínez, P., & Schittekatte, T., 2023. Network tariff design with flexible customers: Ex-post pricing and a local network capacity market for customer response coordination. *Submitted to Energy Policy*.
>
> https://www.iit.comillas.edu/publicacion/workingpaper/en/488/Advancing_in_the_implementation_of_forward-looking_incremental_network_charges:_locational_granularity,_ex-post_pricing,_and_customer_response_coordination.

Finally, an open-access digital repository has been established to facilitate replicability and encourage further research development. The repository can be accessed at the following link: https://github.com/Nmorelldam/PhD-Thesis-Nicolas-Morell-Dameto. This repository is organized into three distinct folders, each corresponding to one of the journal papers. Within each folder, you will find the spreadsheets and code files that were employed to substantiate the arguments presented in the papers, as well as to create the accompanying figures and tables. Additionally, there are instructions to assist users.

6.3. Future work

This section presents some proposals for future developments which follow the idea that network tariffs must evolve from merely being instruments to recover network costs to the regulatory tool to coordinate the grid users and the network in order to foster the most efficient network development. These future research topics are:

- As shown in the literature review chapter, network tariffs are not the only tool to recover network costs. When designing network tariffs, their potential interactions with other mechanisms, such as connection charges, exit fees, flexibility charges, or other explicit flexibility mechanisms should be considered to avoid double charging or double reward. These possible interactions deserve further research.
- While increasing locational granularity in network charges has demonstrated to increase economic efficiency, an optimal way of defining and differentiating network areas is not solved. Some examples of locational differentiation could be based on network topology, number of customers, congested assets, etc. Literature would benefit from analysis in this research line.
- In many countries, a usual concern against network tariff reform lays on the low expected customer reaction and engagement. Sound cost-benefit analysis on the implementation costs of more complex and cost-reflective network tariffs should be the only reason leading to suboptimal network tariff designs. Therefore, future research on such cost-benefit analyses would help regulators to take the most economically efficient decisions.
- Driven by institutional inertia, many countries adopt short-term solutions to deal with cross-subsidies created by decentralization, decarbonization and digitalization, rather than making a thorough network tariff design revision. Long-term effects on both active and passive customers should be considered in any tariff reform. More importantly, in the case of adopting short-term solutions that will lead to future network tariff reforms, the costs of regulatory instability should be considered.
- The coordination mechanism has been theoretically proposed and tested. However, its practical implementation in real-world systems would be challenging due to the increased data to be exchanged between market participants, regional differentiation of customers, the underlying contract terms between DSOs and customer representatives, etc. In addition, simultaneity of auctions, and coupling among different auctions and temporal horizons could increase complexity. Thus, further research in this line is required.
- The increased complexity derived from the proposed forward-looking methodology suggest the key role that aggregators and retailers will play as intermediaries between DSOs and customers, providing hedging for those customers with higher risk aversion, and representing customers in the different markets, including the proposed customer

response coordination mechanism. Further research on how regulators could ensure fair competition among retailers is a suggested future work.

References

Abdelmotteleb, I., Gómez, T., Chaves Ávila, J. P., & Reneses, J. (2018). Designing efficient distribution network charges in the context of active customers. *Applied Energy*, *210*, 815-826. https://doi.org/10.1016/j.apenergy.2017.08.103

Abdelmotteleb, I., Gómez, T., & Reneses, J. (2017). Evaluation Methodology for Tariff Design under Escalating Penetrations of Distributed Energy Resources. *Energies*, *10*(6), Article 6. https://doi.org/10.3390/en10060778

ACER. (2021). *Report on Distribution Tariff Methodologies in Europe*. ACER. https://documents.acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Report%20on%20D-Tariff%20Methodologies.pdf (accessed Jul. 2023)

ACER. (2023). *Report on Electricity Transmission and Distribution Tariff Methodologies in Europe*. ACER. https://www.acer.europa.eu/Publications/ACER_electricity_network_tariff_report.pdf (accessed Jul. 2023)

ACER and CEER. (2022). *ACER Market Monitoring Report 2020 – Electricity Wholesale Market Volume*. ACER and CEER. https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/ACER%20Market%20Monitoring%20Report%202020%20%E2%80%93%20Electricity%20Wholesale%20Market%20Volume.pdf (accessed Jul. 2023)

ACER/CEER. (2022). *Annual Report on the Results of Monitoring the Internal Electricity and Natural Gas Markets in 2021*. https://www.acer.europa.eu/Publications/MMR_2021_Energy_Retail_Consumer_Protection_Volume.pdf (accessed Jul. 2023)

Anaya, K. L., & Pollitt, M. G. (2015). Options for allocating and releasing distribution system capacity: Deciding between interruptible connections and firm DG connections. *Applied Energy*, *144*, 96-105. https://doi.org/10.1016/j.apenergy.2015.01.043

Azuatalam, D. (2019). *Technical and Economic Assessments of Electricity Distribution Networks with Active Customers*. https://hdl.handle.net/2123/21791

Barrera, F. (2019, junio 27). *Peajes eléctricos. Una barrera para la transición energética. Frontier Economics.* https://www.frontier-economics.com/media/3346/frontier-peajes-el%C3%A9ctricos-junio-2019.pdf (accessed Jul. 2023)

Bastida, H., Ugalde-Loo, C. E., Abeysekera, M., Qadrdan, M., & Wu, J. (2019). Thermal Dynamic Modelling and Temperature Controller Design for a House. *Energy Procedia*, *158*, 2800-2805. https://doi.org/10.1016/j.egypro.2019.02.041

Batalla-Bejerano, J., Trujillo-Baute, E., & Villa-Arrieta, M. (2020). Smart meters and consumer behaviour: Insights from the empirical literature. *Energy Policy*, *144*, 111610. https://doi.org/10.1016/j.enpol.2020.111610

Batlle, C. (2011). A method for allocating renewable energy source subsidies among final energy consumers. *Energy Policy*, *39*(5), 2586-2595. https://doi.org/10.1016/j.enpol.2011.02.027

Batlle, C., Mastropietro, P., & Rodilla, P. (2020). Redesigning residual cost allocation in electricity tariffs: A proposal to balance efficiency, equity and cost recovery. *Renewable Energy*, *155*, 257-266. https://doi.org/10.1016/j.renene.2020.03.152

Bergaentzlé, C., Jensen, I. G., Skytte, K., & Olsen, O. J. (2019). Electricity grid tariffs as a tool for flexible energy systems: A Danish case study. *Energy Policy*, *126*, 12-21. https://doi.org/10.1016/j.enpol.2018.11.021

Berkson, W. (1974). *Fields of force; the development of a world view from Faraday to Einstein.* —. London : Routledge and K. Paul. http://archive.org/details/fieldsofforcedev0000berk (accessed Jul. 2023)

Bhagwat, P., & Hadush, S. (2020). *Dynamic Retail Electricity Tariffs: Choices and Barriers*. FLorence School of Regulation. https://cadmus.eui.eu/handle/1814/66851;jsessionid=C0A4AF1EC5904356BA6B855EC46600BD.

Boiteux, M. (1949). La tarification des demandes en pointe: Application de la théorie de la vente au coût marginal. *Revue Générale de l'Electricité*, 58, 321-340.

Boiteux, M., & Stasi, P. (1964). The determination of costs of expansion of an interconnected system or production and distribution of electricity. En *Marginal cost pricing in practice* (Nelson, J.). Englewood Cliffs, N. J. Prentice-Hall Inc. doi:10.1017/S0770451800040604

Bonbright, J. C. (1961). *Principles of Public Utility Rates.* http://media.terry.uga.edu/documents/exec_ed/bonbright/principles_of_public_utility_rates.pdf (accessed Jul. 2023)

Borenstein, S. (2016). The economics of fixed cost recovery by utilities. *The Electricity Journal*, *29*(7), 5-12. https://doi.org/10.1016/j.tej.2016.07.013

Borenstein, S. (2017). Private Net Benefits of Residential Solar PV: The Role of Electricity Tariffs, Tax Incentives, and Rebates. *Journal of the Association of Environmental and Resource Economists*, *4*(S1), Article S1. https://doi.org/10.1086/691978

Borenstein, S., Fowlie, M., & Sallee, J. (2021). Designing Electricity Rates for An Equitable Energy Transition. *Energy Institute at Haas*, *WP 314*. https://haas.berkeley.edu/wp-content/uploads/WP314.pdf (accessed Jul. 2023)

BP Energy Outlook 2019. (2019). https://www.bp.com/content/dam/bp/business-sites/en/global/corporate/pdfs/energy-economics/energy-outlook/bp-energy-outlook-2019.pdf (accessed Jul. 2023)

Brown, D. P., & Sappington, D. E. M. (2018). On the role of maximum demand charges in the presence of distributed generation resources. *Energy Economics*, *69*, 237-249. https://doi.org/10.1016/j.eneco.2017.11.023

Brown, T., Faruqui, A., & Lessem, N. (2018). *Electricity Distribution Network Tariffs. Principles and analysis of options*. Brattle Group. https://www.brattle.com/wp-content/uploads/2021/05/14255_electricity_distribution_network_tariffs_-_the_brattle_group.pdf (accessed Jul. 2023)

Burger, S. P., Knittel, C. R., Perez-Arriaga, I. J., Schneider, I., & vom Scheidt, F. (2020). The Efficiency and Distributional Effects of Alternative Residential Electricity Rate Designs. *The Energy Journal*, *41*(1). https://doi.org/10.5547/01956574.41.1.sbur

Burger, S., Schneider, I., Botterud, A., & Pérez-Arriaga, I. (2019a). Chapter 8—Fair, Equitable, and Efficient Tariffs in the Presence of Distributed Energy Resources. En F. Sioshansi (Ed.), *Consumer, Prosumer, Prosumager* (pp. 155-188). Academic Press. https://doi.org/10.1016/B978-0-12-816835-6.00008-5

Burger, S., Schneider, I., Botterud, A., & Pérez-Arriaga, I. (2019b). Chapter 8—Fair, Equitable, and Efficient Tariffs in the Presence of Distributed Energy Resources. En F. Sioshansi (Ed.), *Consumer, Prosumer, Prosumager* (pp. 155-188). Academic Press. https://doi.org/10.1016/B978-0-12-816835-6.00008-5

Byatt, I. C. R. (1963). The Genesis of the Present Pricing System in Electricity Supply. *Oxford Economic Papers*, *15*(1), 8-18.

CEER. (2017). *Electricity Distribution Network Tariffs CEER Guidelines of Good Practice*. https://www.ceer.eu/documents/104400/-/-/1bdc6307-7f9a-c6de-6950-f19873959413 (accessed Jul. 2023)

CEER. (2020). *Paper on electricity distribution tariffs supporting the energy transition*. CEER. https://www.ceer.eu/documents/104400/-/-/fd5890e1-894e-0a7a-21d9-fa22b6ec9da0 (accessed Jul. 2023)

Clark, J. M. (1911). Rates for Public Utilities. *The American Economic Review*, *1*(3), 473-487.

Circular 3/2020, de 15 de enero, de la Comisión Nacional de los Mercados y la Competencia, por la que se establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad., (2020). https://www.cnmc.es/sites/default/files/2808021_15.pdf (accessed Jul. 2023)

CNMC. (2020). *Memoria justificativa de la circular de la comisión nacional de los mercados y la competencia por la que se establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad* (CIR/DE/002/19; Número CIR/DE/002/19). Comisión Nacional de los Mercados y la Competencia. https://www.cnmc.es/sites/default/files/2808025_42.pdf(accessed Jul. 2023)

CNMC. (2019, julio 25). *Propuesta por la que se establece la metodología para el cálculo de los peajes de transporte y distribución de electricidad.* https://www.cnmc.es/sites/default/files/editor_contenidos/Energia/Consulta%20Publi ca/01%20Propuesta%20_CIR_DE_002_19_peajes_el%C3%A9ctricos.pdf (accessed Jul. 2023)

Cohen, M. A., Kauzmann, P. A., & Callaway, D. S. (2016). Effects of distributed PV generation on California's distribution system, part 2: Economic analysis. *Solar Energy*, *128*, 139-152. https://doi.org/10.1016/j.solener.2016.01.004

CoordiNet. (2021). *CoordiNet—Deliverable D2.1—Markets for DSO and TSO procurement of innovative grid services: Specification of the architecture, operation and clearing algorithms* (p. 197). https://private.coordinet-project.eu//files/documentos/6033b5fe475cdCoordiNet_WP2_D2.1_Markets%20for%20DSO%20and%20TSO%20procurement%20of%20innovative%20grid%20services_V1.0_20.02.2021.pdf (accessed Jul. 2023)

Dancker, J., Martinez, P. D., & Wolter, M. (2023). Impact of Heat Pumps, Rooftop PV, and Hydrogen Blending on Gas-Electricity Distribution Networks in Northeast US. *IEEE Access*, *11*, 12963-12972. https://doi.org/10.1109/ACCESS.2023.3241593

De Albuquerque, J. M., Vieira, D., & Lamin, H. (2019, junio 3). Net Metering in Brazil: Setting the scene for the regulatory framework review. *CIRED, 25th International Conference on Electricity Distribution*. CIRED, 25th International Conference on Electricity Distribution, Madrid, Spain.

Directorate-General for Energy (European Commission), Tractebel Impact, Alaton, C., & Tounquet, F. (2020). *Benchmarking smart metering deployment in the EU-28: Final report*. Publications Office of the European Union. https://data.europa.eu/doi/10.2833/492070

Dondi, P., Bayoumi, D., Haederli, C., Julian, D., & Suter, M. (2002). Network integration of distributed power generation. *Journal of Power Sources*, *106*(1), 1-9. https://doi.org/10.1016/S0378-7753(01)01031-X

Dupont, B., De Jonghe, C., Olmos, L., & Belmans, R. (2014). Demand response with locational dynamic pricing to support the integration of renewables. *Energy Policy*, *67*, 344-354. https://doi.org/10.1016/j.enpol.2013.12.058

Ecobee. (2023). https://www.ecobee.com/en-us/eco-plus/ (accessed Jul. 2023)

Eero, V. (2018). *Battery Storage Costs and Impact on PV Competitiveness.* http://www.iea-pvps.org/fileadmin/dam/intranet/ExCo/51st_Malaysia/Vartiainen_Battery_Storage_Costs_and_Impact_on_PV_Competitiveness_20180924.pdf (accessed Jul. 2023)

Eid, C., Reneses Guillén, J., Frías Marín, P., & Hakvoort, R. (2014). The economic effect of electricity net-metering with solar PV: Consequences for network cost recovery, cross subsidies and policy objectives. *Energy Policy*, *75*, 244-254. https://doi.org/10.1016/j.enpol.2014.09.011

Energy KnowledgeBase. (2019). *Locational marginal pricing (LMP)*. https://energyknowledgebase.com/topics/locational-marginal-pricing.asp (accessed Jul. 2023)

ENTSO-E. (2020). *Overview of Transmission Tariffs in Europe: Synthesis 2019* (p. 72). https://eepublicdownloads.entsoe.eu/clean-documents/mc-documents/201209_ENTSO-E%20Transmission%20Tariff%20Overview_Synthesis%202019.pdf (accessed Jul. 2023)

EU Directive. (2019). *Directive (EU) 2019/944 of the European Parliament and of the Council of 5 June 2019 on common rules for the internal market for electricity and amending Directive 2012/27/EU*. https://eur-lex.europa.eu/eli/dir/2019/944/oj (accessed Jul. 2023)

EU Regulation. (2019). *Regulation (EU) 2019/943 of the European Parliament and of the Council of 5 June 2019 on the internal market for electricity*. http://data.europa.eu/eli/reg/2019/943/oj/eng (accessed Jul. 2023)

EUniversal. (2020). *D1.1. Characterisation of current network regulation and market rules that will shape future markets*. https://euniversal.eu/wp-content/uploads/2020/08/EUniversal_D1_1.pdf (accessed Jul. 2023)

Eurelectric. (2016). *Network tariffs*. EURELECTRIC. https://www3.eurelectric.org/media/268408/network_tariffs__position_paper_final_as-2016-030-0149-01-e.pdf (accessed Jul. 2023)

Eurelectric and E.DSO. (2021, enero 14). *Connecting the dots: Distribution grid investment to power the energy transition - Eurelectric – Powering People*. https://www.eurelectric.org/connecting-the-dots/ (accessed Jul. 2023)

European Commission. (2023a). *Joint Statement on European Energy Security*. European Commission. https://ec.europa.eu/commission/presscorner/detail/en/STATEMENT_22_4149 (accessed Jul. 2023)

European Commission. (2023b, mayo 26). *Heat pumps – action plan to accelerate roll-out across the EU*. https://ec.europa.eu/info/law/better-regulation/have-your-say/initiatives/13771-Heat-pumps-action-plan-to-accelerate-roll-out-across-the-EU_en (accessed Jul. 2023)

Faruqui, A., & Sergici, S. (2010). Household response to dynamic pricing of electricity: A survey of 15 experiments. *Journal of Regulatory Economics*, *38*(2), 193-225. https://doi.org/10.1007/s11149-010-9127-y

Gerres, T., Chaves Ávila, J. P., Martín Martínez, F., Abbad, M. R., Arín, R. C., & Sánchez Miralles, Á. (2019). Rethinking the electricity market design: Remuneration mechanisms to reach high RES shares. Results from a Spanish case study. *Energy Policy*, *129*, 1320-1330. https://doi.org/10.1016/j.enpol.2019.03.034

Glachant, J.M., & Rossetto, N. (2018). *The digital world knocks at electricity's door: Six building blocks to understand why*. http://cadmus.eui.eu//handle/1814/59044 (accessed Jul. 2023)

González, A. (2014). *PhD dissertation (Spanish): Implicaciones de la continuidad de suministro en el diseño de la tarifa de red de distribución.* Universidad Pontificia de Comillas. http://hdl.handle.net/11531/1396

GOPACS. (2022). Public Announcements. *GOPACS*. https://en.gopacs.eu/public-announcements/ (accessed Jul. 2023)

Haapaniemi, J., Haakana, J., Räisänen, O., Lassila, J., & Partanen, J. (2019). *DSO tariff driven customer grid defections – Techno-economical risks for DSO?; 25th International Conference on Electricity Distribution (CIRED 2019)*. 25th International Conference on Electricity Distribution (CIRED 2019). http://dx.doi.org/10.34890/846

Hayward, J. A., & Graham, P. W. (2017). *Electricity generation technology cost projections: 2017-2050.* https://publications.csiro.au/rpr/download?pid=csiro:EP178771&dsid=DS2 (accessed Jul. 2023)

Hendam, M., Schittekatte, T., Abdel-Rahman, M., & Kamh, M. Z. (2022). Rethinking electricity rate design: Fostering the energy transition in North Africa. *Energy Policy*, *169*, 113172. https://doi.org/10.1016/j.enpol.2022.113172

Hoarau, Q., & Perez, Y. (2019). *Network tariff design with prosumers and electromobility: Who wins, who loses?* https://doi.org/10.1016/j.eneco.2019.05.009

Hopkinson, J. (1892). On the cost of electric supply. *Presidential Address to the Joint Engineering Society. November 4, 1892. Appears in Original Papers by the Late John Hopkinson, Volume 1, Technical Papers, Edited by B. Hopkinson, Cambridge University Press, 1901.* http://archive.org/details/cu31924012334466 (accessed Jul. 2023)

Houthakker, H. S. (1951). Electricity Tariffs in Theory and Practice. *The Economic Journal*, *61*(241), 1-25. https://doi.org/10.2307/2226608

HPA. (2019). *A Roadmap for the Role of Heat Pumps.* Heat Pumps Asssociation. https://www.heatpumps.org.uk/wp-content/uploads/2019/11/A-Roadmap-for-the-Role-of-Heat-Pumps.pdf (accessed Jul. 2023)

HPUC. (2015). *In the Matter of Public Utilities Commission insitituting a proceding to investigate distributed energy resurce policies. Docket No. 2014-0192, Decision Order No. 33258*. https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A15J13B15422F90464 (accessed Jul. 2023)

HPUC. (2019). *HPUC Expands Options for Customers to Install Rooftop Solar and Energy Storage*. https://puc.hawaii.gov/wp-content/uploads/2017/10/Hawaii-PUC-Rooftop-Solar-and-Storage-Press-Release-10-20-17-FINAL.pdf (accessed Jul. 2023)

Hughes, T. P. (1993). *Networks of Power*. https://doi.org/10.56021/9780801828737

IEA. (2021). *Net Zero by 2050—A Roadmap for the Global Energy Sector*. International Energy Agency. https://www.iea.org/data-and-statistics/data-product/net-zero-by-2050-scenario (accessed Jul. 2023)

IEA. (2023). *Global EV Outlook 2023: Catching up with Climate Ambitions*. OECD. https://doi.org/10.1787/cbe724e8-en

IEA. (2022). *The Future of Heat Pumps*. IEA. https://www.iea.org/reports/the-future-of-heat-pumps (accessed Jul. 2023)

Integrated NECP of the Republic of Slovenia (35400-18/2019/14). (2020). Slovenian government. https://ec.europa.eu/energy/sites/ener/files/documents/si_final_necp_main_en.pdf (accessed Jul. 2023)

Ioannis, T., Tarvydas, D., & Lebedeva, N. (2018). *Li-ion batteries for mobility and stationary storage applications* (p. 72). https://publications.jrc.ec.europa.eu/repository/bitstream/JRC113360/kjna29440enn.pdf (accessed Jul. 2023)

Jessoe, K., & Rapson, D. (2014). Knowledge Is (Less) Power: Experimental Evidence from Residential Energy Use. *American Economic Review*, *104*(4), 1417-1438. https://doi.org/10.1257/aer.104.4.1417

Krishnan, V., Bugbee, B., Elgindy, T., Mateo, C., Duenas, P., Postigo, F., Lacroix, J.-S., Roman, T. G. S., & Palmintier, B. (2020). Validation of Synthetic U.S. Electric Power Distribution System Data Sets. *IEEE Transactions on Smart Grid*, *11*(5), 4477-4489. https://doi.org/10.1109/TSG.2020.2981077

Lewis, W. A. (1941). The Two-Part Tariff. *Economica*, *8*(31), 249-270. https://doi.org/10.2307/2549332

Li, F., & Tolley, D. L. (2007). Long-Run Incremental Cost Pricing Based on Unused Capacity. *IEEE Transactions on Power Systems*, *22*(4), 1683-1689. https://doi.org/10.1109/TPWRS.2007.908469

Lima, J. W. M., Noronha, J. C. C., Arango, H., & dos Santos, P. E. S. (2002). Distribution pricing based on yardstick regulation. *IEEE Transactions on Power Systems*, *17*(1), 198-204. https://doi.org/10.1109/59.982214

Lopes, J. A. P., Hatziargyriou, N., Mutale, J., Djapic, P., & Jenkins, N. (2007). Integrating distributed generation into electric power systems: A review of drivers, challenges and opportunities. *Electric Power Systems Research*, *77*(9), 1189-1203. https://doi.org/10.1016/j.epsr.2006.08.016

Manuel de Villena, M., Fonteneau, R., Gautier, A., & Ernst, D. (2019). Evaluating the Evolution of Distribution Networks under Different Regulatory Frameworks with Multi-Agent Modelling. *Energies*, *12*(7), Article 7. https://doi.org/10.3390/en12071203

Manuel de Villena, M., Gautier, A., Ernst, D., Glavic, M., & Fonteneau, R. (2021). Modelling and assessing the impact of the DSO remuneration strategy on its interaction with electricity users. *International Journal of Electrical Power & Energy Systems*, *126*, 106585. https://doi.org/10.1016/j.ijepes.2020.106585

Martín-Martínez, F., Sánchez-Miralles, A., Rivier, M., & Calvillo, C. F. (2017). Centralized vs distributed generation. A model to assess the relevance of some thermal and electric factors. Application to the Spanish case study. *Energy*, *134*, 850-863. https://doi.org/10.1016/j.energy.2017.06.055

Mastropietro, P. (2019). Who should pay to support renewable electricity? Exploring regressive impacts, energy poverty and tariff equity. *Energy Research & Social Science*, *56*, 101222. https://doi.org/10.1016/j.erss.2019.101222

Mateo, C., Gómez, T., Sanchez-Miralles, Á., Gonzalez, J. P. P., & Martinez, A. C. (2011). A Reference Network Model for Large-Scale Distribution Planning With Automatic Street Map Generation. *IEEE Transactions on Power Systems*, *26*(1), Article 1. https://doi.org/10.1109/TPWRS.2010.2052077

Maurer, L., & Barroso, L. (2011). *Electricity Auctions*. The World Bank. https://doi.org/10.1596/978-0-8213-8822-8

McKinsey. (2020). *Net Zero Europe—Decarbonisation pathways and socioeconomic implications*. https://www.mckinsey.com/~/media/mckinsey/business%20functions/sustainability/our%20insights/how%20the%20european%20union%20could%20achieve%20net%20zero%20emissions%20at%20net%20zero%20cost/net-zero-europe-vf.pdf (accessed Jul. 2023)

Meeus, L., Govaerts, N., & Schittekatte, T. (2020). *Cost-reflective network tariffs: Experiences with forward looking cost models to design electricity distribution charges*. https://cadmus.eui.eu//handle/1814/67674 (accessed Jul. 2023)

Mohar, T., Kuzmic, B., & Bakic, K. (2005). The methodology for the calculation network use tariffs in Slovenia. *18th International Conference and Exhibition on Electricity Distribution (CIRED 2005)*, *2005*, v6-64-v6-64. https://doi.org/10.1049/cp:20051441

Morell Dameto, N., Chaves-Ávila, J. P., & Gómez San Román, T. (2020). Revisiting Electricity Network Tariffs in a Context of Decarbonization, Digitalization, and Decentralization. *Energies*, *13*(12), Article 12. https://doi.org/10.3390/en13123111

Morell Dameto, N., Chaves Ávila, J. P., & Gómez San Román, T. (2021). Electricity Tariff Design in the Context of an Ambitious Green Transition. En *Energy Regulation in the Green Transition: An Anthology* (Vol. 1, pp. 48-64). https://forsyningstilsynet.dk/aktuelt/publikationer/danish-utility-regulators-anthology-project-series-on-better-regulation-in-the-energy-sector/vol-1-energy-regulation-in-the-green-transition (accessed Jul. 2023)

Morell-Dameto, N., Chaves-Ávila, J. P., Gómez San Román, T., & Schittekatte, T. (2023a). Forward-looking dynamic network charges for real-world electricity systems: A Slovenian case study. *Energy Economics*, *125*, 106866. https://doi.org/10.1016/j.eneco.2023.106866

Morell-Dameto, N., Chaves-Ávila, J. P., Gómez San Román, T., Dueñas-Martínez, P., & Schittekatte, T. (2023b). Network tariff design with flexible customers: Ex-post pricing and a local network capacity market for customer response coordination. *Submitted to Energy Policy*. https://www.iit.comillas.edu/publicacion/workingpaper/es/488/Advancing_in_the_implementation_of_forward-looking_incremental_network_charges:_locational_granularity,_ex-post_pricing,_and_customer_response_coordination (accessed Jul. 2023)

Muratori, M., & Rizzoni, G. (2016). Residential Demand Response: Dynamic Energy Management and Time-Varying Electricity Pricing. *IEEE Transactions on Power Systems*, *31*(2), 1108-1117. https://doi.org/10.1109/TPWRS.2015.2414880

Nest. (2023). Google Store. https://store.google.com/us/product/nest_learning_thermostat_3rd_gen?hl=en-US

Nijhuis, M., Gibescu, M., & Cobben, J. F. G. (2017). Analysis of reflectivity & predictability of electricity network tariff structures for household consumers. *Energy Policy*, *109*, 631-641. https://doi.org/10.1016/j.enpol.2017.07.049

OECD (2011). Regulatory Policy and Governance: Supporting Economic Growth and Serving the Public Interest. OECD. https://doi.org/10.1787/9789264116573-en

Ofgem (2018). Reform of network access and forward-looking charges. Ofgem. https://www.ofgem.gov.uk/electricity/transmission-networks/charging/reform-network-access-and-forward-looking-charges (accessed Jul. 2023)

Ofgem (2019a). Charge design options for distribution and transmission charges – discussion note. https://www.ofgem.gov.uk/sites/default/files/docs/2019/09/summer_2019_-_working_paper_-_charge_design_note_final_nd.pdf (accessed Jul. 2023)

Ofgem (2019b). Current arrengements. https://www.ofgem.gov.uk/sites/default/files/docs/2019/12/winter_2019_-_working_paper_-_existing_arrangements_publish.pdf (accessed Jul. 2023)

Ofgem (2019c). Introduction on Access and Forward-looking charges significant code review. https://www.ofgem.gov.uk/system/files/docs/2019/09/111_-_working_paper_-_summer_2019_-_intro_note_final.pdf (accessed Jul. 2023)

Ofgem (2019d). *Targeted Charging Review: Decision and impact assessment.* https://www.ofgem.gov.uk/system/files/docs/2019/12/full_decision_doc_formatted_updated9.pdf (accessed Jul. 2023)

Ofgem (2022). Access and Forward-Looking Charges Significant Code Review: Decision and Direction. https://www.ofgem.gov.uk/publications/access-and-forward-looking-charges-significant-code-review-decision-and-direction (accessed Jul. 2023)

Passey, R., Haghdadi, N., Bruce, A., & MacGill, I. (2017). Designing more cost reflective electricity network tariffs with demand charges. *Energy Policy*, *109*, 642-649. https://doi.org/10.1016/j.enpol.2017.07.045

Pérez-Arriaga, I. J. (2016). *Utility of the future. An MIT Energy Initiative response to an industry in transition.* http://energy.mit.edu/wp-content/uploads/2016/12/Utility-of-the-Future-Full-Report.pdf (accessed Jul. 2023)

Perez-Arriaga, I. J., Jenkins, J. D., & Batlle, C. (2017). A regulatory framework for an evolving electricity sector: Highlights of the MIT utility of the future study. *Economics of Energy & Environmental Policy*, *6*(1). https://doi.org/10.5547/2160-5890.6.1.iper

Piclo Flex. (2019). *Energy on Trial—Piloting a flexibility market place to upgrade our energy system*. https://uploads-ssl.webflow.com/6123718de4b96c44035b9af8/616d7e527197650028345fec_piclo_whitepaper_energy-on-trial.pdf (accessed Jul. 2023)

PJM. (2023). *Locational Marginal Pricing Map*. https://www.pjm.com/library/maps/lmp-map.aspx (accessed Jul. 2023)

Pollitt, M. G. (2018a). Electricity Network Charging in the Presence of Distributed Energy Resources: Principles, Problems and Solutions. *Economics of Energy & Environmental Policy*, *7*(1). https://doi.org/10.5547/2160-5890.7.1.mpol

Pollitt, M. G. (2018b). Electricity Network Charging in the Presence of Distributed Energy Resources: Principles, Problems and Solutions. *Economics of Energy & Environmental Policy*, *7*(1), Article 1. https://doi.org/10.5547/2160-5890.7.1.mpol

Poudineh, R., & Jamasb, T. (2014). Distributed generation, storage, demand response and energy efficiency as alternatives to grid capacity enhancement. *Energy Policy*, *67*, 222-231. https://doi.org/10.1016/j.enpol.2013.11.073

Prettico, G., Flammini, M. G., Andreadou, N., Vitiello, S., Fulli, G., & Masera, M. (2019). Distribution System Operators observatory 2018: Overview of the electricity distribution system in Europe. Joint Research Centre. http://publications.jrc.ec.europa.eu/repository/bitstream/JRC113926/jrc113926_kjna29615enn_newer.pdf (accessed Jul. 2023)

Prettico, G., Marinopoulos, A., & Vitiello, S. (2021). Distribution System Operator Observatory 2020: An in-depth look on distribution grids in Europe (EUR 30561 EN,). Publications Office of the European Union; ISBN 978-92-76-28430-7.

Regalini, E. (2019). Capcity-based network tariffs for Italian electricity households. https://www.ceer.eu/documents/104400/-/-/c2310057-9124-4708-8f56-6a587f76f569 (accessed Jul. 2023)

Reneses, J., Gómez, T., Rivier, J., & Angarita, J. L. (2011). Electricity tariff design for transition economies: Application to the Libyan power system. *Energy Economics*, *33*(1), Article 1. https://doi.org/10.1016/j.eneco.2010.04.005

Reneses, J., Rodríguez, M. P., & Pérez-Arriaga, I. J. (2013). Electricity Tariffs. In I. J. Pérez-Arriaga (Ed.), *Regulation of the Power Sector* (pp. 397-441). Springer. https://doi.org/10.1007/978-1-4471-5034-3_8

Reneses, J., & Rodríguez Ortega, M. P. (2014). Distribution pricing: Theoretical principles and practical approaches. *IET Generation, Transmission & Distribution*, *8*(10), 1645-1655. https://doi.org/10.1049/iet-gtd.2013.0817

Renewables.ninja. (2022). In 21st of December 2022, from https://www.renewables.ninja/

Rodríguez Ortega, M. P., Pérez-Arriaga, J. I., Abbad, J. R., & González, J. P. (2008). Distribution network tariffs: A closed question? *Energy Policy*, *36*(5), 1712-1725. https://doi.org/10.1016/j.enpol.2008.01.025

Rossetto, N., & Reif, V. (2021). *Digitalization of the electricity infrastructure: A key enabler for the decarbonization and decentralization of the power sector. RSC2021/47.*

Sauer, P. W. (1981). On The Formulation of Power Distribution Factors for Linear Load Flow Methods. *IEEE Transactions on Power Apparatus and Systems*, *PAS-100*(2), Article 2. https://doi.org/10.1109/TPAS.1981.316928

Schittekatte, T., & Meeus, L. (2017). How future-proof is your distribution grid tariff design? *Policy Briefs, 2017/03, Florence School of Regulation*. https://doi.org/10.2870/27688

Schittekatte, T., & Meeus, L. (2018). *Introduction to network tariffs and network codes for consumers, prosumers, and energy communities*. https://doi.org/10.2870/934379

Schittekatte, T., & Meeus, L. (2020). Least-cost Distribution Network Tariff Design in Theory and Practice. *The Energy Journal*, *41*(01). https://doi.org/10.5547/01956574.41.5.tsch

Schittekatte, T., Momber, I., & Meeus, L. (2018). Future-proof tariff design: Recovering sunk grid costs in a world where consumers are pushing back. *Energy Economics*, *70*, 484-498. https://doi.org/10.1016/j.eneco.2018.01.028

Siano, P. (2014). Demand response and smart grids—A survey. *Renewable and Sustainable Energy Reviews*, *30*, 461-478. https://doi.org/10.1016/j.rser.2013.10.022

Simshauser, P. (2016). Distribution network prices and solar PV: Resolving rate instability and wealth transfers through demand tariffs. *Energy Economics*, *54*, 108-122. https://doi.org/10.1016/j.eneco.2015.11.011

SP Energy Networks. (2022). *Capacity and Development Report*. https://www.spenergynetworks.co.uk/userfiles/file/SPD%20NDP%20-%20Parts%201%20and%202%20-%20Capacity%20and%20Development%20Report%20v1.pdf (accessed Jul. 2023)

Steen, D., Tuan, L. A., & Carlson, O. (2016). Effects of Network Tariffs on Residential Distribution Systems and Price-Responsive Customers Under Hourly Electricity Pricing. *IEEE Transactions on Smart Grid*, *7*(2), 617-626. https://doi.org/10.1109/TSG.2015.2464789

Steiner, F. (2000). *Regulation, Industry Structure and Performance in the Electricity Supply Industry*. OECD. https://doi.org/10.1787/880084226021

Steiner, P. O. (1957). Peak Loads and Efficient Pricing. *The Quarterly Journal of Economics*, *71*(4), 585-610. https://doi.org/10.2307/1885712

Strielkowski, W., Štreimikienė, D., & Bilan, Y. (2017). Network charging and residential tariffs: A case of household photovoltaics in the United Kingdom. *Renewable and Sustainable Energy Reviews*, *77*, 461-473. https://doi.org/10.1016/j.rser.2017.04.029

Tado. (2023). https://www.tado.com/all-en/products (accessed Jul. 2023)

Tesla. (2023). Tesla. https://www.tesla.com/home-charging (accessed Jul. 2023)

Trabish, H. K. (2016, junio 16). How Storage Can Help Solve the Distributed Energy 'Death Spiral': A New Navigant Paper Lays out Three Examples of How Storage Can Facilitate the Transition to a More Distributed Grid. *Utility Dive*. https://www.utilitydive.com/news/how-storage-can-help-solve-the-distributed-energy-death-spiral/421160/ (accessed Jul. 2023)

Trebolle, D., Gómez, T., Cossent, R., & Frías, P. (2010). Distribution planning with reliability options for distributed generation. *Electric Power Systems Research*, *80*(2), 222-229. https://doi.org/10.1016/j.epsr.2009.09.004

Valarezo, O., Gómez, T., Chaves-Avila, J. P., Lind, L., Correa, M., Ulrich Ziegler, D., & Escobar, R. (2021). Analysis of New Flexibility Market Models in Europe. *Energies*, *14*(12), Article 12. https://doi.org/10.3390/en14123521

Van Langen, V. (2019). Network tariffs in electricity and gas*.* https://www.energy-community.org/dam/jcr:57a0a8a5-e7e8-4a6f-95f4-0c970f04250f/REG102019_ACM.pdf (accessed Jul. 2023)

Wallbox. (2023). Wallbox Chargers SL. https://wallbox.com/en_catalog (accessed Jul. 2023)

Western Power Distribution—What causes Losses? (2022). Western Power Distribution. https://www.westernpower.co.uk/smarter-networks/losses/what-causes-losses (accessed Jul. 2023)

Wood, L., Hemphill, R., Howat, J., Cavanagh, R., Borenstein, S., Deason, J., & Schwartz, L. (2016). Recovery of Utility Fixed Costs: Utility, Consumer, Environmental and Economist Perspectives*.* https://escholarship.org/uc/item/7n604608 (accessed Jul. 2023)

Yee, A. W. L. (2017). The impact of distributed energy resources (DERs) in integrated gas-electricity energy systems. Thesis, Massachusetts Institute of Technology. https://dspace.mit.edu/handle/1721.1/115030 (accessed Jul. 2023)

Young, S., Bruce, A., & MacGill, I. (2019). Potential impacts of residential PV and battery storage on Australia's electricity networks under different tariffs. *Energy Policy*, *128*, 616-627. https://doi.org/10.1016/j.enpol.2019.01.005