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The Allocation of System Costs: Future-Proofed Methodologies for Decarbonising Power Sectors

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Corresponding Author:	Paolo Mastropietro, PhD Universidad Pontificia Comillas Instituto de Investigacion Tecnologica Madrid, SPAIN
First Author:	José Pablo Chaves Ávila, PhD
Order of Authors:	José Pablo Chaves Ávila, PhD
	Paolo Mastropietro, PhD
	Matteo Troncia, PhD
	Pedro González
	Tomás Gómez San Román, Prof.
Abstract:	The increased use of renewable energy sources, among other factors, is causing system costs to grow quickly in European power sectors, especially those related to frequency control and congestion management. Currently, most European countries allocate these costs to consumers using simplistic methodologies, either via network tariffs or specific volumetric charges. These methodologies require urgent reform. This article reviews the economic theory and European experiences regarding the allocation of system costs and puts forward a comprehensive proposal to improve the design of these charges. Balancing capacity costs should be partially embedded in the imbalance price, with price caps limiting the possibility of very high prices during periods of low imbalance volumes. Congestion management costs, like network expansion costs, are driven by transmission capacity scarcity and should be recovered through network tariffs. Any system costs that cannot be allocated according to cost causality should be recovered through stabilised residual charges that do not distort the efficient signals sent by cost-reflective charges and prices. Discounts and exemptions for certain categories of end users should only apply to these residual charges. The impact of this proposal has been tested in a case study based on the Spanish power system.

Paolo Mastropietro
Instituto de Investigación Tecnológica
Universidad Pontificia Comillas
28008 Madrid, Spain
Paolo.Mastropietro@comillas.edu
September 10th, 2025

Dear Prof. Gianfranco Chicco and the rest of the Editorial Board,

We are submitting this article to the "Special Issue SEGAN Decennial", which was developed in collaboration with our co-author Tomás Gómez San Román, who served as an Associate Editor of the journal from its creation in 2015 until the end of 2024 and has been invited to submit an article for this special issue.

In this article, we present a future-proofed methodology for the allocation of system costs. As you are aware, the increased use of renewable energy sources, among other factors, is causing system costs to grow rapidly in European power sectors, particularly with regard to frequency control and congestion management. Currently, most European countries allocate these costs to consumers using simplistic methodologies. In most Member States, this is done via network tariffs, while Great Britain, Italy, Spain and Portugal apply specific volumetric charges. These methodologies require urgent reform. This article reviews the economic theory and European experiences of allocating system costs, and puts forward a comprehensive proposal to improve the design of these charges.

We propose partially embedding balancing capacity costs in the imbalance price, with price caps limiting the possibility of very high prices during periods of low imbalance volumes. Like network expansion costs, congestion management costs are driven by transmission capacity scarcity, and we propose recovering them through network tariffs. Any system costs that cannot be allocated according to cost causality should be recovered through stabilised residual charges that do not distort the efficient signals sent by cost-reflective charges and prices. Discounts and exemptions for certain categories of end users should only apply to these residual charges.

The impact of this proposal has been assessed through a case study of the Spanish power system. We are currently discussing the proposal with stakeholders and the National Regulatory Authority in Spain. We believe that the findings of this article could also inform regulators and policymakers in other jurisdictions, as well as stimulate academic discussion on a regulatory aspect in urgent need of reform.

With kind regards,
Paolo Mastropietro

The Allocation of System Costs: Future-Proofed Methodologies for Decarbonising Power Sectors

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THE ALLOCATION OF SYSTEM COSTS: FUTURE-PROOFED METHODOLOGIES FOR DECARBONISING POWER SECTORS

José Pablo Chaves Ávila [a], Paolo Mastropietro [a], Matteo Troncia [a], Pedro González [b], Tomás Gómez San Román [a]

[a] Instituto de Investigación Tecnológica, Universidad Pontificia Comillas, Rey Francisco 4, 28008, Madrid, Spain.

[b] Asociación de Empresas con Gran Consumo de Energía, Hermosilla 31, 28001, Madrid, Spain.

Highlights

- System costs are growing quickly in many European power sectors.
- These costs are currently allocated to consumers via simplistic methodologies.
- Balancing capacity costs should be partially embedded in the imbalance price.
- Congestion management costs should be recovered through network tariffs.
- Residual charges should be stabilised and should not distort efficient signals.

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Abstract

The increased use of renewable energy sources, among other factors, is causing system costs to grow quickly in European power sectors, especially those related to frequency control and congestion management. Currently, most European countries allocate these costs to consumers using simplistic methodologies, either via network tariffs or specific volumetric charges. These methodologies require urgent reform. This article reviews the economic theory and European experiences regarding the allocation of system costs and puts forward a comprehensive proposal to improve the design of these charges. Balancing capacity costs should be partially embedded in the imbalance price, with price caps limiting the possibility of very high prices during periods of low imbalance volumes. Congestion management costs, like network expansion costs, are driven by transmission capacity scarcity and should be recovered through network tariffs. Any system costs that cannot be allocated according to cost causality should be recovered through stabilised residual charges that do not distort the efficient signals sent by cost-reflective charges and prices. Discounts and exemptions for certain categories of end users should only apply to these residual charges. The impact of this proposal has been tested in a case study based on the Spanish power system.

Keywords

System services; Ancillary services; System costs; Grid congestions; Network tariffs.

1 INTRODUCTION

Power systems must maintain a constant balance of injections and withdrawals of both active and reactive power. Although the dispatch of liberalised power sectors depends on the clearing of the electricity market, system operators procure ancillary or system services to guarantee such a balance and a swift restart of the grid in case of a major outage. The resulting costs, which in the European Union are known as system costs, must be allocated among grid users. System costs depend both on the volume of ancillary services that have to be procured, commonly determined by the operator according to the expected system conditions, and the price at which they are offered, usually determined through competitive mechanisms.

At the beginning of the energy transition, many experts expected system costs to grow swiftly with increased renewable penetrations [1][2], mainly due to the variability of their generation, prediction errors on the availability of their primary energy source [3] and new requirements that emerge with penetration of renewables sources such as ramps [4] or inertia [5]. This was not always the case, at least in certain power systems, and the initial penetration of renewable resources often did not cause a significant increase in system costs [6][7]. However, many power systems have registered a fast-paced increase in system costs, due to a growth in both contracted volumes and average unitary prices.

Despite this significant growth, system costs are typically allocated using simplistic methodologies. In Europe, the geographical scope of this article, the most common approach is to recover these costs through network tariffs [8], in most cases, without clearly differentiating them from other network-related costs [9]. In other power systems, these costs are recovered through variable volumetric charges that can provide inefficient signals to end-users [10][11]. In both cases, the largest part of the system costs is socialised, without considering cost causality. In recent years, many experts have called for more sophisticated methodologies for allocating system costs, particularly for frequency control [12][13][14], although proposals have also been put forward for voltage control [15].

This article delves into this topic. Section 2 provides an overview of system services and the recent evolution of their costs in some specific systems. Section 3 presents a brief theoretical framework on tariff design and cost allocation, focusing on system costs. Sections 4 to 6 present the main contributions of this article, i.e.:

- A broad review of European practices in the allocation of system costs (Section 4).
- A set of recommendations and innovative proposals on the allocation of system costs in European power systems (Section 5).
- A case study in which the impact of applying these recommendations is quantitatively assessed using real data from the Spanish power system (Section 6).

Section 7 concludes and summarises the key findings of the article.

2 SYSTEM SERVICES AND RECENT COST TRENDS

There is no consensus on a definition or classification of system services. The European Electricity Directive [16] defines ancillary services as any service that is required to operate the network, including balancing and non-frequency ancillary services. However, most European power systems consider congestion management costs, which is one of the cost items that is increasing more rapidly, to be system costs and recover them together with other network costs. This approach seems aligned also with the definition of SO services provided in the new European guidelines on demand response [17]. This article focuses on the system services commonly procured by the transmission system operator[1], including [18]:

- Frequency control, including Frequency Containment Reserves (FCR), Automatic and Manual Frequency Restoration Reserves (aFRR and mFRR), and Replacement Reserves (RR), among others.
- Voltage control, i.e., services meant at maintaining voltage within acceptable ranges through reactive power injections and withdrawals.
- Congestion management, i.e., services to solve network congestion through redispatching the system.
- Emergency and restoration, e.g., black-start services, among others.

The aim of this section is not to provide a detailed technical description of these services. Further details can be found in references [19], [20], or [21]. European system operators use different classifications to present disaggregated information on the system costs in their networks. Figure 1 illustrates the evolution of system costs in Great Britain over the past seven years, revealing a significant upward trend, interrupted only by some reforms to the methodology for calculating the volume of system services [22]. The National Energy System Operator estimates that system costs could reach 8 £bn by 2030.

[1] As demonstrated by the data on European power systems shown in this section, the two cost elements that account for the vast majority of system costs are frequency control and congestion management. This article therefore focuses strongly on these two elements.

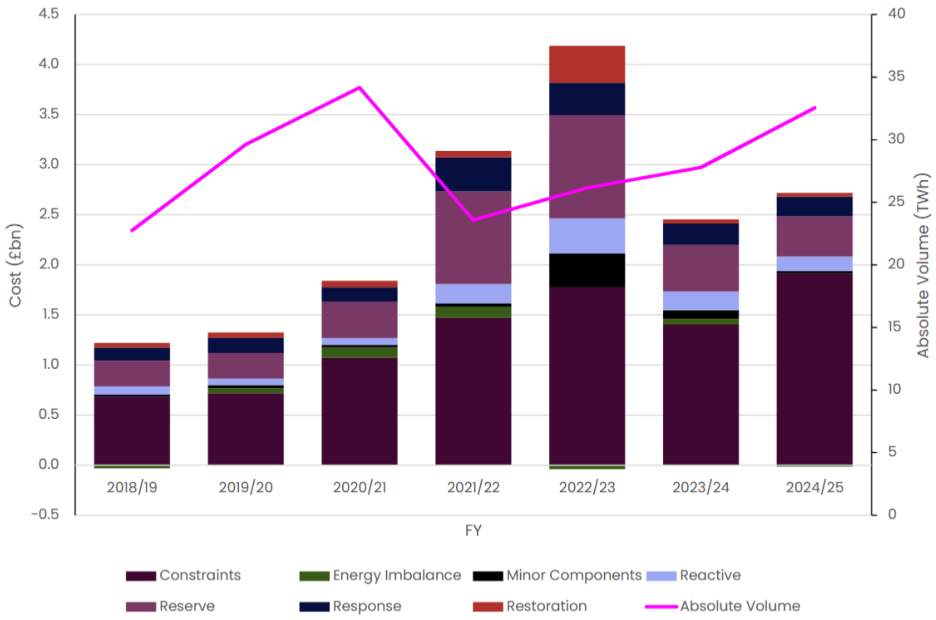

Figure 1. Recent evolution of the British system services, in terms of cost and volume; chart from [22]

Similar recent developments and expected trends can be observed in many systems across Europe. Figure 2 shows how the Spanish unitary cost of system services has changed over the last five years. In Spain, many system services are grouped together under the cost items referred to as "technical restrictions" in both the day ahead and real time. These items include congestion management, but also services for frequency and voltage control. Beyond the strong upward trend, Figure 2 also shows the volatility of system costs and the corresponding unitary charges[2].

[2] Actually, Spanish unitary charges for the recovery of system costs vary on an hourly basis and the volatility problem is much larger than the one showed in Figure 2.

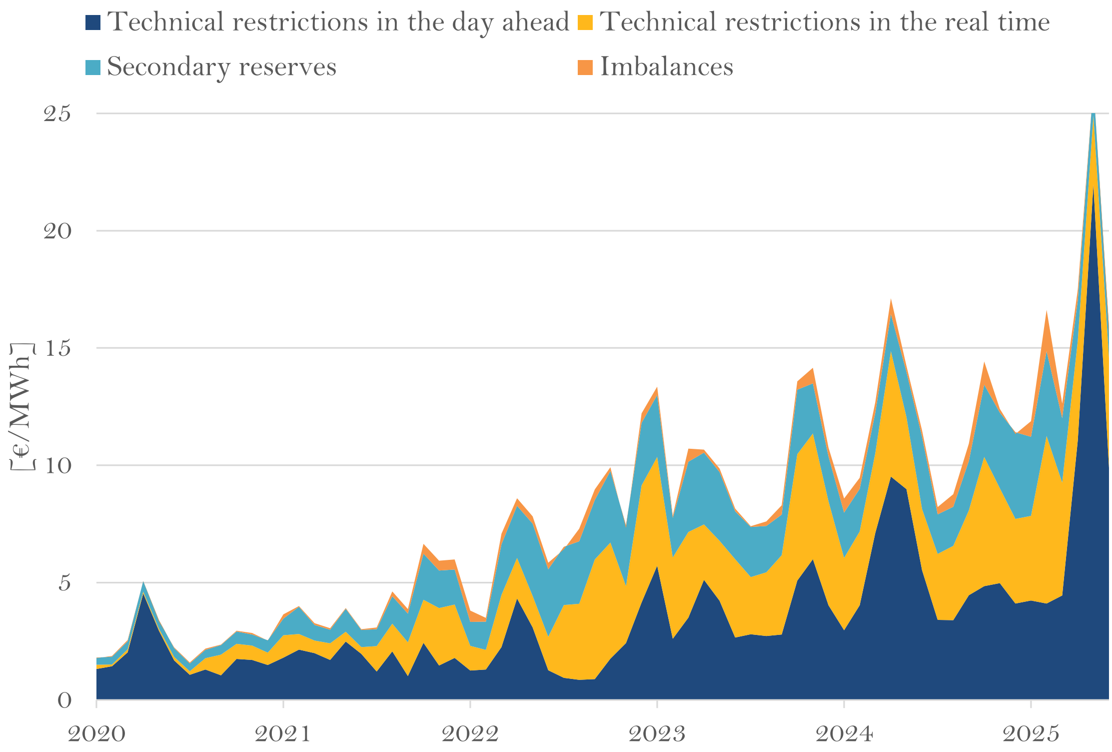

Figure 2. Recent evolution of the unitary cost of system services in Spain; own elaboration based on data from Red Eléctrica de España[3]

Another emblematic example of the recent increase in system costs is Germany. Although aggregated data on system services procured by the four system operators active in the country is not available, Figure 3 shows the recent evolution of the fastest-growing system cost item, i.e., congestion management. The volume of congestion management has steadily increased over the last four years, while its cost spiked in 2022 due to the electricity price crisis caused by the Russian invasion of Ukraine, before decreasing in 2023.

[3] The peak in system costs registered in May 2025 is due to the way the system was temporarily operated after the blackout that the Spanish power system suffered on 28 April 2025.

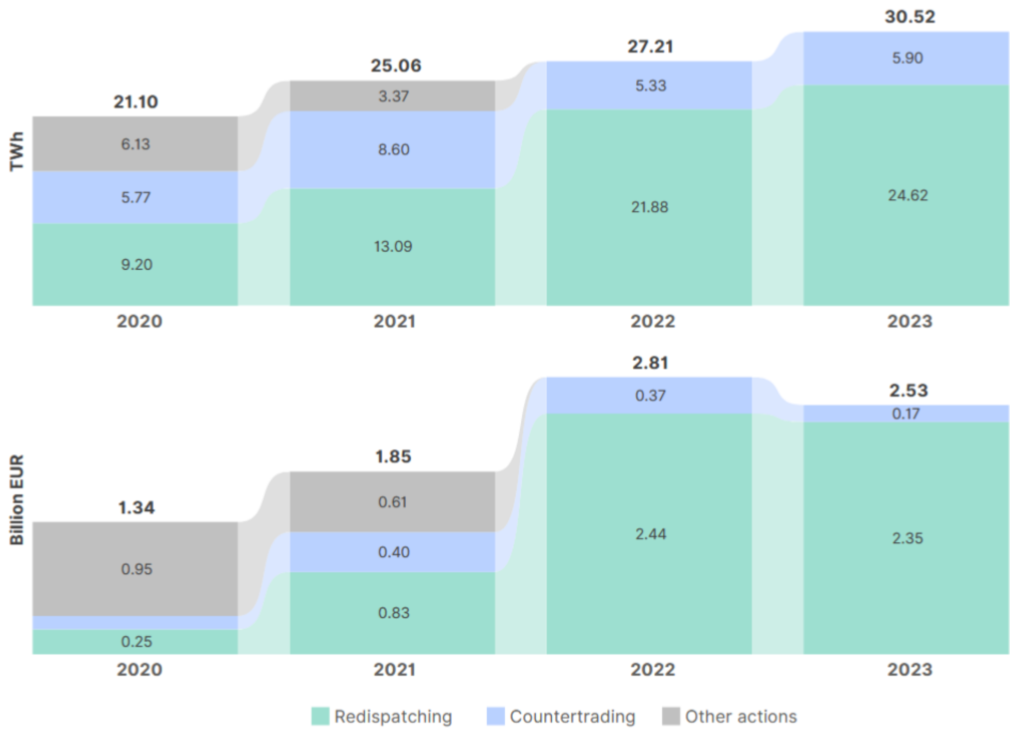

Figure 3. Recent evolution of congestion management costs in Germany; chart from [23]

These examples, although not exhaustive, are meant to show how system costs have increased rapidly in recent years, because of the energy transition. Recent data clearly show a correlation between system costs and the penetration (and dispatch) of intermittent renewable resources, as demonstrated, for instance, in [24] for congestion management in Germany and Great Britain.

3 COST ALLOCATION THEORY

An economic-efficient cost allocation methodology shall be based on the marginal pricing theory, including short-term marginal costs and long-term (forward-looking) marginal costs, and be complemented by Ramsey pricing to allocate residual costs. Charges based on short-term and long-term marginal costs are referred to as cost-reflective, whereas residual charges[4] are necessary to ensure the full recovery of residual costs and economic sustainability. This theory has been proven to maximise social welfare and can be applied to the allocation of all costs [26]. Below, we divide the allocation of system costs into cost-reflective prices and charges and residual charges.

[4] Residual charges are also commonly referred to as cost-recovery charges [25], which highlights their ultimate goal.

3.1 Cost-reflective prices and charges

This section discusses the cost-reflective allocation of the cost of balancing services and network-related services. The cost-reflective allocation of energy (and partially capacity) costs derived from balancing services results in imbalance prices computed per imbalance settlement time unit (currently every 15 minutes). Cost-reflective charges for network-related costs can be defined using different methodologies, which are assessed below in terms of their relevance to the allocation of congestion management costs.

3.1.1 Balancing service costs

In the European context, frequency regulation services are referred to as balancing services [18]. These services have two main cost components that must be allocated efficiently: balancing capacity (reserved in advance) and balancing energy (activated, when needed, closer to real-time system operation). The way in which these costs are determined varies between jurisdictions, depending on the overall market design. In liberalised US markets, federal regulations (FERC Order 755) stipulate that tariffs for recovering frequency regulation services costs must be just and reasonable; however, implementation varies among Independent System Operators (ISOs) and Regional Transmission Organisations (RTOs). In these markets, balancing costs are usually recovered as uplifts to real-time prices or specific rates [27][28].

In Europe, the rules for the allocation of balancing energy costs are set out in Regulation 2017/2195 (Electricity Balancing Guidelines [18]) and the Electricity Regulation 2019/943 [29]. The imbalance settlement must incentivise Balance Responsible Parties (BRP) to maintain balanced positions and help restore the system balance when needed. The resulting imbalance prices should reflect the real-time value of energy. These regulations adhere to the theory of short-term marginal pricing, reflecting the marginal cost of activating balancing services in real time.

The Regulation 2019/943 specifies that the settlement of balancing energy shall be based on marginal pricing (pay-as-cleared) unless all regulatory authorities approve an alternative pricing method based on a joint proposal by all Transmission System Operators (TSOs), following an analysis which demonstrates that the alternative pricing method is more efficient.

Conversely, the EU regulation does not specify how balancing capacity should be allocated. Regulation 2019/943 only states that the Commission has the power to adopt implementing acts in order to ensure consistent and uniform implementation of this Regulation by establishing network codes. The cost of balancing capacity depends on the volume of reserves procured by the TSO and is not directly related to the actual cost of maintaining system balance or the imbalances of a specific market agent. Although these costs do not have any clear cost driver to which they can be allocated, they can be used to reinforce the signal conveyed by the imbalance price. However, this allocation can result in disproportionate charges in specific hours, which should be avoided.

The literature on imbalance pricing is diverse and abundant. Single imbalance pricing has clear benefits, such as incentivising BRPs to support system balance by deviating from schedules if this favours the system (i.e., passive balancing [30]). However, when congestions occur, single imbalance pricing could provide economic signals that may exacerbate congestions [31].

3.1.2 Network-related costs

According to economic theory, electricity network costs can be recovered via i) congestion rents, which are generated when locational prices are calculated (resulting in price differentials), ii) cost-reflective charges, which are commonly based on forward-looking methodologies (where each user pays in proportion to the needs of new network investment they impose on the system), and iii) cost-recovery charges for residual costs [32][33]. The European electricity market is based on a zonal clearing, with most countries being represented by a single zone and computing a single price for their entire network. Network constraints within each zone are addressed through redispatch and other measures that incur congestion management costs [34]. With locational pricing, these costs related to network constraints are embedded in the market prices. However, when a single price is computed for the entire network, congestion management costs appear as a separate cost item. The latter has no clear cost driver (who is responsible for the scarcity of network capacity?) and is usually recovered as a residual cost. Further details on the design of network charges are presented in section 4.1.2, while a proposal for the allocation of congestion management costs is presented in section 5.2.

3.2 Residual charges

The main objective of cost-recovery charges is to recover residual costs without distorting the efficient signals conveyed by cost-reflective charges and other prices or charges [36]. Such distortions could lead to inefficient decisions, both at the operational level, affecting the optimal consumption profile, and at the investment level, for example, the inefficient installation of resources behind the meter, grid disconnection, or, in the case of industrial customers, relocation to other countries.

These distortions could be avoided by applying the so-called Ramsey pricing [37]. According to this theory, residual costs should be allocated in inverse proportion to the elasticity of consumer demand. The most inelastic consumers are those who react the least to prices and charges. With Ramsey pricing, residual costs are therefore allocated among those consumers who are not expected to react to cost-reflective charges anyway, thus minimising distortions. Conversely, a simple socialisation of residual costs among all consumers (according to a specific cost driver, either energy or capacity) would affect and distort the signals conveyed by cost-reflective charges.

According to economic theory, residual charges should not be applied to generation. In fact, generators incorporate any charges they incur into the prices they bid in the electricity market. They could be exposed to cost-reflective charges, which send efficient signals at the operational or investment level, if the regulator deems it appropriate. However, applying residual charges to generators does not encourage more efficient decisions and results in an eventual allocation of residual costs to consumers, through market prices, which the regulator cannot control.

Residual charges are the only ones that could be affected by exemptions or discounts for certain consumer categories, a common practice with network-related costs. In fact, any discount applied to cost-reflective charges would distort the efficient economic signal.

4 REVIEW OF EUROPEAN PRACTICES

The rigorous application of the tariff design theory presented in section 3 to the allocation of system costs is rarely found in Europe. This section first describes the cost items that are commonly recovered through cost-reflective charges, before presenting some European experiences of recovering residual costs.

4.1 Cost-reflective prices and charges

4.1.1 Balancing services

European power systems adopt diverging approaches as regards which costs should be included in the imbalance price [21]. Although balancing capacity costs account for the largest share of total balancing costs, most of the Member States internalise only balancing energy costs in the imbalance price. Figure 4 illustrates these different approaches for a selection of European Member States. Although this chart is from 2016 [38] (this series of charts is no longer published in market monitoring reports), it clearly shows a situation that has not changed significantly since then.

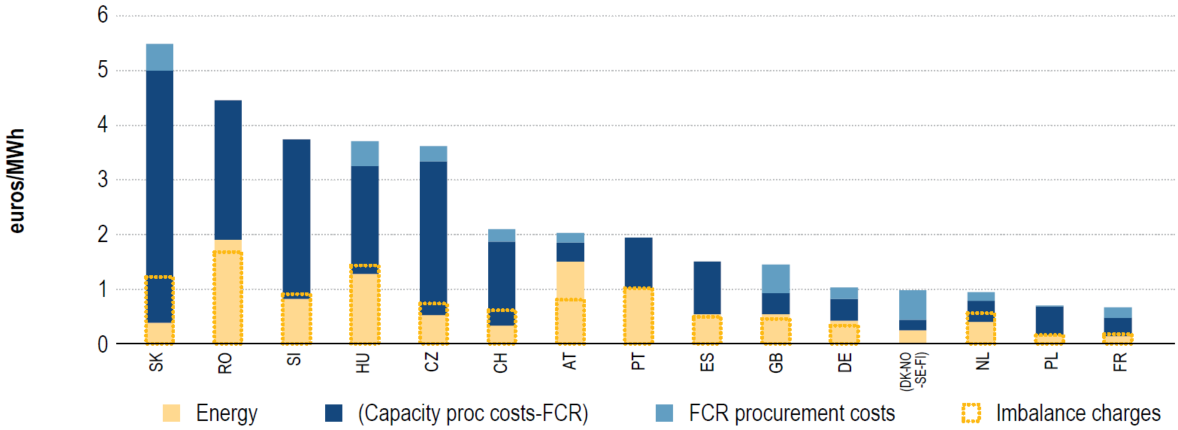

Figure 4. Overall costs of balancing (capacity and energy) and imbalance prices in European countries in 2015, chart from [38]

The same report by the European Union Agency for the Cooperation of Energy Regulators (ACER) also suggested that one option to recover balancing capacity costs would be to allocate part of them to imbalanced BRPs via an additive component in the imbalance price or a separate settlement mechanism. Some European countries have implemented this approach to allocate at least part of balancing capacity costs to BRPs (via specific charges) [39]. Another option highlighted by ACER is to introduce some sort of scarcity pricing through an administrative adder in the imbalance price to be calculated based on the concepts of VOLL (value of lost load) and loss of load probability (LOLP), which aims to simulate the scarcity value at times of reduced reserve margins. Inspired by the Operational Reserve Demand Curve (ORDC) applied in Texas, this model has been proposed and assessed in several European countries and has been introduced, for instance, in Ireland, in the context of the capacity remuneration mechanism [40], as well as in Sweden [39]. However, it should be noted that scarcity pricing cannot be considered as a structural solution for recovering balancing capacity costs, since these mechanisms are rarely activated (as demonstrated by the Irish experience [41]).

4.1.2 Network charges

Network tariff designs vary significantly across the EU [42]. While some countries still apply relatively simple structures that do not incentivise consumers to shift or optimise their electricity usage to minimise network costs, while others have adopted more advanced designs that encourage such behaviour to some extent [9]. In several Member States, such as Germany or Hungary, many households are still subject to flat volumetric network tariffs based on energy consumption in €/kWh. By contrast, countries such as Spain or Slovenia have introduced more sophisticated tariff structures for residential users. In most EU countries, network tariffs at higher voltage levels have evolved towards more dynamic and cost-reflective designs. ACER highlights that network tariffs are being reformed across the EU. Two-thirds of the EU countries have already introduced significant changes to their network tariff methodologies in recent years or intend to do so. Examples of these advancements include the introduction of power-based tariffs in line with the cost-causality principle (in Austria, Belgium, Estonia, Luxembourg, and Slovenia); the introduction of time-of-use signals (in Belgium, Germany, and the Netherlands); and the removal of unjustified discounts (in the Netherlands to large consumers, in Sweden to small generators).

4.2 Residual charges

Any residual system costs that cannot be recovered through cost-reflective charges must be allocated through residual charges. In Europe, there are essentially two approaches:

- Power systems that incorporate residual system costs into transmission network tariffs, usually without clearly distinguishing these costs from other network costs.
- Power systems that recover residual system costs through specific demand charges, which can be stable over a certain time horizon or variable.

4.2.1 Allocation through network tariffs

By far the most widespread approach in Europe is the inclusion of residual system costs in network tariffs. Figure 5 from the ACER (the European Union Agency for the Cooperation of Energy Regulators) report on grid tariffs [9] clearly shows that, with the exception of Spain, all European Member States recover part of these residual costs through network tariffs.

Country	Costs for building, upgrading and/or maintaining infrastructure	Costs for grid losses	Costs for system services	Costs for metering
Austria	Yes	Yes	Yes	Yes
Belgium	Yes	Yes[329]	Yes	Yes
Bulgaria	Yes	Yes	Yes	Yes
Croatia	Yes	Yes	Yes[330]	Yes
Cyprus	Yes	Yes	Yes	Yes
Czechia	Yes	Yes	Yes	Yes
Denmark	Yes	Yes	Yes	Yes
Estonia	Yes	Yes	Yes[331]	Yes
Finland	Yes	Yes	Yes	
France	Yes	Yes[332]	Yes	Yes
Germany	Yes	Yes	Yes	Yes
Greece	Yes	No	Yes	Yes
Hungary	Yes	Yes[333]	Yes	
Iceland	Yes	Yes	Yes	
Ireland	Yes	No[334]	Yes	
Italy	Yes	No[335]	Yes[336]	
Latvia	Yes	Yes	Yes	
Lithuania	Yes	Yes	Yes	
Luxembourg	Yes	Yes	Yes	Yes[337]
Malta	N/A	N/A	N/A	N/A
Netherlands	Yes	Yes	Yes	Partially[338]
Norway	Yes	Yes	Yes[339]	Yes
Poland	Yes	Yes	Yes	Yes
Portugal	Yes	No[340]	Yes[341]	Yes
Romania	Yes	Yes	Yes[342]	
Slovakia	Yes	Yes	Yes	
Slovenia	Yes	Yes	Yes[343]	
Spain	Yes	No[344]	No[345]	
Sweden	Yes	Yes	Yes	

Figure 5. Cost items recovered or partially recovered through network tariffs; chart from [9]

The report explains that only nine of the 28 Member States covered by the assessment have specific charges for the recovery of system costs within their network tariffs. This means that the remaining Member States (including the largest power systems, such as Germany, France, or Italy) combine residual system costs with other network-related costs, recovering all costs through the same charges. These charges and the tariff structure for their application are defined based on the cost drivers for network costs, which may differ greatly from those for system costs, causing inefficiencies. In other cases, network tariffs have a simplistic design that basically socialises network costs among consumers, causing inefficiencies also in this case. It should also be noted that this approach implicitly stabilises charges related to system services, since network tariffs are calculated ex ante based on forecasts and remain stable for a relatively long period.

When residual system costs are included in network tariffs, they are typically recovered through volumetric charges, although power-based charges or lump sums can also be found. These charges are mainly applied to consumers, although, in a few power systems, they are also applied to generators. Furthermore, different categories of network users (energy-intensive industries, storage facilities, prosumers, or energy communities) are subject to discounts or exemptions on network tariffs, which often apply to system costs too, especially if charges are not differentiated by cost item. This may also result in inefficiencies, since the rationale behind these discounts and exemptions[5] is based on these categories' responsibility for network costs rather than their impact on system costs.

4.2.2 Allocation through specific charges

A minority of electricity system operators in Europe (Great Britain, Italy, Spain, and Portugal) recover most of the system costs through specific charges. While all these charges are volumetric, they differ in terms of signal stability. In fact, system service costs and, consequently, their residual part, show a significant volatility in both the short term (frequency control and congestion management costs can be high in a certain hour and low a few hours later, e.g., due to the dispatch of a larger volume of intermittent resources) and the long term (e.g., due to the progressive exacerbation of network constraints or an increase in market prices). When residual system costs are recovered through network tariffs, they undergo an implicit stabilisation, since grid charges are usually fixed for a specific tariff period. However, this is not always the case when these costs are allocated through specific charges.

In Great Britain and Italy, system-service charges are stabilised through an ex-ante calculation based on forecasts of the system costs they are intended to recover. In Great Britain, the methodology for recovering system costs was reformed in 2022. In the first two years after the reform, system-service charges were calculated with a nine-month notice period (i.e., the period between defining the fixed charge and it coming into force) and a six-month fixed period (i.e., the period during which the fixed charge remains in place) [46]. A recent amendment to the methodology for setting these charges has reduced the notice

[5] Discounts and exemptions to network tariffs, especially for large industrial consumers, have been scrutinised in recent years. Many justifications for these discounts are no longer valid in decarbonising power sectors that need large amounts of flexible resources, also on the demand side. The Netherlands phased out discounts to large industrial loads in 2024 [43] and Germany is discussing an in-depth reform of its discounts for industrial users [44]. In countertrend, Denmark have recently introduced a specific 90% discount on the network charge corresponding to system services, applicable to large industrial users, but only for the share of consumption exceeding 100 GWh/year [45].

period to three months and the fixed period to twelve months (although two different values can be defined for each semester) [47].

In Italy, system costs are recovered through a specific charge called "uplift", which is calculated ex ante, published 15 days before it comes into force, and kept fixed for the following three months [48]. When system-service charges are stabilised and calculated ex ante, they are subject to adjustments in the following fixed period to account for forecast errors. This effect can clearly be observed in Figure 6 for Italy. The unexpected spike in the actual cost of system services in the second quarter (April to June) is reflected in higher charges in the third quarter (July to September), with a characteristic delay between actual costs and billing. To cover potential imbalances between billing and costs without resetting the charges during the fixed period, British institutions assessed the possibility of introducing a ring-fenced reserve fund, an option that was eventually discarded due to the potential impact on electricity bills that the creation of the fund could have.

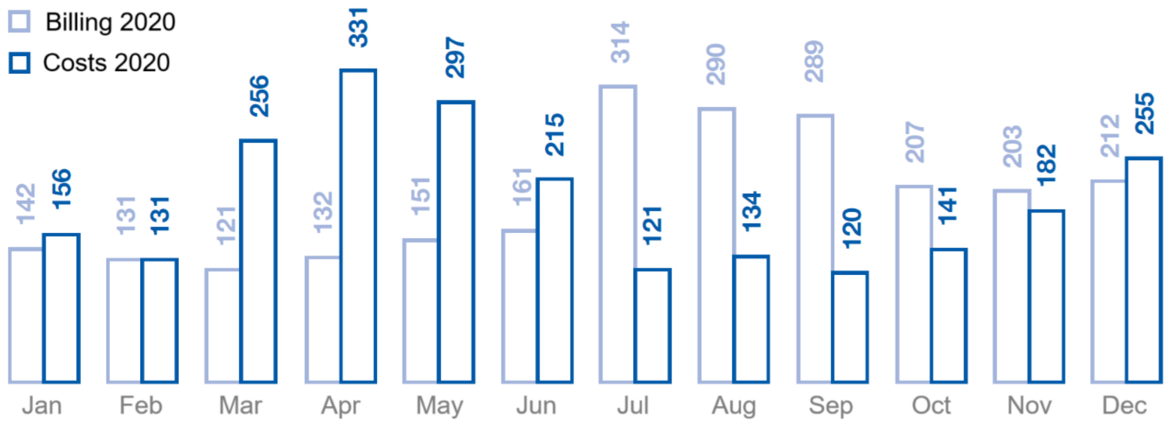

Figure 6. Evolution of system-service billing and actual costs in Italy in 2020; chart from [49]

System-service charges in Spain and Portugal are not stabilised. The residual part of system costs for each hour is allocated to the electricity demand for that hour through a volumetric charge, which is calculated ex post. Prior to the 2022 reform, a very similar allocation strategy, based on half-hourly charges, was in place also in Great Britain.

These hourly or half-hourly charges for the recovery of residual system costs may be subject to significant short-term volatility, and the lack of stabilisation may impede or complicate a proper financial hedging strategy. The British regulator recognised that the so-called BSUoS (Balancing Services Use of System) charges, before 2022, were varying between -6 £/MWh and 100 £/MWh [10]. This volatility, coupled with ex-post calculation, resulted in high-risk premiums for contracts that included system costs.

Furthermore, allocating residual system costs to the demand in each settlement interval provokes the so-called "denominator factor effect". When the demand is low, the charge increases, which incentivises further reductions in demand that could make system operation more difficult [10]. This effect is particularly detrimental overnight, when demand is naturally lower than during the day, resulting in so-called "overnight signal distortion" (Figure 7).

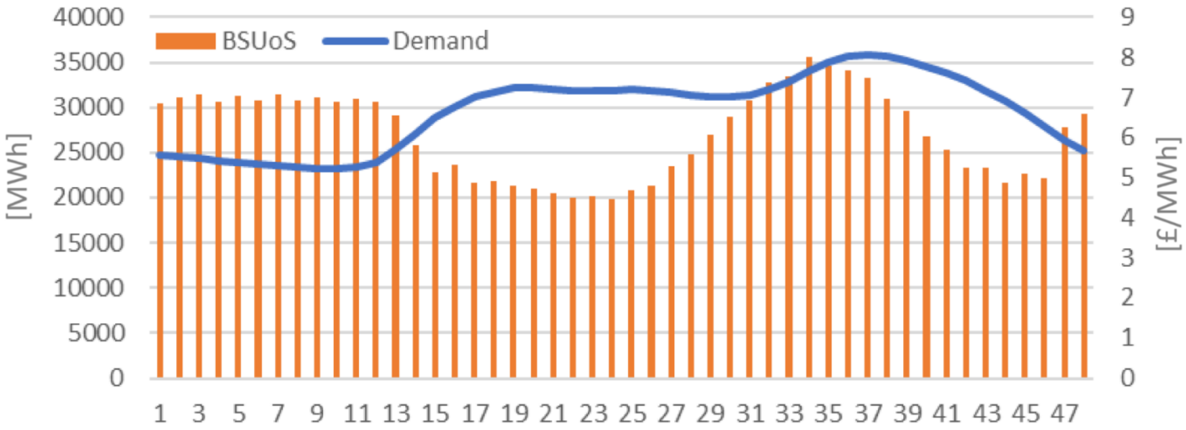

Figure 7. Average half-hourly values of system demand and BSUoS charges in 2021 in Great Britain; chart from [10]

The same effect has also been recognised by the Spanish regulator in a recent public consultation [11]. Instead, the Portuguese regulator is studying the possibility of reducing system-service charges by allocating part of the system costs to those generators that do not provide ancillary services (mainly, intermittent renewable generators) [50].

5 PROPOSALS FOR EUROPEAN POWER SYSTEMS

This section sets out a proposal for allocating system-service costs in Europe, based on the theoretical principles outlined in section 3. As much as possible, system costs should be allocated through cost-reflective charges by identifying the driver of each cost item or a suitable proxy. These charges would provide market agents and end users with efficient signals to align their operations with the needs of the system. As illustrated in Figure 8, this could be achieved by recovering most of the frequency control costs through the imbalance price (section 5.1) and the congestion management costs through efficiently designed network tariffs (section 5.2).

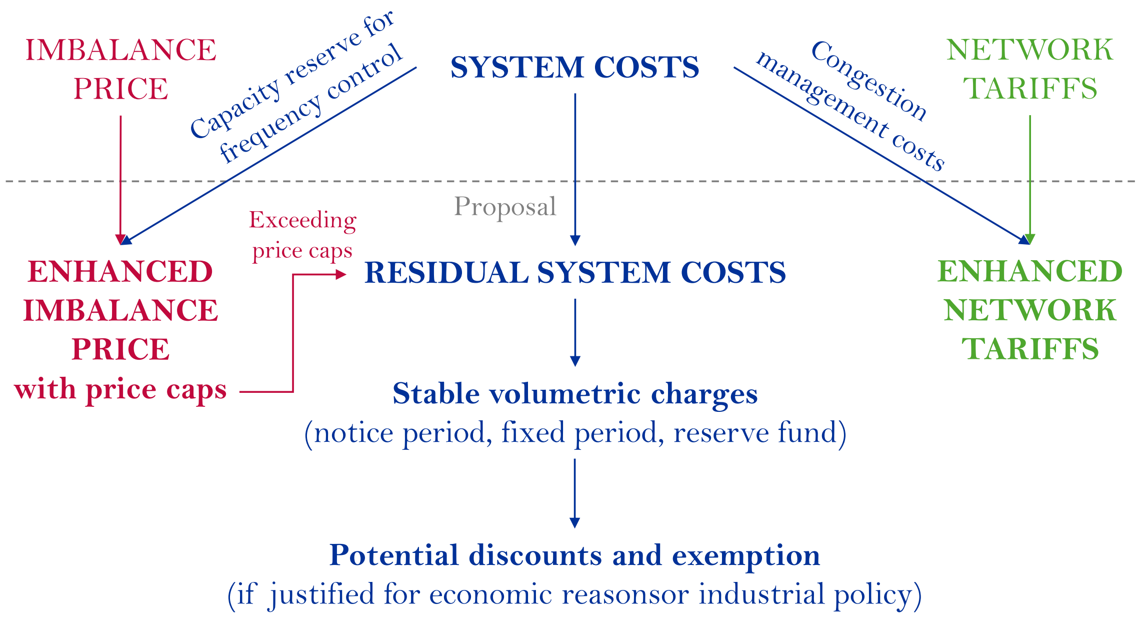

Figure 8. Graphical schematization of the proposal

Residual system costs (including the frequency control costs that cannot be recovered through the imbalance price, as well as other costs) should be recovered via a stable volumetric charge (section 5.3). Any discounts or exemptions for specific categories of end users should be applied to these residual charges, without distorting efficient signals (section 5.4).

5.1 Enhanced imbalance settlement price

As stated in Section 3.1.1, European institutions have already defended that the imbalance price should reflect the actual cost of balancing the system in real time, including the cost of balancing energy and balancing capacity. This should be applied to the cost of standard balancing products but also non-standard or specific ones, as stated in Articles 18, 30 and 32 of Regulation (EU) 2017/2195. This approach is intended to incentivise market participants to keep their own balance or help to restore the system balance in their imbalance price area. However, including balancing capacity costs, which do not depend on the actual imbalance registered in the system, in the imbalance price, which is computed by spreading balancing costs across the imbalance volume, may result in extremely high prices. Therefore, we propose to enhance the imbalance price by including part of the balancing capacity costs and applying price caps to avoid disproportionate imbalance prices in periods of low system imbalance. These price caps may be based on the day-ahead market price.

5.2 Congestion management costs and network tariffs

Congestion management and network expansion costs are complementary cost items. Investing heavily in new networks can reduce or eliminate network constraints, which in turn causes congestion management costs to decrease [51]. However, if the network is not expanded, the system faces lower grid investment costs, but congestion management costs spike. This means that these cost items share the same cost drivers. For example, if a new demand at a certain node increases the need for grid investment, it also increases congestion costs until the investment is carried out. This complementarity has been recognised and frequently assessed in the academic literature [52][53]. Economically efficient network planning should seek to balance these complementary costs.

Because congestion management costs are closely linked to other network costs, they should be separated from other system service costs and recovered through network tariffs. In theory, the same tariff structure could be used to recover both network and congestion costs, since the cost drivers coincide. However, if network costs are mostly treated as residual costs and network tariffs are mainly composed of cost-recovery charges that do not send efficient signals, a specific tariff structure and cost-reflective charges should be defined for congestion management costs[6].

The discussion presented so far regarding transmission congestion management could also apply to the distribution network in the near future. The development of distributed services and local markets for their procurement could soon generate congestion management costs at the distribution level too [54][55]. These distribution congestion costs could also be recovered through efficiently designed network tariffs.

5.3 Stable charges for residual costs

As the international experiences described in section 4.2.2 demonstrate, allocating residual system costs through variable volumetric charges can prevent market agents from deploying an effective risk-hedging strategy and send inefficient signals to demand, as with the "overnight signal distortion". Residual charges for system costs must be stabilised. Adopting the British terminology, this means defining a notice period and a fixed period and deciding whether a specific reserve fund is needed to avoid the risk of having to reset

[6] The alternative is to reform the entire design of network tariffs so that they send the efficient signals, which are becoming increasingly important during the energy transition.

charges during the fixed period. These decisions must be tailored to each power system, depending on the expected volumes and volatility of residual system costs. Therefore, no generic recommendation can be made on this topic.

5.4 Discounts and exemptions

As already mentioned in section 3.2, discounts and exemptions should only apply to residual charges. This holds true not only for residual system costs, but also for the residual part of other cost items, such as residual network costs. Once the regulator has decided how to allocate all these residual costs through cost-recovery charges that do not distort efficient signals, they may consider exempting or discounting these charges for certain categories of end users.

Discounts and exemptions may be particularly relevant for the industrial sector, especially for energy-intensive industries, in terms of their competitiveness in the international market [35]. In this case, discounts can be interpreted as an application of Ramsey pricing that focuses on long-term decisions. Some industries may decide to relocate their production facility in search of lower electricity prices, whereas other consumers do not have this long-term demand elasticity. Other regulators may be willing to apply discounts and exemptions to residual charges to encourage the deployment of flexible resources, such as electricity storage, or of specific energy-intensive demands, such as those from electrolysers or data centres[7].

6 CASE STUDY: SYSTEM COSTS IN THE SPANISH POWER SECTOR

The recent evolution of system costs in Spain has been presented in Section 2 and illustrated in Figure 2. The current methodology to recover system service costs in the Iberian countries has been outlined in section 4.2.2. In summary, the cost of balancing energy is included in the imbalance price, while the cost of balancing capacity is treated as a residual cost. Congestion management costs, as well as other costs (voltage control and emergency and restoration costs), are also treated as residual costs. All these residual costs are recovered through volumetric hourly charges that socialise them among the demand in that hour. Hourly charges are calculated ex post.

[7] Whenever discounts and exemptions are introduced, it is important to design a proper strategy for funding them, either through the state budget or using cross-subsidies. This topic exceeds the scope of this article.

6.1 Enhanced imbalance settlement price

We propose to enhance the imbalance price settlement in Spain, for it to internalise:

i. Balancing energy costs relative to a specific balancing service for demand response. Since 2023, the Spanish TSO has introduced a specific balancing product known as SRAD (service for active demand response, which has a capacity and energy component as mFRR) [56], which overlaps with the activation of mFRR and RR and whose costs should therefore be recovered through the imbalance price.
ii. Balancing capacity costs with price caps. Balancing capacity is currently only procured for aFRR and for the SRAD product. These costs are reported by the Spanish TSO as separate cost items, which should both be recovered via the enhanced imbalance price[8].

To estimate the economic impact of this proposal, we use data from 2024 from the Spanish TSO [57]. In 2024, Red Eléctrica de España reported 666 million euros from balancing capacity and SRAD. The following procedure was followed to compute the enhanced imbalance settlement prices:

i. The SRAD activation cost (only 12 hours during 2024) is added to the balancing energy cost to be recovered via the imbalance price.
ii. Upward and downward hourly costs for aFRR balancing capacity plus the capacity costs of SRAD during the contracted period are divided between the hours with negative and positive system imbalance, accordingly.
iii. A price cap equal to twice the day-ahead market price is applied to resulting imbalance prices (the regulator may also define other criteria to set this price cap, e.g., the marginal cost of activated balancing energy services).
iv. The enhanced upward and downward imbalance prices for each hour are calculated by dividing the corresponding costs by the imbalance volume in that hour and then limited by the price caps (the remaining costs exceeding the price cap are considered as residual costs).

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[8] Actually, as part of real-time congestion management, the Spanish TSO can procure additional capacity reserves when a shortage of upward balancing reserves is registered. Currently, these costs are bundled with other congestion management costs in a cost element defined as “technical constraints”, but they should be reported as part of balancing capacity. However, due to the impossibility of unbundling these costs from other “technical constraints” cost elements, they could not be accounted for in the quantitative assessment.

Table i shows the cost allocation resulting from the application of the enhanced imbalance price methodology. With a price cap of twice the day-ahead market price, 28% of the balancing capacity costs (190 M€) would be allocated through enhanced imbalance prices, while 72% of these costs would be treated as residual (476 M€), since the resulting imbalance price exceeds the price cap. This happens in 25% of the hours for the upward enhanced imbalance price and in 4% of the hours for the downward one.

Table i. Balancing cost allocation following the proposed enhanced imbalance price methodology

	Upward balancing capacity costs [M€]	**Downward balancing capacity costs [M€]**	**SRAD [M€]**	**Total costs [M€]**	**Total costs [%]**
Total costs	**515**	**47**	**106**	**666**	100%
Allocated via enhanced imbalance prices	170	19	1	190	28%
Residual	344	28	105	476	72%

6.2 Congestion management costs and network tariffs

In Spain, the day-ahead electricity market is cleared without considering network constraints, and a single national price is calculated for each hour. Transmission network congestions (including voltage control issues) are solved in a redispatch market known as the market for technical constraints, which is cleared at two different timeframes: in the day-ahead, after the energy market clearing, and closer to real time [34]. This market for technical constraints generates congestion management costs, which are currently bundled with other system costs and allocated to consumers through volumetric hourly charges calculated ex post.

As proposed in section 5.2, these congestion management costs should be allocated via network tariffs, following the methodology used by the Spanish regulator [58]. A detailed description of this methodology can be found in [59]. In a nutshell, network costs are allocated via energy and contracted capacity charges. Broadly speaking, energy charges relate to the costs of energy losses and capacity charges with the cost of network capacity. The methodology involves a cascade model to allocate network costs across voltage levels and defines ex ante six tariff periods, according to the period of the year and the time of the day. In period 1 (P1), which includes peak demands, higher charges are applied, since it contains more critical hours for network utilization. On the other extreme, period 6 (P6), which includes off-peak periods, is the one with the lowest charges. The Spanish methodology fulfils the recommendations from the European Commission, which states that National Regulatory Authorities should include time-of-use elements in tariff structures, to correlate cost allocation with peak network usage, in order to incentivise efficient use of the network [60].

During 2024, congestion management costs in Spain represented 2 462 million euros[9] [57]. These costs are expected to be higher during tariff periods with greater demand, due to the emergence of larger congestions at those times. Also, during off-peak hours, when there are larger voltage issues, an increase in demand can help reduce these voltage problems, which is incentivized with lower network charges. This means that, if congestion management costs would be allocated through network tariff, maintaining the current methodology and tariff periods[10], the economic signals would be efficient. In order to check this effect with real data, we have divided congestion costs per tariff period and calculated an average hourly cost for each period, as shown in Table ii.

[9] Due to the lack of more detailed breakdowns by the Spanish TSO, a minor part of the costs within the item "cost of the real-time security technical constraints resolution process" may not be actual congestion costs. However, this does not affect the findings of this section. In the future, the Spanish TSO should provide a more detailed breakdown that allow to isolate congestion management costs from other costs.

[10] Notice that the current network tariff methodology allocates all network costs between energy and capacity terms, without differentiating between forward-looking and residual. This is a limitation of current network charges that should be revisited in the future, but which do not impact congestion costs, which are short-term costs.

Table ii. Allocation of congestion management costs by tariff periods

Tariff periods	Day-ahead congestion costs (M€)	Real-time congestion costs (M€)	Average hourly congestion costs (k€/h)
P1 (peak-high season)	41	175	314
P2 (peak-mid season & valley high season)	137	277	403
P3 (valley mid-season)	110	225	318
P4 (peak low season)	96	115	291
P5 (valley low season)	66	97	257
P6 (off-peak hours)	715	408	241
Total	1164	1298	-

The average hourly congestion management costs follow approximately the same pattern as the tariff periods defined in the network tariff methodology, that is, they are higher in P1, P2, and P3, and lower in P4, P5, and P6. Therefore, the Spanish methodology for the calculation of network tariffs is confirmed to be suitable for the allocation of congestion management costs, providing efficient price signals. It must be remarked that these results arise from the Spanish methodology, which is already aligned with the recommendations of European institutions on time-of-use elements in tariff structures. If the proposal on the allocation of congestion management costs is to be applied to another power system, first, it must be checked that the network tariff design is already sending efficient economic signals.

6.3 Stable charges for residual costs

Any system cost that cannot be assigned through a cost-reflective charge, either through an enhanced imbalance price (due to the activation of price caps) or via enhanced network tariffs, should be treated as residual and recovered through residual charges. In the Spanish case, most of these residual costs arise from applying price caps to the enhanced imbalance price. Although for the Spanish case, these residual costs are low compared to total system costs, they should be allocated through stable volumetric charges. As already mentioned in section 5.3, the notice period and the fixed period should be selected based on the volatility of the residual system service costs. If the latter are mostly related to frequency reserves, Figure 2 shows how these costs do not present a very high volatility in Spain. This allows for long notice and/or fixed periods.

Discounts and exemptions can be applied to these stable volumetric charges for certain categories, such as energy-intensive industries, storage assets, electrolysers, and data centres. This need for these discounts and exemptions depends on the Spanish regulatory framework (these categories may be the recipient of other economic benefits for their electricity demand) as well as on the energy and industrial policy of the country.

7 CONCLUSIONS

Following years of sustained renewable energy integration, European power systems have recently witnessed rapid growth in the cost of system services, particularly regarding frequency control and congestion management. In most European countries, these costs are currently allocated to consumers using simplistic methodologies. In many countries, these costs are embedded in network tariffs designed to allocate costs to different drivers. In other countries, system costs are socialised through volumetric charges, which hinder risk hedging strategies due to their high volatility and may convey inefficient economic signals, particularly overnight. Over the next decade, it will become increasingly important to define robust strategies for the efficient allocation of system costs.

This article puts forward a thorough proposal for achieving this, whereby system costs are divided between those that can be recovered by applying cost causality via cost-reflective charges and prices, and those that must be considered residual and allocated through cost-recovery charges.

Currently, balancing capacity costs derived from reserving capacity for frequency control are allocated as residual system costs. However, they could be partially internalised in the imbalance price, thereby reinforcing its signal. During periods of low imbalance volume, this approach can result in very high imbalance prices, but this effect can be mitigated by applying price caps (e.g., based on the day-ahead market price). Congestion management costs can be considered complementary to network expansion costs since they have equivalent cost drivers (i.e., transmission capacity scarcity). Therefore, congestion management costs should be separated from other system service costs and recovered through network tariffs. If the methodology used to set the network tariff already sends efficient signals, it could also be used to allocate congestion management costs. In the future, this recommendation could also apply to distribution networks and their congestion-related costs, which will become more visible with distributed services and local markets.

Any system costs that cannot be assigned according to the principle of cost causality must be considered residual costs to be recovered through charges that do not distort the efficient signals sent by other charges and prices. To avoid high volatility and inefficient signals, these residual charges should be stabilised. Following the British example, this can be achieved by setting fixed charges calculated in advance based on a given notice period. Where high volatility is expected, a specific reserve fund may be required to avoid the risk of having to reset charges during the fixed period. Discounts and exemptions for certain categories of end users (e.g., energy-intensive industries, storage, or electrolysers) should only apply to residual charges.

The impact of this proposal has been tested using real data from the Spanish power system. In Spain, system costs (including balancing capacity and congestion management costs) are treated as residual and recovered through hourly volumetric charges, calculated ex post, that distribute system costs among demand in each hour. The Spanish case study shows that including balancing capacity costs in the imbalance price could lead to frequent activation of the price cap (set at twice the day-ahead market price). This would limit the proportion of these costs that can be allocated according to cost causality, while increasing residual costs. A quantitative assessment based on Spanish data also shows that congestion management costs can be efficiently recovered through network tariffs. This would take advantage of the current tariff structure and tariff periods, while reinforcing the signal conveyed by network charges.

Both the theoretical framework and the quantitative assessment presented in this article could be refined further in future work. One area for future research is to identify and evaluate alternative approaches to internalising balancing capacity costs in the imbalance price, as well as defining and applying price caps to prevent excessive pricing. The allocation methodology must also prevent arbitrage opportunities and perverse incentives when clearing different market segments, from the day-ahead market to the balancing market. Another area for further research is determining which network tariff calculation methodology is best suited to efficiently allocating congestion management costs, and whether a specific tariff structure should be defined for this purpose. The quantitative assessment could be replicated for other power systems experiencing rising system costs, including those with less sophisticated network cost allocation methodologies. The quantitative analysis could also be refined by focusing on the distributional impact that this proposal may have on different consumer categories.

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THE ALLOCATION OF SYSTEM COSTS: FUTURE-PROOFED METHODOLOGIES FOR DECARBONISING POWER SECTORS

José Pablo Chaves Ávila [a], Paolo Mastropietro [a], Matteo Troncia [a], Pedro González [b], Tomás Gómez San Román [a]

[a] Instituto de Investigación Tecnológica, Universidad Pontificia Comillas, Rey Francisco 4, 28008, Madrid, Spain.

[b] Asociación de Empresas con Gran Consumo de Energía, Hermosilla 31, 28001, Madrid, Spain.

CRediT Author Statement

José Pablo Chaves Ávila: Conceptualization, Data curation, Formal analysis, Methodology, Validation, Visualization, Writing - Original Draft. **Paolo Mastropietro**: Conceptualization, Formal analysis, Methodology, Validation, Writing - Original Draft. **Matteo Troncia**: Methodology, Data curation, Investigation, Writing - Review & Editing. **Pedro González**: Conceptualization, Validation, Writing - Review & Editing. **Tomás Gómez San Román**: Conceptualization, Methodology, Validation, Writing - Review & Editing, Supervision.