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Calculating efficient Distribution use of System (DUoS) charges for Ireland: Indicative tariffs for residential, commercial and industrial consumers

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Abstract

This paper considers the design of efficient Distribution Use of System (DUoS) tariffs for the Irish electricity distribution network. We calculate indicative cost-reflective 'Coasian' tariff for residential, commercial and industrial consumers. Under a cost-reflective 'Coasian' structure, non load-related costs are recovered by the fixed ('standing') charge, whilst load-related costs are recovered by either an energy or capacity-related charge. There is a plausible argument in favour of both energy or capacity-related charges to recover load-varying costs. A capacity-related charge is our preferred specification. Distribution network costs are driven primarily by non load-varying components. This motivates a switch in tariff structure from a predominance for energy-related charges towards a structure with a predominance for fixed or capacity-related charges. We consider nameplate capacity charges. Further Further work should consider a more precise specification of capacity charges, possibly incorporating time-of-use consumption data, such that capacity charges can be directly linked with each user's impact on the capacity requirement in the system.

Keywords: Electricity Tariffs, Distortion, Welfare Loss, Distributional Impacts

JEL Classification: K32, L94, L98, Q42, Q48, Q51, Q53, Q54, Q55

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1. Introduction

This paper calculates indicative cost-reflective 'Coasian' Distribution Use of System (DUoS) tariffs for electricity provision in Ireland. We calculate tariffs for residential, commercial and industrial consumers. Setting the price of a good or service equal to the marginal cost guides efficient allocation of resources (Coase, 1946). For services with high fixed costs, marginal cost pricing leads to an under-recovery of total costs. Two-part 'Coasian' tariffs facilitate marginal cost pricing in such circumstances; volumetric tariffs are priced equal to marginal cost and a fixed 'standing charge' recovers fixed costs (Borenstein, 2012a; Coase, 1946; Farrell, 2021). Tariffs in many markets often follow the multi-part structure as advocated by 'Coasian' principles but they are not cost-reflective: the volumetric price is not equal to marginal cost.

The subject of this paper is one of active consideration for utilities in many markets. The cost-reflectivity of Italian, German and British network tariffs have been reviewed, while a review process is currently underway with respect to Irish tariffs. However, the design of a cost-reflective DUoS tariff for each of domestic, commercial and residential consumers has not been calculated to date. This paper provides this contribution. In doing so, we extend the general Coasian principle to consider capacity-related costs; costs that vary with the infrastructural requirement to meet demand during peak periods.

This analysis comprises the following constituent components. First, the factors that may comprise a fixed, energy or capacity-related component are discussed and, depending on the structure of cost drivers assumed by the analyst, potential tariff structures are proposed. The method of recovering capacity-related costs, in particular, is open to many practical interpretations. We discuss the most desirable method and then consider the practical limitations evident in an Irish context. These are also present in other markets. Building on the work of Farrell and Meles (2023), cost-reflective 'Coasian' tariffs are then calculated for each type of electricity consumer (domestic, small industrial and large industrial).

In providing this insight, this paper is structured as follows. Section 2 reviews the literature. The data and methodology are outlined in Section 3. The results, that is the final set of cost-reflective tariffs, are presented in Section 3.4. Section 5 provides some concluding comments.

2. Literature

2.1. 'Coasian' pricing and the importance of cost-reflectivity

Setting the price of a good or service equal to the marginal cost guides efficient allocation of resources (Coase, 1946). However, the implementation of this principle can lead to an under-recovery of total costs for services with high fixed costs, such as electricity distribution networks. To remedy this, the literature has converged on a 'Coasian' multi-part tariff as the preferred least-distortionary tariff structure for services with high fixed costs such as electricity distribution networks.

Discussed by Farrell (2021) and Farrell and Meles (2023), the difficulty in implementing marginal cost pricing for utilities with high fixed costs has been studied since the early 20th century. A number of potential solutions have been proposed to achieve full cost-recovery in the least-distortionary manner. Ramsey-Boiteaux pricing, proposed by Ramsey (1927) and Boiteux (1956), was the fist such suggestion. This method of cost-recovery involves a discriminatory markup inversely proportional to the consumers price elasticity of demand. This operates on the principle that any resulting distortion that arises through a departure from marginal cost pricing is allocated to a greater extent among those who respond the least to a change in pricing, thus minimising any potential welfare loss. While a sound theoretical conclusion, Ramsey-Boiteaux pricing creates distributional considerations and the potential for perverse incentives.

Multi-part tariffs have emerged as the preferred solution to retain the marginal cost principle. The 'Hotelling-Lerner' solution involves the recovery of fixed costs through additional tax receipts Hotelling (1939); Lerner (1944). However, Coase (1946) disputed the merits of this solution as it distorts resource allocation and redistributes income. The 'Coasian tariff' solution advocates fixed cost recovery through a standing charge in a two-part tariff. This is often cited as the first-best solution to utility pricing and many utilities have since followed this tariff structure (Borenstein, 2016). Intuitively, this overcomes the distortive effects of the Hotelling-Lerner solution whereby the volumetric tariff guides efficient consumption of the good/service while the fixed 'standing' charge guides efficient connection to the network.

While utilities in many markets provide a multi-part tariff, they do not necessarily follow the Coasian principle; the volumetric tariff is not equal to marginal cost and the standing charge is not equivalent to each consumer's share of fixed costs. This can lead to a welfare loss in both the short and long run.

In the short run, tariffs that do not follow the Coasian principle may distort consumption decisions. If the volumetric price is greater than marginal cost, for instance, the consumer may forego consumption that would have enhanced their welfare to a degree greater than the costs of production. If prices are less than marginal cost, consumers may consume to the extent that the cost of that consumption exceeds their private value. In both circumstances, society is less well-off than it would have been under a Coasian tariff.

The welfare losses that result from these changes at the 'intensive margin'[1] have been estimated in many contexts, including for water tariffs in Spain and France (Garcia and Reynaud, 2004; Garcia-Valinas, 2005; Porcher, 2014), the US (Swallow and Marin, 1988) and Vancouver, Canada (Renzetti, 1992). Borenstein (2012b) quantifies the welfare losses due to non-linear electricity pricing in the US, while Borenstein (2012a) estimates welfare losses for US gas prices. Farrell and Meles (2023) estimate the welfare impacts of a Coasian reform of Distribution Use of System (DUoS) charges in Ireland for domestic consumers only.

In the long run, a general departure from marginal cost can distort decision-making at the extensive margin, that is, the decision to connect to the network or not. Borenstein (2012a) examine how tariff changes may affect the decision to connect a gas network while Smith (2016) find that non-marginal cost electricity pricing leads to air conditioner over-investment.

[1] That is, the decision to alter the number of units consumed

Of particular interest as electricity systems decarbonise is the effect of inefficient tariffs on a consumer's decision to install their own distributed generation source, such as solar photovoltaic. This may be distorted if volumetric prices are greater than marginal cost. It may be rational for the consumer to install their own distributed generation source when the cost of self-consumed electricity is less than the price of grid-sourced electricity but greater than the marginal cost of grid-sourced electricity. In this way, the consumer is avoiding the markup on the volumetric price for grid-sourced electricity. Tariff recalibration may increase the relative price difference between grid and DER-sourced electricity, increasing the incentive to invest in DER resources, perpetuating a spiral of cost under-recovery. This is known as the 'utility death spiral' (e.g. Costello and Hemphill, 2014; Muaafa et al., 2017). Farrell (2021) estimates the potential welfare effects of such distributed generation adoption in the presence of inefficient tariffs for UK consumers, highlighting the effect of a Coasian tariff structure in avoiding these welfare losses.

2.2. The cost-reflectivity of network tariffs

It is the purpose of this paper to investigate whether Irish Distribution Use of System (DUoS) tariffs follow the cost reflective Coasian principles and to propose a Coasian counterfactual tariff structure for domestic, commercial and industrial consumers. Network tariffs are often a constituent component of retail electricity tariffs. In many markets, distribution and transmission use of system charges (DUoS and TUoS charges, respectively) are passed on to consumers as part of their final electricity tariff. The method with which these costs are to be recovered through the final electricity tariff through fixed, energy-varying or capacity-varying components that are often specified explicitly by the network operator. This is the case in Ireland (see Commission for Regulation of Utilities, 2015b).

If one were to apply Coasian principles to either DUoS and or TUoS tariffs, each of the fixed, capacity and energy-related components should be reflective of each consumer's share of the respective cost. Many regulators state a desire to follow such a cost-reflective structure in the design of their tariffs (Australian Energy Market Commission, 2014; Lo Schiavo and Regalini, 2018; Europe Economics, 2021; Ofgem, 2017a,b). The Australian Energy Market Commission (AEMC), for instance, states "that the network prices that a distribution business charges each consumer should reflect the business' efficient costs of providing network services to that consumer". The AEMC continues, stating that "each network tariff must be based on the long run marginal cost of providing the service" (Australian Energy Regulator, Australian Energy Regulator). Despite the fact that many regulators and systems operators have a stated objective to offer 'cost-reflective' network tariffs (a synonym for a Coasian tariff structure), their tariffs do not necessarily reflect this cost breakdown.

While studies exist to estimate the impact of general Coasian tariff departure, much less research exists to explore the efficient design of electricity network tariffs. Reviewed by Australian Energy Market Commission (2014), such work is concentrated in the policy and industry-oriented 'grey' literature, as opposed to the peer-reviewed literature. The most notable study in this field was produced by NERA Economic Consulting (2014), who calculate cost-reflective network tariffs for Australia. A number of methods are considered in relation to cost apportionment. Interestingly, this study considers the use of capacity-related charges in the multi-part Coasian tariff framework.

However, this is the only such study to consider the efficient cost-reflective design of electricity network tariffs.

Europe Economics (2021) provide a review of network tariff structures in various countries. Three concerns arise in relation to the setting of these tariffs. First, tariff transparency is often an issue. In Germany, for instance, Europe Economics (2021) find that tariffs vary widely between regions. This makes it difficult to regulate grid expansion and the efficient allocation of costs. Expansion is a particular issue in Germany as regions in the North, for example, face much required reinforcements on foot of additional wind generation in this region.

In the UK, the Targeted Charging Review (Ofgem, 2017b) was tasked with identifying a cost-reflective structure for UK network tariffs. The approach that the UK regulator wishes to take to recover costs was informed by equity, efficiency and proportionality/practicality. The outcome of the Targeted Charging Review, published in 2019 resulted in costs that were not driven by network usage - so-called 'residual costs', to be recovered by a fixed charge. This was deemed least-distortive and aligns with Coasian principles. For domestic users, there will be a single transmission residual charge and a single distribution residual charge within each of the 14 licensed distribution areas in the UK. The reform is being introduced incrementally to mitigate distributional impacts and help with predictability of charges for consumers (Europe Economics, 2021).

The Italian system is a useful example of a multi-part structure, where both distribution and transmission network costs are recovered through energy (volumetric), capacity and fixed components. The volumetric term is predominant, and the capacity term is based on the size of connection rather than measurements. The volumetric component essentially represents transmission costs, and is charged on a kWh basis. Distribution costs are mostly recovered through a capacity charge based on a peak load (€/kW) that is selected by the user, much like the Maximum Import Capacity in Ireland (Europe Economics, 2021).

3. Materials and methods

In this section we calculate a set of cost-reflective 'Coasian' tariffs for Distribution Use of System (DUoS) charges in Ireland. The methodology is similar to that adopted by Farrell and Meles (2023), in that we re-allocate costs according to the distribution of capacity-varying, energy-varying and fixed costs identified in published accounts (Commission for Regulation of Utilities, 2021b). The initial steps of this methodology and associated description are therefore identical to those of Farrell and Meles (2023). The method of this paper departs from Farrell and Meles (2023) in the final stages as we calculate cost-reflective tariffs for multiple consumer classes, as opposed to a tariff for a single domestic consumer class. The approach differs in this paper as we allocate total cost recovery among consumer classes according to each consumer class' contribution towards individual system peak, whereas the methods of Farrell and Meles (2023) assumes that total cost recovery from domestic consumers remains constant, with the Coasian counterfactual calculated accordingly.

There are a number of constituent steps in this calculation. First of all, total costs are broken down according to operating and capital cost components.[2] We then disaggregate each of these components into fixed, capacity-varying and energy consumption-varying cost components.[3] These steps are identical to those adopted by Farrell and Meles (2023). We then calculate the proportion of total network costs to be recovered by each consumer category via either energy-varying, capacity-varying or fixed tariff components. This step results in a departure from the calculations of Farrell and Meles (2023). The cost-reflective Coasian tariff can then be calculated from these components. Each step will now be discussed.

3.1. Disaggregating total costs into fixed and operating cost components

Given the structure of the Irish network cost data, we must first disaggregate total costs into fixed and operating cost components. Fixed costs relate to long-lived assets. Therefore, the capital expenditures incurred for a given time period are not necessarily reflective of the services received during a given period from long-lived capital assets. To accommodate this, we consider capital costs according to the allowed return on asset base, as opposed to period-specific asset expenditure. This metric represents that period's share of longer-term costs associated with the entire asset base.

We consider costs for the Price Review 5 regulatory period for this analysis Commission for Regulation of Utilities (2021b). To do this, we follow the procedure of Farrell and Meles (2023). As Farrell and Meles (2023) note, the energy, capacity and fixed cost components are similar across PR4 (2016-2020) and PR5 (2020-2025) price review periods (Commission for Regulation of Utilities, 2015a, 2021b). As such, we are confident that a given period's capital expenditure is representative of the longer-term cost share.

Table 1 shows the allowed DUoS revenues for the PR5 2020-2025 regulatory period (Commission for Regulation of Utilities, 2021b). Cost categories comprise operating expenditure; capital cost recovery; depreciation; and PR4 adjustments. PR4 adjustments cover discrepancies between expected and actual expenditures during the PR4 regulatory period, recovered through an adjustment in the PR5 regulatory period. Examining Table 1, we can see that operating expenditures are have their own category. Each cost component will now be analysed to identify whether they vary with energy or capacity requirements, or whether they are fixed.

3.1.1. Weighted Average Cost of Capital

Under the review process, the DSO is allowed to recover a fair return on their Regulatory Asset Base (RAB) such that the efficient operation, development and maintenance of the network is facilitated. The DSO invests in capital stock on an ongoing basis and these assets are long-lived. While investment in these assets is not necessarily ongoing, the cost to finance the debt and equity raised to purchase these assets is an ongoing expense, calculated according to the weighted average cost of capital (WACC) methodology. The cost categories apportioned to each regulatory period are shown in Table 1. As such, these costs relate to capital expenditure.

[2] We do this to accommodate the nature of the Irish data which is in capital and operating cost components

[3] This process has benefitted from comments received from ESB Networks

3.1.2. Depreciation

The DSO writes off the value of capital stock over the project's useful life, receiving revenue proportional to this incurred cost. There are a number of possible economic depreciation methods. The straight line method is applied by the CRU Commission for Regulation of Utilities (2015a, 2021b). As such, these costs relate to capital expenditure.

3.1.3. PR4 adjustment

PR3 adjustments for the 2016-2020 period are assumed to be capital expenditures while PR4 adjustments for the 2021-2025 period are assumed to be operating expenditures. PR3 operational expenditures were broadly in line with ex-ante allowed expenditures, with the net underspend during that period attributable to capital expenditure Commission for Regulation of Utilities (2015a). The PR4 overspend, however, is attributable to operational expenditure activities, primarily repair works due to unexpected storms, while there was an underspend in capital expenditure during this period (Commission for Regulation of Utilities, 2021b).

Table 2 aggregates the costs of Table 1 into the identified operating and capital cost components. The breakdown as a proportion of total costs is then calculated, where we see that capital expenditure comprises 65.44% of total distribution network costs for the PR5 regulatory period.

Table 1: DSO allowed revenue 2021-2026 (PR5)

Description	2021-2025 (PR5)	
	€million	% of total
Operating expenditure	1,632	35.85%
Weighted Average Cost of Capital (WACC)	1,224	26.89%
Depreciation	1,755	38.55%
PR4 adjustment	-59	-1.30%

Note: Data show total expenditure for PR5 2021-2025 period. Values are as listed in 2019 cost terms in the PR5 decision paper (Commission for Regulation of Utilities, 2021b). Please see Commission for Regulation of Utilities (2021b) for further details. All the values have not been adjusted for outturn, yearly updates or inflation.

Table 2: Operating and capital cost breakdown (in %): 2016-2025

	2021-2025
Capital expenditure	65.44%
Operating expenditure	34.56%

Note: Authors' calculations, summing identified capital and operating cost components from Table 1

3.2. *Operating and capital cost disaggregration*

The next step is to disaggregate each of operating and capital cost components into fixed, capacity-varying and energy-varying subcomponents.[4]

Table 3 displays operating costs by component. From this list, one can see that cost categories cover various aspects of business performance. It is clear that these costs do not vary with the energy delivery or capacity requirement for the system. These costs are therefore assumed to form part of the fixed tariff. While a greater network capacity may require a greater maintenance costs, this is likely to form an insignificantly small element of the total maintenance requirement and this cost is therefore assumed fixed.

Table 3: Operating expenditures for PR5 determination period

Operating expenditure	2021-2025 (€million)
Network O&M	627
Asset Management	107.3
Metering	88.7
Smart Metering OPEX	59.1
Customer Service	123.8
Provision of information	65.7
Commercial	0
Sustainability and R&D	20
Other (admin; insurance network rates	540.2
	1631.8

Note: Data show operating expenditures for the PR5 determination period (Commission for Regulation of Utilities, 2021b). Data have not been adjusted for outturn, yearly updates or inflation. Please see Commission for Regulation of Utilities (2021b) for further details.

Next, we separate capital cost into fixed, capacity-related and energy-related components. This is shown in Table 4. We will discuss each cost component individually. Load-related capital expenditure is expenditure incurred to connect new consumers (Commission for Regulation of Utilities, 2021b). This varies with the volume of electricity consumed. It may plausibly be driven by either energy or capacity requirements. When considering DSO costs, past applications have interpreted such costs as varying with capacity. In Italy Europe Economics (2021) report that load-related costs are levied according to capacity. This follows the assumption that distribution system often has a lesser capacity than the transmission network. We follow this precedent.

Non load-related capital costs consist of network upgrades to facilitate renewable energy integration, associated with renewable energy policy and targets (Commission for Regulation of Utilities,

[4]This process was informed by discussions with ESB Networks. We also consulted the PR5 Final Determination Paper and the PR5 Excel Revenue Model (Commission for Regulation of Utilities, 2021b).

2021b) alongside standard infrastructure upgrades which are not related to load changes. As this does not vary with load, this cost is assigned for recovery via the fixed charge. Capital expenditure deemed 'non network' relates to investment associated with generation. This is unrelated to consumption and comprises an element of the fixed tariff (Commission for Regulation of Utilities, 2021b). Smart-metering expenditures relate to the smart meter rollout. These do not vary with energy delivery or capacity. They are assumed to comprise part of the fixed tariff.

Table 4: PR5 Capital Expenditure Breakdown

Capital expenditure	2021-2025 (€million)
Load related capital expenditure	1391.2
Non-load related capital expenditure	693.8
Non-network capital expenditure	322
Smart metering	882
Contributions	-445.6

Source: Data show capital expenditure component for each determination period. Data sourced from Commission for Regulation of Utilities (2021b).

The 'contributions' noted in Table 4 are revenues received from customers for services provided by ESB Networks. These costs must be deducted from the appropriate cost component. Consumer contributions consist of customer contributions, contributions received for generation connections, capital grants, and repayable line diversions.

Customer contributions relate to network connection. These are set against load-related capital expenditures. Generator connections and repayable line diversions are set against load-related capital expenditure (see Commission for Regulation of Utilities, 2021b). Table 5 disaggregates 'contributions' among subcategories.

Table 5: Contribution breakdown

Category	PR5
Customer contributions	56%
Generator connections	31%
Repayable line diversions	13%

Source: Data sourced from Commission for Regulation of Utilities (2021b) and the DSO excel model.

Incorporating the breakdown of contributions from Table 5, we update the breakdown of capital costs into fixed and energy/capacity components in Table 6.

3.3. Energy, capacity or fixed cost recovery

The third stage is to identify what proportion of total costs are to be recovered by either capacity, energy or fixed components. Once again, we follow the method of Farrell and Meles (2023) to

Table 6: Load and non load-related capital costs less consumer contributions (in €million)

Category	PR5	
Load-related capital expenditure		1391
Less customer, generator and line-diversion contributions		-388
Net load-related capital expenditure		1003
Non load-related capital expenditure	694	
Non network capital expenditure	322	
Smart metering	882	1898
Less remaining contributions		-58
Net non load-varying capital expenditure		1840

Note: Data show total expenditure. Values are as listed in the PR5 decision paper (Commission for Regulation of Utilities, 2021b). They have not been adjusted for outturn, yearly updates or inflation. Please see Commission for Regulation of Utilities (2021b) for further details.

carry this out.

The previous sections have identified that all operating costs and non load-varying capital costs are to be recovered via the fixed charge. Load-varying capital costs may be plausibly recovered by either a capacity or energy charge. When considering DSO costs, past applications have interpreted such costs as varying with capacity. Europe Economics (2021) report that load-related costs associated with the distribution network are levied according to capacity in Italy. This follows the assumption that the distribution system often has a lesser capacity than the transmission network. We follow this precedent and consider load-related DSO costs to be driven to a greater extent by capacity costs and consider this to be our preferred analysis. We also carry out the calculation where these costs are assumed to be driven by energy consumption and these costs are recovered via a volumetric tariff.

Taking both capital and operating costs together, the proportional breakdown for Coasian cost recovery is shown in Table 7. 78% of total costs incurred should come from a fixed charge, on average, while 22% should be recovered via an energy/capacity component. The energy capacity/component is stable across periods of analysis.

Table 7: Proportion of DSO revenue to be recovered via fixed and energy/capacity components

Category	PR5	
	€million	%
Operating cost (fixed)	1,632	36%
Capital cost (fixed)	1,840	42%
Capital cost (energy/capacity)	1,003	22%

3.4. *Coasian tariff calculation*

Drawing the calculations of the preceding sections, this section will calculate the representative Coasian tariffs. The fixed and energy/capacity components will now be considered in turn.

3.5. *Fixed charge*

Following Coasian principles, each consumer should pay a share of fixed costs proportional to the burden they impose on the system. In practice, a regulator should choose a disaggregation which best approximates this concept. In the absence of data on this burden, we follow the precedent set by Irish policy when delineating Public Service Obligation (PSO) levies among consumer categories,[5] where the proportion of total revenue to be recovered from each consumer category is calculated based on system burden, proxied by contribution to individual peak.

This carries the implicit assumption that consumers that contribute a greater deal to the overall capacity of the system also contribute a greater deal towards network fixed costs. Furthermore, it should be noted that consumer numbers, sourced from CRU (2019-2022) may be subject to error as they contain transmission-connected sites. This is a particular issue for Large Industrial Users, many of whom connect directly to the transmission network. As such, these results should be interpreted in this context as a lower bound on the cost for industrial users.

Table 9 outlines fixed cost recovery where cost allocation to consumer categories is carried out under the assumption that each consumer's share of fixed costs is proportional to their contribution towards peak load. We disaggregate each total according to the revenue to be recovered from Domestic, Small industrial and Large industrial consumers. We do so according to each consumer category's contribution towards individual peaks, sourced from the CRU's PSO Decision Paper. There is a separate decision paper for each regulatory year, and we take the average of those published during the PR5 period to date (2019/20-2022/23) (Commission for Regulation of Utilities, 2019, 2020, 2021a, 2022).

In Table, 10, total costs to be recovered (Table 9) are then divided by the number of consumers in each category (outlined in Table 8) to calculate the fixed cost per consumer by consumption category. It should be noted that large industrial consumers are delineated according to their Maximum Import Capacity (MIC), with costs allocated per MIC.

3.6. *Energy/Capacity costs*

We now consider the apportionment of non-fixed costs according to either an energy or capacity charge. In this section we calculate both. There is a precedent in the literature to attribute energy-related network costs by capacity (Europe Economics, 2021) and this is therefore our preferred approach.

3.6.1. *Capacity charge*

A capacity charge may be allocated a number of ways. Ideally, this would closely approximate a consumer's contribution towards the total network capacity required. There are many ways one can

[5] This is a levy designed to finance renewable energy supports.

Table 8: Number of consumers by consumption category

	PR5
Domestic	2,157,740
Small industrial	167,355
Large industrial (MIC)	6,104,948

Consumer numbers are calculated as the average for the price review period, incorporating years for which data are available (2020/21-2022/23) Commission for Regulation of Utilities (2019, 2020, 2021a, 2022)

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Table 9: Fixed tariff revenue recovery: cost allocation by contribution to system peak

	PR5
Average revenue (€m)	694.4
% Revenue recovered from	
Domestic	41%
Small industrial	11%
Large industrial (MIC)	48%
€m revenue recovered from	
Domestic	285
Small industrial	76
Large industrial (MIC)	333

Average fixed charge revenues calculated as total fixed charge revenues (1632 + 1840) divided by the number of time periods (5). Revenue shown as average annual revenue per review period, with each period's total sourced from Commission for Regulation of Utilities (2021b). Percentage contributions are calculated as the average for the price review period, incorporating years for which data are available (2020/21-2022/23) Commission for Regulation of Utilities (2019, 2020, 2021a, 2022)

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Table 10: Fixed charge per consumer per annum: cost allocation by contribution to system peak

	PR5
Domestic	132
Small industrial	456
Large industrial (MIC)	55

Calculated by dividing the total revenue per consumer category (Table 9) by consumer numbers per consumer category (Table 8).

approximate this. Conceptually, one could quantify, at each node on the network, the proportion of total consumption that each consumer contributes during periods of peak electricity transfer. As consumption during peak periods is the primary driver of the capacity requirement, this would approximate the contribution each consumer makes towards the capacity required at that node. In practice, there may be sophisticated weighting systems to ensure that consumption at various peaks at various nodes are represented proportionally in the capacity burden calculation.

In practice, data limitations limit the ability to may quantify each consumer's contribution to peak requirements. In many circumstances, nameplate capacity is employed as a proxy (e.g. Commission for Regulation of Utilities, 2022; Europe Economics, 2021). This is a somewhat crude approximation, often necessary, with limitations. For instance, it does not incentivise minimisation of the capacity burden for many consumers, particularly domestic and small industrial consumers. With greater adoption of time of use pricing, this may change.

Capacity-based cost apportionment follows the nameplate approach under previously discussed PSO cost apportionment methodology. Should energy/capacity costs be apportioned according to capacity, we demonstrate the capacity component of the levy in the following tables. The revenue to be recovered by each consumer category is calculated in Table 11, while the tariff per consumer is then calculated in Table 12. This is calculated by dividing the total revenue to be recovered (Table 11) by the number of consumers per category (Table 8).

Table 11: Capacity tariff: revenue recovery by consumer category

	PR5
Average revenue (€m)	200.6
% Revenue recovered from	
Domestic	41%
Small industrial	11%
Large industrial (MIC)	48%
€m revenue recovered from	
Domestic	82
Small industrial	22
Large industrial (MIC)	96

Average capacity charge revenues calculated as total capacity-related costs (1003) divided by the number of time periods (5). Revenue shown as average annual revenue per review period, with each period's total sourced from Commission for Regulation of Utilities (2021b). Percentage contributions are calculated as the average for the price review period, incorporating years for which data are available (2020/21-2022/23) Commission for Regulation of Utilities (2019, 2020, 2021a, 2022)

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3.6.2. Energy-related charge

Alternatively, one may allocate the energy/capacity costs according to units of energy consumed. This is appropriate if it is more reasonable to assume that load-related costs in the distribution network are driven by energy consumption rather than capacity requirements. This calculation is

Table 12: Capacity charge per consumer per annum

	PR5
Number of consumers	
Domestic	2,157,740
Small industrial	167,355
Large industrial (MIC)	6,104,948
Capacity charge per consumer per annum	
Domestic	38
Small industrial	132
Large industrial (MIC)	16

shown in Table 13, calculated as the total revenue to be recovered divided by the number of units consumed. It is important to note that this carries an implicit assumption that there is no demand response. This is not a strong assumption as the change in price is quite small at ¡ 1 cent. As Farrell and Meles (2023) show, this leads to a negligibly small demand response.

Table 13: Energy charge per consumer per annum

	PR5
Average revenue (€m)	200.6
Average annual units consumed	27,920
Unit charge	0.0072

4. Results: Final tariffs

Taking Table 10 and Table 12 together, we calculate a Coasian tariff that incorporates fixed cost apportionment due to each consumer category's contribution towards peak load. This is shown in Table 14. It is important to point out some factors that drive these results and how they differ from comparable studies, such as that of Farrell and Meles (2023). In particular, there is an assumption in these calculations that costs are allocated between consumer groups according to each group's contribution towards individual peak. This differs from the calculated Coasian tariffs of Farrell and Meles (2023), who concentrate on domestic consumers and assume that cost apportionment to this consumer category stays constant.

The tariffs calculated in Tables 14 and 15 differ somewhat from those implemented in 2022/23 for Irish distribution network tariffs (ESB Networks, 2022). For 2022/23, Irish urban domestic consumers are charged €67.22 per annum standing charge, while rural domestic consumers are charged €98.04 per annum. Unit rates are 4.019c/kWh for a consumer using a standard uniform tariff (ESB Networks, 2022). Comparing these values with the tariff schedule and average consumer costs outlined in Tables 14 and 15, we see that there is a shift from a volumetric unit-centred charging structure towards a fixed charging structure. This reflects the fact that much of the costs associated with the delivery of the distribution network do not vary with energy or capacity provision. Should these costs be allocated on a nameplate capacity basis, the entire tariff effectively becomes a standing charge.

Assuming small industrial users are comparable to ESB Networks' DUoS Group 5 (low Volatage non-domestic consumers) (ESB Networks, 2022), we can observe that these consumers see a considerable increase in their fixed charge, rising from €110.54 to €456 per annum. However, it should be noted that these consumers see a reduced unit rate from 5.101c/kWh to 0.0072c/kWh (or €132 per annum if a capacity charge is introduced), while a low power factor surcharge is not considered in this calculation. Once again, we see a shift from volumetric to fixed costs, reflective of the non load or capacity-varying nature of most distribution network costs.

If we assume that large industrial users are comparable to ESB Networks' DUoS Group 6-8 (ESB Networks, 2022), we see a different pattern of incidence. ESB networks currently put in place both a fixed standing charge per customer and a capacity charge per kVA of MIC. The calculations of this paper, however, allocated costs according to kVA of MIC. Therefore, the fixed and capacity-categorised costs allocated according to kVA of MIC proposed in this paper are greater than the MIC-related costs charged by ESB Networks in 2022/23. Data availability on the number of customers could allow for a customer-centred fixed charge which would further refine the calculations of Tables 14 and 15.

The assumption that costs are allocated according to contribution towards individual peak implies that consumer burden on distribution network costs are proportionate to the capacity required. While this is not a strong assumption, it is perhaps a simplification, the implications of which will now be discussed. This is an important factor that must be considered when interpreting these results.

Many network costs are allocated according to a 'cost cascading' framework. Such a framework exists in Portugal, for instance, where costs are allocated according in extent with which each consumer group utilises a portion of the network. To illustrate, consider a low voltage-connected user. They will pay a separate distribution tariff for each voltage level utilised (i.e. High Voltage, Medium Voltage, Low Voltage). In contrast, a High Voltage-connected user only pays a tariff corresponding to the use of the High Voltage network. Residential and many commercial users are often low voltage users while industrial users are often high voltage users (ACER, 2021).

The distribution network is the low and medium voltage network in Ireland whilst the transmission network is the high voltage network. Applying the cost cascading principle to the Irish distribution network would alter the cost allocation procedure such that a greater share of costs would be incurred by domestic and small industrial users, with a lesser share incurred by large industrial users. The results of this section should be interpreted in this context, with domestic and small industrial tariffs representing a likely lower bound on cost-reflective tariffs while large industrial tariffs representing an upper bound the cost-reflective tariffs.

It should be noted that there are limitations in the calculation of tariffs used in this paper. Firstly, a nameplate capacity charge is a second-best methodology for capacity cost allocation as it does not reflect observed capacity burden and therefore there is no incentive for efficient capacity usage. Real time data can facilitate such a calculation. Secondly, we use three consumer categorisations to represent the variation in cost. Improved data on the pattern of usage by consumer group, and relationship between this and total system costs, particularly in relation to non-domestic consumers, would further refine these calculations. Nevertheless, these findings may prove useful when reforming tariffs on a cost-reflective basis.

Table 14: Coasian tariff: capacity-driven fixed costs

Consumer type	Fixed charge (€)	Capacity charge (€)	Total (€)
Domestic	132	38	170
Small industrial	456	132	588
Large industrial (MIC)	55	16	71

Note: Costs allocated according to each consumer category's contribution towards individual peak. Domestic and small industrial tariffs likely represent a lower bound relative to tariffs calculated using a cost-cascading approach while large industrial tariffs likely represent an upper bound relative to tariffs calculated using a cost-casading approach. Costs attributable to domestic and small industrial consumers are calculated per consumer. All costs attributable to Large Industrial users are per kVA of Maximum Import Capacity (MIC)

Taking Table 10 and Table 13 together, we calculate a Coasian tariff that corresponds to a fixed cost portion and an energy cost portion, under the assumption that fixed costs vary with capacity requirement. This is shown in Table 15.

Table 15: Coasian tariff: energy-driven load-related costs

Consumer type	Fixed charge (€)	Energy-related charge (€/kWh)
Domestic	132	0.0072
Small industrial	456	0.0072
Large industrial (MIC)	55	0.0072

Note: Costs allocated according to each consumer category's contribution towards individual peak. Domestic and small industrial tariffs likely represent a lower bound relative to tariffs calculated using a cost-cascading approach while large industrial tariffs likely represent an upper bound relative to tariffs calculated using a cost-cascading approach. Fixed costs attributable to domestic and small industrial consumers are calculated per consumer. Fixed costs attributable to Large Industrial users are per kVA of Maximum Import Capacity (MIC)

5. Conclusion

This paper has calculated cost-reflective Coasian tariffs for Irish Distribution Use of System (DUoS) charges. Building on the work of Farrell and Meles (2023), we have calculated representative tariffs for domestic, small industrial and large industrial consumers. While these tariffs are indicative and limited by data availability, a number of important findings emerge. A tariff reform on Coasian principles leads to an increase in the fixed portion of the DUoS tariff and a corresponding reduction in the components that vary with either energy use or capacity burden. This reflects the fact that much of the costs for the Irish distribution network are invariant to changes in energy or capacity.

It is important to point out some factors that drive these results and how they differ from comparable studies, such as that of Farrell and Meles (2023). In particular, there is an assumption in these calculations that costs are allocated between consumer groups according to each group's contribution towards individual peak. This differs from the calculated Coasian tariffs of Farrell and Meles (2023), who concentrate on domestic consumers and assume that cost apportionment to this consumer category stays constant. It should also be noted that consumer numbers, sourced from CRU (2019-2022) include transmission-connected sites, so calculated Distribution Use of System Tariffs for large industrial users therefore represent a lower bound on the likely values.

Nevertheless, there are a number of important findings from this research. This analysis shows that distribution network costs are driven primarily by non load-varying components. This motivates a switch in emphasis from energy-related charges in the current DUoS tariff design towards more fixed or capacity-related tariff structures. We have shown the potential change in strucure for domestic, small industrial and large industrial users as a result of such a change. There is a plausible argument in favour of both energy or capacity-related charges to recover load-varying costs. Our preferred results relate to capacity-related charges. Further work should consider a more precise specification of capacity charges, possibly incorporating time of use consumption data, such that capacity charges can be directly linked with each user's impact on the capacity requirement in the system. This would be an important step in ensuring that not only are tariffs cost-reflective but that they incentivise efficient use and capacity provision for the electricity distribution network.

removing energy-related charges and to recover load-related charges via a capacity-related charge. Should this be allocated on the basis of nameplate capacity, and should fixed charges also be allocated by consumer category on the basis of contribution towards individual peak, this essentially results in all network costs being recovered via a nameplate capacity charge.

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