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The equity and efficiency of electricity network tariffs

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Abstract

We estimate the welfare implications of a cost-reflective 'Coasian' reform of electricity network tariffs using an Irish case study. We find that current Distribution Use of System (DUoS) tariffs deviate considerably from a cost-reflective structure. At the individual level, tariff reform leads to large welfare changes. However, positive welfare effects are largely cancelled out by negative welfare effects resulting in a small net welfare impacts in aggregate, up to €33 million. The distribution of incidence is strongly regressive. Households in the lowest income decile incur losses of up to €40 per annum while households in the highest income decile benefit by up to €62 per annum. Despite these effects, we show that inefficient DUoS tariffs represent a costly distributional policy. We demonstrate that it is more efficient to counter the regressive effects through the tax-benefit system.

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

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

1. Introduction

Marginal cost pricing is a fundamental tenet of efficient allocation; consumers buy according to their preferences at prices that reflect the scarcity of supply. For utilities with high fixed costs, such as electricity networks, marginal cost pricing often leads to an under-recovery of total costs. Multi-part 'Coasian' pricing facilitates marginal cost pricing in such circumstances; a volumetric tariff is set equal to marginal cost to recover operating costs while a fixed 'standing charge' recovers fixed costs (Coase, 1946; Borenstein, 2012b; Farrell, 2021).

This paper considers the design of a Coasian tariff for electricity network cost-recovery, where costs are potentially determined by marginal, fixed and capacity-related components. We explore Distribution Use of System (DUoS) costs which are levied by the distribution network operator, via suppliers, on consumers. Using an Irish case study, we compare the welfare effects of switching the existing DUoS tariff structure to the less-distortive Coasian alternative. A Coasian DUoS tariff differs substantially from existing DUoS tariffs. At the individual level, tariff reform leads to large welfare changes. However, positive welfare effects are largely cancelled out by negative welfare effects resulting in a small net welfare impacts in aggregate, up to €33 million. This is due to the relatively small change in the volumetric portion of the tariff, resulting in a relatively small demand response and therefore small change in consumer surplus. There is a relatively large increase in standing charges under a Coasian reform which drives a regressive impact; households in the lowest income decile lose out by up to €40 per annum while households in the highest income decile benefit by up to €62 per annum. Despite these effects, we show that inefficient DUoS tariffs represent a costly distributional policy. We demonstrate that it is more efficient to counter the regressive effects through the tax-benefit system.

This analysis builds on a wide body of work. Reviewed by Farrell (2021), a theoretical literature emerged in the early 20^{th} Century to identify the most efficient tariff structure conditional on full cost recovery. Many potential tariff designs were considered, beginning with a discriminatory mark-up inversely proportional to a consumer's price elasticity of demand (i.e. 'Ramsey-Boiteaux pricing') (Ramsey, 1927; Boiteux, 1956). While theoretically attractive, Ramsey-Boiteaux pricing is difficult to implement in practice as a consumer's price elasticity is often unobservable, while discriminatory tariffs may create distributional concerns (Ji et al., 2022). This literature soon converged on multi-part tariffs to preserve the marginal cost principle. The 'Hotelling-Lerner' solution was the first such attempt, where fixed costs are recovered through additional tax receipts (Hotelling, 1939; Lerner, 1944). Coase (1946) disputed the merits of this solution as it distorts resource allocation and redistributes income. The 'Coasian tariff' solution advocated fixed cost recovery through a standing charge in a two-part tariff. This is often cited as the least-distortive solution to utility pricing and many utilities have since followed this tariff structure (Borenstein, 2016).

While utilities in many markets have adopted a two-part tariff (Farrell, 2021; Farrell and Lyons, 2015; Borenstein, 2012b; Porcher, 2014), they do not 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. Much research exists to estimate these welfare effects in various contexts (for a review, see Farrell, 2021). Inefficient tariffs can distort decision making at the both the intensive and extensive margin. Welfare losses arising from distortions at the intensive margin have been estimated 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 at the intensive margin due to non-linear electricity pricing in the US, while Borenstein and Davis (2012) estimates welfare losses for US gas prices.

A number of studies assess welfare losses arising from distortions at the extensive margin. Borenstein and Davis (2012) 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. Changes at the extensive margin are of particular interest as electricity systems decarbonise. Inefficient tariffs may distort a consumer's decision to install their own distributed generation source, such as solar photovoltaic. While the decision to invest has not been considered in the literature to date, Farrell (2021) consider the distribution of welfare that results, finding that if volumetric tariffs exceed marginal cost then this may lead to a redistribution of welfare from non-adopters to adopters.

Much less work has been carried out on network tariffs and the welfare impacts of Coasian departure. In many markets, the electricity tariff faced by the final consumer is comprised of constituent charges levied at the supplier level. These include charges by distribution and transmission network operators for use of their network assets. For distribution networks, these are known as 'Distribution Use of System, or DUoS, costs. These charges are subsequently passed on to consumers as a component of their final electricity tariff. In many instances, the method with which these costs are to be recovered through the final electricity tariff is specified explicitly by the network operator. This is the case in Ireland (see Commission for Regulation of Utilities, 2015b).

In setting these charges, many regulators and systems operators have a stated objective to offer 'cost-reflective' network tariffs (Australian Energy Market Commission, 2014; Lo Schiavo and Regalini, 2018; Europe Economics, 2021; Ofgem, 2017a,b)[1]. In the pursuit of this objective, network operators have commissioned a number of studies in the 'grey literature', estimating these welfare effects. It is these studies that provide the closest contribution to this paper, with Australian Energy Market Commission (2014) providing a review of relevant studies. NERA Economic Consulting (2014) estimate efficient network tariffs for Australia, who incorporate capacity-related charges in proposed mulit-part network tariffs. Europe Economics (2021) provide a review of network tariff structures in various countries.

[1]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' Australian Energy Market Commission (2014).

Indeed, the use of a capacity-related charge is generally less common in the Coasian tariff literature, with analyses to date focussing on the relative balance between fixed and volumetric components (e.g. Borenstein, 2012a; Borenstein and Davis, 2012; **?**). Many system costs are driven by capacity and this is a particular concern for electricity networks, with tariffs in many jurisdictions incorporating such charges (Europe Economics, 2021). Indeed, capacity-related costs are particularly important for distribution networks. In the Italian system, for instance, distribution and transmission network costs are recovered through energy (volumetric), capacity and fixed components. The volumetric term is predominant, primarily covering transmission costs. A fixed charge covers metering and measurement costs (and a very small amount of distribution costs). Distribution costs are mostly recovered through the capacity charge which is based on peak demand (€/kW) for that consumer. The capacity term is based on the size of connection rather than measurements (Europe Economics, 2021).

The rationale for levying distribution costs through a capacity, rather than energy, charge is not covered by Europe Economics (2021), however, many argue that the costs of the distribution network, as a lower capacity network, are driven to a greater extent by capacity requirements rather than energy flows. Following Coasian principles, it would then be cost-reflective to levy these costs as a function of capacity. Indeed, this was the rationale for the removal of combinations of volumetric and capacity tariffs for they levying of distribution network costs on consumers in the Netherlands. It was determined that a flat capacity charge better reflected the peak demand driver of distribution network costs, which, in turn, is is strongly linked to capacity requirements (Europe Economics, 2021).

While analyses and reviews, such as that of Europe Economics (2021), explore the cost-reflective nature of distribution tariffs, they do not give insight into potential welfare losses arising from a Coasian cost-reflective departure. This paper provides this contribution using an Irish case study. To carry this out, we first construct an efficient distribution network tariff for Ireland using published data on distribution network cost-recovery.[2] Next, we combine household level consumption data with data on electricity tariffs to calculate the counterfactual electricity demand under a revenue-neutral Coasian tariff reform. We calculate welfare changes and distributional effects.

This paper is structured as follows. Section 2 provides insight into the institutional background for establishing network tariffs in Ireland. Section 3 presents the methods and data, including calculating a Coasian distribution network tariff for the considered Irish case study. Section 4 provides results of the main analysis. We estimate the welfare impacts of a Coasian distribution network tariff reform. Section 5 concludes the paper.

2. Institutional background

Electricity networks in many markets can be broken down into transmission and distribution networks. The transmission network is the high voltage system usually used for moving electricity across long distances. The distribution network is a lower voltage system used to move electricity across shorter distances. The transmission network is often managed by a transmission system operator (TSO), while the distribution network is often managed by a distribution system operator. In Ireland, ESB Networks is the DSO while Eirgrid is the TSO.

Distribution System Operators (DSOs) in many countries, including Ireland (Commission for Regulation of Utilities, 2022a) and Great Britain (Ofgem, 2014, 2017a), operate as a regulated monopoly. The network operator is either publicly or privately-owned, with the allowed revenues determined by a regulatory process. In Ireland, revenues are regulated by the Commission for the Regulation of Utilities (CRU) (Commission for Regulation of Utilities, 2022a). The CRU sets a five-year revenue allowance for both distribution and transmission companies through what is called a Price Review in Electricity. This process is currently in its fifth iteration, with Price Review 5 (PR5) covering the 2021-2025 period (Commission for Regulation of Utilities, 2021).

[2] We would like to thank ESB Networks for aiding us in navigating relevant network cost data

The price review process begins with the CRU considering the revenue business cases put forward by the network company. This business case outlines their required spend. In addition, the CRU review the expenditure incurred by the network company during the previous five-year period to assess the efficient delivery of agreed outputs during that period (Commission for Regulation of Utilities, 2022a). When the initial review period is complete, the CRU publishes a consultation paper. This sets out the revenue that the network companies should recover through consumer charges over the forthcoming five-year period. The consultation paper seeks the views of relevant stakeholders and, having considered these responses, the CRU then publish a ‘Final Determination Paper’ on DSO Revenue (Commission for Regulation of Utilities, 2015a, 2021) accompanied by an Excel Revenue Model. The Revenue Model outlines all capital and operating costs, alongside consumer contributions (consumer connection charges, generator connection charges and repayable line diversions) expected over the forthcoming five-year period.

The five-year revenue allowance is split into annual allowances. A number of adjustments are made to these allowances. First, the price control process sets incentives for efficiency by reducing the allowed revenues by a certain factor. These incentives are designed to encourage the network companies to manage the network as efficiently as possible. Second, an adjustment is made to equalise revenues across time periods to avoid volatility in network charges. Once these allowed revenues have been established, the DSO in conjunction with the regulator issue annual ’Distribution Use of System (DUoS)’ charges (Commission for Regulation of Utilities, 2015c). These charges stipulate the manner in which distribution network charges are to be recovered by suppliers from the final consumer. Each consumer type, delineated according to peak load (‘maximum import capacity’), is assigned a separate tariff. This tariff is a constituent component of the final tariff received by the consumer.

3. Materials and methods

The purpose of this analysis is to consider the welfare implications of reforming Irish distribution network tariffs for residential consumers on Coasian principles. We consider a revenue-neutral reform of the tariff structure, where the total cost currently recovered from residential consumers remains constant. There is an implicit assumption that changes in DUoS tariffs are passed on to consumers in direct proportion to the changes in DUoS tariff structure. Currently, retail electricity suppliers are not obliged to reflect these changes in retail tariffs. The implications of this assumption will be discussed further in Sections 4 and 5. To carry out the analysis of this paper, we must calculate a Coasian tariff based on the identified distribution network cost structure. Then, the welfare impact of reform is simulated.

3.1. Calculating a Coasian DUoS tariff

To calculate a Coasian DUoS tariff, we must first identify the cost components that vary with the quantity of electricity consumed, the capacity of the system and those that vary with neither of these factors. This calculation comprises a number of constituent steps. First, total costs are broken down to operating and capital costs. This aids identification of cost components. Second, we then disaggregate each of these components into constituent cost components. For each component, we identify whether it is fixed or varies with either the volume of electricity consumed or network capacity.[3] Third, based on these categorisations, we calculate how much of the total network cost should be recovered via either energy, capacity or fixed charges. Fourth, the efficient Coasian tariff is constructed. Each step will now be outlined in turn.

3.1.1. Step 1: Fixed and operating cost identification

The first step is to break down total costs into fixed and operating components. For this calculation, we consider costs for two regulatory periods: the 2016-2020 PR4 (Price Review 4) regulatory

[3]These steps of disaggregating and identifying fixed, energy-varying and capacity-varying components have been informed by discussions with ESB Networks

period (Commission for Regulation of Utilities, 2015a) and the 2020-2025 PR5 (Price Review 5) regulatory period (Commission for Regulation of Utilities, 2021). The reason for doing so is as follows. While energy costs are directly related to the volume of energy transmitted within a given regulatory period, and are therefore easy to identify, fixed and capacity-related costs relate to long-term expenditures and are more difficult to attribute to a given time period. Should the energy, capacity and fixed cost components be similar across both price review periods, then we are confident that a given period's capital expenditure is representative of the longer-term cost share.

In addition, we consider capital costs according to the allowed return on asset base, as opposed to period-specific asset expenditure. This metric is less-sensitive to period-specific expenditures, representing that period's share of longer-term costs associated with the entire asset base.

Table 1 shows the allowed DSO revenues for the 2016-2020 PR4 (Price Review 4) regulatory period Commission for Regulation of Utilities (2015a) and the 2020-2025 PR5 (Price Review 5) regulatory period Commission for Regulation of Utilities (2021), respectively. Costs incurred are presented according to categories of operating expenditure; capital cost recovery; depreciation; previous period adjustments and 'incentives and innovation'.[4] Operating expenditures are explicitly categorised. All other costs are capital costs (see Appendix A for further investigation to confirm this). Considering these categorisations, Table 2 shows the proportional breakdown according to fixed and operating components for both PR4 and PR5 periods, alongside an average of both. This concludes the first step of the Coasian tariff specification process.

[4]Previous period adjustments indicate discrepancies between expected and actual expenditures as allowed revenues are calculated ex-ante. These differences are recovered through an adjustment in the following period.

Table 1: DSO allowed revenue 2016-2020 (PR4) and 2021-2026 (PR5)[a]

Description	2016-2020 (PR4)		2021-2025 (PR4)	
	€million	% of total	€million	% of total
Operating expenditure	1,362	33.01%	1,632	35.85%
Weighted Average Cost of Capital (WACC)	1,379	33.42%	1,224	26.89%
Depreciation	1,196	28.99%	1,755	38.55%
PR3/PR4 adjustment	48.8	1.18%	-59	-1.30%
Incentives and innovation	140	3.39%	0	0.00%

[a]Note: For the 2016-2020 (PR4), values are in 2014 terms and are as listed in the PR4 decision paper (Commission for Regulation of Utilities, 2015a). Please see Commission for Regulation of Utilities (2015a) for further details. Similarly, For the 2021-2025 (PR5), values are as listed in 2019 cost terms in the PR5 decision paper (Commission for Regulation of Utilities, 2021). Please see Commission for Regulation of Utilities (2021) 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[b]

	2016-2020	2021-2025	Average
Capital expenditure	66.99%	64.15%	65.57%
Operating expenditure	33.01%	34.56%	34.43%

[b]Note: Authors' calculations based on cost components in Table 1

3.1.2. Step 2: Operating and capital cost disaggregration

Having identified operating and capital cost components, we then disaggregate each of these into fixed, capacity-varying and energy-varying components.[5]

We first disaggregate operating cost into its components. Table 3 reports the average operating costs by category for each Price Review determination period, where cost categories cover various aspects of business performance. These costs are associated with adminstration and day-to-day operation. Should there be a marginal change in system energy consumption or capacity, this is likely to have a negligible impact on these costs.[6] These are therefore assumed independent of the

[5]This process was informed by consultation with the Distribution System Operator, ESB Networks. We also consulted the PR4 and PR5 Final Determination Papers and the accompanying Distribution System Operator (DSO) Excel Revenue Models (Commission for Regulation of Utilities, 2015a, 2021). The revenue models outline all capital and operating costs, alongside consumer contributions (consumer connection charges, generator connection charges and repayable line diversions) incurred by year.

[6]While it may be the case that a greater network capacity may require greater maintenance costs, this is likely to

amount of energy sold or capacity of the system and assumed to form part of the fixed tariff.

Table 3: Total operating expenditure by determination period[c]

Operating expenditure	2016-2020 (€million)	2021-2025 (€million)
Network O&M	537.7	627
Asset Management	72.2	107.3
Metering	167.2	88.7
Smart Metering OPEX		59.1
Customer Service	85	123.8
Provision of information	53.7	65.7
Commercial	0	0
Sustainability and R&D	11.1	20
Other (admin; insurance network rates	434.7	540.2
	1361.6	1631.8

[c]Note: 2016-2020 values are in 2014 terms and are as listed in the PR4 decision paper (Commission for Regulation of Utilities, 2015a). They have not been adjusted for outturn, yearly updates or inflation. Please see Commission for Regulation of Utilities (2015a) for further details. 2021-2025 values are as listed in the PR5 decision paper (Commission for Regulation of Utilities, 2021). They have not been adjusted for outturn, yearly updates or inflation. Please see Commission for Regulation of Utilities (2021) for further details.

Next, we disaggregate capital cost into fixed, capacity-related and energy-related components in Table 4. Each cost component will be discussed in turn. Load-related capital expenditure relates to the connection of new consumers (Commission for Regulation of Utilities, 2015a, 2021). This varies with the volume of electricity consumed. It may plausibly be driven by either energy or capacity requirements. As the review of Section 1 has discussed, there is a precedent to interpret such costs as varying with capacity when discussing DSO costs (see Europe Economics, 2021). We follow this precedent for our primary results. We carry out a sensitivity analysis which defines this as an energy-related cost.

Non-load related capital expenditures comprise network upgrades primarily attributable to a renewable energy program (Commission for Regulation of Utilities, 2015a, 2021) and general infrastructural investments unrelated to changes in load. This cost category is therefore assumed to

be a small portion of total maintenance costs and is therefore assumed negligible comprise part of the fixed tariff. Non-network capital expenditure is related to generation-related upgrades and therefore unrelated to consumption and assumed part of the fixed tariff (Commission for Regulation of Utilities, 2015a, 2021). Similarly, smart-metering expenditures are not energy or capacity-varying and assumed to comprise part of the fixed tariff.

Table 4: PR4 and PR5 Capital Expenditure Breakdown[d]

Capital expenditure	2016-2020 (€million)	2021-2025 (€million)
Load related capital expenditure	950.9	1391.2
Non-load related capital expenditure	475.9	693.8
Non-network capital expenditure	196.7	322
Smart metering	265.6	882
Contributions	-351.5	-445.6

[d]Source: Data sourced from Commission for Regulation of Utilities (2021). PR4 calculations account for an underspend in smart metering relative to budgeted amounts contained within Commission for Regulation of Utilities (2015a).

One should note that there are 'contributions' noted in Table 4. These contributions are payments made by customers for services rendered by the DSO which must be deducted from the appropriate cost component to ensure accurate tariff calculation. The contributions comprise the following components: customer contributions; contributions received for generation connections; capital grants; and repayable line diversions.

Customer contributions are contributions made by consumers towards connection to the network and partially offset load-related capital expenditure. Generator connections and repayable line diversions also partially offset load-related capital expenditure, a per the PR5 revenue model (Commission for Regulation of Utilities, 2021). Capital grants offset fixed costs and are contributions received during the PR4 period only. The resulting disaggregation of 'contributions' among subcategories is shown in Table 5. Incorporating the breakdown of contributions from Table 5, we update the breakdown of capital costs into fixed and energy/capacity components in Table 6.

Table 5: Contribution breakdown[e]

Category	PR4	PR5
Customer contributions	63%	56%
Generator connections	27%	31%
Repayable line diversions		13%
Capital grants	10%	

[e]Source: Data from Commission for Regulation of Utilities (2015a) and Commission for Regulation of Utilities (2021) and the accompanying excel models. PR4 contributions also include 'interest during construction' but as this was zero throughout the duration of the determination period, this was excluded.

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

Category	PR4		PR5	
Load-related capital expenditure		950		1391
Less customer, generator and line-diversion contributions		-316		-388
Net load-related capital expenditure		634		1003
Non load-related capital expenditure	476		694	
Non network capital expenditure	197		322	
Smart metering	266	939	882	1898
Less remaining contributions		-35		-58
Net non load-varying capital expenditure		904		1840

3.1.3. Step 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. The preceding discussion has identified that all operating costs and non load-varying capital costs are to be recovered via the fixed charge. However, load-varying capital costs may be plausibly recovered by either a capacity or energy charge.

TThe 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. While operating costs increase in PR5, this is countered by a reducution in the fixed portion of capital costs. As such, the energy capacity/component is stable across periods of analysis. Having identified the proportion of total costs to be recovered via a fixed charge and the proportion to be recovered by either an energy or capacity charge, the next section will specify the cost-reflective tariff at the household-level.

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

Category	PR4 €million	%	PR5 €million	%	Average %
Operating cost (fixed)	1362	47%	1632	36%	42%
Capital cost (fixed)	904	31%	1840	41%	36%
Capital cost (energy/capacity)	634	22%	1003	22%	22%

3.2. Calculation of Coasian tariff

The previous section identified the proportion of total costs to be recovered by either fixed or variable tariff components. The next stage is to specify a tariff that facilitates such cost recovery. In this paper, we focus on domestic consumption and we therefore specify a revenue-neutral reform by calculating the total revenues consumed by a sample profile of domestic households and then re-calculating the network tariffs such that 22% of total costs are recovered through energy/capacity charges and 78% through fixed charges. To do so, we must divide the total fixed costs by the number of consumers in our profile of households. Similarly, the total variable costs must be divided by either the number of units consumed or an appropriate metric of each consumer's contribution towards the total capacity requirement.

The 2015/2016 Irish Household Budget Survey (HBS) provides the sample of households used in our analysis[7] (Central Statistics Office, 2017). The Household Budget Survey (HBS) provides a representative sample of income, electricity expenditure and other socio-demographic characteristics for the population of 1.7 million Irish households. Table 8 provides some summary statistics of the main variables of interests by quintile of disposable income. One can see that while electricity consumption is correlated with income, the burden is much greater for low-income households.

[7] Accessed via the Irish Social Science Data Archive - www.ucd.ie/issda.

Distributional concerns surrounding a switch to a Coasian tariff therefore warrant further investigation.

Table 8: Descriptive statistics of household characteristics by quintile of disposal income[f]

Variables	First	Second	Third	Fourth	Fifth	Total
Disposable income (weekly)	257.69	516.05	769.37	1097.56	1842.78	911.55
	(81.30)	(68.14)	(77.47)	(111.44)	(708.56)	(644.77)
Total weekly expenditure	353.11	544.24	743.03	1002.00	1490.61	837.47
	(301.98)	(316.54)	(372.49)	(395.71)	(637.73)	(583.07)
Electricity expend. (weekly)	12.86	15.95	18.32	20.31	22.93	18.17
	(9.69)	(11.00)	(11.13)	(11.31)	(11.61)	(11.52)
Income share of electricity expend.	0.08	0.03	0.02	0.02	0.01	0.03
	(0.27)	(0.02)	(0.01)	(0.01)	(0.01)	(0.12)
Household size	1.44	2.26	2.80	3.33	3.71	2.73
	(0.80)	(1.09)	(1.32)	(1.39)	(1.41)	(1.47)
No. of children	0.11	0.37	0.62	0.76	0.90	0.56
	(0.44)	(0.77)	(0.96)	(1.08)	(1.15)	(0.96)
No. of adults	1.33	1.89	2.18	2.56	2.81	2.17
	(0.62)	(0.78)	(0.86)	(1.00)	(1.15)	(1.04)
No. of persons at work	0.24	0.57	1.09	1.59	2.01	1.12
	(0.50)	(0.68)	(0.79)	(0.82)	(0.86)	(0.99)
Home owner	0.47	0.46	0.34	0.30	0.27	0.36
	(0.50)	(0.50)	(0.47)	(0.46)	(0.45)	(0.48)
Washing machine	0.91	0.98	0.99	1.00	1.00	0.98
	(0.28)	(0.14)	(0.12)	(0.07)	(0.05)	(0.16)
Dish washer	0.37	0.54	0.65	0.77	0.88	0.65
	(0.48)	(0.50)	(0.48)	(0.42)	(0.32)	(0.48)
Observations	1,368	1,368	1,368	1,368	1,367	6,839

[f]Data source: 2015/2016 Irish Household Budget Survey. Table 8 provides the weighted average values by quintile of household disposal income, with standard deviations in parentheses.

The HBS data contains information on electricity expenditure. Recall, we need to identify the total amount levied on this cohort in lieu of DUoS tariffs. We therefore combine these data with electricity tariff data to disaggregate this monetary expenditure according to constituent tariff components. This information is not contained within the HBS so we match each household with a representative electricity tariff.

We source historical tariff information to identify what tariffs were available during the 2015/16 time period. Ireland's retail electricity market was dominated by four suppliers during this time: Electric Ireland, Bord Gais, SSE Airtricity and Energia. An internet archive provides a snapshot of published tariffs at a given moment. For each supplier, we collect the archived tariff snapshot that is closest to the 2015/16 HBS sample period.[8] We weigh each tariff by market share to create a composite that reflects the relative weighting of charges faced by households. This process is outlined in full in Farrell and Humes (2022) with the set of representative tariffs employed shown in Table 9.

Households may be subject to either a standard tariff or a 'Nightsaver' tariff. Under a standard tariff, all units consumed have the same volumetric price. Under a 'NightSaver' tariff, day and night consumption are subject to different prices. The final step is to assign a standard or 'Nightsaver' tariff to a household. The HBS does not provide information on whether a household is using the standard or Nightsaver tariff. Following Farrell (2021) and Centre for Sustainable Energy (2016), we use electric heating as a proxy for being on the NightSaver tariff, as the day/night meter is generally recommended for those with electric storage heaters. When calculating consumption, We assume 60% peak and 40% off-peak usage, following the assumptions of Farrell (2021) and Centre for Sustainable Energy (2016). A sensitivity analysis on this assumption is also carried out by Farrell and Humes (2022), demonstrating that the conclusions of analyses such as that presented in this paper are insensitive to variations to these assumptions. Finally, urban and rural households face different tariffs. The HBS contains an urban/rural indicator and this is used to assign the appropriate tariff to households.

Alongside a standing charge and a volumetric charge, electricity tariffs in Ireland include a Public Service Obligation (PSO) levy. This is charged to all electricity customers to support price supports for renewable energy, indigenous fuels (peat) and security of energy supply provisions

[8]For Electric Ireland, tariffs are sourced from September 2014 [Standard] and September 2015 [NightSaver]; for SSE Airtricity, rates are for April 2015; for Bord Gais, rates are for March 2015; for Energia, rates are for November 2017

Table 9: Representative electricity tariffs (2015/2016)[g]

Tariff category	Volumetric charge (€/kWh)		Standing charge
	Day	Night	(€/household/week)
Urban Standard	0.1907	0.1907	2.80
Rural Standard	0.1914	0.1914	3.65
Urban Nightsaver	0.2016	0.0996	3.76
Rural Nightsaver	0.2022	0.0998	4.71

[g]Note: Tariffs calculated using retail price data from Ireland's three primary electricity suppliers in 2015/16, sourced from Internet Archive (2022). Please see Farrell and Humes (2022) for a full outline of the data collection and representative tariff calculation process.

(Commission for Regulation of Utilities, 2015b). The PSO levy must also be considered when calculating the quantity of electricity consumed. Using published information from the Commission for the Regulation of Utilities, the PSO levy was €1.34/week/household (€5.36/month/household) from 1st October 2014 to 30th of September 2015 (Commission for Regulation of Utilities, 2014) and €1.25/week/household (€5.01/month/household) for the period covering 1st October 2015 – 30th of September 2016 (Commission for Regulation of Utilities, 2015b). The relevant PSO levy for each household is assigned based on the survey period noted in the HBS.

The tariffs of Table 9 are used to calculate the units consumed by each household. For each household, the standing charge and appropriate Public Service Obligation levy are subtracted from total expenditure and the remaining expenditure is divided by the appropriate volumetric tariff to identify the number of units consumed.[9].

When calculating units consumed, any social assistance must be accounted for. Certain vulnerable households are recipients of the household benefits package (HHB). HHB comprises an electricity or gas allowance, and a free television licence. To cover fuel costs, the allowance is €1.15 per day (Citizen's Information Board, 2021). Households eligible for the HHB are therefore assumed to spend an additional €8.05 per week on electricity.

[9]For nightsaver consumers, a weighted tariff reflecting the assumed share of consumption is used to simplify this calculation. This is equivalent to: $\frac{expenditure}{(NightTariff*0.4)+(DayTariff*0.6)}$

Having identified the units consumed and the tariff faced by each household, we must simulate a tariff reform. To do this, we isolate the distribution network charges levied on each supplier for each household. We use the published Distribution Use of System (DUoS) charges for 2015/2016 (Commission for Regulation of Utilities, 2015c). Domestic consumer charges, including VAT at 13.5%, are outlined in Table 10.

Table 10: Electricity network tariffs in 2015/2016 (including 13.5% VAT)[h]

Tariff category	volumetric charge (€/kWh)		Standing charge
	Day	Night	(€/household/week)
Urban Standard	0.0428	0.0428	1.38
Rural Standard	0.0428	0.0428	2.00
Urban Nightsaver	0.0525	0.0067	1.38
Rural Nightsaver	0.0525	0.0067	2.01

[h]Note: Distribution Use of System Tariffs sourced from Commission for Regulation of Utilities (2015c).

Section 3 has illustrated that a Coasian distribution network tariff in Ireland comprises a charge where 78% of costs are recovered via the standing charge and 22% of costs are recovered via either a volumetric or capacity charge. We simulate a revenue-neutral reform of the DUoS tariffs these principles and assume that this change in reflected in the final retail tariffs (the implications of this assumption will be discussed in Sections 4 and 5). We calculate the sum total of revenue to be recovered from each household in the HBS data. 22% of this is to be recovered via a volumetric/capacity charge and 78% to be recovered via a standing charge.

Should an energy charge be in place, we take the sum total of volumetric-apportioned revenue and divide by the number of units consumed in the dataset.[10] Should a capacity charge be in place, we take the sum total of capacity-apportioned revenue and apportion according to capacity. There are many ways to do this. Ideally, this would be a function of the capacity requirement of each

[10]One must account for a demand response to ensure a revenue-neutral reform; as the price surcharge increases, demand falls (and revenue falls) if the price elasticity of demand is non-zero. To account for this, an iterative procedure is employed; the levied surcharge increases incrementally from the revenue-neutral surcharge imposed when no demand response is in place. This continues until the total revenue recovered is equal to that of the uniform consumer levy. This procedure is repeated under each assumed price elasticity of demand.

home. This information is unobservable in the current data. Instead, we apportion according to the nameplate capacity for each domestic consumer, which is uniform. This follows the precedent in capacity-based cost allocation taken by the Irish regulator in many tariff-related decisions (Commission for Regulation of Utilities, 2022b) and also the approach taken for capacity-related charges in jurisdictions such as Italy and the Netherlands Europe Economics (2021).[11] Finally, we take the sum total of fixed-apportioned revenue and divide by the number of households in the dataset. The Coasian tariffs are presented in Section 4.

3.3. Estimating the welfare impact of Coasian reform

This paper employs a simulation-based estimation procedure to estimate welfare change, expanding on the methods of Borenstein (2012b); Borenstein and Davis (2012) and Farrell (2021). The application takes the following constituent steps. A socioeconomic profile of income and electricity consumption is first constructed.

Under the assumption of a revenue-neutral tariff reform, producer surplus remains constant. Welfare change is predicated on changes in consumer surplus only. Should the prices change, household welfare will change according to the change in the standing charge and the change in the volumetric charge. A change in standing charge has a direct impact on welfare equivalent to an increase or decrease in the monetary cost. A change in volumetric charge results in an additional effect due to a demand response; an increase (decrease) in price leads to a decrease (increase) in demand, all else equal. Following Borenstein (2012b); Borenstein and Davis (2012) and Farrell (2021), we assume that Demand by consumer k (D_k) follows an isoelastic demand function:

$$D_i(p) = \alpha_i p^{\epsilon} \tag{1}$$

Where D_i is electricity demand by consumer i at an overall volumetric charge of p. The parameter

[11]The implications of this assumption are discussed in Sections 4 and 5

ϵ is the price elasticity of demand for electricity and α_i is consumer specific constant. The change in consumer surplus for a consumer i is the area under the demand curve bounded by the change in volumetric price (from p_o to p_n), less the change in standing charge (S_o to S_n):

$$\Delta CS_i = \left(\int_0^{p_o} D_i(p_o)\, dp \; - p_o q_o - S_o \right) - \left(\int_0^{p_n} D_i(p_n)\, dp \; - p_n q_n - S_n \right) \tag{2}$$

Based on the demand function specified in equation (1), we calculate the quantity demanded under an alternative network tariffs, assuming a range of demand elasticities. We consider a plausible wide range of long-run elasticites of demand and calculate the resulting change in consumer surplus. The empirical literature on residential electricity demand (e.g., Baker et al., 1989; Espey and Espey, 2004; Labandeira et al., 2017; Ros, 2017) suggests that the long run price elasticity of demand is most likely within a range of -0.3 to -0.8. We consider the entire range of possible elasticities; ϵ=0.0 to ϵ=-0.8. We take the conventional assumption that consumers respond to marginal price. [12]

4. Results

We first present Coasian DUoS tariffs for the considered Irish case study. These are presented in Table 11. For comparison, we restate the 2015/2016 electricity tariff for urban residential consumers. Under the existing distribution tariff structure, approximately 70% of total revenue is recovered via the volumetric charge under this existing tariff structure. As the preceding sections have shown, a Coasian structure requires that at least 78% of distribution network costs should be recovered via the the standing charge. This represents a considerable shift from the prevailing cost-recovery structure. Should load-related costs be recovered via a nameplate capacity charge,

[12] While Ito (2014) finds evidence to suggest consumers respond to average price when faced with complex, non-linear price schedules, Ito and Zhang (2020) find that consumers do respond to marginal price in the presence of a two-part tariff. Following similar analyses (Borenstein, 2012b; Borenstein and Davis, 2012; Farrell, 2021), we follow this precedent.

all costs are de facto recovered via the fixed standing charge.

The impact that this changing pattern of DUoS cost recovery has on electricity tariffs can be seen in Table 11. Focussing on DUoS tariffs, Table 11 shows that the standing charge component increases from €1.38/week to €4.035/week, assuming that load-related costs are recovered using an energy-related charge. This is an increase of almost three times. The volumetric component falls by around 70% to accommodate the changes in the standing charge component, assuming an energy-related charge to recover load-related costs, falling from €0.043/kWh to €0.013/kWh. Should variable costs be recovered via a capacity charge, the standing charge rises to €5.173, an increase of almost four times.

While these are considerable changes to the network charge, these changes translate into relatively small changes when considered in light of the total electricity tariff. Assuming that a utility fully passes these DUoS tariff changes through to the schedule of retail tariffs, the standing charge component increases from €2.80/week to €5.574/week, under energy-based load-related cost recovery. This is an approximate doubling of the cost. This increases to an increase of about 2.3 times under a capacity related charge only, to €6.713. The volumetric component falls by a much lesser amount. Under energy-based load-related cost-recovery, there is a fall in volumetric tariffs of about 16% to counteract the increase in standing charges. This falls by a slightly greater amount, about 23%, under capacity-related cost-recovery. The relatively small change in volumetric charges and relatively large change in standing charges is a key driver in the results relating to consumer welfare that follow.

4.1. Aggregate welfare effect of Coasian tariff reform

We first estimate the impact a Coasian tariff reform may have on consumer welfare on foot of these price changes. We consider reform under both an energy/capacity tariff structure, where load-related costs are recovered via the volumetric price, and a capacity-only tariff structure, where load-related costs are recovered via a nameplate capacity charge. Table 12 presents the results for

Table 11: Weighted average electricity tariffs under existing and Coasian counterfactual structures[i]

Tariff category	Existing	Coasian	
	(urban)	Energy	Capacity only
Network electricity tariff:			
Volumetric charge (€/kWh)	0.043	0.013	0.00
Standing charge (€/week)	1.380	4.035	5.173
Retail electricity tariff:			
Volumetric charge (€/kWh)	0.191	0.160	0.147
Standing charge (€/week)	2.800	5.574	6.713

[i]Data source: Author calculations.

the former scenario, where an energy/capacity network tariff structure is in place. Columns (1) and (2) show the weighted average change in household consumer surplus per week and per year, respectively, while the final column shows the annual total change in welfare. If demand is perfectly inelastic, ($\epsilon = 0.0$), we observe neither gain nor loss in consumer welfare, in aggregate. This is because the switch in levies from those that emphasise the volumetric to those that emphasise the standing charge perfectly offset each other; there is no demand response and therefore no net loss in consumer surplus. However, there are winners and losers; those who consume more electricity tend to benefit as the reduction in volumetric charge outweighs the increase in standing charge. The opposite is true for households who consume lesser amounts of electricity.

In practice, a demand response may be observed. Assuming load-related costs vary with electricity consumption, and that an energy consumption-related tariff is appropriate, Table 12 shows that there is a total annual welfare gain of up to €30 million. Households benefit by up to €18 per annum, on average. Table 12 presents a range of price elasticities. As discussed previously, the empirical literature has found that the expected long-run price elasticity of demand is likely to fall in the rang of -0.3 to -0.8. As such, we would expect the total welfare gain to fall within €10-30m per annum, with households benefitting by €6-18 per annum, on average. The magnitude of this effect is small. This is due to the relatively small change in volumetric price resulting from the

Coasian reform, as discussed when reporting the findings of Table 11.

Table 12: Household welfare change due to Coasian reform when load-related costs are recovered via an energy consumption-levied tariff[j]

	Weighted average per household		Total
Price elasticity	Weekly (€)	Annually (€)	(€m)
(ϵ)	(1)	(2)	(3)
ϵ=0.0	0.00	0.00	0.00
	(1.76)	(91.64)	
ϵ=-0.1	0.04	2.06	3.51
	(1.79)	(93.04)	
ϵ=-0.2	0.08	4.17	7.09
	(1.82)	(94.48)	
ϵ=-0.3	0.12	6.32	10.75
	(1.85)	(95.94)	
ϵ=-0.4	0.16	8.51	14.49
	(1.87)	(97.44)	
ϵ=-0.5	0.21	10.77	18.32
	(1.90)	(98.97)	
ϵ=-0.6	0.25	13.06	22.23
	(1.93)	(100.53)	
ϵ=-0.7	0.30	15.41	26.22
	(1.96)	(102.13)	
ϵ=-0.8	0.34	17.81	30.31
	(2.00)	(103.77)	

[j]Note: Table 12 presents total annual welfare change and weekly weighted average welfare change per household on foot of a Coasian tariff reform under an energy and capacity-based cost recovery scheme. Standard deviations of calculated averages are in parentheses.

In addition to the results of Table 12, we consider welfare change assuming load-related costs are recovered under a capacity-related charge. Table 13 presents the welfare change from this scenario. It can be seen that the welfare impacts are similar under this scenario, with gains of a slightly greater magnitude to be experienced on foot of a tariff reform. As there is a greater switch in the cost emphasis from volumetric to fixed costs, the magnitude of the welfare change is also greater. Table 13 shows that aggregated welfare change is slightly greater, up to €33 m in the case of a price elasticity of -0.8, with expected average welfare change in the range of €7 - €19 per annum.

As discussed in Section 3, a capacity-related charge is our preferred method for load-related cost-recovery and thus the results of Table 13 are our preferred results. However, a comparison of Tables 12 and 13 show that the final result changes by a relatively small amount depending on the nature of the reform.

Table 13: Household welfare change from switching to network electricity tariff when load-related costs are recovered from capacity-related charge[k]

Price elasticities (ϵ)	(1)	(2)	(3)
	Weighted average per household		Total
	Weekly (€)	Annually (€)	(€m)
ϵ=0.0	0.00	0.00	0.00
	(2.54)	(132.00)	
ϵ=-0.1	0.04	2.30	3.91
	(2.57)	(133.57)	
ϵ=-0.2	0.09	4.63	7.88
	(2.60)	(135.17)	
ϵ=-0.3	0.13	7.01	11.93
	(2.63)	(136.80)	
ϵ=-0.4	0.18	9.42	16.04
	(2.66)	(138.46)	
ϵ=-0.5	0.23	11.88	20.21
	(2.69)	(140.14)	
ϵ=-0.6	0.28	14.37	24.46
	(2.73)	(141.85)	
ϵ=-0.7	0.33	16.91	28.78
	(2.76)	(143.59)	
ϵ=-0.8	0.37	19.49	33.18
	(2.80)	(145.37)	

[k]Note: Standard deviations are in parentheses.

4.2. Distributional effect of Coasian tariff reform

Next, we analyse the distributional effects of a Coasian reform. As Table 11 has shown, a Coasian network tariff will result in a greater shift towards standing charges, relative to volumetric-based network charging. This will benefit some consumers and others will lose out.

Table 14 presents these distributional findings, assuming load-related costs are recovered through an energy-related charge. The change in annual welfare is presented by quintile of household disposable income, at different price elasticities of demand. A negative value indicates a welfare loss arising from a Coasian reform, while a positive value indicates a welfare gain.

Table 14: Weighted average annual welfare change by quintile of household disposable income when load-related costs are recovered via an energy consumption-levied tariff[m]

Price elasticities (ϵ)	Quintile of disposable income				
	First	Second	Third	Fourth	Fifth
ϵ=0.0	-28.33	-9.18	-2.01	9.93	27.22
	(78.00)	(87.03)	(91.59)	(93.11)	(97.08)
ϵ=-0.1	-26.72	-7.26	0.03	12.15	29.70
	(79.18)	(88.37)	(92.99)	(94.54)	(98.55)
ϵ=-0.2	-25.07	-5.31	2.12	14.42	32.24
	(80.40)	(89.75)	(94.43)	(95.99)	(100.06)
ϵ=-0.3	-23.39	-3.31	4.25	16.73	34.83
	(81.64)	(91.15)	(95.89)	(97.48)	(101.59)
ϵ=-0.4	-21.67	-1.27	6.43	19.10	37.48
	(82.90)	(92.58)	(97.39)	(99.00)	(103.17)
ϵ=-0.5	-19.91	0.82	8.66	21.52	40.19
	(84.20)	(94.05)	(98.92)	(100.56)	(104.78)
ϵ=-0.6	-18.12	2.95	10.94	23.99	42.95
	(85.53)	(95.55)	(100.49)	(102.15)	(106.42)
ϵ=-0.7	-16.28	5.13	13.26	26.51	45.78
	(86.88)	(97.08)	(102.08)	(103.77)	(108.10)
ϵ=-0.8	-14.41	7.36	15.64	29.10	48.67
	(88.27)	(98.65)	(103.72)	(105.43)	(109.82)

[m]Standard deviations are in parentheses.

If the price elasticity of demand is perfectly inelastic, a Coasian reform leaves low-income households (1^{st}, 2^{nd} and 3^{rd} quintile) worse off, with corresponding weighted average annual welfare loss of €28.33, €9.18, and €2.01, respectively. In contrast, households in the 4^{th} and 5^{th} income quintile are better off, with a weighted average annual welfare gain of about €9.93 and €27.22, respectively. These patterns are driven by the consumption tendencies among low and high income households. The benefit of the Coasian reform at the household level is driven by the quantity of electricity consumed. Low income households consume less electricity, on average, and therefore

Table 15: Weighted average annual welfare change by quintile of household disposable income when load-related costs are recovered via a capacity-based tariff[m]

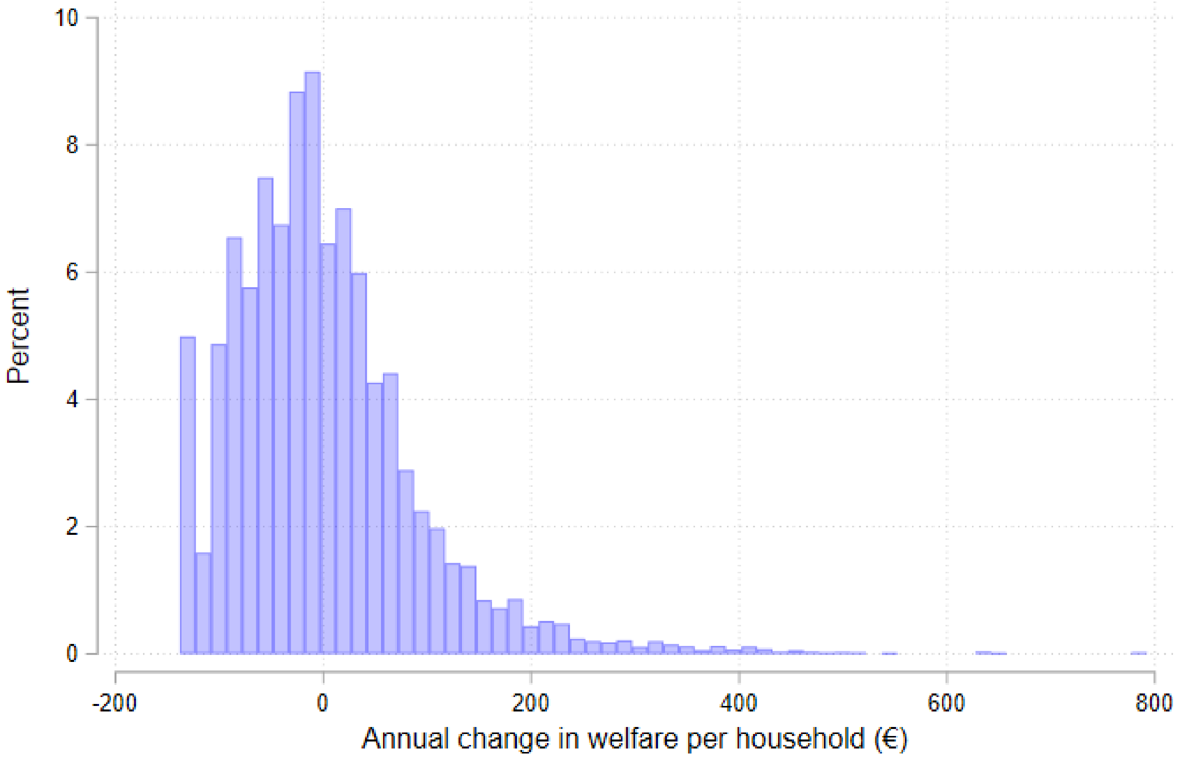
Price elasticities (ϵ)	Quintile of disposable income				
	First	Second	Third	Fourth	Fifth
ϵ=0.0	-40.70	-13.12	-2.47	14.11	38.81
	(112.82)	(126.34)	(131.88)	(133.75)	(139.22)
ϵ=-0.1	-38.90	-10.99	-0.19	16.59	41.58
	(114.15)	(127.85)	(133.45)	(135.35)	(140.87)
ϵ=-0.2	-37.08	-8.82	2.12	19.10	44.39
	(115.51)	(129.38)	(135.05)	(136.98)	(142.55)
ϵ=-0.3	-35.23	-6.62	4.47	21.66	47.26
	(116.89)	(130.94)	(136.68)	(138.63)	(144.26)
ϵ=-0.4	-33.34	-4.38	6.86	24.26	50.17
	(118.30)	(132.52)	(138.34)	(140.31)	(146.00)
ϵ=-0.5	-31.43	-2.10	9.30	26.90	53.13
	(119.72)	(134.14)	(140.02)	(142.03)	(147.77)
ϵ=-0.6	-29.48	0.21	11.77	29.59	56.14
	(121.18)	(135.77)	(141.73)	(143.77)	(149.56)
ϵ=-0.7	-27.50	2.57	14.29	32.33	59.20
	(122.65)	(137.44)	(143.48)	(145.54)	(151.39)
ϵ=-0.8	-25.49	4.96	16.84	35.11	62.32
	(124.16)	(139.14)	(145.25)	(147.34)	(153.25)

[m]Standard deviations are in parentheses.

the increase in standing charge outweighs the reduction in volumetric charge, on average. The converse is true for households in high income groups, where the reduction in price outweighs the increased standing charge.

The distribution of welfare impacts, assuming perfectly-inelastic demand and load-related cost-recovery via an energy-related charge, is shown in Figure 1. While the average consumer incurs a loss of zero, one can see that the distribution is skewed towards those who incur a loss, rather than those who incur a benefit. The median impact under an inelastic demand profile is a net loss of €11 per annum, extending to €98 at the lowest 10 percentile. On the other hand, those in the 90th percentile benefit by up to €106 per annum.

Figure 1: Distribution of welfare change when load-related costs are recovered through an energy-related charge[l]



[l]Data source: Authors' calculations.

Interestingly, the loss to low income households is, on average, similar to the gain for households in the top income quintiles under perfect inelasticity. The ordinal ranking of effects remains if consumers are more price elastic, however the magnitude of the effect changes. As consumption becomes increasingly responsive to changes in prices, low income groups lose out to a lesser extent, while high income groups gain to a greater extent. This is because the impact of reducing the volumetric price is having a greater effect with a greater price elasticity of demand. For low income groups, this is compensating for the added cost somewhat, but not entirely. For high income groups, this is exaggerating what is already a net benefit.

As stated previously, the empirical literature suggests that the long-run price elasticity of demand is expected to be in the range of -0.3 to -0.8. As such, the poorest income quintile is expected to lose out by around €14-23/annum, while the richest income quintile is likely to gain by around €34-48/annum.

As before, we also consider the distributional effect should load-related costs be recovered via a capacity-related charge. These results are presented in Table 15. The results in Tables 14 and 15 are similar in terms of ordinal ranking, however, a capacity-related tariff yields impacts of greater magnitude. Under the expected range within which the elasticity paramter is likely to fall, -0.3 to -0.8, the poorest income quintile is expected to lose out by around €25-35/annum, while the richest income quintile is likely to gain by around €47-62/annum. These effects are not insignificant, and it is the distributional impact, rather than total welfare effect, that takes precedent in this policy consideration as a result.

As discussed in Section 3, a capacity-related charge is our preferred method for load-related cost-recovery and thus the results of Table 15 are our preferred results. However, a comparison of Tables 14 and 15 show that the final result changes by a relatively small amount depending on the nature of the reform.

4.3. A comparison of equity and efficiency effects of a Coasian DUoS reform

The preceding subsections have highlighted that there is a small welfare loss and a large regressive distributional effect associated with a Coasian DUoS tariff reform. In this section, we consider whether the distributional effects should take precedent over the small welfare loss to incentivise retention of the inefficient tariff structure. To carry this out, we calculate the welfare loss per euro redistributed to low-income households. This provides a benchmark implicit cost of redistribution. If this implicit cost of redistribution is less than the welfare loss associated with redistribution through the tax system, then the distortion may be justified on distributional grounds; it is cheaper to redistribute income through inefficient tariffs than it is through the tax benefit system.

The marginal cost of public funds, the cost of distortions associated with raising taxes, is the appropriate metric when estimating the welfare loss associated with raising taxes. Barrios et al. (2013) estimate the marginal cost of public funds. For every €1 raised through labour taxes in Ireland, €1.33 is lost through economic distortion.[13]

Tables 16 and 17 respectively show that the implicit welfare cost of redistribution through 2015/16 tariffs, relative to energy/fixed cost recovery and capacity/fixed cost-recovery only. The latter approach results in a greater implicit transfer of welfare as the counterfactual Coasian tariff results in a greater welfare loss among low consumers of electricity. In all considered scenarios, we see that the implicit cost of distribution is greater than the marginal cost of public funds in Ireland. For every €1 distributed to households in the first and second decile via current tariffs, Irish households lose out by at least €2.04. This value increases should the price elasticity of demand be greater.

[13]Barrios et al. (2013) also consider the distortionary effect of raising funds through energy taxes. For every €1 raised, there was a welfare loss of €0.62 (Barrios et al., 2013). In effect, there is a net improvement in efficiency. This reflects the underpricing of greenhouse gas emissions in Ireland in 2013, with these taxes representing an improvement in efficiency. Caution should therefore be taken when interpreting this finding. Ireland has implemented a more sustainable carbon price trajectory since 2013 and the marginal cost of raising taxes via energy surcharges is likely to be greater. We abstract from the use of DUoS charges in this way as second-best climate policy and instead assume that environmental externalities are captured by carbon pricing

Table 16: Marginal cost of redistribution relative to energy/fixed cost-recovery

	$\epsilon = 0$	$\epsilon = 1$	$\epsilon = 2$	$\epsilon = 3$	$\epsilon = 4$	$\epsilon = 5$	$\epsilon = 6$	$\epsilon = 7$	$\epsilon = 8$
Welfare redistributed ('000)	27,742	27,264	26,787	26,322	25,860	25,403	24,976	24,554	24,132
Welfare loss ('000)	56,811	59,180	61,628	64,188	66,831	69,582	72,460	75,435	78,516
Loss per € redistributed	2.048	2.171	2.301	2.439	2.584	2.739	2.901	3.072	3.254

Table 17: Marginal cost of redistribution relative to capacity/fixed cost-recovery

	$\epsilon = 0$	$\epsilon = 1$	$\epsilon = 2$	$\epsilon = 3$	$\epsilon = 4$	$\epsilon = 5$	$\epsilon = 6$	$\epsilon = 7$	$\epsilon = 8$
Welfare redistributed ('000)	40,010	39,468	38,938	38,413	37,886	37,364	36,867	36,378	35,896
Welfare loss ('000)	81,428	84,056	86,778	89,584	92,458	95,414	98,489	101,700	104,900
Loss per € redistributed	2.035	2.129	2.229	2.332	2.440	2.554	2.671	2.796	2.922

5. Discussion and Conclusion

This paper estimates the welfare effects of a Coasian Distribution Use of System (DUoS) tariff reform for domestic households in Ireland. This is the first paper to estimate the welfare effects of electricity network tariff reform on cost-reflective principles and is the first to consider the welfare implications of capacity-related retail charges.

We find that existing DUoS tariffs deviate considerably from the Coasian structure. We show that this tariff restructuring has large household-level effects, with positive impacts cancelling negative impacts in aggregate to yield a net impact of up to €33 million. The net impact of Coasian reform therefore comprises a small net increase in efficiency accompanied by a strong distributional effect; households in the lowest income decile lose out by up to €40 per annum while households in the highest income decile benefit by up to €62 per annum.

The distribution of the impact at the household level is predicated on the extent with which the uniform increase in standing charge is offset by the welfare gain associated with a lower volumetric charge. On average, households with higher incomes consume more electricity. For low income consumers, losses outweigh the benefits of a Coasian reform, on average, with the converse true for high income consumers. This drives a regressive distributional effect, the magnitude of which grows with the elasticity of demand. There is a precedent for recovering load-related distributional costs from a capacity-related charge. Should load-related costs be recovered via a capacity charge, the regressive effects are of even greater magnitude. Despite these effects, we show that inefficient DUoS tariffs represent a costly distributional policy. We demonstrate that it is more efficient to counter the regressive effects through the tax-benefit system.

The findings of this paper are predicated on existing network costs and focus on welfare loss at the intensive margin. While we explore the potential impacts for decision-making at the extensive margin in an online appendix, a natural extension of this work is to consider these effects in greater detail. Electricity networks are facing structural change with the increasing deployment of distributed energy resources. Connection to the grid is no longer guaranteed and efficient household-level decisions on whether to connect to the grid can guide efficient network development. Coupled with information on network development costs, the findings of this paper may provide a foundation to quantify the implications that distortive tariffs may have on the efficient development of the electricity network.

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Appendix

Appendix A. Operating and capital cost disaggregation

Table A.18 shows the allowed DSO revenues for the 2016-2020 PR4 (Price Review 4) regulatory period Commission for Regulation of Utilities (2015a) and the 2020-2025 PR5 (Price Review 5) regulatory period Commission for Regulation of Utilities (2021), respectively.

Costs incurred are presented according to categories of operating expenditure; capital cost recovery; depreciation; previous period adjustments and 'incentives and innovation'.[14] Operating expenditures are explicitly categorised. All other costs are capital costs, the designation of which requires further investigation for clarity. These will now be discussed in turn.

Table A.18: DSO allowed revenue 2016-2020 (PR4) and 2021-2026 (PR5)

Description	2016-2020 (PR4)		2021-2025 (PR4)	
	€million	% of total	€million	% of total
Operating expenditure	1,362	33.01%	1,632	35.85%
Weighted Average Cost of Capital (WACC)	1,379	33.42%	1,224	26.89%
Depreciation	1,196	28.99%	1,755	38.55%
PR3/PR4 adjustment	48.8	1.18%	-59	-1.30%
Incentives and innovation	140	3.39%	0	0.00%

Note: For the 2016-2020 (PR4), values are in 2014 terms and are as listed in the PR4 decision paper (Commission for Regulation of Utilities, 2015a). Please see Commission for Regulation of Utilities (2015a) for further details. Similarly, For the 2021-2025 (PR5), values are as listed in 2019 cost terms in the PR5 decision paper (Commission for Regulation of Utilities, 2021). Please see Commission for Regulation of Utilities (2021) for further details. All the values have not been adjusted for outturn, yearly updates or inflation.

Allowed return on asset base

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.

[14] Previous period adjustments indicate discrepancies between expected and actual expenditures as allowed revenues are calculated ex-ante. These differences are recovered through an adjustment in the following period.

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 A.18. As such, these costs relate to capital expenditure.

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, 2021). As such, these costs relate to capital expenditure.

PR3/PR4 adjustments

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, 2021).

Incentives and innovation

During the 2016-2020 period, appropriate incentives were included to encourage the DSO to improve both its efficiency and the quality of its service to customers. Such expenditures are denoted 'incentives and innovation' in Table A.18 and deemed to be capital expenditure.

Appendix B. Changes at the extensive margin: benchmark for timely evaluation

Efficient tariffs also provide important signals for decisions at the extensive margin, which we will now explore. This section quantifies the extent with which inefficient tariffs may accelerate or delay disconnection from the electricity grid, should this be a cost-effective outcome for a household.

Cost-reflective tariffs are important in guiding efficient connection and disconnection to the electricity grid. As there has historically been no viable alternative to grid-sourced electricity, inefficient connection is not a concern when it comes to such effects. However, efficient disconnection is a growing consideration with the increased deployment of Distributed Energy Resources (DERs) such as household-level Solar PV (Castaneda et al., 2017; Von Hirschhausen, 2017; Sabadini and Madlener, 2021). As costs fall (Way et al., 2022), households will increasingly consider whether or not to install DERs by comparing the cost of grid-sourced electricity with the cost of the DER-sourced alternative. Should the underlying tariffs be efficient and reflective of costs, households will be incentivised to switch when the DER alternative truly costs less than grid-sourced electricity. If the underlying tariffs are not reflective of costs, then a different set of households will be incentivised to switch at a different point in time.

Efficient signals are important to guide efficient network development. In addition to the changing pattern of generation with the adoption of renewables, network requirements will also change as DER-sourced electricity becomes more prevalent. For instance, there may be a lesser capacity requirement in locations that are better served by DER-sourced electricity. A distorted pattern of individual household-level defection may cumulate to guide inefficient development of the network.

The extent with which this will become an issue in an Irish context is unknown. Full grid defection is becoming an active policy discussion in markets with a strong solar resource (Castaneda et al., 2017; Von Hirschhausen, 2017; Sabadini and Madlener, 2021). A lesser solar resource exists in Ireland and the extent with which this may occur is subject to greater uncertainty. Estimating this likelihood and the associated network cost implications of sub-optimal changes at the extensive margin is outside the scope of this paper. However, we can identify the marginal change in the decision to disconnect.

Efficient disconnection is predicated on the cost of grid-sourced electricity relative to DER-sourced electricity. Should current DUoS tariffs be in place, this paper has shown that there is an additional cost for high-consumption households relative to a Coasian pricing structure. This is because the benefits of a lesser standing charge outweigh the costs of a higher volumetric charge. Should these households ever wish to leave the grid, cost parity, and therefore the point of cost-effective transition to DER-sourced electricity, will be delayed. Conversely, we have shown that there is a lesser cost for low-consumption households under current tariffs, relative to a Coasian pricing structure. This is because the benefits of a lesser standing charge are greater than the costs of a higher volumetric charge. Should these households ever wish to leave the grid, cost parity, and therefore the point of cost-effective transition to DER-sourced electricity, will be accelerated.

By examining points on the distribution of associated with current tariffs, we can identify cost thresholds at which point a certain proportion of the population is incentivised to accelerate or delay their potential disconnection. For the Fixed/Energy tariff, these findings are reported in Table B.19. We focus on cost-recovery of load-related costs through energy surcharges to give insight to a lower bound of potential effects.

Table B.19 shows that between 42% to 51% incur a welfare gain under current tariffs, relative to a Coasian tariff where load-related costs are recovered via an energy-related charge. These households may potentially be subject to delayed adoption. Conversely, between 48 to 57% of households incur a welfare loss under the current tariffs, relative to a Coasian tariff where load-related costs are recovered via an energy-related charge. These households may potentially be subject to accelerated disconnection.

The next step is to consider the extent with which the population may be incentivised to accelerate or delay disconnection due to these inefficient tariffs. Focussing on households who incur a welfare gain, the top 5th percentile of the consumption distribution benefit by at least €166 to €206 per annum, when load-related costs are recovered via an energy-related charge. Therefore, it is cost-effective for 5% of the population to delay defection until the annualised cost of DER-sourced electricity is less than the cost of grid-sourced electricity by between €166-206 per annum. This threshold falls as we move down the consumption distribution. Those in the top 25th percentile benefit by at least €40 to €63/annum, delaying defection for 25% of the population until this additional cost threshold is passed.

Focussing on households who incur a welfare loss, Table B.19 shows that those in the top 5th percentile incur a welfare loss of at least €120 to €122/annum. For these households, non-Coasian tariffs could hasten disconnection. The discounted and annualised cost of DER-sourced electricity must reach parity less €120-122 per annum for cost-effective disconnection. As before, these thresholds change at different points in the impact distribution.

Table B.19: Welfare gains and losses of Irish DUoS tariff relative to Coasian alternative quantified at various points in distribution of household-level welfare change

		ϵ = 0	ϵ = -0.1	ϵ =-0.2	ϵ =-0.3	ϵ = -0.4	ϵ =-0.5	ϵ = -0.6	ϵ =–0.7	ϵ =–0.8
Welfare gain										
Prop. pop. welfare gain		42.4%	43.3%	43.9%	45.7%	46.5%	47.7%	49.7%	50.5%	51.5%
Quantified welfare gain (€)										
Percentile	*75th*	40.85	43.55	46.46	49.08	51.83	54.88	57.66	60.49	63.46
	90th	106.31	110.21	114.19	118.27	122.42	126.68	131.03	135.47	140.01
	95th	166.51	171.37	176.33	181.41	186.34	191.10	196.07	201.58	206.77
	99th	325.35	332.20	339.20	346.36	353.67	361.15	368.79	376.59	384.58
Welfare loss										
Prop. pop. welfare loss		57.6%	56.7%	56.1%	54.3%	53.5%	52.3%	50.3%	49.5%	48.5%
Quantified welfare loss (€)										
Percentile	*25th*	-60.36	-59.12	-57.85	-56.56	-55.23	-53.88	-52.50	-51.08	-49.63
	10th	-98.19	-97.55	-96.90	-96.23	-95.55	-94.85	-94.14	-93.42	-92.67
	5th	-122.65	-122.41	-122.15	-121.89	-121.63	-121.36	-121.08	-120.80	-120.51
	1st	-138.18	-138.19	-138.19	-138.19	-138.19	-138.19	-138.19	-138.19	-138.19

Note: ‘Prop. pop. welfare gain’ denotes proportion of population who incur a welfare gain under the current Irish DUoS tariff, relative to the Coasian alternative. ‘Prop. pop. welfare loss’ denotes proportion of population who incur a welfare loss under the current Irish DUoS tariff, relative to the Coasian alternative. Quantified welfare gain/loss denotes average household-level welfare gains/losses, per annum, at specified points in the distribution of household-level welfare change.