Balancing Environmental Incentives and Fairness in Household Electricity Distribution Tariffs

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Abstract

Adapting energy distribution systems to new patterns of energy generation and usage often creates tensions between environmental and equity objectives by challenging traditional distributional arrangements and associated charging methodologies. We discuss the principles of fairness and efficiency which might be applied to designing tariffs for residential consumers with self-generation opportunities, and identify the main examples of charging methodologies used in practice. Based on this experience, we develop a stylised model to simulate the effects of a wide range of tariff designs on households with diverse energy use profiles and ability to self-generate. We observe a clear trade-off between incentives to self-generate and distributional concerns across tariff scenarios and show how a net metering scheme may aggravate the trade-off.

Key words: Distributed Generation; Electricity; Fairness; Network; Renewables; Tariff

JEL codes: D61; L51; L94; L97; Q41; Q42

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1. Introduction

New ways of generating and using electricity require significant reform of the inherited distribution system, raising questions of how to recover the costs both of the new investment required and of assets from traditional networks which may become wholly or partially ‘stranded’. We explore the inherent tension between providing appropriate incentives to those who can respond by taking initiatives necessary for future development, while protecting those who are unable or unwilling to respond to such incentives, at least in the short term, from excessive burdens. We describe a range of representative tariffs currently being levied or introduced, and simulate their effects on households with different demand and supply characteristics in a hypothetical system which must recover total distribution costs.

Distribution network costs typically form 20-30% of household bills in Europe[1] and the US (Burger et al., 2019), and cover local, lower voltage distribution services rather than higher tension transmission. Electricity distribution has been revolutionised by a range of technological innovation, in particular distributed generation and electric vehicle charging. By adopting renewable energy systems such as solar photovoltaic (PV) to generate their own electricity, households both make an important contribution to the transition towards cleaner energy, and enhance the flexibility potential of the distribution network (Cohen et al., 2016). If households use less electricity at times of system peak, they may generate savings to the distribution system both in the short term, and for longer term investment requirements. Various incentives[2] have encouraged renewable energy generation by households[3], many incorporating a rather crude relationship with the associated cost savings, where a simple message may be an important part of encouraging adoption in the early stages of innovation. For example, net metering schemes that typically oblige utilities to buy any excess generation may charge very little for use of the distribution system to consumers who self-generate across the billing period. Such schemes have been introduced in the early stages of solar PV adoption in Australia, Europe and the US (Cohen and Khermouch, 2013).

However such generous incentive schemes to encourage adoption may leave any legacy and fixed forward-looking costs of the system uncovered, so either the Distribution System Operators experience falling revenue, or the costs may need to be recovered from a smaller base of households who have not installed micro-generation. Some of these non-adopters may have been excluded from participation by lower income, wealth or dwelling rights. Ironically, such issues are exacerbated if the incentives have successfully stimulated extensive solar PV penetration, and tariffs feature a high component of per kWh charge (Simshauser, 2016; Pollitt, 2018). Indeed the co-existence of distributed generation and volume-based network tariffs triggers discussions on distributional fairness even in the absence of net metering schemes (Burger et al., 2019).

This paper explores the distributional impacts of different tariff structures by simulating bills under each tariff for ‘notional’ households whose energy use profiles and ability to self-generate vary, within a stylised model where the costs of the distribution system are held constant. We observe a clear trade-off between incentives to self-generate renewable energy and distributional

[1] See, e.g., https://www.ofgem.gov.uk/data-portal/breakdown-electricity-bill.

[2] The incentive scheme concerned in this paper is net metering. For an analysis on how some other measures such as feed-in tariffs can facilitate renewable energy generation growth see Carley et al. (2017).

[3] This paper refers to solar PV as the typical self-generation technology and does not discuss how incentive schemes may differ by technology. For an analysis on technology-neutral and technology-specific schemes, see Lehmann and Söderholm (2018).

concerns across different tariff scenarios, and demonstrate how a net metering scheme may interact with tariff scenarios to aggravate the trade-off.

The timeliness of this analysis is demonstrated by the European Commission's[4] recent call for "a fair deal for consumers", alongside an increase both in energy efficiency and in the share of renewable sources (European Commission, 2016a). The proposals show the opportunities and challenges facing distribution networks, and highlight potential conflicts between sustainability, cost recovery and fairness. Resolving these tensions is essential to achieve a smooth transition to cleaner energy.[5] In the UK, the Office of Gas and Electricity Markets (Ofgem) has consulted on removing certain incentive schemes for distributed generation and changes to network tariffs that recover both forward-looking and residual costs "so that costs are shared fairly now and in the future".[6] Similar conflicting objectives are experienced in the US (Borenstein, 2016). Our findings offer some insights on tariff choices.

The paper proceeds as follows. Section 2 reviews relevant concepts of fairness and associated literature on designing distribution network tariffs. Section 3 summarises the major existing charging methodologies and their applications, both in Europe and in North America, before presenting the framework for our simulation analysis. Section 4 presents and discusses the results, and Section 5 concludes.

2. Concepts of fairness and relevant literature

Fairness is often linked to cost reflectivity, which can be seen as economically efficient from two perspectives. From the network point of view, if a consumer pays the costs of her supply, her participation is neither a burden nor a bonus for the rest of the network. From her individual perspective, she makes decisions about consumption (in this case whether to become connected to, stay connected to, and use the distribution network, at what times and on what terms and whether to install and use self-generation system) according to the costs that she imposes on the network. It follows that a 'fair' price paid by a network user should reflect the additional (or marginal) cost imposed on the network. Such marginal cost pricing should in principle apply to all margins, including those for recovering the costs of initial connection, maintaining connection, providing sufficient capacity to meet maximum demand on the system and transporting the electricity at times of varying congestion. Prices based on long-run marginal costs are more stable and provide long-term investment signals, while those based on short-run marginal costs send signals for efficient short-run consumption decisions and are particularly important if network capacity is itself fixed and liable to congestion so that demand management may be required (Borenstein, 2016).

However, marginal cost pricing may not achieve full recovery of electricity distribution costs for three main reasons. First, distribution networks exhibit economies of scale and/or density, i.e. average costs are lower, the more consumers are attached to the system, and are therefore above the marginal cost of supply. Second, some 'unallocated' costs may be difficult to categorise because they are not attributable to any particular activity or user. Third, there may be 'legacy' costs

[4] https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans.

[5] The Council of European Energy Regulators (CEER) (2018) reflects this priority in its own strategic objectives, namely to "build consumer confidence in the market by ensuring all consumers benefit in a fair way, notably through the efficiency of the network tariff, and promote the participation of consumers without discrimination between consumers/prosumers."

[6] See https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-minded-decision-and-draft-impact-assessment. This particular consultation focuses on residual charges, while our analysis also includes forward-looking costs.

inherited from past system design, which are not affected by users' current decisions, widening the gap between forward-looking marginal and average costs.

One traditional approach to identify the 'optimal' departure from marginal cost pricing to recover full costs is based on minimising demand distortions, so price reflects the demand responsiveness or elasticity of an individual user (or a group of users). Such Ramsey pricing (1927) almost always raises significant distributional concerns, since it imposes price discrimination, and charge higher mark-ups for 'essential' consumption (where demand is less responsive, and therefore 'distorted') than for more discretionary consumption. Moreover, like many necessities, electricity expenditure increases with income, but less than proportionately, so that low-income households tend to devote a higher proportion of their expenditure to energy than do high-income households (Levell and Oldfield, 2011; Deller and Waddams, 2015).[7] Therefore, even uniform percentage increases in price impose a higher proportionate burden on the low-income households. Introducing a fixed charge would be even more regressive.[8]

Distribution networks have traditionally been dominated by users relying exclusively on the network for electricity supply, and costs have been mainly recovered through a volume-based charge. Since users within a certain group have previously tended to have similar electricity demand profiles, the use of volume-based tariffs could be justified, even though it did not directly reflect the capacity-driven nature of network costs (Azarova *et al*., 2018). As supply and demand patterns change, and the relationship between peak and volume demand diverges, tariffs need to become more reflective of peak demand as the main driver of network costs (Eurelectric, 2016), and a flat volumetric rate is unlikely to be efficient or 'fair'.[9] Some studies find that most households with solar PV remain connected to the grid and use only slightly less peak capacity than the other households (Simshauser, 2016), while others argue that under the current centralised system small scale generation would entail efficiency losses that can increase, rather than decrease, costs (Schill et al., 2017). A number of relevant questions thus arise: is it fair for users who impose different costs on the network to pay the same price? Is it fair for users who self-generate and remain connected to the grid to receive substantially lower bills when they may make similar demands on the system's capacity at peak as other users? Is it fair that as a result of lower bills for micro generators, others pay more?

Capacity-based and Time-of-Use (ToU) tariffs may be appropriate instruments to resolve some of the conflicting objectives. Since higher network costs are associated with peak demand, capacity-based and ToU tariffs, each associated (in different ways) with peak demand, can give more appropriate cost signals than a flat volumetric tariff, helping to optimise the use of networks and enhance flexibility. They can also neutralise the impact of variations in volumetric consumption on DSOs' revenues as adoption of renewable energy systems grows, and so mitigate or avoid cross-subsidy between consumer groups.

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[7] European Commission (2016b) states that "In 2014, the lowest income households in the EU spent close to 9% of their total expenditure on energy." See http://europa.eu/rapid/press-release_MEMO-16-3986_en.htm.

[8] General taxation can be another way to meet the difference and might be viewed as fair in the sense that the tax and benefits system of a country would presumably be designed to reflect the distributional priorities. However taxes themselves cause inefficiencies elsewhere in the economy, and support of energy systems through taxation raises issues of state aid. They are also challenging to administer if distribution systems are privately owned.

[9] Currently distribution tariffs for households in the Europe are mainly based on volumetric usage, not peak demand.

There are other aspects of tariff design and reform that are relevant to distributional justice [10]. For example, it could be argued that any cost allocation should lead to neither sudden and sharp increases, nor significant fluctuations, in bills, because this would 'cloud' the price message and the efficiency characteristics of consumer response. Similarly it could be argued that the bills of consumers within the same tariff class should change by similar amounts, and any changes should not disadvantage consumers who are poor and vulnerable, unless adequate support can be provided, either through tariffs or other means.[11] This latter requirement may be a particular challenge when previous tariffs have not been broadly cost-reflective, or if changes on the demand or supply side result in substantial alterations in the nature and pattern of costs.

The relevant literature on network cost recovery can be considered in three broad groups. The first group considers the principles of charging, some of which we have discussed earlier on, particularly where there are stranded or residual costs. Borenstein (2016) provides an excellent review of the concepts of fairness involved in enforced departure from efficient pricing as represented by social marginal costs, for example through recovery of fixed costs, and identifies potential tensions between raising prices in a way that minimises demand distortions and taking account of potential adverse distributional effects across the whole electricity supply chain.

The second group explores the application of such principles across the entire electricity supply chain, taking account of changing supply and demand patterns. Several papers apply the principles of fairness and cost reflectivity as the electricity sector changes from a traditional centralised system to one employing new distributed technologies. Pérez-Arriaga et al. (2017) focus on the importance of prices to guide the individual decisions of network users and the need to reduce inefficient barriers and wasteful competition. They propose that tariffs should be technology neutral and symmetrical, with improved granularity of signals in terms of time and location, and that residual costs should not affect incentives. Batlle et al. (2018) and Burger et al. (2019) both follow their discussions of general principles with proposals to redesign two specific tariffs, in Spain and the US, recommending a compromise between efficient price signals and distributional impacts.

The third group focuses on the electricity distribution part of the supply chain, focusing on forward-looking costs or those inherited from past decisions, or both. The increasing significance of distributional issues in solar PV incentives as adoption rates increase is emphasised by Pollitt (2018), who draws attention to the more general difficulty of meeting efficiency, revenue recovery and distributional objectives simultaneously. Eid et al. (2014) emphasise the need for clearer incentives for solar PV, and consequent distributional concerns for those without such facilities who do not benefit from lower bills. Simshauser (2016) focuses on rate instability, and recommends a capacity-based demand charge as an efficient, cost-reflective, stable and equitable pricing mechanism within a rate-of-return based regulatory structure. Passey et al. (2017) focus on how demand charges can be adjusted to increase their cost reflectivity. Brown et al. (2015) review a wide range of tariffs to ensure economic efficiency in distribution network services, incorporating both efficient long-run marginal costs and recovery of residual costs, and highlight the potential tension between efficiency and cost recovery, echoing other papers in appealing for greater transparency in how these objectives are balanced. Schittekatte et al. (2018) focus on recovering sunk network costs without distorting consumer response and investment incentives for distributed generation, again

[10] For some other alternative interpretations of fairness, see Brown et al. (2015).

[11] For example, through the use of social tariffs. While social tariffs will not be discussed in the rest of this paper, the idea is that, regardless of the provision of social tariffs, it may be desirable if the overall distribution tariff design could reflect some considerations of fairness and equity.

emphasising the increasing challenges as systems mature, and identify both efficiency and fairness issues.

In terms of methodology, a number of studies have simulated outcomes to explore the effects of network tariffs on household bills, either using hypothetical households or actual consumption data from a sample of households. Brown et al. (2015) and Azarova et al. (2018) examine distributional effects of electricity tariffs, but do not consider the possibility of distributed generation. Burger et al. (2019) consider distributed generation and analyse bill impacts of tariffs across different socioeconomic groups, but do not consider net metering. Compared to the few studies analysing the combination of net metering and tariff design (Eid et al. 2014; Picciariello et al., 2015; Schittekatte et al. 2018), our simulation covers a wider range of tariff scenarios drawn from principles and experience, and directly demonstrates the trade-off in the absence and presence of net metering. This allows us to examine policy changes beyond separating net metering and volumetric charges (or removing net metering), and to address the core issue of designing fair network tariffs that are future-proof. We suggest that such tariffs are likely to contain multiple components (with the volume component being moderate) and/or a ToU element.

3. Developing a stylised tariff design model from current distribution tariffs

This section assesses a series of stylised network tariffs for recovering distribution network costs, based on the principles and context discussed in previous sections. The choice of stylised tariffs are based on a number of representative tariffs already in use or proposed.

3.1 Tariff scenarios

Network tariffs generally vary according to tariff classes[12], tariff components, and charging bases.[13] Most current network tariffs reflect three main components, used either alone or in combination: fixed (€/period); capacity (€/kW); and volume (€/kWh). Fixed component tariffs are commonly known as standing service charges[14], and are independent of consumers' maximum demand and consumption volume. Capacity component tariffs charge consumers for the availability of a maximum load, either *ex ante* (based on the maximum contractual capacity), or *ex post* (based on consumers' actual peak demand over a period) or a mixture of both. Volume component tariffs charge consumers according to their total usage of electricity from the grid.

Within each component, charges may be linear or non-linear.[15] ToU tariffs charge different prices per volume of electricity consumed at different times of the day, week or year (e.g. peak, shoulder, off-peak), and provide an alternative approach to charging directly for capacity. Static ToU tariffs pre-define the charging time periods and rates, which remain fixed until the next adjustment;

[12] Tariff classes can be defined by voltage level (kV) as a measure of capacity (e.g. high, medium or low), customer types (e.g. household or industrial), metering (e.g. whether metered or unmetered and type of meter), geographic zone, etc. Consumers belonging to different classes may face different tariff constituents and levels. In the EU, tariff classes are mostly defined by voltage level (European Commission, 2015).

[13] Individual tariff components and charging bases, and their relative advantages are summarised in Appendix I.

[14] This is different from an up-front fee, which is typically a one-off charge associated with initial connection to the system.

[15] For example, under an Increasing Block Tariff (IBT), the price paid for each unit (consumed, or of capacity) increases when volumetric consumption or capacity reaches a particular predetermined level, or block. The practical challenges of IBTs regarding their designs and consumer responses are discussed in depth in Lu et al. (2019), albeit in the context of residential water consumption. The fixed component may vary between tariff classes. We focus on a single class, namely household consumers.

while dynamic ToU tariffs can vary on an hourly or daily basis or more frequently in response to real-time network congestion (e.g. corresponding to half-hourly settlement in the wholesale market[16]).

Distribution network tariff structures are changing in response to new supply and demand patterns and vary considerably across jurisdictions. We have selected a broadly representative suite of cases to reflect the tariff structures outlined above, including four EU states, one EEA state and one US state.[17] Table 1 summarises the key features of tariff structures in each state and whether net metering is an option, and the organisation which carries the main responsibility for setting distribution tariffs, i.e. whether a national regulatory agency (NRA) or a DSO. These examples provide the basis of our stylised tariff scenarios.

Case	Tariff component			Tariff charging basis		Net metering	Main responsibility in setting tariffs
	Fixed	Capacity	Volume (weight)	Non-linear	Time-of-Use		
Italy	YES	YES	YES (66%)	YES	NO	YES	NRA
Portugal	NO	YES	YES (62%)	NO	YES	NO	NRA
Romania	NO	NO	YES (100%)	NO	NO	NO	NRA
The Netherlands	YES	YES	NO (0%)	NO	NO	YES	NRA and DSOs
Norway	YES	NO	YES (70%)	NO	NO	NO	DSOs
California (PG&E)	YES	NO	YES (n/a)	YES	YES	YES	DSO(PG&E)

Table 1. Key features of household tariffs in selected cases

The suite of stylised tariffs to be examined, derived from principles and practice, is described in Table 2. These stylised tariffs vary in the weights applied to each tariff component.[18] In addition, 30F70Vt is a ToU tariff, under which peak time price is assumed to be five times higher than the off-peak price. We also include an option for net metering for households who feed excess generation into the grid.

Tariff scenario	Fixed component (€/year)	Capacity component (€/kW)	Volume component (€/kWh)	ToU	Net metering when available
100V	-	-	100%	NO	YES
100C	-	100%	-	NO	NO
100F	100%	-	-	NO	NO
30F70V	30%	-	70%	NO	YES
30F70C	30%	70%	-	NO	NO
50C50V	-	50%	50%	NO	YES
20F40C40V	20%	40%	40%	NO	YES
30F70Vt	30%	-	70%	YES	YES

Table 2. Stylised tariff scenarios

3.2 Network and notional households

We use a simplified set of parameters to describe the network usage and consequent costs across a small number of notional households with a range of different demand (and supply) patterns,

[16] Ofgem is considering half hourly metering for households , see https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement.
[17] Case studies of household electricity distribution tariffs in these states are in Appendix II.
[18] Note that the tariff in Romania is 100% volume-based (100V). Norway uses a combination of 30% fixed component and 70% volume component (30F70V). The tariff scenario 30F70C has no volume component, which resembles the case of the Netherlands. Portugal uses a combination of capacity and volume components (close to 50C50V). The tariff scenario 20F40C40V features all three components, resembling the Italian case.

classified according to their various electricity use profiles. Table 3 shows how the eight households differ from each other in one or more ways regarding:

- Annual contractual capacity (low, average or high),
- Annual electricity consumption (very low, low, average or high),
- Ratio of consumption at peak time (1/2, 2/3 or 1),
- Whether there is any PV solar system installed; and, if so,
- Whether the household is able to feed excess supply into the grid.

As defined at the end of Table 3, we denote each household with an abbreviation. The first letter of each abbreviation refers to the level of contractual capacity (L, A, H); the next to the level of (net) volumetric consumption from the grid (vL, L, A, H); while an f at the end indicates that the household is able to feed surplus generation into the grid. Note that the three households with solar PV all withdraw very little from the grid.

Household abbreviation	**Contractual capacity** (kW/year)	**Volumetric consumption** (kWh/year)	**Ratio of consumption (kWh) at peak time**	**Solar PV**	**Amount fed into grid if allowed** (kWh/year)
LL	Low (4)	Low (1500)	1/2	NO	-
HL	High (10)	Low (1500)	2/3	NO	-
LH	Low (4)	High (5500)	1/2	NO	-
HH	High (10)	High (5500)	2/3	NO	-
AA	Average (6)	Average (3500)	1/2	NO	-
LvL	Low (4)	Very low (500)	1	YES	0
HvL	High (10)	Very low (500)	1	YES	0
LvLf	Low (4)	Very low (500)	1	YES	500
				Total consumption (kWh/year)	19000
				Total contractual capacity (kW/year)	52
				Average revenue per household (€/year)	200
				Total revenue (€/year)	1600

LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Table 3. Notional households

The specific values of different levels of contractual capacity and volumetric consumption shown in Table 3 are based on a typical household with a contractual capacity of 6 kW and an annual consumption of 3,500 kWh (European Commission, 2015). Households are assumed to have different ratios of peak time to total consumption.[19] Those with high contractual capacity and no solar PV (HL and HH) display very peaky demand (a ratio of 2/3), and households with average or low contractual capacity and no solar PV are assumed to spread consumption more evenly across time (a ratio of 1/2). We assume that households with solar PV rely on the network for supply only during

[19] These ratios are for symbolic purposes only, since their calculation depends on how the peak period is defined.

peak time, so their peak to total consumption ratio is 1. Among the three households with solar PV, only LvLf generates surplus (500 kWh), which is fed into the grid during off-peak time. [20] Finally, total consumption is the sum of consumption from all households and total contractual capacity is the sum of capacity connection of all households.

Network costs vary substantially across countries. We assume, for ease of calculation, that the average revenue required from each household to cover network costs is €200/year,[21] and that there are equal numbers of consumers within each type of household. While this assumption is purely notional, and unlikely to hold in any particular case, the model can be adapted to particular circumstances as the proportions of each type of household varies across jurisdictions and over time. In our notional system, total revenue would be €1600/year, which could be interpreted as a regulated revenue cap. This forms the basis for the stylised tariffs derived for each combination of components in Table 2,[22] and is used to simulate network bills for each of the eight notional households. For simplicity, we do not associate different costs with different tariff structures; since one objective of such tariffs is to reduce total system costs by offering efficient incentives, our example can be seen as an upper bound in terms of overall costs.

We take advantage of our stylised model to compare the simulated bills within the overall revenue cap, and highlight general trends and key observations, rather than compare tariff options to any specific benchmark or existing tariff.

4. Results and analysis

We use the tariffs derived in the previous section to simulate bills of the hypothetical households under each tariff scenario, both excluding and including net metering.

4.1 Bill variations with usage profile and tariff design

We first consider the situation where households consume the electricity they self-generate, but cannot feed any surplus into the grid, i.e. LvLf is identical to LvL. The simulated bills for each of the remaining seven households under each tariff scenario are presented in Table 4.

Bill	100V	100C	100F	30F70V	30F70C	50C50V	20F40C40V	30F70Vt
LL	126.32	123.08	200.00	148.42	146.15	124.70	139.76	137.94
HL	126.32	307.69	200.00	148.42	275.38	217.00	213.60	155.26
LH	463.16	123.08	200.00	384.21	146.15	293.12	274.49	345.77
HH	463.16	307.69	200.00	384.21	275.38	385.43	348.34	409.28
AA	294.74	184.62	200.00	266.32	189.23	239.68	231.74	241.86
LvL	42.11	123.08	200.00	89.47	146.15	82.59	106.07	103.30
HvL	42.11	307.69	200.00	89.47	275.38	174.90	179.92	103.30
LvLf	42.11	123.08	200.00	89.47	146.15	82.59	106.07	103.30
Total	1600	1600	1600	1600	1600	1600	1600	1600

LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

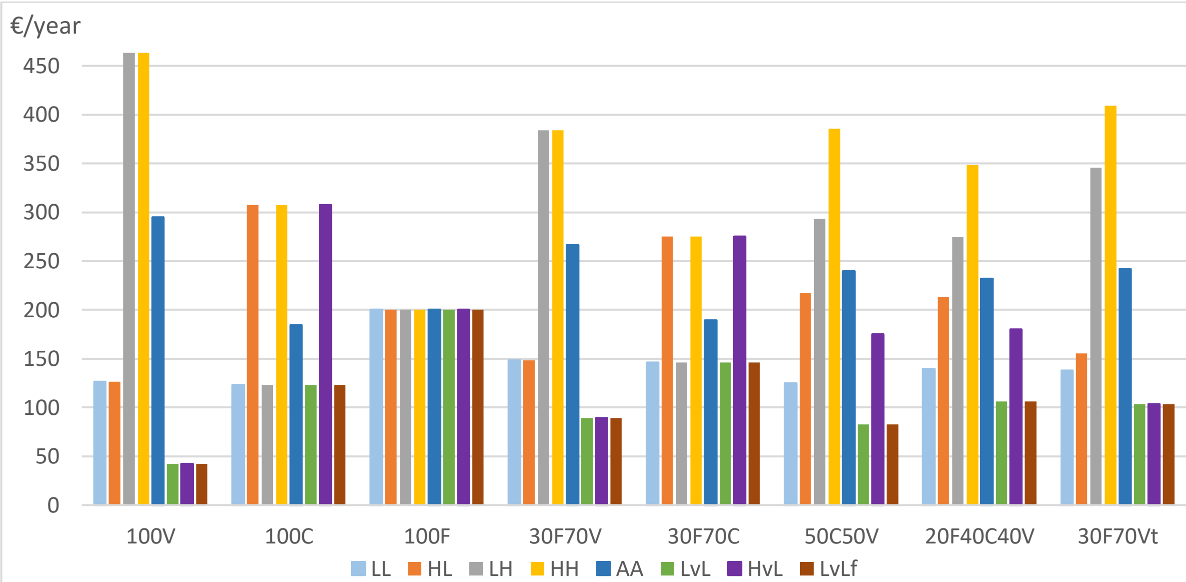
Table 4. Simulated bills (€)

[20] While the selection of notional households means that each of them represents 12.5% of the population in our model, it should be noted that we do not imply equal weighting of these households in the wider population, or that 12.5% of the population can fed into the grid.

[21] The average total charge for a household consumer in EU Member States was about €172/year in 2013, see Figure 11 (p.126) in European Commission (2015).

[22] See Table A5 in Appendix III for specific rates charged under different tariff scenarios.

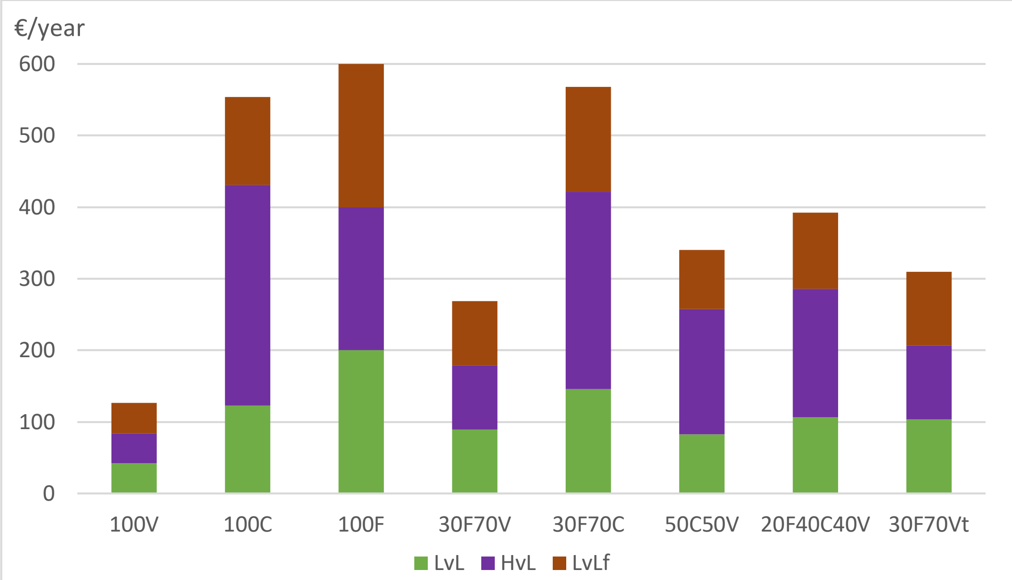
Based on Table 4, Figures 1 to 4 below illustrate the variation of household bills with electricity use and tariff design, and offer qualitative insights rather than quantitative determinations. Tariff 100F generates an identical bill for each household, while 100V and 30F70V (similar to traditional volume based tariffs) each produces four different bills across household types, reflecting the four different levels of consumption which the households represent. Similarly, tariff 100C generates three different bills, while bills vary more when the tariff includes both capacity and volume components, such as 50C50V, 20F40C40V and 30F70Vt, because the tariff reflects more dimensions of usage. In practice, the marginal costs attributable to each component of the tariff (fixed, capacity, volume) vary both across distribution systems and over time, according to factors such as patterns of supply and demand (e.g. peakiness), density of consumers and maturity. Cost-reflective tariffs would generally include all three elements, but in different proportions.



LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Figure 1. Simulated bills (€) for each household under each tariff scenario

We focus particularly on the opportunity for self-generation by the two household types: LvL and HvL, and consequent distributional impacts for all consumers. Recall that each self-generator has very low level of consumption from the grid, but we assume that they rely on the grid during its peak period. Figure 2 illustrates the contribution to the total cost of €1600 by each of these households under each tariff. The contribution differs considerably across scenarios. Amongst all seven (non feed-in) tariffs, households with solar PV contribute least to distribution expenses under tariff 100V (only €42.11 each), and most under 100F, with a bill almost five times higher (€200 each). Furthermore, tariffs with a capacity component, such as 100C and 30F70C, charge large bills to household HvL who has high contractual capacity. Note that the ToU tariff 30F70Vt, although attaching a high weight to its volume component and no weight to the capacity component, generates a much higher bill for households with solar PV than does 100V because of its high unit price for peak consumption.

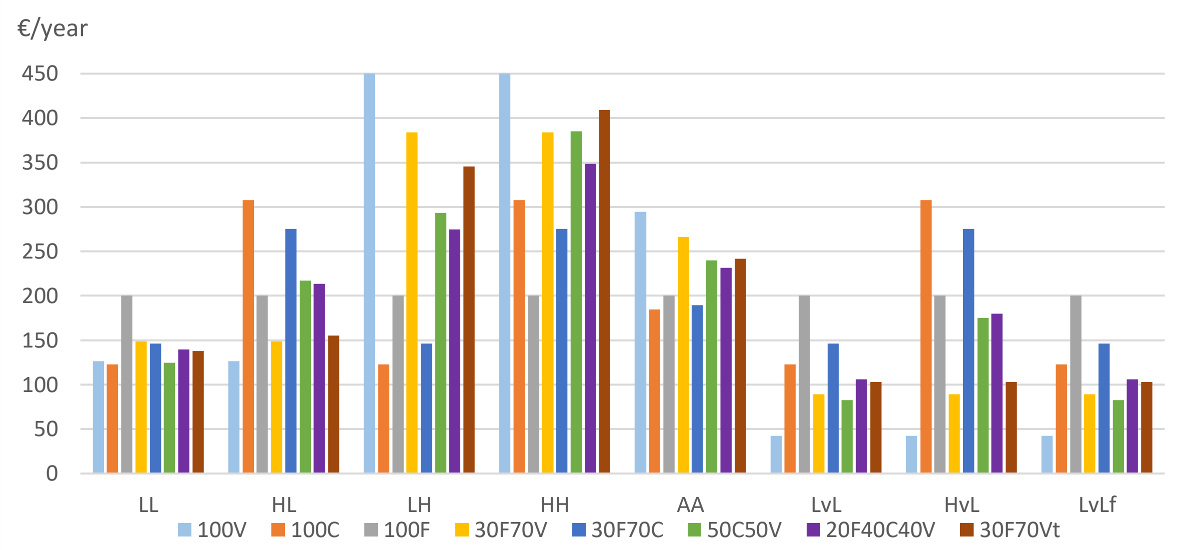


LvL – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Figure 2. Costs allocated (€) to 3 households with self-generation under each tariff scenario

To explore distributional effects across the system, we compare the bill levied under each tariff for each household, shown in Figure 3. Since our model assumes no change in the total network costs from self-generation, the lower the costs allocated to households with solar PV, the more remain to be recovered from other households. Here the trade-off between incentives and distributional fairness is clearest: a volume-based tariff can offer a strong incentive to encourage the deployment of renewable energy systems, but if initial savings for the system as a whole are low and the cost of such an incentive is borne by the other consumers, then a volume-based tariff may lead to substantial redistribution. This may be a cause for concern if higher income households are more likely to undertake renewable energy investments,[23] as bills for lower income households would increase as a result. A fixed tariff allocating the identical amount to all households may appear very equitable but does little to encourage efficiency or system flexibility, and is thus only attractive for recovering the residual and non-marginal parts of network costs. Tariffs that are more cost-reflective, including those which are capacity-based and ToU, may constrain potential redistribution in the presence of distributed generation, but can weaken households' incentive to adopt renewable energy systems. Note that for some households, such as LL and AA, variations in their bills under different tariffs are relatively small, whereas for others, such as LH and HvL, the differences are considerable. Changing from one tariff design to another would have major effects on electricity bills for these households.

[23] CLEAR 2.0 (project in progress) identifies financial incapacity as one of the main barriers to adopting new technologies. See https://www.clear2-project.eu/.



LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Figure 3. Simulated bills (€) for each household

In particular, each household's the highest and lowest bills are generated by the 'single component' tariffs 100V, 100C, and 100F. The extent of difference between the highest and lowest bills of each household also varies considerably across households, reflecting both the overall size of their energy demand and whether one dimension of their demand is at a very high or very low extreme relative to the average. Households with such usage profiles may be prone to large bill increases (and decreases) under certain tariff reform programmes. In changing its residential tariff to be more capacity-based, the Netherlands implemented compensation schemes to ensure that households who could not reduce their contractual capacity did not suffer adverse impacts.

4.2 Net metering

In this sub-section we extend the analysis to consider the opportunity for household LvLf to feed surplus (500 kWh) into the grid during off-peak time, receiving remuneration at the same rate per volume[24] as for electricity taken from the grid, through net metering. Since we assume that 'credit' for surplus generation is paid according to volume, LvLf would only receive remuneration in tariff scenarios which include a volume element.[25]

We make two assumptions: first, that the electricity fed into the grid by household LvLf is not then supplied to others, i.e. total consumption from the grid remains at 19000 kWh/year as in Table 3. Secondly, that no remuneration is available from external financial resources but must be met endogenously, with a consequent impact on the bills of all households. Table 5 reports the simulated bills for each household and tariff scenario under these assumptions.

[24] In reality, net metering may not always take this simple form.

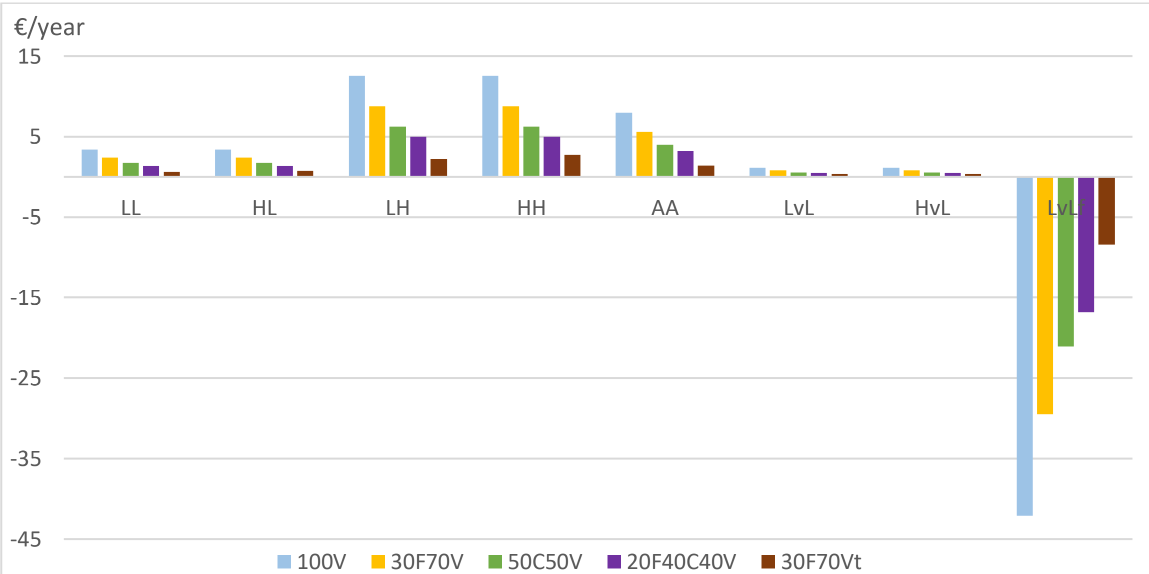
[25] We assume that any remuneration as a result of net metering is calculated through the volume component, which is indeed the case in practice, for example, in California and Italy.

Bill	100V	100C	100F	30F70V	30F70C	50C50V	20F40C40V	30F70Vt
LL	129.73	123.08	200.00	150.81	146.15	126.40	141.12	138.55
HL	129.73	307.69	200.00	150.81	275.38	218.71	214.97	156.00
LH	475.68	123.08	200.00	392.97	146.15	299.38	279.50	348.00
HH	475.68	307.69	200.00	392.97	275.38	391.68	353.35	412.00
AA	302.70	184.62	200.00	271.89	189.23	243.66	234.93	243.27
LvL	43.24	123.08	200.00	90.27	146.15	83.16	106.53	103.64
HvL	43.24	307.69	200.00	90.27	275.38	175.47	180.37	103.64
LvLf	0.00	123.08	200.00	60.00	146.15	61.54	89.23	94.91
Total	1600	1600	1600	1600	1600	1600	1600	1600

LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Table 5. Simulated bills (€) (including net metering)

The effect of introducing net metering, i.e. the difference between the corresponding cells in Tables 5 and 6,[26] are illustrated in Figure 4 for the five tariffs which include a volume element. Since there is no volume component in tariffs 100C, 100F and 30F50C, they are not affected by net metering.



LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Figure 4. Bill differences (€) due to net metering

The size of bill reduction for household LvLf, the household taking advantage of net metering, varies considerably across tariff scenarios. As intuition suggests, remuneration increases in the weight of the volume component in the tariff scenario, with the exception of 30F70Vt. Although this tariff includes a 70% volume component, remuneration is reduced (to €8.39) because it is a ToU tariff so the bill reflects the household's relatively high demand on the system at peak. LvLf gains the greatest reduction (€42.11) under tariff 100V, where it is able to offset completely the amount of electricity withdrawn from the grid with the amount injected and so faces a zero bill.

[26] See Table A6 in Appendix III.

Remuneration of household LvLf is funded by all other households, resulting in increases in their bills of between 0.25% and 2.8% in our simulation model. In particular, the two households with high volumetric consumption, LH and HH, together bear 60% of the burden of net metering, whereas a household with solar PV and thus very low volumetric consumption (Lvl or HvL) bears only about 3%. This cross remuneration to implement net metering exacerbates the trade-off between incentives and distributional fairness that arises from using a volume-based tariff as identified in Section 4.1. The combination of a volume-based tariff and net metering offers strong incentives for households both to self-generate and to feed into the grid, which may help towards environmental objectives, but could raise the costs for other households.

While this stylised model is static, it reflects some realistic incentives for households to install renewable energy systems, self-generate and feed surplus into the grid, and so contribute to a clean energy transition and fulfil environmental obligations. However, there are clear adverse impacts for households who are unable or unwilling to install solar PV, and thus are faced with higher bills. Such households may have lower income and wealth than those who are able to take advantage of net tariffs, and social imbalance in benefits and costs may hamper the public acceptability of new supply technologies.

5. Conclusion

Our simulation results demonstrate how combining a tariff based mostly on volumetric consumption with net metering offers strong incentives to encourage deployment of renewable energy systems, but may substantially increase the bill burdens of households without solar PV. Such a combination can be appropriate when few households use solar PV and the policy priority is to promote the deployment of renewable energy in the residential sector. However, as solar PV installers scale up and the policy priority turns to reducing distributional burden and specific cross-subsidies, incentive schemes such as net metering may require modification so that tariffs become more cost-reflective and distributionally fair.

We have outlined the arguments that to maximise efficiency and minimise forward-looking costs, consumers should make their energy decisions on the basis of the effect that their demand has on the total costs of the system. We consider the case where consumers who self-generate and feed electricity into the network does not necessarily save many costs if they still use the grid at times of system peak. Our simulations illustrate how basing charges on net volume use would result in very low charges for such consumers. Other users may have to bear the costs of their savings, which would impact particularly negatively on those who are unable to invest in new generation technologies or experience other impediments to participation. This example illustrates the potential tension between designing electricity tariffs to maximise incentives for adopting cleaner energy generation and potentially adverse distributional effects, especially in a system where distribution costs change little as a result of new patterns of use, and the cost of the incentives are met by other consumers within the system (i.e. there are few external subsidies).

These tensions underline the importance of understanding the likely distributional impacts of introducing tariff reforms, especially in the presence of incentive schemes such as net metering and feed-in tariffs. Much depends on tariff design, in particular the balance between different charging components, as our simulation examples have shown. If we ignore the overall savings to the distribution system which we hope would result in the longer term from better aligned incentives and consumer responses, then reduced bills for households with self-generation imply higher costs paid by other consumers when the tariff in place is mainly volume-based. When the tariff becomes more nuanced and cost-reflective, such as through a capacity component or a ToU element, then any cost reduction from self-generation depends on how peak demand is affected by self-generation. If self-generating consumers typically rely on the general grid for peak time supply, capacity and ToU tariffs do not guarantee savings for micro generators, and therefore can provide appropriate consumption signals while providing some mitigation of redistributive concerns.

Moreover, the effects of any tariff change depend on how consumers respond in practice, and empirical evidence and application of such behaviour are critical to understanding both the incentives offered by and distributional effects of tariff changes. Three practical issues are relevant to tariff reform. The first follows directly from our simulation example, namely that not all consumers are in a position to respond to the incentives offered. As in any distributional matters, the way that initial wealth and opportunities are distributed has direct consequences for how markets work. It is important to understand what barriers to participation exist, and to address these in an equitable manner. Such inequality in opportunity is often related to financial and tenancy limitations: consequences in the energy market may be rooted in causes which lie beyond it, as do the best instruments to reduce such barriers.

The second issue is that environmentally friendly tariffs cannot incentivise the desired change if consumers do not understand them. Even the most active consumers need to have confidence in clear signals about how their decisions affect monetary rewards, and be able to take action accordingly.

The third issue, related to the first two, is the speed of change, both to enable those consumers who are in a position to do so to respond to the new incentives, and to enable appropriate protection for those who cannot react and may suffer adverse consequences. The challenge is not just how to redesign distribution tariffs so that they incorporate and incentivise the wider changes to the electricity system, but how to estimate the associated aggregate and distributional impacts on different consumer groups and confront any adverse consequence, especially for vulnerable consumers. This may suggest a gradual and smooth transition, even if it delays adaption to changes and benefits for the overall system.

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Appendices

Appendix I: Table A1

Tariff component	Fixed	Capacity		Volume
		ex ante	*ex post*	
Advantage	• Simple • Stable • Predictable	• Signals that capacity has a price	• Signals that capacity has a price • Cost reflective	• Acceptable to consumers
Disadvantage	• Does not signal long term costs and so does little to encourage energy efficiency and system flexibility	• Reflects capacity costs to a limited extent	• Requires smart metering • Complex • Less predictable • Less acceptable to consumers	• Does not reflect capacity costs • Can raise revenue uncertainty for DSOs
Tariff charging basis for capacity and volume components	**Flat rate**	**Non-linear**	**Time-of-Use**	
			static	**dynamic**
Advantage	• Simple • Acceptable to consumers	• Can be designed to balance multiple objectives of affordability, conservation, efficiency and cost recovery	• Mitigates congestion • Reflects capacity costs • Signals the value of flexibility • Benefits engaged consumers financially	• Mitigates congestion • Reflects capacity costs • Signals the value of flexibility • Benefits engaged consumers financially • Can target specific system events on short notice
Disadvantage	• Less cost reflective • Can over-incentivise self-generation which does not always synchronise with system peaks	• Complex • Potential adverse consequences due to poor design or consumer understanding	• Predicted peak times may not coincide with actual system peak • Does not allow for variability when peak conditions occur	• Requires advanced metering • The risk of all consumers responding simultaneously to a single price signal • Traditional consumers who cannot change consumption pattern may face higher prices

Table A1. Tariff components and charging bases (based on CEER, 2017)

Appendix II: Case studies

At the core of practical tariff design and reform is the balance of different tariff components and/or combinations of the charging bases, and so it is useful to review the existing tariff structures in different jurisdictions, especially those attempting to accommodate new structures. This suite of cases is broadly representative, including four EU Member States, one EEA state and one US state, each tariff structure having a distinctive feature:

- **Italy**, where non-linear volumetric tariffs have been a key feature, but are to be discontinued;
- **Portugal**, where static ToU tariffs have been in place for a long time and dynamic ToU tariffs are to be introduced;
- **Romania**, where distribution tariffs are based only on volume;
- **The Netherlands**, where tariffs for household consumers are capacity-based and have no volume component;
- **Norway**, where the capacity component is expected to be given more weight, and public consultation has taken place to gather industry and consumer feedback on different models of capacity charging;
- **California – Pacific Gas & Electricity (PG&E)**, where comprehensive tariff plans, including more household-specific designs, are in place and have been extensively studied.

Italy[27]

Overview

Italy has 151 DSOs, which provide cost and quality data to the regulator, who in turn determines the distribution tariff structure. Tariff classes are first defined by customer types, namely household and business, and within each type further by voltage levels (low, medium, high and extra high). Tariffs for all classes contain fixed, capacity and volume components, but volume has a much higher weight in the design of residential tariff (66%) than in industrial tariffs (17%). Distribution and transmission tariffs are not separated for residential customers, and tariffs are not geographically differentiated. A social tariff scheme is implemented in the form of a discount for households with income lower than a fixed threshold. The cost of the scheme is not borne by DSOs.

Key features in tariff components and charging bases

In Italy, the capacity component is *ex ante* through the contractual capacity, and households can choose the size of the power limit: ≤ 3 kW or > 3 kW, to differentiate between low-use and intensive-use. The large majority of Italian households belong to the low-use group, and second homes that are not owner-occupied are charged as intensive-use households. One function of the smart meters installed in Italian homes is to ensure that the power delivered does not exceed the contractual limit, and to adjust the limit remotely upon any household request to change the limit.

ToU is not used for any of the tariff classes, but Italian households have faced IBTs for their electricity bills since the early 1970s. The volume component of distribution tariffs has a progressive structure. The initial design included three blocks which over the years grew to six, but the sizes of

[27] The case study on Italy is based on information from Austrian Energy Market Commission (2014), European Commission (2015), CEER (2017), European Commission (2017), and RES LEGAL Europe http://www.res-legal.eu/search-by-country/.

the initial blocks stay the same, as shown in Table A2. Block prices are different between the two household groups for the first two blocks: cheaper for low-use households and higher for intensive-use households (and second homes that are not owner-occupied).

Block	Size (kWh)
6	4,441 and above
5	3,541 – 4,440
4	2,641 – 3,540
3	1,801 – 2,640
2	901 – 1,800
1	0 – 900

Table A2. Block design of IBTs for Italian households

IBTs for energy distribution were initiated in Italy for conservation purposes as they provide incentives to save energy through higher marginal prices at larger consumption levels. Although block prices are not directly linked to income, since the initial consumption is priced low, IBTs also address the issue of affordability. However, the fact that the sizes of the first few blocks have not changed for the past forty years suggests that such design of IBTs has not taken account of the radical changes in households' socio-demographics and consumption patterns, and the development of technologies and the electricity sector in general.

While IBTs are an equitable option in theory, they do not always serve their purpose in practice (Lu et al., 2019). The Italian Parliament and Government identified the existing IBTs for households as ineffective and outdated. In relation to consumers, the existing IBTs are considered to have hindered transparency and hence consumer responses to investment incentives and energy efficiency measures, as the block structure has made bills extremely difficult to understand.

Tariff reform is under way to replace IBTs with linear tariffs[28], to allow more flexibility to household consumers in defining their contractual capacity. Such a change may have negative distributional impacts for low-income households.

Self-generation and net metering

In Italy, consumers with small-scale self-generation of renewable energy are entitled to be connected to the national electricity grid upon request. All consumers generating up to 500 kW are eligible to submit an application. Plants commissioned before 31 December 2007 were only eligible if their generation capacity did not exceed 20 kW, and plants commissioned before 31 December 2014 were eligible if their generation capacity did not exceed 200 kW. Net consumption is calculated once a year. If more energy is fed in to the network than is taken from it, plant operators are entitled to receive an economic compensation, which is calculated on the ToU basis.

Portugal[29]

Overview

The national energy regulator determines and publishes distribution tariffs for the one national and ten local DSOs in Portugal. Tariff classes are defined by voltage levels:

[28] A similar reform took place in California in recent years, where a simplified block structure has been retained. See the case study on California for more details.

[29] The case study on Portugal is based on information from Apolinário et al. (2006), European Commission (2015), CEER (2017), European Commission (2017), and RES LEGAL Europe http://www.res-legal.eu/search-by-country/.

- Standard low – typically households;
- Special low – typically small business customers;
- Medium – typically small industrial customers;
- High – typically large industrial customers;

Tariffs for all classes contain the same components, capacity and volume, but volume has a much higher weight in tariffs for households (62%) than tariffs for large industry (17%). Tariffs are not geographically differentiated. A social tariff scheme is applied to the network access tariff to enable an equal discount to be offered to all consumers, regardless of the contracted final tariff.

Key features in tariff components and charging bases

In Portugal, the capacity component is charged through contracted power for households. While both capacity and volume components are linear, the latter can be differentiated by static ToU. The options for households are no ToU, two-period ToU (peak and off-peak), and three-period ToU (peak, off-peak and super off-peak). Industrial customers are charged on a minimum four-period ToU for their energy consumption (peak, half-peak, off-peak and super off-peak), or more periods if they request it, together with variations between two seasonal periods.

Static ToU tariffs have been used in Portugal for a long time, representing 80% of the total demand. To benefit further from demand-side flexibility and to promote more efficient use of the network, the Portuguese energy regulator has created the regulatory framework to introduce dynamic ToU. As part of the cost benefit analysis, a pilot project has recently started with volunteer industrial users. Such a gradual, phased approach avoids the potential adverse impact on some consumer groups who are unable to react to price signals.

Romania[30]

Overview

Romania has eight DSOs. The Romanian Energy Regulatory Authority takes the main responsibility for setting distribution tariffs. DSOs may propose a change in the tariff for the regulator to access. Tariff classes are defined by voltage level (low, medium and high), which typically correspond to household, small industrial and large industrial, although no formal distinction is made between customer types. Households whose members earn an average income equal to or below the minimum wage may be eligible for social tariffs.

Key features in tariff components and charging bases

Romania is a special case where customers in all classes are charged only by the volume component. The pricing of the volume component is linear, although tariff levels differ across the eight DSO regions. Tariffs are not time-differentiated.

The Netherlands[31]

Overview

[30] The case study on Romania is based on information from Diaconu et al. (2009), European Commission (2015) and European Commission (2017).

[31] The case study on The Netherlands is based on information from European Commission (2015), CEER (2017) and European Commission (2017).

Eight DSOs distribute electricity in The Netherlands, and propose tariff structures to the regulator, who makes the final decision. Tariff classes are defined mostly by customer types, namely residential, small industrial and large industrial. Residential and small industrial customers are also defined as small users (connection size $\leq 3\times$ 80 A). Tariffs for different classes contain different components:

- Residential: fixed and capacity;
- Small industrial: capacity;
- Large industrial: capacity and volume.

Tariffs are similar for customers belonging to the same class. A separate, nationally-uniform metering tariff is available for residential and small industrial customers; for large industrial customers the market for metering is liberalised. There is no social tariff in The Netherlands.

Key features in tariff components and charging bases

In The Netherlands, all tariff components used are linear within each tariff class. ToU is used to a limited extent for large industrial customers. One distinctive feature is that the combination of tariff components differs across tariff classes, and, in particular, there is no volume component for residential and small industrial classes. Such capacity-based tariffs were introduced in 2009 for greater cost reflectivity and efficiency, as well as to reduce administrative costs considerably through simplified billing.

Small users are further divided into six capacity categories. As shown in Table A3, each category is assigned an 'accountable capacity' factor, which is lowest (0.05) in category 1 and increases to 50 in category 6. The tariff level charged for each category is determined by the product of a general tariff (€/kW) set by ACM, the competition authority, and the respective category factor.

However, the distributional impact of this tariff reform needed to be considered. *Ceteris paribus*, compared to volume-based tariffs, capacity-based tariffs would benefit households whose volumetric consumption is relatively high but connection capacity is relatively low; and would recover more costs from households whose volumetric consumption is relatively low but have high connection capacity. To mitigate the distributional impacts, such as sudden and large bill increases for some, households in The Netherlands were encouraged, through a reduction in connection fee, to lower their connection capacity. Those who could not reduce connection capacity were offered compensation, as their new bills would be significantly higher. However, because of the favourable conditions offered to consumers, the incomes of DSOs did not increase with the expected cost reduction.

Customer category	**Capacity**	**Accountable capacity factor**
1	$\leq 1\times6$ A on the switched network	0.05
2	$\leq 3\times25$ A + all 1-phase connection	4
3	3×25 A – 3×35 A	20
4	3×35 A – 3×50 A	30
5	3×50 A – 3×63 A	40
6	3×63 A – 3×80 A	50
Tariff level for each category is given by *General tariff €/kW × factor*		

Table A3. Capacity tariffs for small users in The Netherlands

Self-generation and net metering

The market for solar PV is relatively mature in The Netherlands, with prosumers being defined and regulated in general Energy or Electricity law. The Electricity Act sets out residential prosumers' right to feed self-generated electricity into the grid, for which grid operators must provide a contract to prosumers. Compensation to prosumers is determined by the net metering scheme. Under the net metering scheme, the electricity bill summarises how much electricity the prosumer has produced and the supplier has delivered, respectively, and the prosumer is only invoiced for the difference, i.e. net consumption. In order to participate in the scheme, the prosumer has to be a small user (connection size $\leq 3\times$ 80 A), with electricity supplied to and extracted from the same connection.

Norway[32]

Overview

The 131 DSOs in Norway have a high degree of freedom in designing network tariffs, which are subject to revenue caps set by NVE, the regulator, but not to detailed regulatory approval. Tariff class is defined by the voltage level to which a customer is connected. As a minimum, tariffs contain fixed and volume components, and a capacity component usually applies in addition for customers with high consumption ($>$ 100,000 kWh/year) or high installed capacity ($>$ 80 or 125 A). For small users the fixed component accounts for around 30% of the total network tariff on average.

Key features in tariff components and charging bases

While households in Norway do not currently face capacity charges, NVE intends to make capacity a mandatory component to be included by DSOs in their tariff designs, and that "capacity (kW) requirements are expected to be at least as important as energy (kWh) requirements". In order to achieve this objective, several models for capacity tariffs have been proposed:

- Installed capacity (NOK/A or kW);
- Subscribed capacity, with penalties for over-consumption, or use of smart meters to enforce the subscribed limit (the latter is similar to the Italian experience);
- Measured capacity usage (NOK/kW);
- ToU tariffs as an alternative to measured capacity.

Relating these models to Table A4, installed and subscribed capacity refer to *ex ante* contractual capacity. For installed capacity, the charge would be a fixed annual fee, differentiated by the level of connection. Subscribed capacity would mean a certain amount of capacity at a given price per unit. Measured capacity is *ex post* and requires further definition, e.g. whether it is peak demand within a defined period or an average of several peaks. Measured capacity requires advanced smart metering and all Norwegian households are expected to have the advanced metering system in place by the beginning of 2019. This also enables the use of ToU tariffs, which signal peak demand, and is considered as a potential alternative to measured capacity.

[32] The case study on Norway is based on information from NVE (2016, 2017), CEER (2017) and European Commission (2017).

Models	Public consultation	Household consumer survey	NVE
Installed capacity	• Indicates high capacity is more expensive than low capacity • Not very dynamic • Predictable in cost and revenue for customer and DSOs • Gives customers the scope to respond and influence their costs • Not a strong signal to reduce capacity demand	• Perceived as inflexible • Lack of motivation to adjust behaviour • One may choose higher capacity than usually required to avoid power-cut situation	Encourages DSOs to map customers' installed capacity
Subscribed capacity	• Not obvious in incentivising efficient use of the network • Not preferred	• Most appealing option to most of the survey participants • More comprehensible • Easy to relate to as similar to other subscriptions (e.g. mobile phone and broadband plans)	Does not plan to amend regulations in order to facilitate tariffs based on subscribed capacity
Measured capacity	• Links directly consumer behaviour and bills • Best suited for capacity charging	• Difficult to understand • Complex and unpredictable • Difficult to see implications • No one preferred	Intends to provide clearer guidelines to standardise how the settlement basis and settlement periods for capacity charges are determined
Time-of-Use	• Easy to communicate to customers than the idea of maximum capacity • Simple for customers to relate to and thus change behaviour • Attractive • Relatively easy to calculate and verify profitability	• Intuitive and coherent • Easy to understand and relate to • Not unanimously appealing to everyone • Unfair as punishes inflexibility over daily routine	Intends to open up for ToU tariffs as an alternative to measured capacity charges

Table A4. Consultation responses, consumer survey findings and NVE assessments regarding models of capacity charging

In 2015, NVE launched a public consultation regarding the possible changes to the regulation for setting network tariffs for customers on low voltage supply ($\leq$ 22 kV). The aim was to provide clearer guidelines for network tariff design, including the choice of capacity charging models. NVE also commissioned a survey on households' attitudes and preferences over various models of designing the capacity component. Table A4 above collates the responses to public consultation, findings from the consumer survey, and NVE's intentions with respect to implementing the four models. Note that the responses from the consumer survey differ from those voiced in the public consultation, where a proportion of contributions were from industry players with much better understanding of the capacity component than average household respondents.[33] The contradictory preferences are highlighted in Table A4.

California (PG&E)[34]

Overview

PG&E is a monopoly supplier to the northern part of California and is regulated by the California Public Utilities Commission. The regulator specifies revenue caps and PG&E determines network tariffs. Customers are broadly divided into residential and business classes, and in this case study, we focus entirely on tariffs for households. Household tariffs contain fixed and volume components, and for the volume component both IBTs and ToU tariffs are available.

A number of social and medical tariff schemes are in place. The California Alternate Rates for Energy (CARE) Program offers a discount of 20% or more on monthly bills of eligible and enrolled households. The Family Electric Rate Assistance (FERA) Program offers a discount on monthly bills for income-qualified households with three or more residents upon enrolment. The Medical Baseline Program provides financial assistance to households with special energy needs due to qualifying medical conditions. Any households with one or more residents who have a serious illness that could become life-threatening if energy service is disconnected upon non-payment can apply to become a Vulnerable Customer.

Note that these social and medical schemes, as well as the various tariff plans outlined below, are available if household opt-in for them, so engagement and response from consumers are crucial.

Key features in tariff components and charging bases

California has a long history of using IBTs, also known as tiered rate structures, to charge volumetric electricity consumption. An IBT was established during the energy crisis in 2001, and in 2015, most households were on a four-block IBT. A new design of IBT was introduced in 2015 to provide households with a clearer understanding of consumption and a simpler interpretation of bills.

The new design, as shown in Figure A1, has three blocks. Tier 1 is the baseline allowance, which is priced the lowest. A distinctive feature here is that the size of this allowance to some extent reflects household specifics, i.e. location and heating source, as well as the season, i.e. summer (May 1 – October 31) or winter (November 1 – April 30). Tier 2 is then applied to consumption levels between 101% and 400% of the household's own baseline and is priced at a higher level. Any consumption beyond tier 2, which is more than 400% of the baseline, is regarded as high usage and attracts a high use surcharge.

[33] The main documents of public consultation and summary, and consumer focus-group survey are only available in Norwegian. Table A4 is based on shorter English summaries of the main findings. We are unable to comment on issues related to methodology and process, and hence the robustness of the findings.

[34] The case study on PG&E is based on information available on PG&E's website, especially under the section RESIDETIAL – RATE PLANS.

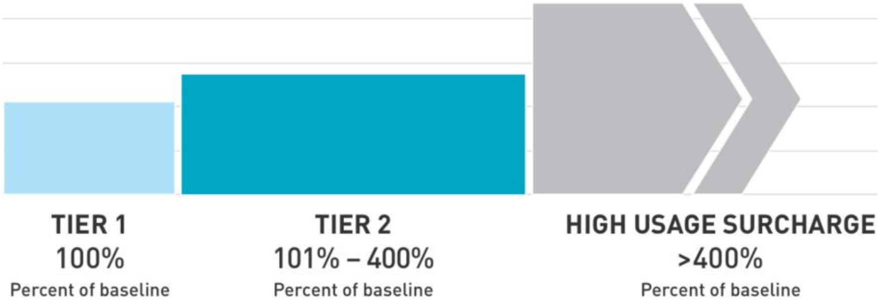

Figure A1. PG&E's tiered rate plan (from PG&E website)

PG&E offers three plans for ToU tariffs, with different peak hours. Prices also vary with season; the eight winter months have lower prices than the four summer months. ToU tariffs may also have a block structure. Under the first ToU plan, a baseline allowance equal to that under the IBT is included. Households enjoy a discount per kWh, known as the Baseline Credit, until the baseline allowance is reached. Households therefore have the opportunity to save more if they can reduce total volumetric consumption and shift consumption to off-peak hours.[35] The second plan does not include any block structure, and the plan price is lower than the price after baseline allowance is reached under the *first scheme*. PG&E expects most households to have transitioned to a ToU plan by 2020.

Besides the two charging bases, IBT and ToU, PG&E further provides "add-ons" that households can choose to enhance their base plans. With SmartRate add-on, households are offered a reduced price if they minimise their electricity consumption on especially hot days (≥ 96°F, called SmartDays) for a maximum of 15 days a year. This add-on is capacity-related and targets system demand peaks in hot weather. Enrolled households are notified the day prior to a SmartDay so that they can plan ahead to reduce consumption. PG&E claims that households can reduce their summer bills by up to 20% on households' summer bills through this scheme.

Solar Choice Plan is another option, giving households the choice of having half or all of their electricity supplied from solar energy, even if they have not purchased and installed any solar PV themselves. This 'go-clean' option further allows households to choose whether they would like supplies from a pool of solar projects in Northern and Central California, or from a regional and specific project. This plan appears to be more inclusive as those who have not invested directly in self-generation are still able to contribute to, and gain benefits from, clean energy.

These various tariff options can only achieve their design objectives if households actually opt-in to them. Fowlie et al. (2017) suggest that, while ToU tariffs have been found to reduce usage significantly during peak hours compared with tariffs that are not time-varying, the effect is much stronger for the group of households whose default tariff plan is ToU-based than the group of households who need to opt-in to a ToU tariff. This default effect, as they explain, is largely due to the inattention of consumers, and mirrors non-engagement from the energy market witnessed in Europe.

Self-generation and net metering

Households with self-generation are invoiced for their net usage under PG&E'S Net Energy Metering option. A special net meter is installed to measure the difference between the amount of self-

[35] Information on PG&E's Find you best rate plan page suggests the third ToU plan includes Baseline Credit as well, which is not clear from the Time-of-Use rate plans page.

generation by an enrolled household and the amount supplied by PG&E. The net meter is read monthly and the net usage appears as a credit or a charge, which accumulates over a 12-month billing cycle. During this cycle the household only needs to pay a non-energy service charge. At the end of the cycle the household will be issued a final balance.

This option requires the household to be on a ToU tariff, and the monthly credits or charges reflect the ToU basis. When the household generates more electricity than the home requires, the surplus will be fed into the grid, and a ToU tariff means higher credit for a surplus fed into the grid during peak time. If at the end of a 12-month cycle the final balance of the household is in credit, the household will receive aNet Surplus Compensation, at a rate set by the regulator.

Appendix III: Tables A5 and A6

Tariff scenario	Fixed component (€/year)	Capacity component (€/kWh)	Volume component (€/kWh)	ToU
100V	-	-	0.0842	NO
100C	-	30.7692	-	NO
100F	200	-	-	NO
30F70V	60	-	0.0589	NO
30F70C	60	21.5385	-	NO
50C50V	-	15.3846	0.0421	NO
20F40C40V	40	12.3077	0.0337	NO
30F70Vt	60	-	0.0866 (peak) 0.0173 (off-peak)	YES

Table A5. Tariff rates (when net metering is not available)

Bill	100V	100C	100F	30F70V	30F70C	50C50V	20F40C40V	30F70Vt
LL	3.41	0.00	0.00	2.39	0.00	1.71	1.37	0.61
HL	3.41	0.00	0.00	2.39	0.00	1.71	1.37	0.74
LH	12.52	0.00	0.00	8.76	0.00	6.26	5.01	2.23
HH	12.52	0.00	0.00	8.76	0.00	6.26	5.01	2.72
AA	7.97	0.00	0.00	5.58	0.00	3.98	3.19	1.42
LvL	1.14	0.00	0.00	0.80	0.00	0.57	0.46	0.34
HvL	1.14	0.00	0.00	0.80	0.00	0.57	0.46	0.34
LvLf	-42.11	0.00	0.00	-29.47	0.00	-21.05	-16.84	-8.39

LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Table A6. Bill differences (€) due to net metering