Designing distribution network tariffs that are fair for different consumer groups

Report for BEUC*

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October 2018

* This report is commissioned by BEUC and we thank BEUC staff and in particular Merce Almuni for helpful comments and discussions during the drafting of the report. The views and statements expressed in this report, however, reflect the authors' own independent views, and do not necessarily represent the views of BEUC or any other organisation.

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Executive summary

Increasing use of distributed generation, the introduction of Electric Vehicles and smart technologies and changing patterns of energy demand have all changed the way in which the distribution network for electricity is used, both in Europe and worldwide. These changes raise the question not only of how distribution systems should be used, but also how costs should be met. In particular, there are concerns about whether costs of 'traditional' networks will be stranded, and, if so, who will bear the costs.

The Clean Energy Package, proposed by the European Commission in 2016, emphasises the importance of competitive prices, efficiency and non-discrimination. It focuses on cost as a basis for tariffs, which should also allow consumers to feed in their own generation, and to pay the appropriate share of distribution system costs. The Package also acknowledges the importance of social objectives by individual Member States, while reiterating prohibition of specific cross-subsidies.

Within this cost-related framework this report outlines some concepts of fairness, emphasising that this criterion does not deliver a unique template, but depends both on how some costs are allocated and on different interpretations of fairness. We review some existing tariff structures, and simulate the effects of some structures through 'notional' households, allowing some households to self-generate. When consumers respond very differently to tariff signals, those who are unwilling or unable to respond to changing tariffs may find themselves bearing a greater burden of the system's costs, which raises particular issues around fairness.

We make the following recommendations:

1. Harmonisation of network tariffs across Europe would not follow the principles emphasised in the Package for two reasons: costs vary between different systems, both within and between Member States; and the preferences for recovering the 'non-allocable' costs may vary between Member States according to their social policies and needs.
2. Optional tariff structures provide a compromise between efficiency and fairness, and enable a smoother adjustment to a more efficient tariff structure. While a single tariff structure can reflect the 'correct' costs incurred by each consumer's demand pattern on the system, the non-allocable costs may be recovered in many different ways, as discussed in this report. Moreover if moving from one tariff charging basis to another (e.g. introducing a ToU tariff), the disruptive effects on household budgets can be minimised by offering options for the new structure, at least for a time. Those most able to recognise the potential benefits to themselves are most likely to be early switchers/adopters, and this will provide additional information for regulators to develop the tariff options over time.
3. Where there is a significant potential cost or saving from changing the number of households on the grid, this should be reflected in a fixed element of the tariff. Whether it should be reduced or increased from present levels depends both on the cost structure of the network and the current tariffs which are applied, as well as the factors in point 1 above.
4. Transparency is an important principle for the EU and for consumer understanding and acceptability. Identifying network costs separately is necessary for effective retail competition, and specifying the charges on the bill may also assist development of competition. Such details need to be presented in a way which clarifies rather than obscures the charges for the consumer.

1. Concepts of fairness in distribution network tariffs

The European Commission's recent Clean Energy for All Europeans proposals[1] call for "a fair deal for consumers", as well as an increase in energy efficiency and the use of renewable sources. The proposals, while requiring electricity tariffs to become market-based to facilitate more flexible supply networks, emphasise that the clean energy transition needs to be fair for different sectors, regions, and vulnerable parts of the society. The concept of fairness in distribution network tariff design could have different interpretations, and we start by presenting some traditional principles of energy pricing in the context of the Clean Energy Package.

Fairness is often linked to cost-reflectivity, which forms a major theme of the Package: namely that the prices which consumers face should reflect the costs which they impose. This can be seen as economically efficient from two broad perspectives.[2] First, from the system 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 system. Second, from the individual perspective, a consumer makes decisions about consumption (in this case whether to become connected to, stay connected to, and use the distribution system, at what times and on what terms) according to the costs she imposes on others using the network. The Strategic Objectives of the Council of European Energy Regulators (2018) include "… 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."[3] While in principle the concepts of cost-reflectivity and fairness overlap in this context, interpretation in detail can be more complex.

Marginal cost pricing is often considered to be an economically efficient charging system. In principle, this should apply to any and all margins; in particular for recovering the costs of initial connection, of maintaining connection and of carrying the electricity through the wires at times of greater congestion. Each of these will have short-run and long-run aspects. Short-run marginal cost differs from its long-run counterpart in assuming that at least one 'production input' is not variable. Such inputs may be the existing network costs, labour costs, or other 'fixed' costs, depending on the time scale and context. Prices based on long-run marginal costs provide long-term investment signals and are more stable, but they may fail to send efficient signals for short-run consumption decisions. Such short-run signals are particularly important if network capacity is itself a fixed element and liable to congestion, so that demand management may be required. Much academic literature (e.g. Borenstein, 2016) focuses on short-run marginal costs so that prices based on volume of electricity supplied reflect the incremental cost, which itself varies with time of day and year and capacity availability. These costs can be allocated to users on an *ex ante* or *ex post* basis. That is, prices can reflect forecast future costs or costs actually incurred to meet current demand. In most EU countries, the allowed revenues set by National Regulatory Authorities (NRAs) to regulated Distribution System Operators (DSOs) are on an *ex ante* basis.[4]

[1] https://ec.europa.eu/energy/en/topics/energy-strategy-and-energy-union/clean-energy-all-europeans.
[2] See, e.g. Council of the European Union (2018) Proposal for a Directive of the European Parliament and of the Council on common rules for the internal market in electricity (recast).
[3] https://www.ceer.eu/documents/104400/-/-/26da5caf-3496-fc45-6eda-4ede31f8e462.
[4] The allowed revenues typically reflect investments that are anticipated during the next regulatory period. See, European Commission (2015).

However, marginal cost pricing may result in a DSO loss if it cannot recover full costs,[5] which could be due to a number of reasons. First, distribution networks have the characteristic that average costs are lower, the more consumers are attached to the system, and so common costs can be shared between more users (i.e. there are economies of scale and/or density). The marginal cost of supplying an additional network user, long-run or short-run, is therefore generally below the average cost of supplying users across the system, so that a tariff based on marginal costs would not achieve full cost recovery. Second, some costs may be difficult to categorise as marginal costs because they are not attributable to any particular activity or user so there will be unallocated costs, e.g. the cost to the operator setting up its headquarters or assets required to supply the system as a whole rather than particular consumers or types of demand. This is to be distinguished from the third reason: unrecovered costs. Unrecovered costs are allocable to particular activities or users but have not been collected. For example, some costs are not directly related to the volume of electricity consumed by users, but are related to service connection or the capacity of the network to carry its maximum load.[6] If the tariff structure in place does not charge for these components, then the associated costs could remain unrecovered. Such costs, which may not be recovered through a volume charge, are particularly salient since the main cost driver of the network is its capacity, which is mostly related to provision for peak demand.

If the revenue collected from users is insufficient to cover the average costs of supply, the difference can be met from general taxation, and this might be viewed as fair in the sense that the tax and benefits system would presumably be designed to reflect the distributional priorities of each Member State. However taxes themselves cause inefficiencies elsewhere in the economy, and support of energy systems through taxation raises issues of state aid and distortion of the Single European Market; they are also challenging to administer if distribution systems are privately owned. So alternative ways of recouping revenue need to be explored.

One traditional approach to situations in which charging the marginal cost of supply does not result in a supplier recovering its full cost, is derived from Ramsey pricing (Ramsey, 1927). This is designed to provide the 'optimal' departure from marginal cost pricing where average costs need to be recovered. The idea is to recover costs whilst minimising demand distortions, by setting price according to an individual user's (or group of users') demand responsiveness or elasticity. Price is set higher for users whose demand is inelastic (not responsive to price changes), and lower for users whose demand is more elastic (responsive), so that demand is changed as little as possible from the level it would have been with marginal cost pricing. However Ramsey pricing almost always raises significant distributional concerns. Not only does it impose price discrimination, because prices are determined by consumers' responsiveness, as well as the costs which they impose; it may also involve requiring low-income users who consume electricity for 'essential' purposes (and so have low price responsiveness) to subsidise high-income users' luxurious consumption (which may be more responsive to prices).

The Clean Energy Package emphasises the importance of efficiency, both in general terms and specifically with regard to distribution tariffs; while cost-reflectivity, transparency and non-

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[5] In this report, we consider the costs of providing the distribution of electricity, not those associated with generation and transmission.

[6] See, Eurelectric (2016).

discrimination[7] are referred to in various contexts.[8] Ramsey pricing, although efficient, would clearly violate the principles of non-discrimination, highlighting potential contradictions and trade-offs between the principles. These are driven by the natural monopoly nature of network provision, a frequent history of public ownership and/or management, and the potential tension between the European Union drive for a common energy market and individual Member States' responsibilities for social provision. For these reasons, and because of supply and demand differences, there is no one-size-fits-all approach or unique 'best' design of distribution network tariffs.[9]

Electricity is generally considered to be an essential product, to which all households should have affordable access. Electricity consumption also has a typical pattern: it increases with income, but less than proportionately. So 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), and thus may be affected to a greater extent by the clean energy transition and any attendant price increases.[10] Such patterns also pose challenges to some ways of recovering costs from users. Increasing prices proportionately would impose an equal percentage (of energy bill) charge on consumers, but this would represent a higher proportion of the income of low income households on average. Levying any fixed charge would be even more regressive. This implies that other interpretations of fairness, especially *distributional justice*,[11] play an important role in tariff design and acceptability. The Clean Energy proposals, while calling for new electricity market design with increased energy efficiency and a rising share of renewables, emphasise the importance of securing "a fair deal for consumers", and contain a number of measures aimed at protecting vulnerable consumers from being left behind (European Commission, 2016).

Given the importance of efficiency in both theoretical concepts of fairness and the Clean Energy Package, this report focuses on balancing appropriate messages to encourage efficient use of the system with acceptability of charges for using a good that is essential to life. Network user groups can be defined in different ways, such as household and industrial users, metered and unmetered users, high-income and low-income users, etc. This research focuses specifically on different patterns of household demand, and discusses concerns around vulnerable consumers who may be less capable than average of reacting to tariffs and participating actively in the network.

Interpreting the idea of efficiency outlined above, one 'fair' way of designing tariffs is that prices paid by network users should, as a minimum, reflect the additional (or marginal) cost which they impose on the network. Since peak demand is associated with higher network costs, capacity-based and Time-of-Use (ToU) tariffs, which are each associated, in slightly different ways, with peak demand,

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[7] Non-discrimination is explicitly defined as explicit cross-subsidies between types of consumers and does not include a subsidy of one group which is funded by the supplier rather than other consumers, even though in practice other consumers will bear this cost unless the supplier receives financial support to meet the costs of the subsidy.

[8] In terms of protection, the Package makes clear the Commission's preference for generic social support to maintain energy affordability amongst vulnerable consumers, rather than doing so through energy tariffs.

[9] As suggested in CEER (2017), network tariffs are only one of many tools to encourage efficient use of the system, and may not be sufficient when used alone.

[10] "In 2014, the lowest income households in the EU spent close to 9% of their total expenditure on energy." http://europa.eu/rapid/press-release_MEMO-16-3986_en.htm.

[11] We focus on distributional justice of outcomes, rather than procedural and recognition justice. The energy justice implications of the latter two are investigated as part of the UKERC project Equity and Justice in Energy Market in the UK, with some emerging findings available at http://competitionpolicy.ac.uk/research/research-projects/equity-and-justice-in-energy-markets/rp2.

can help to give appropriate signals about costs.[12] Through reflecting such costs, they may lead to a more efficient system by reducing total costs of operating the system if peak load (and need for system capacity) is reduced, meaning less for users to pay on average.

With regard to distributional justice of cost allocation, the principles above pose additional challenges: for example, it could be argued that any cost allocation should not lead to sudden and sharp increases, nor significant fluctuations, in bills, because this would 'cloud' the price message and the efficiency characteristics of consumer response, and contradict the predictability criterion. 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 already poor and vulnerable,[13] unless adequate support can be provided, either through tariffs or other means.[14] This latter requirement may be a particular challenge when previous tariffs have not been broadly reflective of costs, or if changes on the demand or supply side result in substantial alterations in the nature and pattern of costs. Some changes of this kind are discussed in the next section of this report.

To mitigate such concerns, one option that is seen as more equitable, is to assign consumers to sub-groups according to grid impact, and base fixed charges and/or marginal prices on an increasing block structure, known as Increasing Block Tariffs (IBTs). Figure 1 illustrates an example of prices based on a three-block structure. Consumers fall into one of the blocks/groups according to, for example, their load factor or consumption (represented in this diagram along the Gaxis). All pay P_1 for the first G_1units, then the higher price (P_2) for the next level up to G_2, then P_3 for even higher units.

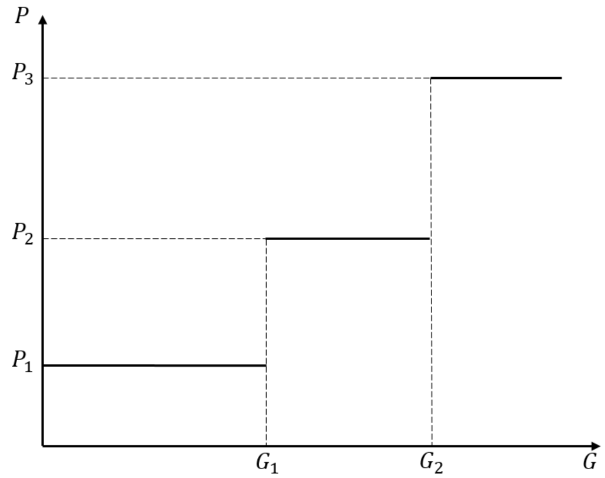

Figure 1. A three-block IBT

The efficiency argument for IBTs is that they provide consumers with incentives to use electricity more efficiently at high consumption levels. The distributional argument is that a first block can be constructed corresponding to the 'essential' amount of consumption at a low price; subsequent blocks reflect usage that is increasingly 'luxurious', and are priced accordingly. An ideal IBT, with sophisticated design, can achieve a balance between affordability, efficiency and cost recovery. Low-income households are more likely to pay only the lower price, since demand levels increase with

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[12] See Table 1 on p.12.

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

[14] For example, through the use of social tariffs. While social tariffs will not be discussed in the rest of this report, 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.

income, though less than proportionately; hence more costs are allocated to high-usage and wealthier consumers. However the empirical evidence on the effectiveness of IBTs in benefiting lower-income households and reducing consumption is mixed (Borenstein, 2016; Lu *et al*., 2018).[15]

In practice a variety of distribution tariffs is currently used, and section 3 discusses existing tariff classes, tariff components, and tariff charging bases, evaluating their pros and cons in theory[16], and including some examples, such as the use of IBTs. Before that, in the next section, we discuss some of the opportunities and challenges posed by changes in the pattern of costs and charges in electricity distribution.

2. Challenges from new electricity supply and demand patterns

In the past, consumers within a certain group (e.g. low consumption residential) tended to have similar demand profiles of electricity, and the use of volume-based tariffs[17] could be justified, even when it did not directly reflect the capacity-driven nature of network costs (Azarova *et al*., 2018). However the nature of electricity supply and demand is changing profoundly. Renewable energy sources, such as solar and wind, have become more widely adopted, with generation which is both more intermittent and less predictable than traditional sources. Electricity distribution has been revolutionised with technical innovation such as smart grids, smart homes, self-generation and storage: the fixed network built to carry electricity from generators to users will face very different demands as these changes evolve. Depending on the deployment of renewable energy systems in different households, consumers can exhibit diverse and less predictable demand patterns. The increase in electric vehicles (EVs) will further affect consumers' usage and potential storage significantly, with consequences for the operation and maintenance of the distribution network. While smart systems will enable more consumer participation (a major objective of the Clean Energy Package), these developments will require investment which impose considerable 'upfront' costs.

These changes, creating both opportunities and challenges, have led to focus on measures exploiting the flexibility potential of the system, and more generally policies emphasising efficiency.[18] The emergence of new opportunities – from advanced smart metering to self-generation – has direct implications for distribution tariff design and market-based dynamic pricing[19]. Consumers can potentially take a much more active role in providing flexibility, not only controlling their own consumption and bills, but also transforming the electricity system. All of these have implications for regulatory approaches and tariff reforms (Rodríguez Ortega *et al*., 2008; Schreiber *et al*., 2015; Jenkins and Pérez-Arriaga, 2017).

These developments render concepts of fairness even more relevant: how can the full benefits of technologies and innovations be unlocked without hindering distributional justice across consumer groups? While encouraging stronger involvement of consumers in the electricity market is clearly an

[15] The practical challenges of IBTs regarding their designs and consumer responses are discussed in depth in Lu *et al*. (2018), albeit in the context of residential water consumption.
[16] See Table 1 on p.12 for a summary.
[17] Currently distribution tariffs for households in the Europe are mainly based on electricity usage, not peak demand. See Section 3 for more details.
[18] For example, CEER (2014).
[19] One important development is feed-in tariffs, which reward and incentivise contributions from micro generation to the grid. The distribution system is a vital link to enable such consumer participation as emphasised in the Clean Energy Package.

EU priority, understanding the costs involved for consumers, and their actual responses to these opportunities, rather than just potential participation, is crucial for the assessment of distributional impacts and identification of barriers to participation.

Consumer participation in other parts of liberalised energy markets has been disappointing. While some consumers may respond enthusiastically to new opportunities, both the opportunities and consumer response are likely to vary considerably. For example, *The Big Switch* in 2012, the largest collective energy switching exercise in the UK, saw only around a quarter of (already highly committed) consumers switch their energy supplier upon being offered a lower price (Deller *et al*. 2014). UK is in the process of reintroducing widespread price caps to protect the two thirds of household consumers who do not take advantage of the best offers available. The increasing scope for consumers to play an active role, and the heterogeneity in their inclination and ability to take advantage of such possibilities, result in an uneven spread amongst consumers of the potential benefits from innovations. This is a particular concern for consumers who are unable or unwilling to invest in such developments and/or have to meet the cost of assets which are 'stranded' by changing usage patterns.

For example, self-generation allows active consumers to self-supply and so take less of their consumption through the wires from other sources, which would translate to lower electricity bills under volume-based tariffs (see Nijhuis *et al*.,2017). Since many of the total network costs remain fixed, this would result in much of the costs being borne by 'traditional' consumers who continue to rely exclusively on the network for supply. If, as is usual, the cost of providing the network (capital and to keep it running) is spread over its lifetime, the lower than predicted use of the grid means these historical costs, designed to serve a demand which was expected to be higher over the lifetime of the assets, would now be spread over the smaller, actual, usage. The subsequent higher network tariffs would raise equity issues for traditional consumers, who would essentially need to cover the costs 'stranded' by the more innovative consumers (see. e.g. Johnson *et al*., 2017) [20]. This begs the question of what would constitute a fair contribution by prosumers towards total cost recovery, particularly since prosumers are generally more advantaged than traditional consumers. Schill *et al*. (2017) regards distributional impacts as one of the main arguments against self-generation.[21]

The CLEAR Consumer Survey (2014) on renewable energy systems provides evidence on the key characteristics of consumers who have and have not adopted new technologies (e.g. solar panels), based on information obtained from 5012 respondents in five EU countries (the Netherlands, Belgium, Italy, Portugal and Spain). The main findings suggest that, 'adopters', i.e. survey respondents who have taken advantage of renewable-source-related technologies, are typically between 26-45 years old, have received higher education and are property owners. In contrast, respondents who have rejected the idea of taking advantage of these technologies, are typically above the age of 55, have fewer

[20] Alternatively, this could be regarded as a challenge to cost recovery for DSOs who are now exposed to volume risk because of lower than expected demand. Many European countries have been experiencing significant reductions in energy usage. Total distributed energy fell by 6.8% in Spain and 8.6% in Italy between 2011 and 2014 (Eurelectric, 2016).

[21] Another argument against self-generation mentions in Schill *et al*. (2017) is efficiency loss. Small-scale distribution generation cannot fully realise the potential flexibility benefits, which is usually obtainable from large-scale generation. As a result, additional costs may be incurred to provide for storage and other specific infrastructures.

educational achievements, and are tenants with no intention of owning a property.[22] CLEAR 2.0 (project in progress)[23] identifies financial incapacity as one of the main barriers to adopting new technologies.

The CLEAR Consumer Survey and a number of other studies confirm that those likely to be bearing the majority of the distribution costs include a higher proportion of more vulnerable consumers (the elderly, the less educated, and the less wealthy); while those who are better-off benefit because they use the distribution system less. Consequently, traditional consumers who remain passive because they are unable to invest and respond to opportunities offered by new technologies not only miss the benefits from innovations, but are also paying higher bills than those who participate actively in the changing system, e.g. becoming prosumers.[24] Such social imbalance may hamper the public acceptability of renewable energy innovations (Azarova *et al*., 2018).

Network distribution tariffs therefore need to evolve to account for flexibility and encourage consumers to draw value from new opportunities, whilst ensuring an appropriate balance of charges between traditional consumers and more innovative and active consumers; this should include protection of vulnerable consumers, especially in the transition period.[25] The recent CEER (2017) report clearly regards some net metering as a potential obstacle to fair cost allocation and efficient use of the system.

This also explains the importance of using other demand-side tools to encourage broader consumer participation and responses. For example, the primary driver for rolling out smart meters in the EU is European level legislation (European Parliament, 2015). Subsidies may be available so that consumers can request a meter free of charge or receive rebates when investing in smart appliances. Besides energy efficiency targets, the Clean Energy Package champions both the empowerment and protection of consumers. Support of energy efficiency investments by low income households, perhaps through energy communities, which are much discussed in the Package, could contribute to network efficiency by eliminating some of the participation barriers and enabling more consumers, not only those with their own financial resources, to benefit from technologies and innovations.

3. Evidence on existing tariff structures in EU Member States and other developed countries

3.1 Distribution network tariff structures

Network tariffs are composed of different elements. Although consumers may typically observe a standing charge and some unit prices in their bills, these prices are themselves dependent on various factors at multiple levels, including tariff classes, tariff components, and charging bases. A tariff class refers to a customer segment or category. 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),

[22] Between the two polar groups of 'adopters' and 'rejecters', the survey also has defined 'intenders', respondents who have planned to take advantage of RES-related technologies within the next two years, and 'thinkers', respondents who would consider taking advantage of these technologies.
[23] https://www.clear2-project.eu/.
[24] Considering beyond household consumer groups, CEER (2014) suggests that industrial users are the main beneficiaries of the current gains from demand-side flexibility as the current arrangements "make it much more attractive for large users with higher electricity consumption than for domestic households."
[25] The objective regarding vulnerable consumers in the Clean Energy Package, as stated in European Commission (2016), "is to ensure that they are not left behind as most consumers become active market participants."

metering (e.g. whether metered or unmetered and type of meter), geographic zone, etc. As a result, depending on the definition of tariff class, 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).

The focus of our review is tariff components and charging bases. Network tariffs typically have three main components, used either alone or in combination: fixed (€/point of delivery); capacity (€/kW); and volume (€/kWh). Common charging bases include flat rate and non-linear rates varying with volume or time of use. The advantages and disadvantages of each tariff component and each charging basis are discussed in CEER (2017) and are summarised in Table 1.

Fixed component tariffs are commonly known as standing service charges, [26] and are independent of consumers' maximum demand and consumption volume. Capacity component tariffs charge consumers for the availability of a maximum load, and they can be *ex ante*, i.e. based on the maximum contractual capacity, or *ex post*, i.e. based on consumers' actual peak demand over a period, or a mix of both. Volume component tariffs charge consumers for the total usage of electricity from the grid.

Within the use of capacity and volume components, further design options are available, for example whether the component is charged on a flat rate or a non-linear basis.[27] Under a flat rate tariff, all consumers pay the same unit price regardless of capacity reached or volume consumed. A non-linear tariff differentiates unit prices according to capacity or volume consumed. Figure 1 (in Section 1) depicts a particular example of a non-linear basis, an Increasing Block Tariff (IBT), where the price paid for each unit (consumed, or of capacity) increases when volumetric consumption or capacity reaches a particular predetermined level, or block.

Time-of-Use (ToU) tariffs charge different prices for volumetric consumption at different time periods of the day, week or year (e.g. peak, shoulder-peak, off-peak), and may be considered as an alternative approach to charging directly for capacity. It can be either static or dynamic. Under static ToU, prices and time periods are pre-defined based on historical data on grid use, and are fixed until the next adjustment (e.g. next month or next year), whereas under dynamic ToU tariffs, prices 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[28]).

[26] This is different from an up-front fee, which is typically a one-off charge. This report does not consider up-front fees.

[27] The fixed component may be different for consumers belonging to different tariff classes. Since we focus on tariff components for household consumers, we do not further discuss charging basis for the fixed component.

[28] This is under consideration by Ofgem, see https://www.ofgem.gov.uk/electricity/retail-market/market-review-and-reform/smarter-markets-programme/electricity-settlement.

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	• Reflect 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 1. Tariff components and charging bases (based on CEER, 2017)

Distribution networks have traditionally been dominated by users relying exclusively on the network for electricity supply, and costs have been mainly recovered to reflect network usage through a volume-based charge. With the changing supply and demand patterns discussed in Section 2, network costs are increasingly driven by the growth of embedded generation, which will be exacerbated by the different demands of EVs; consequently DSOs have been experiencing volume and revenue risk. [29] Capacity-based and ToU tariffs, better reflecting the main driver of network costs, are important instruments to optimise the use of networks and enhance flexibility, and may help to neutralise the impact of variations in volumetric consumption on DSOs' revenues. They can also mitigate or avoid cross-subsidisation between consumer groups, and there is broad support in the EU for a move towards capacity-based tariffs (CEER, 2017). Flexibility could be introduced through other mechanisms, for example auctions to pay for flexibility through aggregators, or more specific arrangements for load shedding when necessary. The effect will be similar in that the costs/rewards will be reflected in lower prices for those who can offer such flexibility.

3.2 Case studies

The structure of existing distribution network tariffs varies considerably across countries, and the optimal tariff design depends on the objectives of each system. In particular, tariff reforms triggered by the development of new technologies and changes in electricity systems are at different stages in different jurisdictions. 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.

After consultation with BEUC, the following for case studies have been chosen for this report:

- **Italy**, where IBTs 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.

This suite of cases is broadly representative, including four EU Member States, one EEA state and one jurisdiction outside the EU area, each tariff structures having a distinctive feature. For all cases, we focus on empirical evidence of tariff structures for households.

Table 2 summarises the key features of each tariff structure, as well as identifying the body which takes the main responsibility for setting distribution tariffs. Net metering refers to the ability of those who feed energy into the grid to pay distribution charges based on the difference between the volume

[29] See footnote 20.

of electricity which they take from the system and that which they put in.[30] Such a net tariff 'underestimates' the total usage of the distribution system, which prosumers use both when exporting and importing energy. We summarise the arrangements for net metering in the cases where the scheme is available.

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 2. Key features of household tariffs in selected cases

3.2.1 Italy[31]

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 (as, for example, shown in Figure 1) which over the years grew to six, but the sizes of the initial blocks stay the same, as shown in Table 3. Block prices are

[30] Under this simple form of net metering, units of electricity taken from and fed into the grid are assumed to have the same value.

[31] 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/.

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 3. 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.

As mentioned in Section 1, while IBTs are an equitable option in theory, they do not always serve their purpose in practice[32]. 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[33], 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.

[32] Lu *et al*. (2018) suggest that the challenges associated with using IBTs are generally in two folds. First is the difficulty and complexity in designing an IBT that meets simultaneously multiple objectives, where decisions on a number of parameters, including the number of blocks, block sizes and block prices, require all relevant data on consumers and usage to be readily available and accurate. Second, the effect of IBTs ultimately depends on whether consumers pay attention and respond to correct price signals. If the complexity associated with IBTs means consumers are less likely to be able to respond, any gain from using IBTs may be modest and there may even be adverse effects.

[33] 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.

3.2.2 Portugal[34]

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:

- 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.

3.2.3 Romania[35]

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.

[34] 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/.

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

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.

3.2.4 The Netherlands[36]

Overview

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 4, 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.

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

Customer category	Capacity	Accountable capacity factor
1	≤ 1×6 A on the switched network	0.05
2	≤ 3×25 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 4. 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 ≤ 3× 80 A), with electricity supplied to and extracted from the same connection.

3.2.5 Norway[37]

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.

[37] The case study on Norway is based on information from NVE (2016), CEER (2017), NVE (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 5. Consultation responses, consumer survey findings and NVE assessments regarding models of capacity charging

Relating these models to Table 2 above, 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.

In 2015, NVE launched a public consultation regarding the possible changes to the regulation for setting network tariffs for customers on low voltage supply (≤ 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 5 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.[38] The contradictory preferences are highlighted in the table.

3.2.6 California (PG&E)[39]

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.

[38] The main documents of public consultation and summary, and consumer focus-group survey are only available in Norwegian. Table 5 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.
[39] The case study on PG&E is based on information available on PG&E's website, especially under the section RESIDETIAL – RATE PLANS.

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.

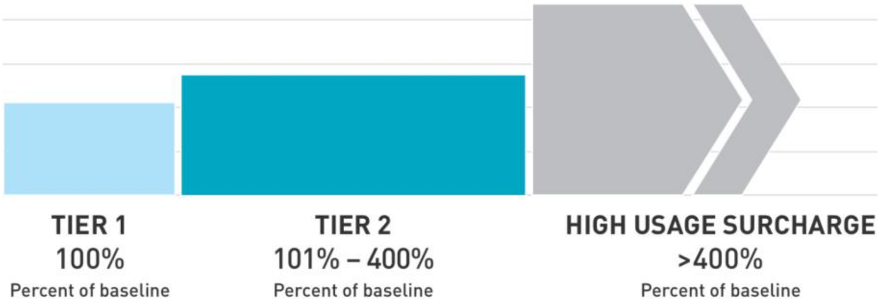


Figure 2. PG&E's tiered rate plan (from PG&E website)

The new design, as shown in Figure 2, 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.

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.[40] 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

[40] 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.

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-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 a Net Surplus Compensation, at a rate set by the regulator.

4. Potential tariff structures and their implications for different consumers

This section assesses a series of stylised network tariffs for recovering distribution network costs, based on the principles and evidence discussed in previous sections, with respect to their effects on the bills of a number of hypothetical households with diverse energy use profiles[41]. These energy profiles are chosen to denote a range of different demand (and supply) patterns, and the tariff options are based on those which have been applied and proposed. They are intended to be illustrative rather than representative, with which we aim to provide insights on the direction of possible changes rather than precise quantitative estimates.

Section 3 has identified the applications of different combinations of tariff components and charging bases in different locations and jurisdictions. Since these tariff elements have different advantages and disadvantages, the actual structures adopted reflect the trade-offs that have been made in finalising tariff designs. As renewable energy systems are deployed in the residential sector, and patterns of household demand change, new tariffs will be developed and it is important to understand the associated distributional impacts on different consumers. For example, while more capacity-based, time-differentiated tariffs have been suggested as fairer ways to allocate network costs from the efficiency-enhancing point of view, and schemes such as net metering have become available for the promotion of clean energy, how will such changes directly influence the monthly bills of household consumers with different demand (and supply) patterns?

[41] Household income as an additional factor is considered in Appendix B.

4.1 Framework

We have constructed a stylised tariff design model, using a simplified set of parameters that describe the network usage across a small number of 'notional' households and network costs.[42] As shown in Table 6, the eight households differ from each other in one or more ways regarding annual contractual capacity, annual electricity consumption and peak time consumption and whether there is any solar system installed; and if there is, whether the household produces more than it consumes at certain times, and hence has the scope to feed excess supply into the grid.

We denote each household with an abbreviation for ease of reference hereafter. The first letter of each abbreviation refers to the level of contractual capacity, and the second/third to the level of volumetric consumption from the grid; while an f indicates that the household is able to feed surplus into the grid. For example, household LL has low capacity and low consumption, household HvL has high capacity and very low consumption, and household LvLf has low capacity, very low consumption and is able to feed into the grid if allowed. Note that the three households with solar PV all have very low volumetric consumption as a result.

Household abbreviation	**Contractual capacity** (kW/year)	**Volumetric consumption** (kWh/year)	**Ratio of consumption (kWh) at peak time**	**Solar PV**	**Amount fed into grid** (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 6. Notional households

We have assigned values to the consumption characteristics listed in Table 6. The values of different levels of contractual capacity and volumetric consumption are based on the typical

[42] Several papers have used this method to understand the distributional effects of electricity tariffs, see, e.g. Brown *et al*. (2015) and Azarova *et al*. (2018), albeit they do not consider the possibility of self-generation and thus net metering.

household with a contractual capacity of 6 kW and an annual consumption of 3,500 kWh considered in European Commission (2015). Households are assumed to have different peak time consumption ratios.[43] Non-prosumers with high contractual capacity, HL and HH, are assumed to have very peaky demand (a ratio of 2/3) and non-prosumers with average or low contractual capacity are assumed to be more able to spread consumption evenly across time (a ratio of 1/2). Prosumer households are assumed to rely on the network for supply only during peak time and therefore have a peak consumption ratio of 1, and household LvLf is assumed to feed 500 kWh into the grid during off-peak time. Total consumption is the sum of consumption from all households and total contractual capacity is the sum of capacity connection of all households.[44]

Network costs vary substantially across EU Member States, with the average total charges for a household consumer being about €172/year in 2013 ,[45] based on which we assume, for ease of calculation, the average revenue can be collected from each household to cover network costs in our model is €200/year. This leads to a total revenue of €1600/year, which one can think of as a regulated revenue cap. This is the basis for the stylised tariffs derived for each combination of components in Table 7.

We emphasise that all the values assigned, including all household descriptions and the network costs, are hypothetical and are not based on any actual data. We include the eight households with diverse electricity use profiles because we focus on the distributional impacts of tariffs with different charging components and charging bases on households. 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.[46] However our model is general enough to be adapted and applied using specific household samples and cost data,[47] where there may be emphases on (i.e. more weights attached to) households with some particular energy use profiles.

By assuming these demand and usage features and combination of households across the network, we can illustrate how different tariff structures would allocate network costs to different households. These notional households may further be associate with specific socio-economic characteristics on average, such as income and household size. We discuss some possible links to income in Appendix B.

Table 7 presents the suite of stylised tariffs that are identified and examined.[48] The set includes tariff structures differing in the weights for each of the three components: fixed, capacity and volume, and some reflect tariffs which are currently used by Member States (e.g. Table 2). For example, as discussed in Section 3, the tariff in Romania is 100% volume-based (100V); Norway uses a combination of 30% fixed component and 70% volume component (30F70V); volume component is not used in household tariffs in The Netherlands; Portugal uses a combination of capacity and volume components (similar to 50C50V if in equal proportions); and Italy uses all three components (similar to 20% fixed, 40% capacity and 40% volume, 20F40C40V). Besides the capacity component, ToU is a

[43] These ratios are for symbolic purposes only, since their calculation depends on how the peak period is defined.
[44] More calculation detail can be found in the simulation excel sheets accompanying this report.
[45] See Figure 11 (p.126) in European Commission (2015).
[46] This also means that 12.5% of the population in our model can fed into the grid, which is much higher than the current reality according to information held by BEUC.
[47] For example, see Azarova *et al*. (2018) using data on Austrian household electricity consumption.
[48] See Table 11 in Appendix A for specific rates charged under each tariff scenario.

desirable feature mentioned in various policy reports and the Clean Energy Package, and is also considered (e.g. 30F70Vt). Under the ToU scenario, peak time price is assumed to be five times higher than the off-peak price. Net metering, when included, may be available for the household who feeds into the grid at times of excess household generation over demand.

Tariff scenario	**Fixed component** (€/year)	**Capacity component** (€/kWh)	**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 7. Stylised tariff scenarios

These tariffs are used to simulate bills for the notional households introduced in Table 6. Since we are not exploring tariff options and their impacts on households in a particular country, there is no benchmark tariff or status quo on which to base our analysis. Instead, we compare the simulated bills of different households, and highlight general trends and key observations. Given the total revenue 'cap' that can be collected from households, the charges on each component differ under different scenarios. That is, the way in which costs are recovered varies with tariff design and is reflected in the simulated bills. Further, comparing the situations with no net metering and with net metering, we can illustrate how various tariff scenarios may benefit the prosumer household differently.

4.2 Simulation results and analysis

4.2.1 Electricity usage profiles, tariff designs and bills

We first consider the state of world where household prosumers can consume the electricity they self-generate, but cannot feed any surplus into the grid, and so net metering is not available. The simulated bills for each household under each tariff scenario are presented in Table 8.[49] All figures produced in this sub-section are based on Table 8 to aid explanation, demonstrating different ways of understanding the results, which we emphasise as offering qualitative insights rather than quantitative estimates.

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

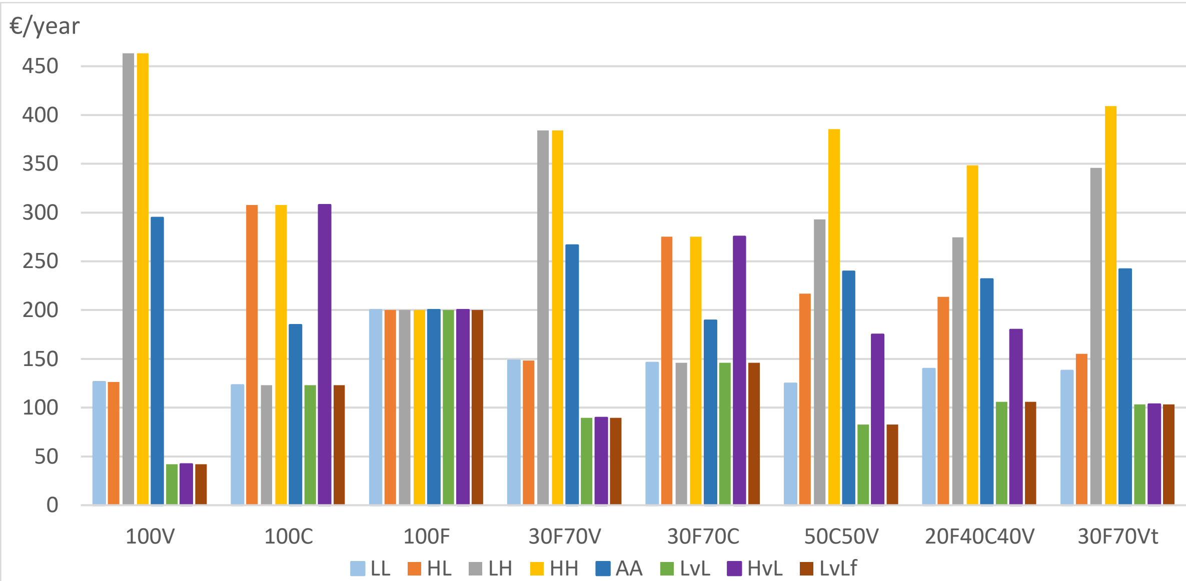
[49] See the simulation excel sheets accompanying this report for how bills are calculated.

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 8. Simulated bills (€)

The bills vary with household electricity use profiles and tariff design, each set generating a total revenue from across the households of €1600 (equivalent to €200 from each of the eight households in tariff 100F, where there is a constant charge across households). Since tariff 100V is entirely volume-based, and we feature four volumetric consumption levels (very low, low, average, high), it generates four different bills and households with the same volumetric consumption level face the same bill. Similarly, as Figure 3 shows, tariff 100C generates three different bills. When the tariff includes both capacity and volume components, such as 50C50V and 20F40C40V, we observe that **bills become more 'tailored' as the tariff takes into account a wider range of usage features for each household**.[50]

The marginal costs attributable to each component of the tariff (fixed, capacity, volume) will vary across distribution systems, according to factors such as patterns of supply and demand (e.g. peakiness), density of consumers and maturity. Cost-reflective tariffs would generally reflect all three elements, but in different proportions. A ToU tariff is a way of capturing the capacity element of the costs at times of peak demand, when extra pressure on the system would incur additional costs.

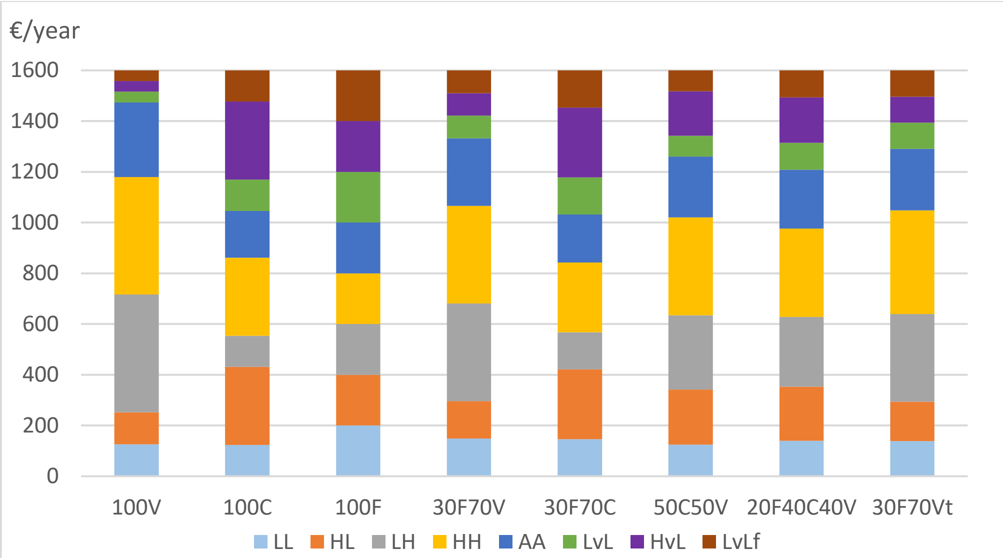


LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption;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

Figure 3. Simulated bills (€) under each tariff scenario

Figure 4 shows an alternative illustration of Table 8, emphasising the different ways in which tariff scenarios allocate the total revenue of €1600 across the eight households. In Figure 4, each bar represents an outcome of revenue allocation, with the different colour sections corresponding to the amount allocated to each household. Some tariffs allocate revenue more evenly than others.

[50] Only households LvL and LvLf face the same bill, as they have the identical contractual capacity and volumetric consumption, and differ only regarding their ability to feed into the grid.



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. Revenue allocation (€) under each tariff scenario

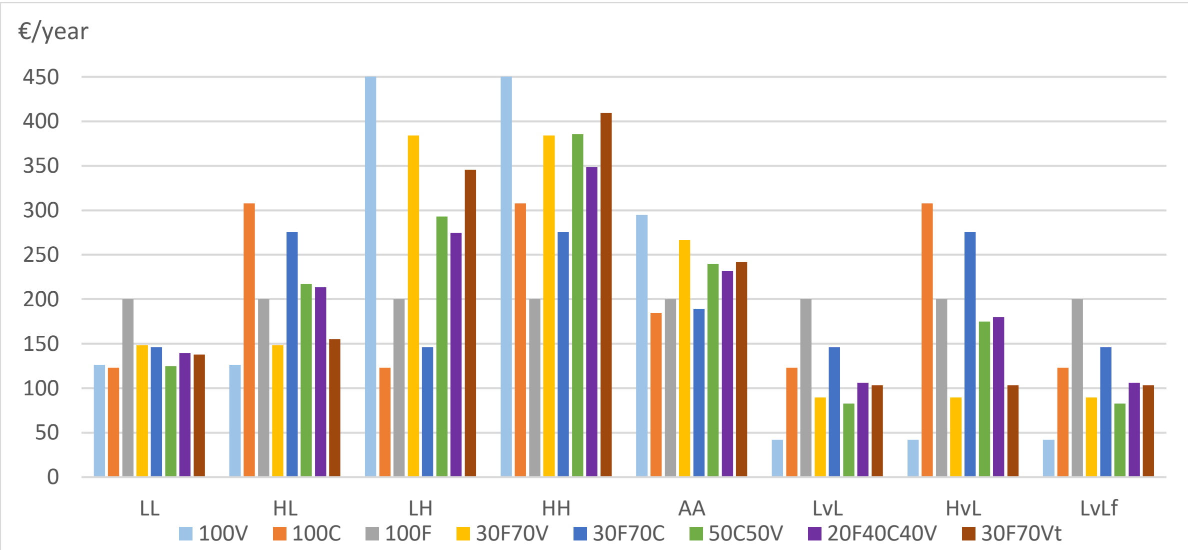
LvL – low capacity, very low consumption; **HvL** – high capacity, very low consumption; **LvLf** – low capacity, very low consumption, able to feed into the grid if allowed

Figure 5. Costs allocated (€) to prosumers under each tariff scenario

Since we are interested in the distributional impacts in the presence of prosumers and others who might be able to reduce demand, for example through high efficiency, it is useful to focus on bills of the three prosumers, LvL, HvL and LvLf, under different tariff scenarios. Recall that they all have very low levels of consumption from the grid as a result of having installed solar PV, all their consumption is during peak time and one of them has high contractual capacity. As shown in Figure 5, the patterns of allocation differ considerably across scenarios. Amongst our tariffs, prosumers benefit the most from self-generation and reduced consumption from the grid under tariff 100V, with the bill being €42.11 each, and the least under 100F, with a bill almost five times higher. Furthermore, tariffs with a capacity component, such as 100C and 30F70C, lead to higher charges for prosumers, especially to household HvL. Note that the ToU tariff 30F70Vt, although attaching a high weight to the volume component and no weight to the capacity component, still generates a much higher bill for prosumers than does 100V. This is because of its high unit price for peak consumption, which forms a high proportion of prosumers' usage from the grid.

Here we observe one potential trade-off: a volume-based tariff can offer a strong incentive to encourage the deployment of renewable energy systems, but if the cost of such an incentive is borne by the other consumers,[51] then a volume-based tariff may lead to substantial distributional concerns. In contrast, a capacity-based tariff may constrain potential redistribution, but may weaken households' incentive to adopt renewable energy systems such as solar.[52] We have omitted feed-in tariffs from this analysis, but they would clearly make a substantial difference to these calculations for both households who would benefit from them, and others who would have to pay for these benefits under our constant revenue assumptions.

We now move on to examine the rows in Table 8. Figure 6 illustrates, for each household, the bills under different tariff scenarios. Variations in bills under different tariffs are relatively small for some households such as LL and AA, whereas they are significant for some others such as LH and HvL. Again, we emphasise that the size of the differences depends partly on our assumptions about the proportion of households in each category, but our simulations indicates the direction of such changes under different assumptions.



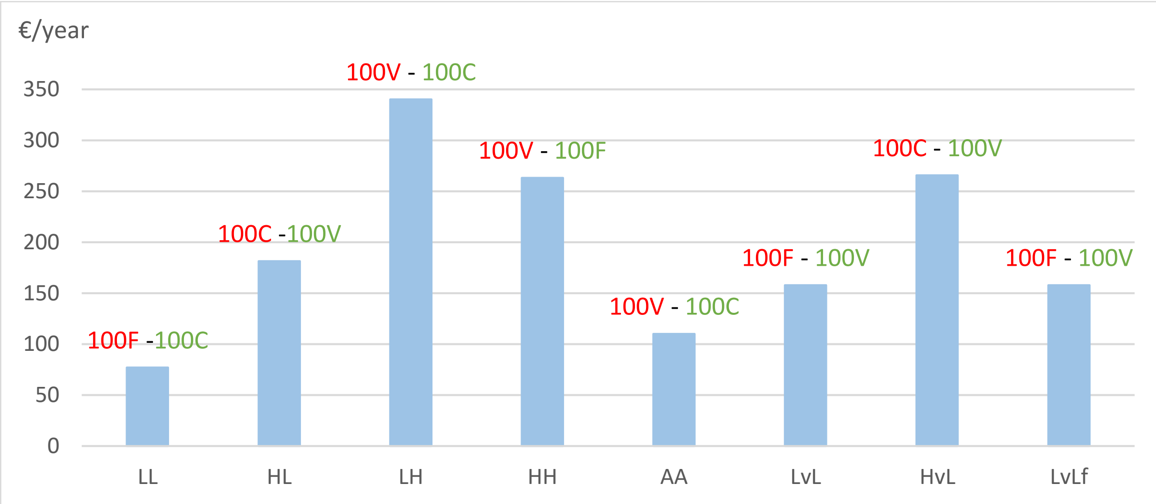
LL – low capacity, low consumption; **HL** – high capacity, low consumption; **LH** – low capacity, high consumption; **HH** – high capacity, high consumption; **AA** – average capacity, average consumption; **LvL** – low capacity, very low consumption; **HvL** – high capacity, very low consumption;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

Figure 6. Simulated bills (€) for each household

[51] The argument will change if the savings made by prosumers are not borne by the other consumers or DSOs, but as a reward for contributing to a reduction of system cost. However, so far there is no clear evidence suggesting that small-scale self-generation reduces system cost. Instead, there may be additional costs to provide for storage and other specific infrastructure (Schill *et al*., 2017). In our model we assume system costs are constant.

[52] Note that in the current reality this trade-off may not be as prominent since the deployment of renewable energy systems is still at its early stage and the current share of prosumers out of total households is much lower than that in our model, however it is important to consider possible distributional impacts and understand this potential trade-off.

Figure 7 presents the largest bill difference shown in Figure 6, i.e. the difference between the highest (red) and lowest (green) bills for each household. For example, household LL receives its highest bill under tariff 100F and lowest bill under tariff 100C, and its largest bill difference is given by the associated blue bar.



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 7. Largest bill differences (€) for each household

As we can see, all the highest and lowest bills are from tariffs 100V, 100C, or 100F. All households receive their 'best' and 'worst' bills under two of these three tariffs. **This observation underlines the tendency of tariffs with a single charging component to generate extreme outcomes for households, since they are based on only one feature of households' electricity usage profiles.**

With regard to the sizes of the largest bill differences, illustrated by the heights of the blue bars in Figure 7, some households face considerably larger bill differences than others: the greatest bill difference for LL is €76.92 whereas that for LH is €340.08. When taking a closer look at those households with high blue bars, namely, LH, HvL, HH, and to some extent, HL, we find that LH, HvL and HL exhibit polarised patterns regarding capacity and consumption – either low capacity but with high consumption, or high capacity but with (very) low consumption – as indicated by their abbreviations. They naturally benefit most from a tariff that does not charge the component where they score highly, and are worst off if the tariff charges entirely through that component, and thus face large bill differences under those two scenarios. **Households with these kinds of usage profiles may be prone to large bill increases 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.

The reason for a high blue bar for household HH in Figure 7 is different. Since it has both high capacity and high consumption, it is better off under tariff 100F where revenues are recovered equally from all households without reflecting these two demand characteristics. Households LL, LvL and LvLf, who feature both low contractual capacity and volumetric consumption, are correspondingly worse off under such a tariff. Therefore, while tariff 100F achieves equal bills for all households (e.g. see Figure 3), it clearly does not charge according to usage of the network. **A fixed rate tariff provides**

equality, but not fairness, if the latter is interpreted as relating charges to usage and the costs incurred.

While our model is single-stage and does not account for any household response to price signals under different tariffs, **one might expect tariffs containing a single component, e.g. 100V, 100C and 100F, to send strong, specific signals to households, and require careful consideration before implementation.** For example, 100F sends the signal that electricity has one cost regardless of usage (effectively a fixed charge to remain connected to the network), which clearly does not offer any incentive for an efficient use of the network.

4.2.2 Net metering

Now we consider the state of world where household prosumers can feed surplus into the grid and may be remunerated through net metering, under which the household pays when it withdraws more units of electricity than it feeds into the grid, and is only billed for the difference. Among the eight notional households introduced in Table 6, households LvL, HvL and LvLf have installed solar panels; LvL and HvL do not generate any surplus and so are unable to feed into the grid, whereas LvLf is able to feed 500 kWh/year into the grid.

However, whether LvLf receives remuneration, and its size, depend on the tariff scenario. As indicated in Table 7, net metering is feasible under the five tariffs which include a volume component: 100V, 30F70V, 50C50V, 20F40C40V, and 30F70Vt.[53] Remuneration is calculated based on the assumption that the units of electricity taken from and fed into the grid are charged at the same rate.[54] For example, if the tariff is entirely volume-based, then the bill for household LvLf would be zero. But if the tariff is entirely fixed, regardless of usage, then there would be no remuneration for feeding electricity into the grid; and if the tariff has a ToU element, then remuneration should also be time-differentiated.

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 9. Simulated bills (€) (net metering)

[53] This is based on the assumption 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.
[54] In reality, net metering may not always take this simple form.

Since remuneration under net metering is not provided by any external financial resource but endogenously by the notional population, it has an impact on the bills of all households.[55] Table 9 reports the simulated bills for each household under each tariff scenario. The results depend on our assumptions about proportions of different types of household, and are therefore indicative of direction of change, rather than its size.

Table 10 reports the bill differences driven by net metering for each household under each tariff scenario. Note that since net metering has an effect through the volume component, it leads to no bill difference under tariffs 100C, 100F and 30F50C. Under the tariffs with bill differences, the differences are negative for household LvLf and positive for all other households, suggesting net metering drives LvLf's bills down and drives all others' up.

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 10. Bill differences (€) due to net metering[56]

Figure 8 provides a graphical comparison of the relative sizes of reduction in bill due to net metering for household LvLf under the five tariffs containing the volume component, and how the burden is distributed across the other households. This of course depends on our assumption that the population consists of one of each of our eight household types – the implications would be different if there were many more of some types of household than of others. We observe that the size of reduction for household LvLf differs considerably across tariff scenarios. Intuitively, it is decreasing in the weight of the volume component in the tariff structure, with the exception of 30F70Vt. Remuneration is the highest (€42.11) under 100V where LvLf is able to offset completely the amount of electricity it withdraws from the grid with the amount it injects, and thus faces a zero bill. As the tariff contains more components, and thus attaches a lower weight to the volume component, the remuneration becomes smaller and LvLf's bill becomes higher. However under tariff 30F70Vt, although the volume component has a high weight of 70%, the reduction in bill for household LvLf is the lowest (€8.39) among the five tariffs because it is a ToU tariff and also reflects the household's demand on the system at peak. Since household LvLf withdraws from the network during peak time but feeds surplus into the grid during off-peak time only, the associated reduction is based on the off-peak rate, which is considerably lower than the peak rate, and so is smaller in total.

[55] The volume fed into the grid by household LvLf is assumed not to be consumed by the notional population, i.e. generate additional distribution volume from them.

[56] See Table 8 for bills when net metering is not allowed.

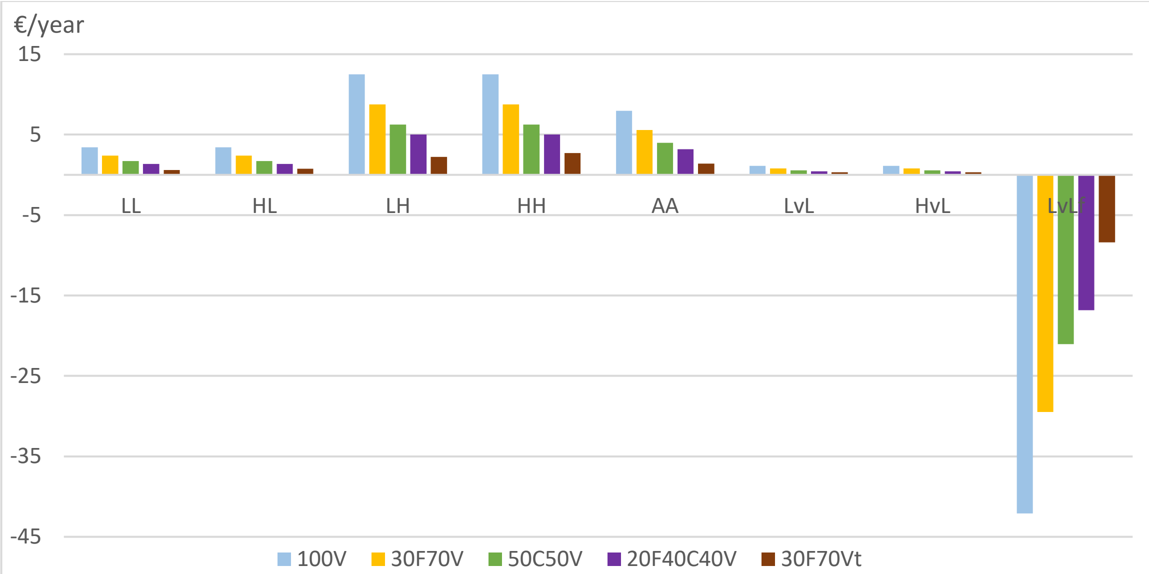


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Figure 8. Bill differences (€) due to net metering

All other households contribute to the remuneration for household LvLf, resulting in increases in their bills of between 0.25% and 2.80% in our simulation model. In particular, the two households with high volumetric consumption, LH and HH, together bear 60% of the burden in the presence of net metering, whereas a household with solar PV and thus very low volumetric consumption bears about 3%.

We have discussed a potential trade-off arising from the use of a volume-based tariff: it can offer a strong incentive to encourage the deployment of renewable energy systems, but may lead to substantial distributional consequences. **Such a trade-off may be more prevalent when a net metering scheme is available, as a volume-based tariff offers the greatest remuneration for not only being a prosumer, but also feeding into the grid. The distributional concerns are clear if the remuneration is met by other households, especially those without renewable energy systems.** It may also lead to volumetric risk for DSOs.

If we allow consumers to respond to incentives, one may expect more households to be attracted by remuneration under net metering and start feeding into the grid. While this increases the share of green energy and may potentially reduce the cost to the system as a whole[57], it may have implications for households who are unable or unwilling to install solar PV and thus face even higher bills as more households benefit from net metering. Tariffs containing multiple components or ToU element may help to alleviate the concern, although the signal to encourage the deployment of renewable energy systems may become weaker.

A net metering tariff is based on a presumption that feeding into the distribution system saves costs equivalent to those incurred by a similar quantity of electricity delivered to a household's premise. Although the need not to convey the electricity would save some costs, including system losses, particularly if it results in lower peak demand for the system as a whole, there may be

[57] Note that this is not captured by our model, see footnote 51.

additional costs. These may include adapting a distribution system which was designed to deliver energy from a centralised point to dispersed households into one which accommodates ‘two-way traffic’ from micro renewable sources. The balance between these savings and costs will vary between systems and at different times and places on each system. While encouraging such micro generation may help to meet renewable targets and environmental obligations, implications for the distribution system may be more complex.

Throughout Section 4 we have focused on our notional households’ electricity usage profiles, rather than any socio-economic characteristics, when discussing the distributional impacts of different tariff structures on these households. In Appendix B, income as one major socio-economic factor is added to household profiles. While information is available on the relationship between total energy expenditure and household characteristics (see, e.g. Deller and Waddams, 2015), using average characteristics is less helpful for this discussion than considering particular examples of energy consumption alongside specific demographic features. We therefore assign income levels to notional households in order to demonstrate both typical and atypical combinations, and the issues which may be raised for alternative interpretations of fairness, especially in the presence of vulnerable consumers.

5. Conclusion, recommendations and directions for future work

The Clean Energy Package “sets out the vision of an Energy Union with citizens at its core, where citizens take ownership of the energy transition, benefit from new technologies to reduce their bills, participate actively in the market, and where vulnerable consumers are protected.” It emphasises the importance of market prices in providing the right incentives for the development of the network and for investing in new electricity generation, and urges the incentivisation of network tariffs which facilitate flexibility and the improvement of energy efficiency in the grid. Distribution tariffs should be non-discriminatory and cost-reflective, and should take account of the long-term, marginal, avoided network costs from distributed generation and demand-side management measures. The Council of European Energy Regulators (2018) reflects these priorities 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.”

The fundamental changes inherent in adapting the electricity distribution system to the new opportunities offered by micro renewable generation, demand management and electric vehicles will require some drastic changes in distribution tariffs, some of which are discussed in this report. We have not included smart metering and feed-in tariffs, though these will undoubtedly be major contributors to the change. We have outlined different concepts of fairness, from basing tariffs on long-term avoidable costs to spreading the average costs evenly among the users of a system, determined by connection, usage, capacity requirements or some combination of these cost drivers. To maximise efficiency, consumers should make their energy decisions on the basis of the costs of the system with and without their demand. The EU imperatives for consumer participation and for tariffs to reflect long-term avoidable costs are likely to deliver efficiency and a lower-cost system for all in the long run. However some consumers are more able to ‘avoid’ these costs than others, and some transitional costs in moving to the new structures may impact particularly negatively on those who are unable to invest in new technologies or have other impediments to participation and taking advantage of opportunities. The challenge is to offer incentives to those who can make efficient decisions, which will be in the interests of lower costs for all in the long run, while extending this possibility to as many as possible, and without unduly burdening those who may be the least able to bear such burdens in the short term.

To address such challenges it is crucial to understand the likely distributional impact of these changes. These will vary by Member State, both because the optimal charging system will diverge according to local conditions and preferences, and different jurisdictions have different 'starting points'. The first important question for policy makers concerns the aggregate and distributional impacts on consumers if tariffs become more reflective of the costs associated with peak demand, where these can be well identified. Some evidence, mainly from the US, suggests that tariffs reflecting costs associated with peak demand, such as ToU tariffs, clearly increase total consumer surplus and that low-income households are responsive in the short-term to such tariffs (Wolak, 2010). If the focus is on making sure that consumers are not negatively affected by such tariff reforms, then DSOs (i.e. either the tax payer or other electricity users) may bear the cost, at least in the short run, as has occurred in The Netherlands.

A second question concerns the aggregate and distributional impacts on consumers if some consumers become prosumers, including the effects of net metering and feed-in tariffs which have been omitted from this analysis. Here much depends on the design of tariffs, as our simulation examples have shown in very simplified circumstances. If the tariff is mainly volume-based, then self-generation and lower net consumption from the grid will certainly reduce prosumers' bills. If the tariff in place is mainly capacity-based, then self-generation does not necessarily lead to lower bills, because it is less clear on how capacity is affected by self-generation. While having a lower volumetric consumption may reduce maximum demand, it does not necessarily mean requiring a lower capacity. Since self-generation occurs mainly at off-peak times (as is likely with solar power in northern Europe) and consumers typically rely on the general grid for peak time supply, capacity and ToU tariffs do not guarantee savings for micro generators.

The fairness of a tariff can be assessed in principle from the extent that it meets the EU's objectives of cost-reflectivity and providing good incentive signals. We have explored some of the issues of balancing the deployment of new technologies and fairness in efficient cost allocation and distributional justice in the distribution system. Much depends on the design of tariffs, in particular the balance between different charging components. If we ignore the overall savings which we hope would result in the long run from better aligned incentives and consumer responses, then reduced bills for prosumers imply higher costs paid by other consumers. This would inevitably result in some rebalancing of tariffs, though the magnitude and impact depends on the starting point for each Member State. If consumers respond very differently to tariff signals, so that some deliver the benefits for the system, while others merely see their tariffs rise, it becomes important to know who is responding and why. Those who are unwilling or unable to respond to changing tariffs may find themselves bearing a greater burden of the system's costs. Therefore it is important for future research to identify the actual aggregate and distributional impacts of tariff reforms in different countries, potentially towards more capacity-based signals, in light of demand-side management, new technologies and efficient measures. In particular, it is crucial to collect and apply empirical evidence on how households change behaviour in the energy market, rather than designing systems solely around potential response to tariff changes.

Three practical issues arise from tariff redesign. The first is that they cannot incentivise the necessary changes adequately 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 second issue is that not all consumers are in a position to respond and participate according to the EU's ambitions, and so there may not be an opportunity for all to benefit. As in all distributional matters, the way that initial wealth and opportunities are distributed has direct consequences for how markets work. Member States need to understand what barriers there may be to participation, and to address these in an equitable manner. Such inequality in opportunity is often related to financial and tenancy limitations, and while there may be consequences in the energy market, the causes lie beyond it, as do the best instruments to reduce such barriers. One route suggested by the Clean Energy Package is energy communities, which may be able to 'aggregate' such opportunities and make them and consequent benefits more generally available. Whether such schemes protect the interests of individual consumers depends crucially on their design.

The third issue 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 methods of protection for those who cannot respond and may suffer adverse consequences. The challenge facing by Member States, regulators and DSOs is not just how to redesign distribution tariffs incorporating 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 the benefit to the overall system.

The following practical implications follow from considering cost-reflectivity and fairness in designing network tariffs:

1. Harmonisation of network tariffs across Europe would not follow these principles for two reasons: costs vary between different systems, both within and between Member States; and the preferences for recovering the 'non-allocable' costs may vary between Member States according to their social policies and needs.
2. Optional tariff structures provide a compromise between efficiency and fairness, and enable a smoother adjustment to a more efficient tariff structure. While in general only one tariff structure will reflect the 'correct' costs incurred by each consumer's demand pattern on the system, the non-allocable costs may be recovered in many different ways, as discussed in this report. Moreover if moving from one tariff charging basis to another (e.g. introducing a ToU tariff), the disruptive effects on household budgets can be minimised by offering options for the new structure, at least for a time. Those most able to recognise the potential benefits to themselves are most likely to be early switchers/adopters, and this will provide additional information for regulators to develop the tariff options over time.
3. Where there is a significant potential cost or saving from changing the number of households on the grid, this should be reflected in a fixed element of the tariff. Whether it should be reduced or increased depends on the cost structure of the network and the current tariffs which are applied, as well as the factors in point 1 above.
4. Transparency is an important principle for the EU and for consumer understanding and acceptability. Identifying network costs separately is necessary for effective retail competition, and specifying the charges on the bill may also help in this. Such details need to be presented in a way which clarifies rather than obscures the charges for the consumer.

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Appendices

A. Tariff rates based on Table 7.

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 11. Tariff rates (when net metering is not available)

Methods of calculation of these rates can be found in the simulation excel sheets accompanying this report.

B. Notional households with income assumptions

Since these usage profiles are not based on actual data, a notional household may correspond to different sets of socio-economic characteristics; hence the particular income level that we assign to a household (Table 12) is hypothetical and represents only one of many possibilities. Incomes are assigned to demonstrate alternative interpretations of fairness, especially in the presence of vulnerable consumers, and should be considered as illustrative only. More nuanced distinction between households should be made and more characteristics can be included when estimating using specific household samples.

Household abbreviation	Contractual capacity	Volumetric consumption	Solar PV	Amount fed into grid	Income
LL	Low	Low	NO	-	Low
HL	High	Low	NO	-	Low
LH	Low	High	NO	-	Low
HH	High	High	NO	-	Low
AA	Average	Average	NO	-	Average
LvL	Low	Very low	YES	0	High
HvL	High	Very low	YES	0	High
LvLf	Low	Very low	YES	500	High

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 12. Notional households with income assumptions

It is reasonable to assume that the households who have installed solar PV (LvL, HvL and LvLf), have a high income level. Based on this, for simplicity, we assume that household AA has an average income, and the other households, LL, HL, LH and HH, have a low income. Among the four low-income households, household LL may be of less concern in the electricity market as it receives relatively low bills for distribution services across tariff scenarios because of its low capacity demand and consumption, whereas bills for HL, LH and HH can be high under some tariffs.

Recall from Figure 3, since HH has high capacity and consumption, it is allocated the most costs by any tariff we considered; under 100V, it is allocated nearly 30% of the total costs. This may not be regarded as unfair from the cost-reflectivity point of view, as the high bills reflect the high costs HH imposes on the network. However, HH might be living in an energy-inefficient house and with several children, or an elderly couple staying indoors most of the time and needing to keep warm. High demand from a low-income household is more likely to be for essential needs compared with similar demand from a high-income household, and low-income households may be in a vulnerable position if their essential needs result in high bills.

HL is more likely to impose higher costs on the network than LH, since costs are mainly capacity-driven. If fairness is identified with cost-reflectivity, tariff 100V does not lead to fair outcomes as it allocates much higher costs to LH than to HL, and such concern is aggravated if LH is a low-income household. A more cost-reflective tariff containing the capacity component or ToU basis can considerably improve the situation. However, this may have adverse distributional impact on HL, who is also low-income and prone to a large bill increases under such a tariff reform. Even within our stylised model we can observe the potential trade-offs between multiple objectives, and how fairness may have different interpretations. Because of this there is no unique definition of fairness, in terms of either tariffs or outcomes. Conclusions depend on which concept of fairness is adopted.

This story may be further complicated by the call for consumers to benefit fully from renewable energy innovation and demand side management, and the emphasis of the Clean Energy Package on consumer engagement and involvement. As the primary driver for households to generate, store and even sell their own electricity to the market is likely to be monetary incentive, such as bill savings, a tariff that offers greater savings for prosumers can be more effective in encouraging deployment. Nevertheless, as discussed above, the tariff offering the strongest incentive for prosumers to self-generate and feed into the grid, also has the strongest adverse distributional impacts on other households, at least in a static and closed model. If high-income consumers are more able to invest in renewable energy systems and energy efficiency measures, as assumed in Table 12, and are more responsive to demand-side management, then they receive the benefits from such investment and engagement. When net metering is available (Figure 8), not only the high-income LvLf benefits from remuneration, the other two high-income households, LvL and HvL, also bear the least burden in subsidising the remuneration. This leads to more concerns on distributional justice, especially under the volume-based tariff. The potential challenge identified in Section 2 is evident from our tariff design model: if low-income households remain passive because they are unable to invest in renewable energy systems, they not only miss the potential benefits, but also pay higher bills as the others become prosumers. Such social imbalance may hamper the public acceptance of renewable energy innovation.