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THE IMPACT OF PVS AND EVS ON DOMESTIC ELECTRICITY NETWORK CHARGES: A CASE STUDY FROM GREAT BRITAIN

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Electric power distribution network charges have become a popular area of study for regulators, industry and academia. Increasing use of photovoltaics (PVs) and electric vehicles (EVs) by domestic customers has created concerns about the fairness of the current tariff structure. Proposing a tariff design, which will be cost reflective, transparent, sustainable, economically efficient is socially desirable. Wealth transfer through electricity distribution tariffs is a major concern for energy regulators. This paper aims to analyse the current distribution network tariffs faced by four main household customer groups in Great Britain - defined as those who own a PV and an EV, those with EV but no PV, those with PV but no EV and finally those with neither EV nor PV – under various uptake scenarios for EVs and PVs. We illustrate the impact on household tariffs for the most and least expensive British network operators, namely London Power Networks and Scottish Hydro Electric Power Distribution. The results show that, due to the current network charges calculation structure, as PV penetration increases, the distribution tariffs increase for all customers regardless of whether someone owns a PV or not. On the other hand, as EV penetration increases, the distribution tariffs decrease for all customer groups. Another key finding is that the distribution tariffs in Great Britain are EV dominated and the future EV and PV penetration projections indicate that the distribution tariffs will likely decrease for all customers in Great Britain.

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Keywords distribution; network; tariff; PV; EV

JEL Classification L94

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The impact of PVs and EVs on Domestic Electricity Network Charges: a case study from Great Britain

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Abstract. Electric power distribution network charges have become a popular area of study for regulators, industry and academia. Increasing use of photovoltaics (PVs) and electric vehicles (EVs) by domestic customers has created concerns about the fairness of the current tariff structure. Proposing a tariff design, which will be cost reflective, transparent, sustainable, economically efficient is socially desirable. Wealth transfer through electricity distribution tariffs is a major concern for energy regulators. This paper aims to analyse the current distribution network tariffs faced by four main household customer groups in Great Britain - defined as those who own a PV and an EV, those with EV but no PV, those with PV but no EV and finally those with neither EV nor PV – under various uptake scenarios for EVs and PVs. We illustrate the impact on household tariffs for the most and least expensive British network operators, namely London Power Networks and Scottish Hydro Electric Power Distribution. The results show that, due to the current network charges calculation structure, as PV penetration increases, the distribution tariffs increase for all customers regardless of whether someone owns a PV or not. On the other hand, as EV penetration increases, the distribution tariffs decrease for all customer groups. Another key finding is that the distribution tariffs in Great Britain are EV dominated and the future EV and PV penetration projections indicate that the distribution tariffs will likely decrease for all customers in Great Britain.

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1. Introduction

Electricity regulators, such as Ofgem in Great Britain, allow their distribution network operators (DNOs) to collect a certain amount of revenue during each regulatory control period. This so-called allowed revenue is calculated with reference to expected operating expenditures (OPEX), depreciation, interest and other costs of the network operators. The tariffs of each DNO are then determined and designed to recover these costs. However, the way to recover this given amount of revenue is a complex problem which is attracting the attention of DNOs, regulatory bodies and academia. Alongside this there is an increase in distributed generation (including domestic solar PV), storage units and electric vehicles (EVs) on the power grid. This has the potential both to reallocate who pays for the distribution network and to substantially increase distribution network cost.

There have been several recent studies aiming to forecast the necessary amount of investment to meet the new challenges posed by the evolving power grid and changing consumer behaviour. The MIT Utility of the Future report (MIT Energy Initiative, 2016) observes that if the distributed PV generation increases to more than 20 percent of total electricity demand, then the cost of the network could double in the most extreme case. Similarly, a study by the Smart Grid Forum from Great Britain estimates that from 2012 to 2050, the network related investments would be as much as £60bn across all distribution and transmission networks in the country (Smart Grids Forum, 2012). During the decentralized energy transition, energy storage could

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be a game changer. With rapidly increasing distributed generation (DG) connected to the grid, intermittency arises as one of the major problems for the power system planners. In addition to the solutions proposed as a part of demand side management techniques, storage could be a viable option especially for domestic loads. Contemporary residential energy storage solutions can be summarized as follows:

- Power to heat, such as heat pumps
- Using electric vehicles as home storage, Vehicle-to-Grid (V2G)
- Batteries

Thanks to the rapid development of electric vehicles (and other sources of battery demand), the cost of batteries has been falling significantly. Average battery pack prices fell from US\$1000 per kWh in 2010, to US\$ 350 per kWh in 2017 (World Energy Council, 2017). It is evident that energy storage could therefore have a significant impact on distribution network costs by directly affecting the volume of energy imports and exports across the day in the presence of time-of-use (ToU) tariffs. Nevertheless, to narrow our focus, this topic has been omitted from the scope of this paper.

To achieve more cost reflective and more efficient network tariffs, different charging methodologies have been suggested by various researchers. A recent study from the United States focuses on distribution system cost analysis in the United States and concludes that if volume (kWh) decreases, the delivery costs are likely to increase in the future (Fares & King, 2017). Hinz et al. (Hinz, et al., 2018) show that the grid charges in Germany are rising with the increasing penetration of distributed generation. The paper by Nijhuis et al. (2017) analyses the cost reflectivity of different tariffs in the presence of changing EV and PV penetrations for the residential customers. Neuteleers et al. introduce alternative tariff schemes for electricity grids for Dutch households by evaluating them with respect to their fairness (Neuteleers, et al., 2017). Passey et al. (2017) present a cost-reflectivity analysis of demand charge tariffs, which was done by using the energy consumption data of household customers in Sydney, Australia. Another study from Australia proposes five different tariff designs for distribution network to recover residual costs (Brown, et al., 2015). However, this study does not designate a best solution for recovering these costs. Rubin (2015) suggests that seasonal residential electric distribution rates with seasonal consumption charges might be used to reach a more efficient rate design. On the other hand, a study from Sweden by Bartusch et al. (2011) proposes a demand-based tariff for residential customers instead of tariffs depending on average system costs, which in general, are not being differentiated by time-of-use. Other studies focusing on how distributed generation affect power delivery costs can be found (M.A.Cohen, et al., 2016; Perez-Arriaga, 2016; Picciariello, et al., 2015; Abeygunawardana, et al., 2015; Georgilakis & Hatziargyriou, 2013; Yilmaz & Krein, 2013).

In a study from the United States, the implications of increasing PV penetration on network tariffs are studied by (Picciariello, et al., 2015). This study concludes that cross-subsidies arise when net metering combined with pure volumetric tariffs is applied. The amount of cross-subsidies varies depending on the amount of the distributed generation (DG) connected to the grid. Another study by Eid et al. (2014) focuses on cross-subsidies due to net metering with increasing PV use and shows that if total PV penetration reaches 20% of the end-users, the cross-subsidies might reach as much as 7.8% of the tariffs. In his comprehensive study, Simshauser (2016) shows that for Queensland in Australia, the existing two-part tariff structure ends up in wealth transfer from the customers who do not possess solar power to the ones who do. The study concludes that the households that do not possess an air-conditioner or a solar PV faced a network charge increase at an amount of 295 AUD per year (Simshauser, 2016). Even though there are numerous papers addressing the impacts of PV uptake on distribution network charges, the literature for EV penetration and its outcomes on distribution charges and tariffs is quite limited.

This paper uses a case study from Great Britain which shows the impact of increasing penetration of photovoltaics (PVs) and electric vehicles (EVs) under existing network charges. Its aim is to show the extent to which different types of customers will see their charges vary under different roll-out scenarios for PVs

and EVs, regardless of the underlying cost increases in network costs that such roll-outs might impose. This is an area which is of active concern to electricity regulators, one of whose primary functions is to protect consumers facing monopoly distribution charges. In Great Britain, the electricity regulator (Ofgem) has been working on a distribution tariff review to reconsider the ‘residual’ charges with the following core principles (Ofgem, 2017a):

- being cost reflective
- reducing distortions
- fairness
- proportionality

In addition to the main principles of Ofgem, the European Commission (EC) has its own guidelines for a better distribution tariffs design, where cost reflectivity is explained as where “costs should be allocated to those agents who impose the costs” (European Commission, 2016, p.35).

At this point, however, we should make a remark that the principle of cost reflectivity in Britain and in Europe is slightly different. By creating cost reflective distribution tariffs Ofgem aims to reflect the full economic costs in the network in ways that give incentives to customers to use the network efficiently. On the other hand, cost reflectivity from the European perspective is more about fairness. Distribution costs are supposed to be charged to those who are responsible for it. However, we see that fair tariffs are the common core concern for both Britain and Europe.

In this paper, our main motivation is to question fairness in distribution tariffs in Britain. For a general discussion of the principles of network charging, see Pollitt (2018). As the problem statement, we ask; what is the situation with the British electricity customers in terms of designing fair distribution tariffs among different types of customers who may or may not own EVs and/or PVs? To analyse this problem we examine two DNOs: the most and least expensive ones in Great Britain. For each, we define four customer types, which are:

- Customers who own PVs and EVs;
- Customers who own PVs but not EVs;
- Customers who own EVs but not PVs;
- And finally, customers who do not own either.

Section 2 of this paper gives brief information about the power distribution system, network charging and solar PV and EV potential in Britain. Section 3 presents the methodology and Section 4 includes the results of the tariff calculations per each customer group with respect to changing PV and EV uptakes. Section 5 concludes our paper with a discussion of the policy implications of our findings.

2. Power Distribution in Great Britain

There are 14 licensed distribution network operators (DNOs) in Britain and these DNOs are owned by six different groups. DNO regions are shown in Figure 1.

The DNO groups and individual DNOs are:

Electricity North West Limited (ENWL)

Northern Powergrid (NPg):

- Northern Powergrid (Northeast) Limited
- Northern Powergrid (Yorkshire) plc

Scottish and Southern Energy (SSEPD):

- Scottish Hydro Electric Power Distribution plc
- Southern Electric Power Distribution plc

Scottish Power Energy Networks (SP):

- SP Distribution Ltd
- SP Manweb plc

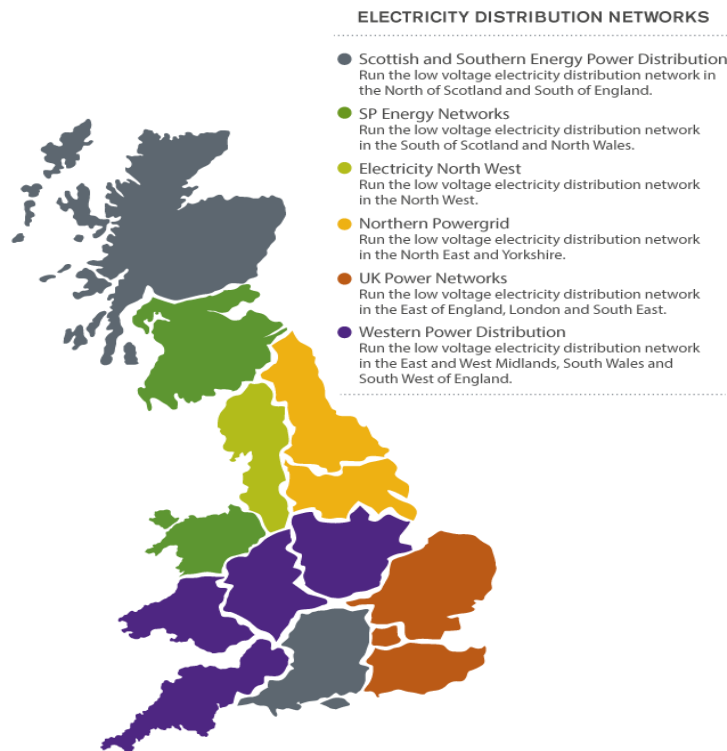
UK Power Networks (UKPN):

- London Power Networks plc
- South Eastern Power Networks plc
- Eastern Power Networks plc

Western Power Distribution (WPD):

- Western Power Distribution (London Power Networks) plc
- Western Power Distribution (West Midlands) plc
- Western Power Distribution (South West) plc
- Western Power Distribution (South Wales) plc

Figure 1: DNO location and ownership in Great Britain (Ofgem, 2017b).



Electricity distribution charges are calculated according to the Common Distribution Charging Methodology (CDCM) for electricity distribution networks in Great Britain. The CDCM was developed and then implemented in April 2010 through a joint collaboration between DNOs, the Office of Gas and Electricity Markets (Ofgem) and other interested stakeholders. The allowed revenue of the DNOs, resulting from the periodic price review process conducted by the regulator, is calculated to cover economic cost. Tariffs are estimated to recover this revenue by adjusting individual tariffs in line with expected volumes. Targeted CDCM net revenue (£/year) is collected through tariffs applied to different customer groups. The details about the CDCM and the targeted net revenue are summarised in Energy Networks Association (2015). DNOs levy these charges on the suppliers who have contracts with low voltage (LV) and high voltage (HV) end users. The Distribution Connection and Use of System Agreement (DCUSA) (DCUSA, 2017) defines

how DNOs charge generators and suppliers for use of their power networks. While the methodologies are identical across all DNOs the inputs to the methodologies reflect the characteristics of the network and the number and consumption characteristics of consumers in each DNO area.

Once the allowed revenues are calculated through the CDCM, the DNOs are allowed to recover the targeted revenue through forward-looking and residual charges. Forward-looking charges, as the name suggests, are meant to reflect current and future (or forward-looking) costs related to both generators and consumers connected to the network. On the other hand, for the network operators, residual charges (or recovery charges) are meant to recover the remaining allowed revenues once forward-looking and connection charges have been calculated².

Definition and calculation of forward-looking charges are easily done via various tariff structures for demand customers. The domestic customer classes are: HH: half hourly; NHH: non half hourly; LV: low voltage; HV: high voltage; and UMS: unmetered supplies. The definition and details of each demand customers can be found in Energy Networks Association (2009). After summing up all the tariffs listed above, the remaining revenue is supposed to be collected through residual charges. These charges vary by DNO and charging periods. For instance, in the SHEPD network the residual charge component is estimated to be 33% of the targeted revenue for the 2017/2018 charging period (Retail Market Monitoring, 2017). Nonetheless, the way of distributing these charges to the customers is still debatable. Ofgem is proposing further assessment of four different ways in which these charges could be collected. These are: fixed charges, ex-post capacity, ex-ante capacity and gross consumption charges (Ofgem, 2017c). Fixed charges are collected from each demand user without regard to actual consumption or capacity. Ex-ante capacity demand charges are based on a user's network connection capacity. On the other hand, ex-post capacity demand charge is defined according to the customer's peak system use. Finally, the gross consumption charges are calculated by gross consumption which covers the user's on-site electricity generation as well. Detailed analysis, together with the advantages and disadvantages of each charging methodology can be found in Ofgem (2017c).

Tariff structures can be a combination of the volume of energy supplied/consumed (kWh), peak power or capacity (kW) and a fixed or standing charge. A volume charge (£/KWh) is often thought to be useful in promoting energy efficiency even if does not reflect the underlying drivers of distribution costs. A peak power or the capacity charge (£/kW) provides less incentive for energy efficiency for end users. However it could be regarded as more cost reflective as the capacity of the distribution system is designed according to the highest expected peak demand during the lifetime of the assets rather than the actual energy volume distributed in any given charging period. Therefore it is potentially a justifiable way of ensuring full cost recovery. A capacity charge on the basis of maximum available capacity, rather than actual peak use, is one basis for a fixed charge. A fixed charge (or standing charge) is meant for the consumers to pay for their connection to the grid independently of how much electricity (kWhs or KWs) they draw from the grid. The fee could be uniform for all users within a particular class of customers, or vary for within each class of customers. However in Britain the tariffs make use of a variable volumetric charge (pence/kWh) and a fixed charge (pence/user/day). Distribution charges and annual average residential customer bills in 2017 for British DNOs are summarized in Table 1.

² These charges two charging classes are explained at Ofgem's Targeted Charging Report, Ofgem (2017c, p. 20) as: "Forward-looking' charges reflect the current and forward-looking costs that an incremental increase in network use - either generation or demand - would impose on electricity networks." "Residual charges don't relate to any specific set of costs, but they recover the rest of the allowed revenues not recovered through connection charges and forward-looking charges, and typically recover a large proportion of total revenues."

Table 1. Distribution charges and annual average customer bills per each DNO in 2017 (Retail Market Monitoring, 2017); (Energy Networks Association, 2017)

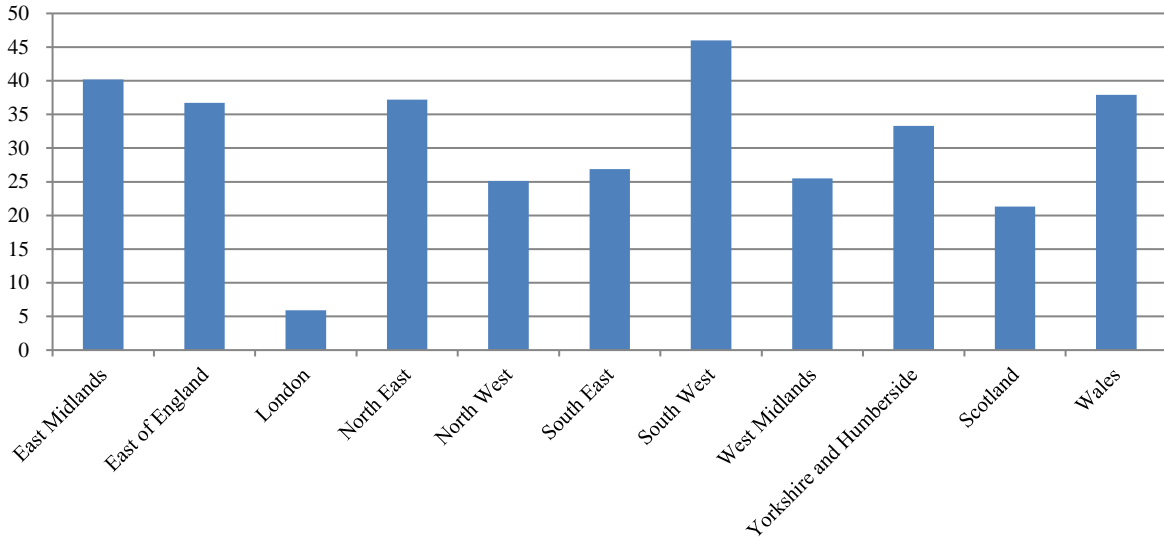
		Variable rate (p/kWh)	Fixed charge (p/customer/day)	Annual averages					
				Consumption (kWh)	Variable costs (£)	Fixed costs (£)	Total costs (£)	Variable costs (%)	Fixed costs (£)
ENWL	Electricity North West	2.06	3.10	3100	63.90	11.30	75.21	84.97%	15.03%
NPg	Northern Powergrid (Northeast)	2.25	4.84	3100	69.60	17.67	87.27	79.75%	20.25%
	Northern Powergrid (Yorkshire)	1.76	5.07	3100	54.47	18.51	72.97	74.64%	25.36%
SSEPD	Scottish Hydro Electric Power Distribution	2.96	8.14	3100	91.63	29.73	121.35	75.50%	24.50%
	Southern Electric Power Distribution	2.13	3.03	3100	66.10	11.05	77.15	85.68%	14.32%
SP	SP Distribution	2.22	5.08	3100	68.89	18.53	87.42	78.81%	21.19%
	SP Manweb	2.73	4.13	3100	84.54	15.08	99.62	84.86%	15.14%
	London Power Networks	1.61	4.05	3100	49.89	14.76	64.65	77.16%	22.84%
UKPN	South Eastern Power	2.24	4.49	3100	69.45	16.39	85.84	80.91%	19.09%
	Eastern Power Networks	1.81	4.66	3100	56.19	17.02	73.21	76.75%	23.25%
	East Midlands	2.25	3.90	3100	69.74	14.23	83.97	83.06%	16.94%
WPD	West Midlands	2.34	4.76	3100	72.43	17.38	89.81	80.65%	19.35%
	South Wales	3.07	4.98	3100	95.12	18.19	113.31	83.95%	16.05%
	South West	3.20	5.46	3100	99.15	19.91	119.06	83.27%	16.73%

For further analysis, we will continue with the most and least expensive DNOs in Britain evaluated at standard consumption of 3100 kWh per year (Retail Market Monitoring, 2017). For the purposes of this paper we adopted the variable and fixed rates of Scottish Hydro Electric Power Distribution (SHEPD) and London Power Networks (LPN) to carry out the impacts of EV and PV penetration on customer bills.

2.1 Potential for Photovoltaics and Electric Vehicles in UK

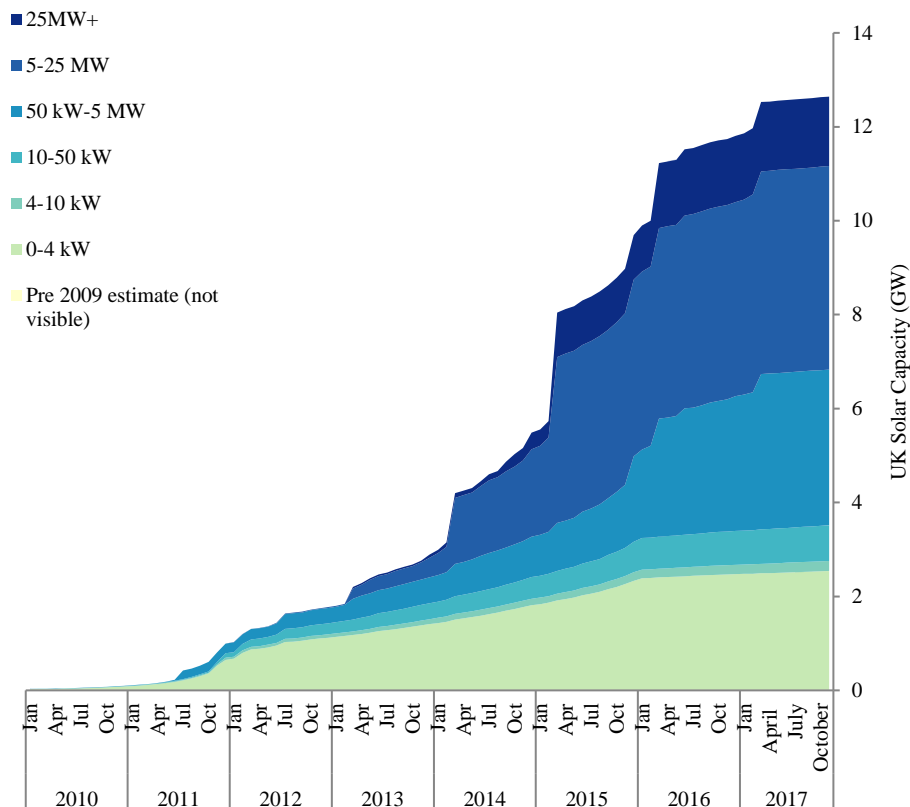
According to the UK's official statistics (National Statistics, 2016), there are 23.4 million habitable homes and 27 million households and residential electricity customers in the United Kingdom (UK). We assume the electrification rate is 100%. 61% of homes are in suburban areas, whereas 21% are located in city or urban centres. 63% of the total homes are owner occupied and 20% are privately rented (National Statistics, 2016). The uptake of PVs in residential sector is also driven by the rapidly declining costs. In Britain, for 4kW rooftop solar panels the installation costs dropped by 67 per cent from 2010 to 2017 (Green Business Watch, 2017). Summary of Solar installations per 1000 households by region in Britain is shown in Figure 2 (Department for Business, Energy and Industrial Strategy, 2017).

Figure 2. Solar installations per 1000 households by region in Britain



On the other hand, as shown in Figure 3, the Department of Energy & Climate Change (DECC) reports that the solar PV capacity reached 12 GW in United Kingdom (UK) in 2017 (DECC, 2017a).

Figure 3. UK Solar Deployment, by Capacity (DECC, 2017a)



A recent report published by the EC reports that the domestic solar PV capacity in UK was 2,499 MW and the number of residential solar PV prosumers reached 755 thousand in 2015 (European Commission, 2017). A report written by the Centre for Economics and Business Research (Cebr) presents three different scenarios which show the annual solar power growth in the UK (Centre for Economics and Business Research, 2014). According to this report, after 2020, the yearly addition of solar power in all sectors might

vary from 500 MW to almost 4000 MW in UK. The Cebr report compiles three different scenarios regarding the PV uptake in UK, which are Solar Strategy, Ministerial Ambition and Bold Scenario. Table 2 presents the estimated domestic rooftop solar PV installation capacities and the number of houses that could be fed by rooftop solar PV generation. In calculating the number of houses, it is assumed that 5 MW requires 1,515 homes (Centre for Economics and Business Research, 2014).

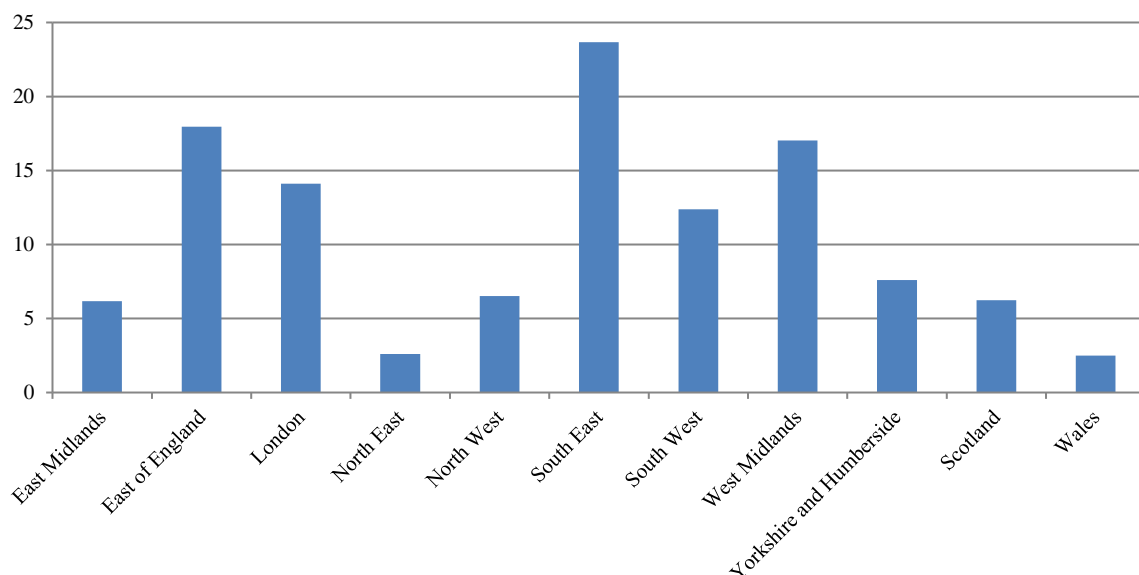
Table 2. Projections for UK domestic rooftop solar PV capacity and number of houses which could be fed by this capacity

Scenario	Domestic rooftop solar PV installation (MW)			Number and percentage of houses fed by rooftop solar PV (millions, % of total households in 2017)		
	2020	2025	2030	2020	2025	2030
Solar Strategy	3,700	5,200	7,300	1.121 (4.15%)	1.576 (5.84%)	2.212 (8.19%)
Ministerial Ambition	6,800	10,500	13,300	2.060 (7.63%)	3.182 (11.78%)	4.020 (14.93%)
Bold Scenario	8,500	14,700	20,000	2.576 (9.54%)	4.454 (16.50%)	6.060 (22.44%)

Within these scenarios we should remember that, by 2020, Solar Strategy estimates the total PV installed capacity in UK to be 11,000 MW, while it is 20,000 MW in Ministerial Ambition and 25,000 MW in Bold Scenario. From Figure 3, we see that solar PV deployment has already exceeded 12,000 MW in UK by 2017. This suggests that somewhere between Solar Strategy and Ministerial Ambition is currently the best guess of future solar PV use in UK by 2030.

In 2016, there were 30,850,000 private cars in the UK (Department for Transport, 2017a). About 77% of UK households have at least one car (81% have access to a car), while 33% households have 2 cars (National Travel Survey, 2016). By the end of 2016, around 350 000 plug-in EVs/EVs had been registered in the UK and EVs constitute around 1.3 per cent of the total new car market in the country (SMMT, 2016). Figure 4 illustrates the regional distribution of EV use in Britain (Department for Transport, 2017b).

Figure 4. Number of Ultra Low Emission Vehicles (Cars only) by region in Britain in 2017 per 1000 vehicle



In the Future Scenarios report, the British Transmission System Operator, National Grid proposes four different scenarios (Two Degrees, Slow Progression, Steady State and Consumer Power) regarding energy demand in Britain (National Grid, 2017a). In this report it is assumed that 66% of houses have off road

parking suitable for charging EVs. The growth of EVs until 2050 is also projected. The EVs are divided into two categories; Pure EVs (PEVs) (100 per cent electric powered) and Plug-In Hybrid EVs (PHEVs) which uses both an electric motor and a conventional internal combustion engine. A 7kW scale charger has been adopted as the home charging standard. The number of EV use by years is shown in Table 3.

Table 3. Number and percentages of PEVs, PHEVs and non EVs in millions in Great Britain per different scenarios per 2015 and 2030 (National Grid, 2017b)

	Total vehicles	Two Degrees	Slow Progression	Steady State	Consumer Power
Year	2015	2030	2030	2030	2030
PEV	0.023 (0.08%)	5.292 (17.08%)	1.984 (6.07%)	0.936 (2.86%)	1.266 (3.87%)
PHEV	0.028 (0.09%)	4.043 (13.05%)	3.149 (9.62%)	0.935 (2.86%)	1.991 (6.09%)
Non EVs	30.250	21.656	27.582	30.874	29.452

As we can see from Table 3, the number of EVs could reach as many as 9.3 million in Britain by the year 2030. We should also mention that, in July 2017, the UK government announced that all petrol and diesel car sales will be banned after 2040 (GOV.UK, 2017). A report written for the Department for Transport provides socio-demographics of EV ownership in UK (Screeton et. al., 2013). Even though the study was done in 2013 with a small sample size (n=192) of early adopters, the report provides most comprehensive data about age, gender and location of EV owners in UK. Table 4 summarizes some of the findings of this report:

Table 4. Socio-demographics of UK EV owners

characteristic	UK EV owners
Gender	89% male, 11% female
Age	7% age 21-39, 23% age 40-49, 29% age 50-59, 23% age 60-69, 17% age 70+, 1% N/A
location	17% urban – London, 46% urban – other, 18% town and fringe, 11% hamlet/village/other
cars in households	80% 2 or more cars, 20% 1 car
ability to charge at home	97% charges at home

Until recently, there has not been any study looking at the income distribution of the British EV ownership. Therefore it is difficult to verify that it is usually only wealthy households that own EVs in Britain. However, a study from California, United States shows that the annual household income of 75% of EV owners in California is over 100,000 USD (£72,000³) (Center for Sustainable Energy, 2015). The same year, the median household income in California was 61,818 USD (£ 44,500³) (Census Bureau, 2017). Another recent study from Norway indicates that only 10% of the EV owners have an annual income of less than 400,000 NOK (£37,000³), where 63% have more than 550,000 NOK (£50,000³) among which 15% of the EV owners have an annual income of more than 999,000 NOK (£92,000³) per year (Bjerkan et. al., 2016). In 2016, the median Norwegian household income was reported to be 497,600 NOK (£46,000³) (Statistics Norway, 2017).

The high *potential* for PV and EV penetration provides our motivation for examining how current distribution tariffs might impact on domestic electricity consumer bills for different types of consumers.

3. Methodology

³ Approximately GBP (£) equivalent at January 2018 exchange rate.

The choice of the regions is pre-determined by the values of the variable distribution costs: we selected the regions where the costs are highest – Scottish Hydro Electric Power Distribution (SHEPD), which serves North of Scotland- and lowest – London Power Networks (LPN), which serves London.

In our analysis we examine four customer types:

- i. Residential customer with no EV and no PV
- ii. Residential customer with PV but no EV
- iii. Residential customer with EV but no PV
- iv. Residential customer who owns both EV and PV

For ease of analysis assume that probability of having EV and PV is independently distributed and thus we can vary uptake rates of EV and PV. From the CDCM reports of the DNOs, metered energy import per domestic customer without PV or EV is calculated to be 3885 kWh per year for SHEPD and 3345 kWh per year for LPN (Energy Networks Association, 2017). This is the average consumption per customer in each region at the moment. Assume EV customers use 3000 kWh at home to charge their cars at home (Newbery, 2016) and PV customers enjoy lower metered import, due to using solar energy generation at home by 914 kWh per year for Scotland (SHEPD) and by 1012 kWh per year for London (LPN) (Mason, 2016) . This allows us to calculate total kWh in each region relative to a baseline (which assumes no PV and no EV). We also assume that the total distribution revenue requirement under different uptake scenarios remains fixed at an initial level. This is because we seek to concentrate on the pure distributional effect. As the metered kWhs vary, we adjust the per kWh charge to collect the required revenue while keeping the fixed charge fixed at the initial level. The energy consumption of all domestic customers (kWh), number of domestic customers, net revenues (or Total Revenues) (£), revenues from unit rates (£) and revenues from fixed charges (£) are given in CDCM reports of each DNO at Table 5 as:

Table 5. CDCM data for Scottish Hydro Electric Power Distribution and London Power Networks (Energy Networks Association, 2017)

	All units (MWh)	Number of domestic customers	Net revenues (£)	Revenues from unit rates (£)	Revenues from fixed charges (£)
SHEPD	2,704,151	695,830	100,612,414	79,927,272	20,685,142
LPN	7,010,349	2,095,594	143,751,119	112,810,633	30,940,486

From these figures, we can calculate the Variable and Fixed rates as:

$$Total\ Revenue = \sum_{i=1}^4 (Fixed * 365 + Variable * Metered\ import) * Number\ of\ customers\ of\ Customer\ type_i \quad (1)$$

Customer type₁: customers with no EV and no PV,

Customer type₂: customers with EV but no PV,

Customer type₃: customers with PV but no EV,

Customer type₄: customers with EV and PV.

$$Variable = \frac{revenues\ from\ unit\ rates}{annual\ energy\ consumption} (\text{£/kWh}) \quad (2)$$

$$Fixed = \frac{\text{revenues from fixed charges}}{\text{number of customers} * 365} (\text{£}) \quad (3)$$

Where, the total revenue is the sum of revenues from unit rates and revenues from fixed charges. Table 6 summarizes the necessary data for SHEPD and LPN for further analysis.

Table 6. Cost Data for Scottish Hydro Electric Power Distribution and London Power Networks

	Year	Fixed charge per day, £	Variable charge per kWh, £	Number of customers	Metered import, kWh	PV metered reduction (kWh)	EV charging (kWh)	Tariff, £ (per household per year)	Total Revenue (TR), £ (per year)
SHEPD	2017	0.0814	0.0296	695,830	3885	914	3000	144.56	100,612,414
LPN	2017	0.0405	0.0161	2,095,594	3345	1012	3000	68.59	143,751,119

4. Results

We should note that these total revenues are the allowed revenues calculated by the CDCM for each DNO. With changing net metering due to varying penetrations of PVs and EVs, the allowed revenues for the DNOs are kept constant. In addition to this, the fixed charges per customer per day are also kept constant. Therefore, in order to collect the same targeted revenues, the only way for DNOs is to adjust the variable volumetric rate which is collected from the customers. To show how the distribution tariffs change with respect to increasing use of PVs and EVs, in our analysis, we used 1%, 5%, 10%, 15%, 20%, 25%, 30%, 35%, 40%, 45% and 50% PV and EV uptake rates. For example, let us assume that 50% of the customers own PVs and EVs. Then the data for the four customer types are summarized in Table 7.

Table 7. Number of customers and metered import for each customer group with 50% EVs and 50% PVs, LPN & SHEPD

	LPN		SHEPD	
	Number of customers	Metered import, kWh	Number of customers	Metered import, kWh
no EV, no PV	523,898	3345	173,957	3885
EV, no PV	523,899	6345	173,958	6885
PV, no EV	523,899	2333	173,957	2971
EV, PV	523,898	5333	173,958	5971

When the allowed revenues are kept constant at £143,751,119 per year for LPN and at £100,612,414 per year for SHEPD, then the tariffs per household per year for each customer types are calculated and shown in Table 8 (ignoring any consumption effect from the low current penetration levels of PV and EV).

Table 8. Tariff per year per customer group, LPN & SHEPD

	LPN		SHEPD	
	Tariff (£ per year) 1% EV & 1% PV	Tariff (£ per year) 50% EV & 50% PV	Tariff (£ per year) 1% EV & 1% PV	Tariff (£ per year) 50% EV & 50% PV
no EV, no PV	68.27	56.26	143.94	120.25
EV, no PV	116.27	93.48	232.14	190.16
PV, no EV	52.09	43.71	117.07	98.96
EV, PV	100.08	80.92	205.27	168.86

As we can see, the maximum distribution network tariff bill decrease depending on the PV and EV penetration occurs among the domestic customer group which own EVs but not PVs. This change is about £23 per year for LPN region and £42 per year for SHEPD region. Figure 5 – Figure 8 summarize the distribution tariff variation in London Power Networks for each customer group.

Figure 5. Distribution tariffs for households with no EV and no PV, LPN

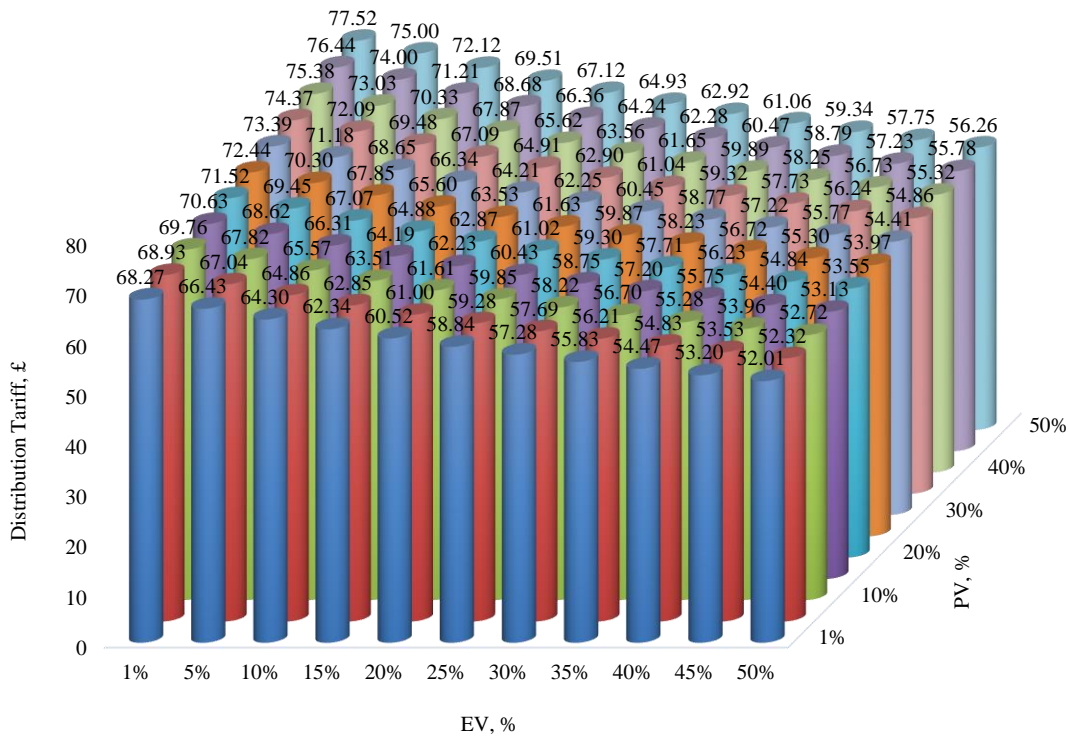


Figure 6. Distribution tariffs for households with EV and no PV, LPN

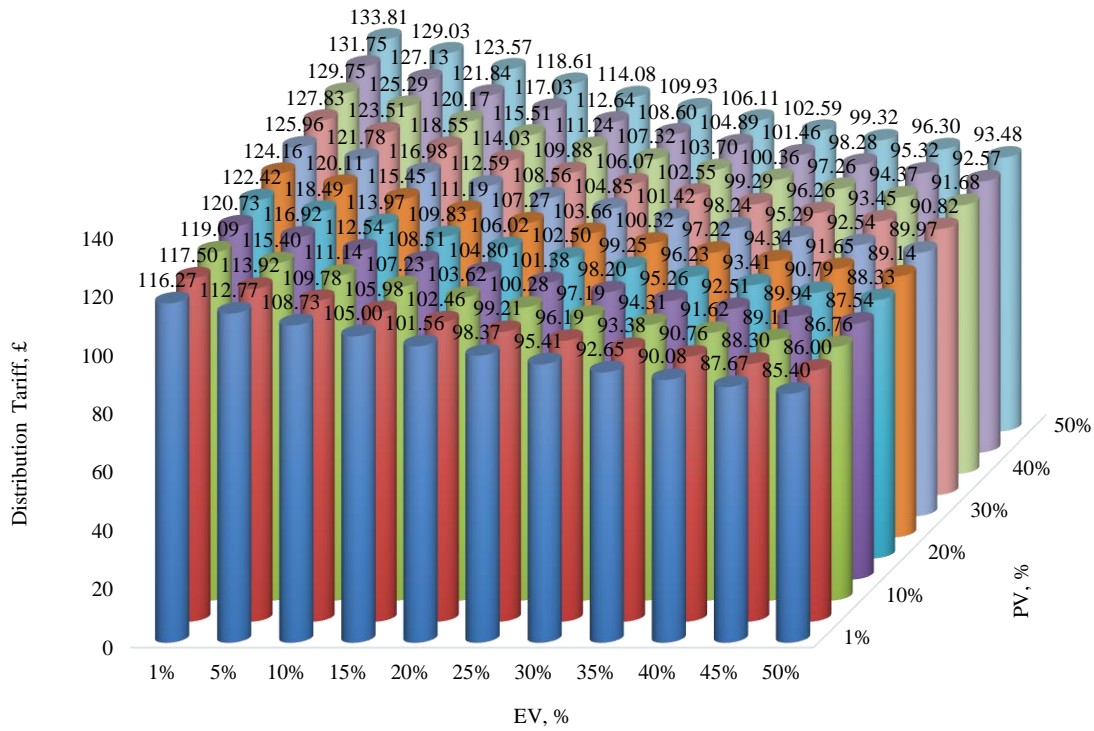


Figure 7. Distribution tariffs for households with PV and no EV, LPN

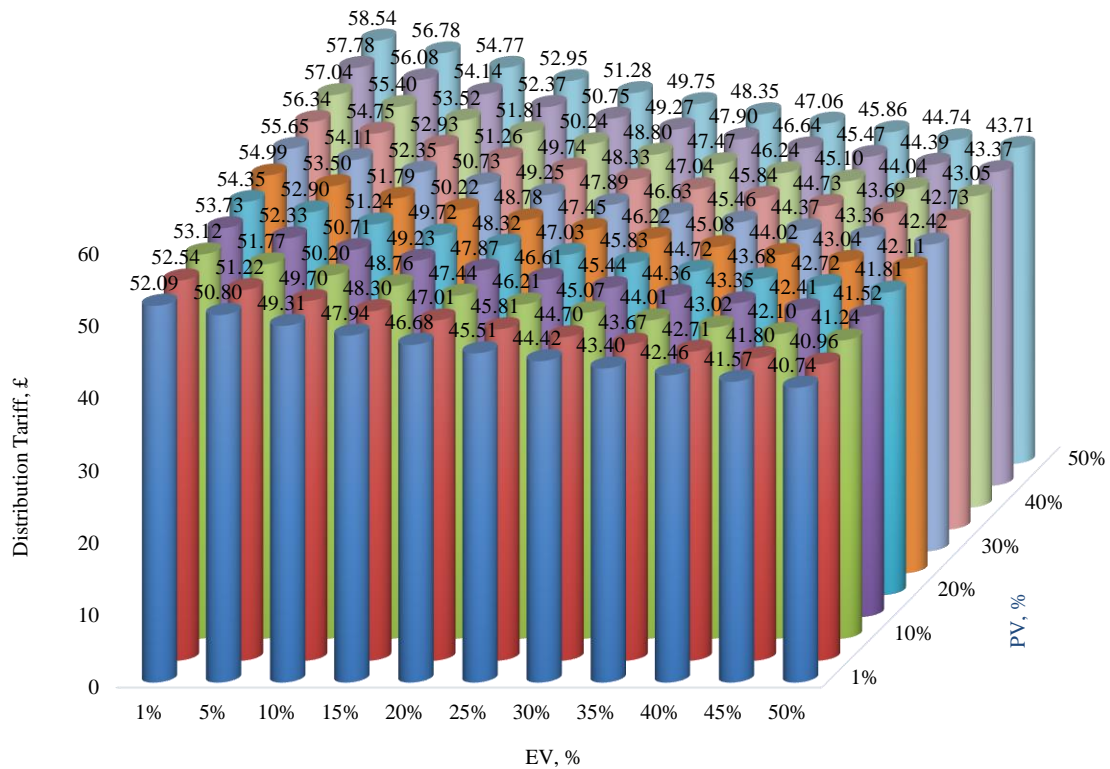
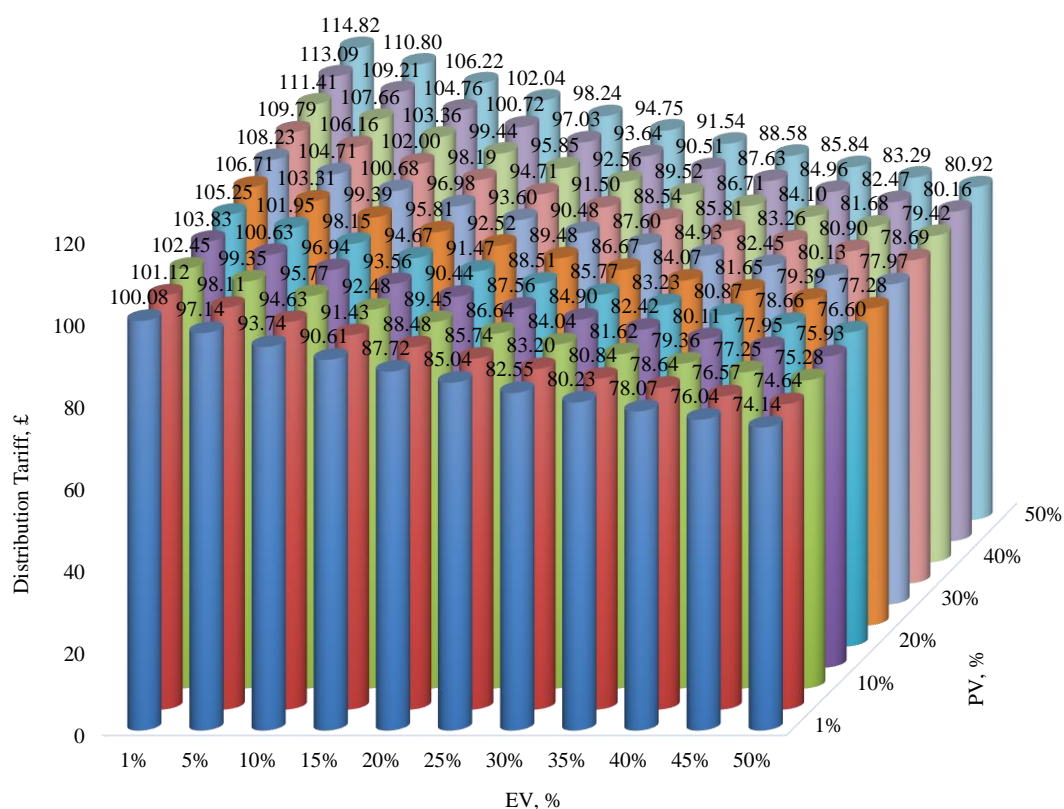


Figure 8. Distribution tariffs for households with EV and PV, LPN



The results clearly show that, as PV penetration increases the tariffs increase regardless of whether a customer owns PV or not. This is an expected result since increase in PV usage means decrease in net volumes purchased by the customers. In order to reach the targeted allowed revenue the variable charge will have to be increased by the DNO. The significant finding is that the highest burden goes to the households who own an EV but not solar power in their homes. The smallest tariffs are paid by households who own PV but not an EV. These results challenge the principle of fair tariffs for fair consumption and ownership, which is strongly emphasised by both British and European regulatory bodies. On the other hand, from the results, we see that as the penetration of EVs increase, the tariffs decrease for all customer groups regardless of their ownership of EVs. This is again a natural result of the two part tariff design. As the allowed revenue and the fixed rates are kept constant, if the amount of energy increases, naturally the value of the variable rate will decrease. This will be reflected in the total tariff eventually. The more EVs are used, the more volume will be demanded from the distribution network. This will lead to unit tariff declines. Figures 9 – 12 show similar results for the SHEPD.

Figure 9. Distribution tariffs for households with no EV and no PV, SHEPD

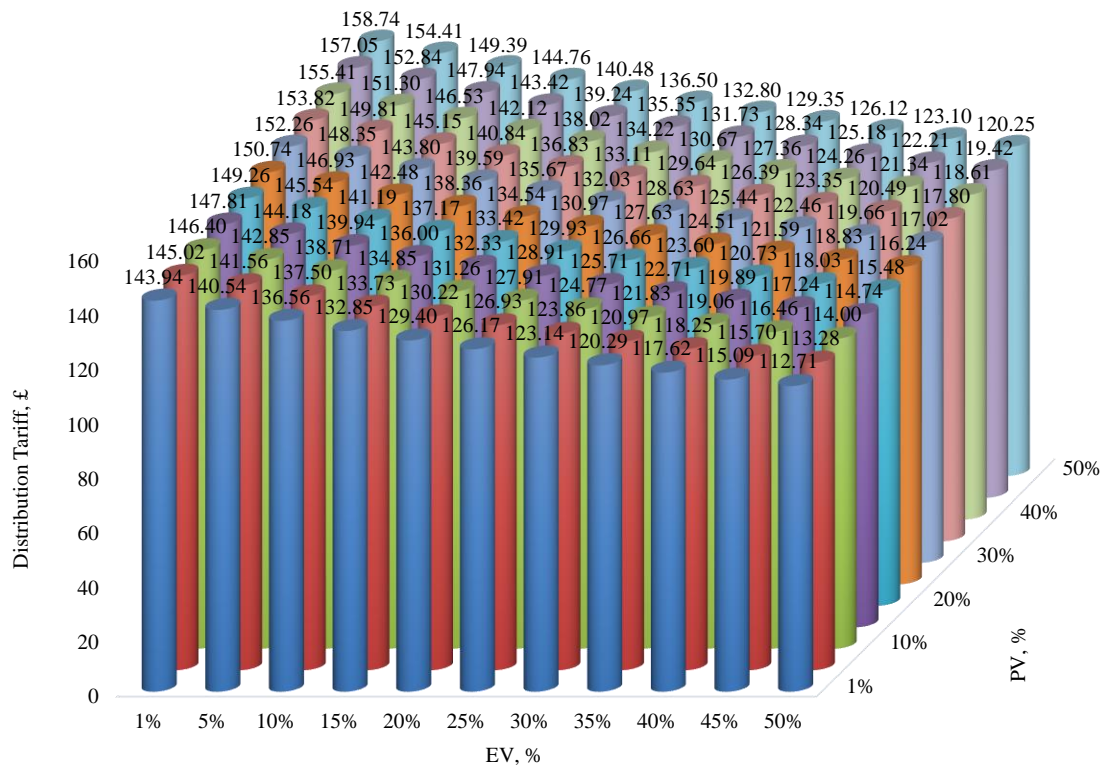


Figure 10. Distribution tariffs for households with EV and no PV, SHEPD

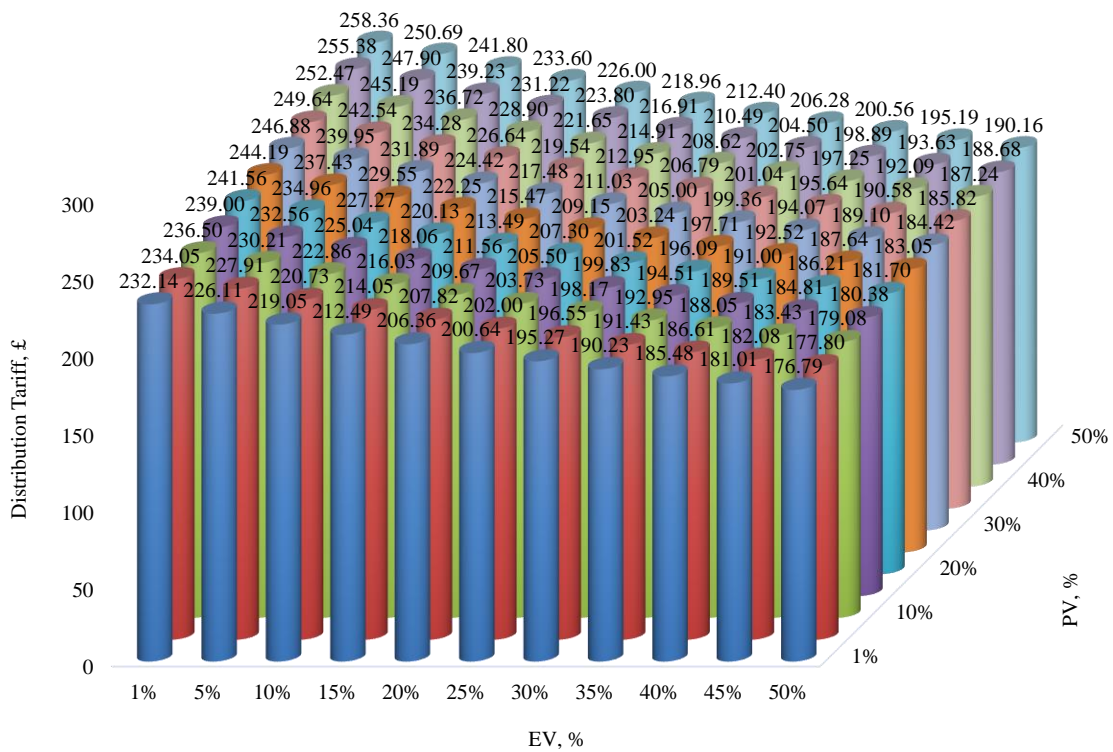


Figure 11. Distribution tariffs for households with PV and no EV, SHEPD

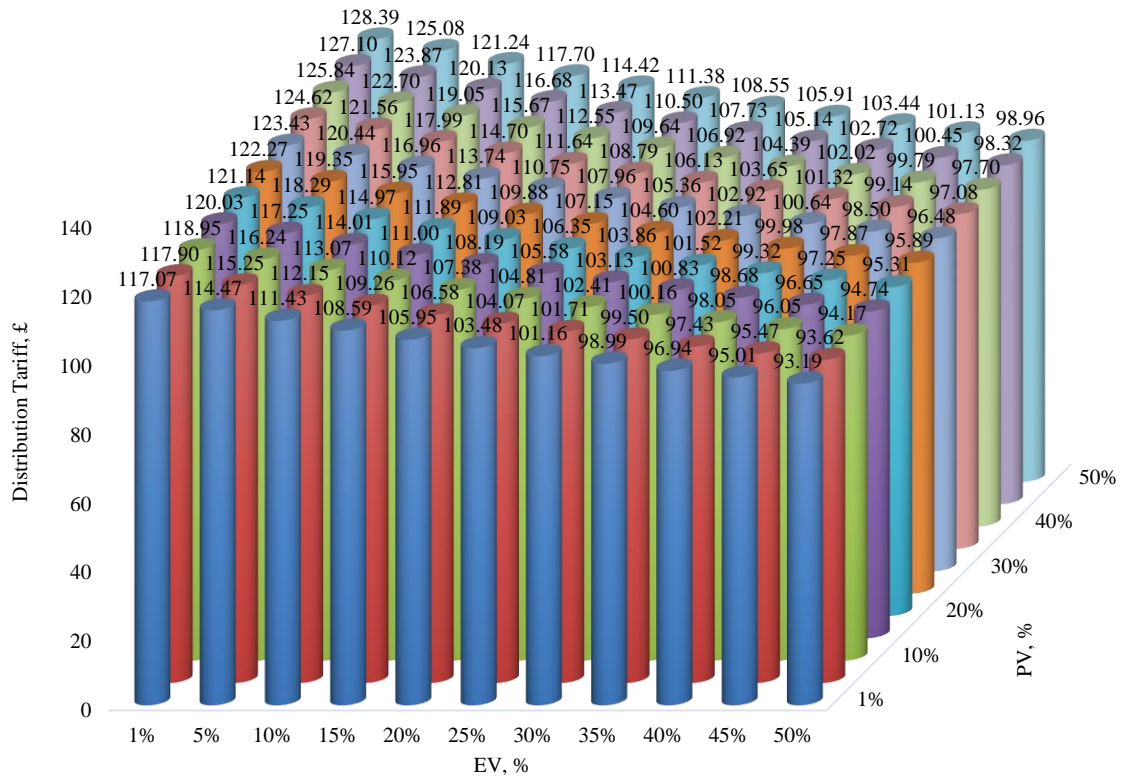
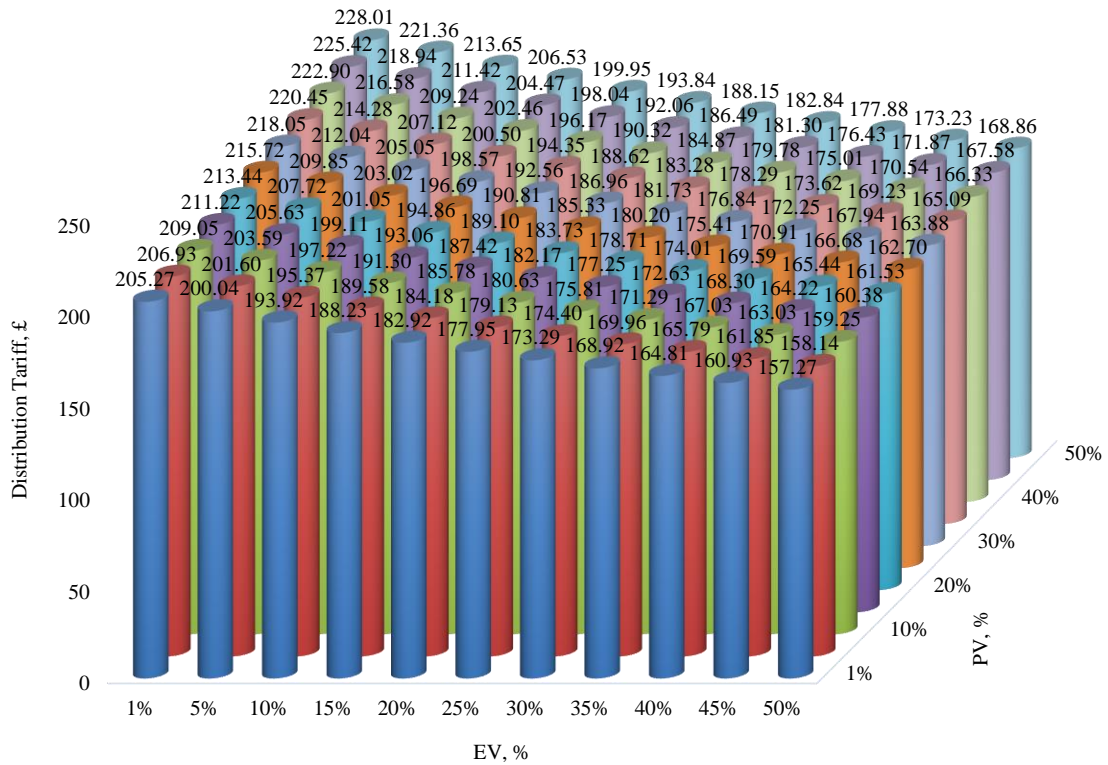


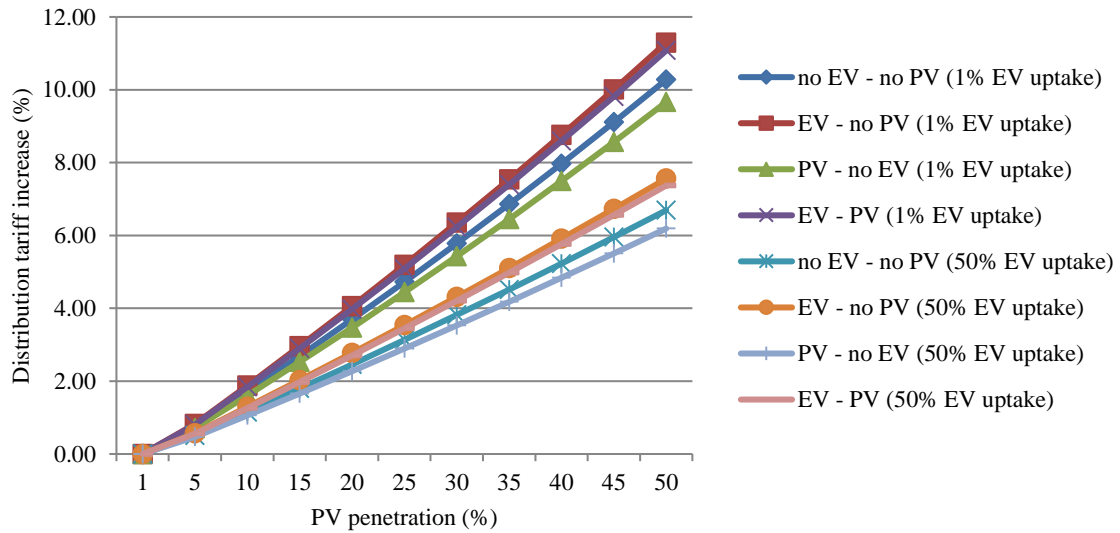
Figure 12. Distribution tariffs for households with EV and PV, SHEPD



To visualise the impact of inequality among customer groups, we plot the distribution tariff (total distribution bill) variations with increasing PV penetration with the minimum and maximum EV uptakes (1% and 50%).

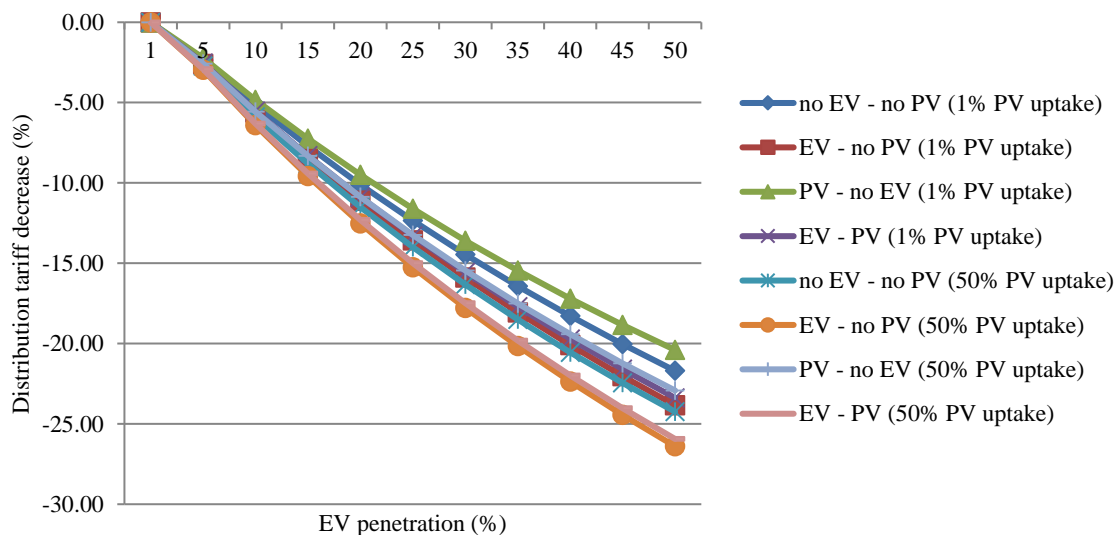
Figure 13 summarizes the results in SHEPD (the results for London result in slightly higher percentages of lower base amounts).

Figure 13. Distribution tariff variation in SHEPD with respect to PV penetration with 1% and 50% EV usage



From Figures 13 we see that the distribution tariff increases with increasing penetration of PV. Furthermore, the rate of tariff increase is higher under 1% EV uptake than at 50% EV uptake. Similarly, Figure 14 shows the decrease in tariffs in SHEPD (the results for London result in slightly higher percentages of lower base amounts). Here the rate of tariff decrease is higher at 50% PV uptake than at 1% PV uptake.

Figure 14. Distribution tariff variation in SHEPD with respect to EV penetration with 1% and 50% PV usage



5. Conclusions and Discussion

According to Department of Energy & Climate Change, Energy and Climate Change Public Attitude Tracker, Wave 23 report (DECC, 2017b) 20% of the British energy customers are either very or fairly worried about paying energy bills in 2017. The worry is highest among customers with household incomes up to £15,999 (26% of the customers) and lowest among those with household incomes over £50,000 (12% of the customers). It is against this background that the impacts of distribution charging methodologies under different PV and EV roll-out scenarios is of concern to regulators.

Increasing behind-the-meter generation will bring down the metered volumes used in two-part tariffs, which will naturally lead to increasing unit prices in order to reach the same allowed revenue. To tackle sharp increases in the distribution network charges among the households which do not own solar PVs in Queensland, Australia, Simshauser (2016) proposes a three-part network charging design instead of the traditional two-part tariffs. The three-part tariff is composed of a fixed component, a capacity component (kW) and an energy component (kWh). Under this proposed new tariff, it is shown that the households which do not own solar PVs and air-conditioners pay 152.49 AUD per year less than under existing two-part tariffs (Simshauser, 2016). We should note that the typical annual mean solar irradiance values are about 200 W/m² in Australia and 105 W/m² in the United Kingdom (World Energy Council, 2013). Due to solar radiance and geographical reasons, whilst the electricity distribution tariffs in Australia are likely to be PV driven, by contrast they are more likely to be EV driven in Britain. As we mentioned in Section 2.1, in Great Britain, the number of customers who are expected to own PVs could be 6 million by 2030 (20% of households), whereas EV ownership might reach as many as 9 million by 2030 (30% of households), with the PV generating half the energy that they might in Australia.

We should also note that there might be regional differences within the same country as well. From Figures 2 and 4 we see that the number of solar installations per 1000 households in Scotland is almost 4 times higher than that of in London. However, again per 1000 vehicles, the number of electric vehicles in London is twice of the number in Scotland. One key question with the EVs is: where will the EV owners charge their vehicles: at home, at work or at public charging stations? A survey conducted in US in 2014 indicates that 81% of electric vehicle charging occurs at home, 7% of charging takes place at work and 10% of charging occurs at public charging stations (InsideEVs, 2014). An EV survey from the UK shows that 81% of the EV owners have access to a dedicated EV charging point at home. 14% of the users charge their cars at work and 51% say that they do not have EV charging facilities at their workplaces (Zapmap, 2015). Another recent study from UK reports that over 80% of all EV charging will likely to take place at home (Chargedev, 2017). Furthermore, the Nordic EV outlook reports that around 80% of the EV owners charge their cars at home (Nordic EV Outlook, 2018). On the other hand, how much of an upgrade and investment is needed for the rapid increase of EVs is another big question. According to the My Electric Avenue report, as the EV penetration reaches between 40% – 70% of customers in Britain, 32% of low voltage (LV) feeders (312,000 circuits) will require upgrading (My Electric Avenue, 2015). However, this figure is calculated for 3.5 kW (16 A) charging whereas the rated value for charging for new EVs is 7 kW. With increasing amounts of distributed generation, EVs and storage systems, more extensive research is needed to understand how much investment is needed for the low voltage networks.

The recent increase in distributed, intermittent and difficult to control generation has posed many different challenges for electricity regulators. There are bold forecasts for rapid increases in household solar energy and electric vehicle use in Britain that raise the question of whether the current distribution charging mechanism is fair or not. In a two-part tariff design, with a fixed rate (£/day) and a volumetric rate (£/kWh), raising a fixed amount of revenue by varying the volumetric charge exacerbates inequalities in charging. This paper takes the most and least expensive British network operators, London Power Networks and Scottish Hydro Electric Power Distribution, as case studies. Our findings can be summarised as:

- According to the most aggressive scenarios, in Great Britain by 2030, the EV uptake will be around 30% and the solar rooftop PV uptake will be around 20%.

- For every 5% increase in EV uptake, the total distribution charge decreases almost by 3%.
- For every 5% increase in PV uptake, the total distribution charge increases almost by 1%.
- As EV penetration increases, the tariffs decrease for all customer groups regardless of whether one owns an EV or not.
- As PV penetration increases, the tariffs increase for all customer groups especially the ones without a PV.
- If both overall EV and PV penetrations are at the same percentage, the total distribution tariff decreases for all customer groups.
- In LPN, the maximum tariff decrease is observed within the customers with EV but no PV at an amount of £23 per year.
- In SHEPD, the same tariff decrease is around and £42 per year for the same customer group.

One major problem is the netting of PV generation reducing the metered kWh consumed. Ofgem is currently working on a tariff reform with the relevant stakeholders to answer these problems so that a more cost reflective and fair tariff design can be achieved.

From the analysis, we see that the current distribution tariff for SHEPD (North of Scotland) is around £145 and for LPN £69 for customers without EV and/or PV. The difference is quite significant, where the customers in SHEPD network region are paying almost double the distribution network costs of those in LPN (London). SHEPD has the highest distribution charges in Great Britain due to its large area and low population density⁴.

In closing we observe that for Great Britain significant roll out of EVs, which are charged at home, has the capacity to reduce distribution charges for poorer households without an EV or PV, under the current volumetric charging methodology, if the impact on total distribution costs is minimised (e.g. by smart home charging of EVs). Thus, precipitant changes to the charging methodology, raised by the experience of high PV penetration in Queensland, may be unnecessary. However, as we show this conclusion is situation dependent and in any given jurisdiction will depend on the relative uptake of PVs and EVs, the percentage of EVs charged at home, the solar intensity and the available roof capacity.

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⁴ The Hydro Benefit Replacement Scheme helps to protect both domestic and non-domestic customers from these high costs (DECC, 2015). In 2015/2016 this assistance was about £41 per household per year for about 680,000 domestic customers in the region.

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