Future-proof tariff design: recovering sunk grid costs in a world where consumers are pushing back

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Abstract

Traditional analysis of distribution network tariff design assumes a lack of alternatives to grid connection for the fulfilment of consumers' electricity needs. This is radically changing with breakthroughs in two technologies: (1) Photovoltaics (PV) enable domestic and commercial consumers to self-produce energy; (2) Batteries allow consumers and self-producers to gain control over their grid energy and capacity parameters. Contributing to the state of the art, the grid cost recovery problem for the DSO is modelled as a non-cooperative game between consumers. In this game, the availability and costs of the two named technologies strategically interact with tariff structures. Four states of the world for user's access to technologies are distinguished and three tariff structures are evaluated. The assessed distribution network tariff structures are: energy volumetric charges with net-metering, energy volumetric charges for both injection and withdrawal, and capacity-based charges. Results show that in a state of the world with new technology choices for grid users both efficiency and equity issues can arise when distribution network charges are ill-designed.

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1. Introduction

In Europe and the USA there is an observable trend towards volumetric network tariffs (in €/ kWh) being gradually replaced by capacity-based network tariffs (CEER, 2017; European Commission, 2015; Hledik, 2015). Especially a volumetric tariff accompanied with net-metering[1], the network tariff design historically in place, is challenged both in the media[2] and in academic circles (e.g. Comello and Reichelstein, 2017; Darghouth et al., 2011; Eid et al., 2014; Pérez-Arriaga et al., 2017). Net-metering is perceived unfair and can over incentivise PV adoption; under this tariff design, active consumers installing PV panels contribute significantly fewer network charges while their costs inflicted on the grid do not necessarily change. In this paper, a game-theoretical model is applied to address the following two research questions:

[1] Net-metering is the practice by which consumers are accounted solely for their net electricity consumption from the grid when distribution charges are determined.
[2] E.g.: Pyper, Julia. 2015. "Ditching Net Metering Is in the 'Best Interest' of Solar, Say MIT Economists." *Greentech Media*. Accessed on 15/04/2017. www.greentechmedia.com/articles/read/MIT-Economists-Say-We-Should-Ditch-Net-Metering

(1) Do capacity-based network charges solve the efficiency problems experienced with volumetric charges with net-metering?

(2) Do capacity-based network charges allow active consumers, investing in PV and batteries when incentivised, to be better off at the expense of passive, sometimes vulnerable, consumers?

It is shown that the answers to both research questions depend on the technology cost scenario. The answers are further nuanced as a result of the chosen modelling approach. Namely, the grid cost recovery problem for the DSO is represented as a non-cooperative game between consumers. In this game, consumers can strategically opt out of part of the grid use by investing in Distributed Energy Resources (DER). Their reaction differs depending on the grid tariff design in place. By opting out of part of the grid use, reactive consumers shift grid costs to passive consumers and at the same time compete to reallocate the grid costs to one another. The added insight obtained from this modelling approach is that it considers uncoordinated investment decisions by reactive consumers. Uncoordinated consumer decisions can result in an overall efficiency loss when price signals, in this case network charges, are not designed properly.

The reallocation effect is not captured by Borenstein (2016), Brown et al. (2015), Hledik and Greenstein (2016), and Simshauser (2016) who either do qualitative or static-quantitative analysis.[3] Hledik and Greenstein (2016) and Simshauser (2016) argue that capacity-based charges (in € per kilowatt (kW) peak) are an attractive option to replace volumetric network tariffs. These authors contend that capacity-based grid charges would avoid inequitable bill increase and allow for better cost reflection. However, not everyone agrees. Borenstein (2016) reasons that challenges arise as a significant part of the network costs are residual or sunk costs.[4] He states that there is no clear guidance from economic theory on how to allocate such costs as cost causation is unclear. He argues that almost surely a combination of higher fixed charges and an adder to time-varying volumetric charges would be the least bad policy option. Similarly, Brown et al. (2015) do not identify any single best option for the recovery of residual costs.

[3] DER adoption as a reaction to network tariff design is considered exogenous and 'revenue neutrality' for the network operator is assumed when assessing different tariff structures with a consumer database. Assuming revenue neutrality is from a modelling perspective not different than assuming grid costs are sunk.

[4] This is especially true in networks experiencing low or no load growth for which costs occurred in the past to dimension distribution grids to the expected peak capacity needed in the local system (Pérez-Arriaga and Bharatkumar, 2014).

They state that the recovery of residual costs through fixed charges would result from prioritising the principle of efficient prices.

Typically, models with a similar mathematical structure as in this paper have been used to analyse imperfect competition in (power) markets (see e.g. Gabriel et al., 2012; Gabriel and Leuthold, 2010). In such equilibrium problems, the numerous optimisation problems are connected, e.g. via either an equilibrium constraint (supply equals demand) or the inverse-demand function in each agent's objective function. In the past, there was no need to apply a similar modelling approach when studying distribution network charges as consumers had little means to react strategically to the tariffs imposed on them. However, this assumption does not hold true anymore. This is mainly due to the sharply decreasing costs of two technologies: photovoltaics (PV) and batteries (see e.g. Lazard, 2016a, 2016b; MIT, 2016; RMI, 2015). These two technologies allow grid users to react to the way electricity supplied by the grid is priced. PV enables consumers to self-produce energy and lowers the net energy need from the grid, while batteries enable self-producers to regulate both their grid energy flows and capacity parameters. Suddenly, network tariff design has become a concern. As described by Pollitt (2016): “ The rise of distributed energy resources (DERs) offers increased opportunities to exploit the existing system of network charges in ways that were not originally envisaged.“ If network tariff design does not anticipate the new sets of actions available to consumers, grid cost recovery for the distribution system operator (DSO) and a fair allocation of costs are at risk.

In this new setup, instead of an equilibrium constraint or inverse-demand functions, the optimisation problems are linked by introducing a ‘grid cost recovery (equilibrium) constraint’. More precisely, the stylised game-theoretical optimisation model presented in this work consists of linked individual optimisation problems of consumers which are minimising their cost to satisfy their electricity demand. The individual optimisation problems are linked with a ‘grid cost recovery constraint’, stating that the total network charges paid by all consumers should equal the total network costs to be recovered by the DSO. By doing so, the optimisation problem of one consumer is impacted by decisions of other consumers. An equilibrium is found when the grid costs are recovered by the DSO and the consumers have no incentive anymore to change their reaction to the network tariff.

Three illustrations have inspired this paper: Zugno et al. (2013), Momber et al. (2016) and Saguan and Meeus (2014). Zugno et al. (2013) build up a game between an electricity retailer and consumers who are reacting by shifting their load to the electricity price set by the retailer. Similarly, Momber et al. (2016) model an aggregator which takes decisions on optimal bidding strategies in the electricity market and on the retail price, while being subjected to decisions of cost-minimising EV owners. Saguan and Meeus (2014) introduce a competitive equilibrium model to calculate the cost of renewable energy in four states of the world, i.e. with renewable trade versus without renewable trade, and with national transmission planning versus international cooperation on transmission planning.

The remaining parts of the paper are structured as follows. In Section 2 the methodology of the paper is highlighted. In Section 3, the proposed model is described in detail. In Section 4, the setup of the numerical example, data and the technology cost scenario matrix is presented. The results are discussed in Section 5. Lastly, a conclusion is formulated and possibilities for future work are summarised.

2. Methodology: three tariff structures, two metrics and four states of the world

Three different tariff structures (TS) are analysed:[5]

- **TS1**: Volumetric network charges with net-metering.
- **TS2**: Volumetric network charges without net-metering, bi-directional metering is applied. Network charges are paid for both each kWh withdrawn and injected and at the same rate.
- **TS3**: Capacity-based charges based on the observed individual peak power withdrawal or injection from the grid over a certain duration (e.g. hourly or quarter-hourly).[6]

The outcomes of the tariff structures are benchmarked with the application of fixed network charges. Fixed network charges serve as a reference as they do not distort the volumetric (€/kWh) and capacity (€/kW) price signal and grid costs are assumed sunk. Going entirely off-grid is not considered an option for consumers in this paper. This is not a

[5] No time or locational variation in the rates is assumed, solely the 'structure or format' of the tariffs differ. See Pérez-Arriaga et al., (2017) for a discussion more focussed on the time and locational granularity of distribution tariffs.
[6] Currently, in most cases, low voltage users are being billed by the contracted capacity, and not through an observed maximum capacity. However, with the envisioned mass roll-out of smart meters accurate maximum capacity charging of network users will be enabled (Eid et al., 2014).

strong simplification as Hittinger and Siddiqui (2017) find that the financial case for grid defection is limited or non-existent given current costs and prevalent policies. Two metrics are introduced to quantify the results. Firstly, a proxy for (in)efficiency is used to quantify the increase of the total system cost as compared to the reference case with fixed network charges. Secondly, a proxy for equity is introduced by looking at the allocation of the sunk costs for different consumer's types under the different tariff structures.

A 'Technology costs matrix', with four extreme states of the world, is set up to analyse the impact of dropping investment costs in PV and batteries (Lazard, 2016a, 2016b; MIT, 2016; RMI, 2015). This matrix is displayed in Table 1. Each state of the world represents a unique combination of costs related to the technologies.

Table 1: Matrix representation of the four states of the world related to technology costs

Technology cost matrix		Capital cost PV (€/kW_p)	
		High	Low
Capital cost batteries (€/kWh)	High	The past?	Today?
	Low	Unlikely?	The future?

In the past, a consumer did not have much means to react to electricity prices as DERs were too expensive to invest in. Today, residential PV becomes more and more competitive with electricity supplied from the central grid, while batteries are still relatively expensive. Nevertheless, a scenario with low PV and battery investment costs can be expected to materialise soon as pointed out by many studies (Lazard, 2016a; MIT, 2016; RMI, 2015). As an illustration, in the Utility of the Future Study by MIT (2016) it is quoted that PV developers and industry analysts expect the installed cost of utility-scale PV to fall below $1000 per kW before the end of this decade, and that one major US automaker projects that lithium-ion battery cell costs will drop below $100 per kWh by 2022— an order of magnitude less costly than 2010 costs.

3. Model: approach and mathematical formulation

In this Section, the modelling approach is presented. This Section is split up into three Subsections. The first Subsection explains shortly the high-level functioning of the model. Also, limitations of the modelling approach are discussed. A second Subsection describes the mathematical formulation of the model. A third subsection explains the solution method applied.

3.1. Modelling approach

The stylised game-theoretical optimisation model consists of several individual optimisation problems which are linked by an equality constraint that needs to be satisfied, the so-called 'grid cost recovery constraint' in this context. The optimisation problem of one consumer is impacted by decisions of other consumers, as all optimisation problems are linked. For example, under volumetric charges with net-metering, if a consumer installs PV, it would mean that the total net volume of electricity requested from the grid is reduced. Consequently, the total amount of network charges paid would reduce. In reaction, the volumetric rate of the network charge must now be increased to allow total cost recovery for the DSO. This rate increase makes it possibly interesting to install additional capacity of PV and so forth. An equilibrium is found where the sunk costs are recovered and the consumers have no incentive anymore to change their reaction to the network tariff.

The formulation is split up into two parts:

- *The grid cost recovery constraint:* This equality represents the cost-allocation problem of a distribution system operator (DSO). The sunk grid costs to be recovered by the DSO need to equal the network charges collected from the consumers. The network charges are set perfectly anticipating the reaction of the consumers to these charges.
- *The optimisation problems of individual consumers:* The consumers are split up as reactive and passive consumers and have the objective to minimise their electricity costs. Reactive consumers have the possibility to invest in solar PV and batteries, while passive consumers do not. The network charges are the variables linking all individual optimisation problems through the grid cost recovery constraint.

It should be added that this modelling approach has certain limitations. Firstly, the investment decisions by the consumers and the setting of the network tariffs are treated as a 'single-shot problem', instead of multi-stage. Further, no stochasticity in the parameters is accounted for. Returns for consumers from investment in DER might be uncertain. Also, eventual future decline in DER investment costs could be anticipated by consumers; there is an option value for waiting. An example of a paper tackling these issues is the risk-constrained multi-stage stochastic programming model proposed by Baringo and Conejo (2013). Addressing these limitations in this context could be a line for further research. Alternatively, an agent-based modelling approach could be used, see e.g. Saguan et al. (2006) for a discussion between equilibrium and agent-based modelling to study imperfect competition in electricity markets and Weidlich and Veit (2008) for a critical survey of agent-based wholesale electricity market models.

3.2. Mathematical formulation[7]

In this Subsection, the two parts of the mathematical formulation and how they are connected are described in more detail. Firstly, the grid cost recovery constraint of the DSO is described. Secondly, the optimisation problem of the individual consumers connected to the distribution network is described.

3.2.1. The grid cost recovery constraint

The cost recovery constraint of the simplified DSO is displayed by Equation 1. The equation states that the total network costs to be recovered have to equal to the total network charges collected by the DSO to recover their costs.[8] This equation should hold while minimising the coefficient of the volumetric (vnt) or capacity-based (cnt) network tariff. By minimising the coefficients of the network charges, the increase in network cost reallocated to passive consumers, not installing DER, are most limited. By assuming grid costs to be sunk, the change in aggregated consumption/injection behaviour of the reactive consumers connected to the distribution grid does not have an influence on the total network costs to be recovered. In other words, costs occurred in the past, anticipating future usage. The sunk cost assumption will be relaxed in future work. To ensure full cost recovery for the DSO, the coefficient of the network tariff will increase in almost all cases when having consumers installing DER when compared to a default situation where all consumers fulfil their electricity needs solely with power from the grid. This increase is minimised by this formulation, while cost recovery is ensured.

The total network charges collected from the consumers are calculated by the right-hand side of the equation. The network charges can be volumetric, capacity-based or fixed charges. α, β and NM parameterise the different tested tariff structures. Please find an overview of all notations in Appendix A.

$$\text{Network costs} = \sum_i \Big[\mathrm{N_i} * \Big(\underbrace{\alpha * vnt * \textstyle\sum_t (qw_{t,i} - qi_{t,i} * \mathrm{NM}) * \mathrm{WDT}}_{\text{Volumetric}} + \underbrace{\beta * cnt * qmax_i}_{\text{Capacity}} + \underbrace{(1 - \alpha - \beta) * \mathrm{FNT}}_{\text{Fixed}} \Big) \Big] \qquad (1)$$

With minimal vnt or cnt

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[7] Variables are represented by italic lower case Latin letters, for parameters upper case Latin or lower case Greek letters are used.

[8] For computational reasons, an error margin δ (e.g. 1% of the network costs) is applied, allowing for a limited deficit or excess.

The parameter $\mathrm{N_i}$ stands for the number of consumers represented by representative consumer i.[9] To limit the computational time, representative consumers standing for homogenous groups are used. The variables set by the grid cost recovery level are vnt the coefficient of the volumetric charge in €/kWh, and cnt the coefficient of the capacity-based charge in €/kW. Depending on the tariff structure a coefficient can be forced equal to 0. Further, $qw_{t,i}$ represents the energy withdrawn from the grid at time step t by consumer i, $qi_{t,i}$ the energy injected into the grid at time step t by consumer i. WDT is a scaling factor for the annualization of all costs. $qmax_i$ is the peak use of the network by consumer i. It is a proxy for the maximum capacity required to service consumer i's network requirements. Finally, FNT is a parameter and represents the fixed network charge per connection, uniform over all consumers.

In Table 2 the different network tariff structures and their parameter settings are displayed. In cases where TS1 or TS2 are applied, the second term of the summation on the right-hand site of Equation 1 will equal zero as cnt is forced to zero. The third term of the equation, representing fixed network charges, will also be zero as α equals 1. By setting parameter NM to 1 the power withdrawn from the grid ($qw_{t,i}$) is netted out with the power injected into the grid ($qi_{t,i}$), representing net-metering. If NM is set to -1, no netting out takes place, and both power withdrawal and injection are subjected to network charge vnt. When applying TS3 vnt will be forced to zero and again the third term of the summation will equal zero as β is set to 1. Lastly, when fixed network charges are applied the first two terms of the summation will equal zero as α and β are set equal to zero. Please note that other implementations can be tested with this model, for example a 3-part network tariffs with a volumetric, a capacity and a fixed component. This can be done by setting α and β to a value between 0 and 1, with the sum of α and β being less (3-part tariff) or equal to 1 (2-part tariff, no fixed component). In this work, we chose to report the more extreme implementations.

[9] Alternatively, proportions of consumer groups relative to all consumers connected could be used. In that case, the total network costs are scaled accordingly.

Table 2: The different network tariff options - description and parameter settings for Equation 1

	Network tariff structure	Description	α Volumetric	β Capacity	NM Net-metering
TS1	Volumetric charges with net metering	Only the net consumption is used to calculate the network charges to be paid by the consumer.	1	0	1
TS2	Volumetric charges without net metering	The sum of the withdrawal and injection into the grid is used to calculate the network charges paid by the consumer. Charge for withdrawal and injection is equal.	1	0	-1
TS3	Capacity-based charge	The withdrawal or injection peak (in kW) measured over the length of the full-time horizon is used to calculate the network charges paid by the consumer.	0	1	0
Ref.	Fixed network charges	The fixed charge is uniform and equal to the sunk cost to be recovered divided by the number of consumers.	0	0	0

3.2.2. Optimisation problem of consumers

The consumer's optimisation problem is a linear programme (LP). The objective function is presented by Equation 2. Each consumer minimises its (annualised) total cost of servicing its electricity requirements. The total costs consist of four parts; the energy costs, the network charges and other charges that constitute the electricity bill, and the investments costs in DER technology.[10] In the case where a consumer is passive, the investment costs will always be zero. For a reactive consumer, investment costs might be positive. This would be the case if additional investment costs are lower than the decrease in the electricity bill due to the DER investment. With 'other charges', e.g. RES levies are meant. It is assumed that these charges are paid as a fixed fee, and do not influence the optimisation problem of an individual consumer.

$$\text{Minimise } \ energy\ costs_i + network\ charges_i + other\ charges + investment\ costs_i \tag{2}$$

With:

$$energy\ costs_i = \sum_t \left(qw_{t,i} * \mathrm{EBP_t} - qi_{t,i} * \mathrm{ESP_t}\right) * \mathrm{WDT} \tag{3}$$

$$network\ charges_i = \sum_t (qw_{t,i} - qi_{t,i} * \mathrm{NM}) * vnt * \mathrm{WDT} \ + qmax_i * cnt + \ (1 - \alpha - \beta) * \mathrm{FNT} \tag{4}$$

$$investment\ costs_i = \ is_i * \mathrm{ICS} * \mathrm{AFS} + ib_i * \mathrm{ICB} * \mathrm{AFB} \tag{5}$$

Equation 3 describes the calculation of the energy cost. $\mathrm{EBP_t}$ represents the price paid by a consumer for withdrawing one kWh of electricity at time step t from the grid, excluding the network or other charges. $\mathrm{EBP_t}$ can be thought of as the wholesale electricity price plus a retail margin. $\mathrm{ESP_t}$ stands for the price received for injecting one kWh of electricity into the grid. Depending on the country context $\mathrm{ESP_t}$ may be labelled the feed-in tariff, again excluding possible network other charges. The energy costs are annualised using a scaling factor WDT.

[10] No costs for operation or maintenance of DER technology is assumed.

In Equation 4 the network charges paid by consumer i are calculated. Depending on the applied tariff structure, two of the three terms of the summation will be forced to zero. When TS1 or TS2 is applied, only the first term will be greater or equal than zero, in the case of TS3 the second term can be positive and finally when TS4 is applied the third term will be greater than or equal than zero.

The investment costs of DER installed by a consumer are described by Equation 5. Variable is_i represents the capacity of installed solar PV (kWp), and variable ib_i represents the installed battery energy capacity of the battery (kWh). In the case of a passive consumer both is_i and ib_i are forced to zero. Capacities of PV and batteries are represented as continuous variables in this formulation, while in reality there may be only discrete choices. ICS and ICB are the investment costs per kWp solar capacity and kWh battery capacity respectively and AFS and ABS are the annuity factors for both technologies.

Consumers are subjected to a set of constraints, shown by Equations 6-16. Equation 6 represents the demand balance, meaning that demand should equal supply at all moments. $\mathrm{D_{t,i}}$ is the demand of consumer i at time step t.[11] The supply of electricity consists of the summation of electricity withdrawn from the grid, the electricity generated from PV and the energy discharged from the battery, minus the summation of the electricity injected into the grid and the electricity used to charge the battery. It is not possible to buy and sell electricity or discharge and charge the battery simultaneously. As such, $qw_{t,i}$ will be equal to zero if $qi_{t,i}$ is positive and vice-versa and the same holds for $qbout_{t,i}$ and $qbin_{t,i}$.[12] $\mathrm{SY_{t,i}}$ stands for the time-varying PV yield in kWh per KWp PV installed, which depends on the observed irradiation and the efficiency of the PV panel. $qbout_{t,i}$ and $qbin_{t,i}$ are variables standing for the energy output and input respectively of the battery of consumer i at time step t.

$$\mathrm{D_{t,i}} = qw_{t,i} - qi_{t,i} + is_i * \mathrm{SY_{t,i}} + qbout_{t,i} - qbin_{t,i} \quad \forall\, t \tag{6}$$

$$soc_{1,i} = qbin_{1,i} * \mathrm{EFC} * \mathrm{DT} - (qbout_{1,i}/\mathrm{EFD}) * \mathrm{DT} + \mathrm{SOC_0} \tag{7}$$

$$soc_{t,i} = qbin_{t,i} * \mathrm{EFC} * \mathrm{DT} - (qbout_{t,i}/\mathrm{EFD}) * \mathrm{DT} + soc_{t-1,i} * (1 - \mathrm{LR} * \mathrm{DT}) \quad \forall\, t \neq 1 \tag{8}$$

$$soc_{tmax,i} = \mathrm{SOC_0} \tag{9}$$

$$qw_{t,i} + qi_{t,i} \leq qmax_i \qquad \forall\, t \tag{10}$$

[11] In this paper, the household power demand ($\mathrm{D_{t,i}}$) is an exogenous parameter and instead the way the demand is met (grid, solar panel or battery) is an optimised decision for a reactive consumer. In future work, also the household power demand could be modelled as a variable e.g. by introducing a price sensitivity of demand for electricity as in Van Den Bergh and Bruninx (2015).
[12] Binaries could be introduced to force this. In this paper, the validity of the LP solution is checked ex-post.

$$soc_{t,i} \leq ib_i \qquad \forall\, t \tag{11}$$

$$qbout_{t,i} \leq ib_i * \mathrm{BRD} \qquad \forall\, t \tag{12}$$

$$qbin_{t,i} \leq ib_i * \mathrm{BRC} \qquad \forall\, t \tag{13}$$

$$is_i \leq \mathrm{MS_i} \tag{14}$$

$$ib_i \leq \mathrm{MB_i} \tag{15}$$

$$qw_{t,i}, qi_{t,i}, soc_{t,i}, qbout_{t,i}, qbin_{t,i}, is_i, ib_i, qmax_i \geq 0 \tag{16}$$

Equations 7-9 describe the battery balance. $soc_{\mathrm{t},i}$ stands for the state of charge of the battery of consumer i at time step t, $\mathrm{SOC_0}$ is the initial energy content of the battery, EFC and EFD are the efficiencies of charging and discharging respectively, LR is the leakage rate of the battery and DT is the length of time step as a fraction of an hour. By Equation 10 the peak withdrawal or injection $qmax_i$ over all time steps is determined. Equations 11-13 limit the energy stored, power discharged at a time step and power charged at a time step respectively. The parameters BRD and BRC define the maximum rate power discharged/charged over the energy capacity of the battery. The capacity of solar and batteries to be installed by a consumer i is capped by Equation 14-15. Equation 16 forces all consumer variables to be non-negative. This formulation of the optimisation problem of a consumer can be considered as a linearised version of a DER sizing problem with possibilities to invest in solar and batteries (See for example: Schittekatte et al., 2016).

3.3. Solution method: connecting the equilibrium constraint and the individual optimisation problems

All individual consumers are connected to one another through Equation 1. An equilibrium is obtained if this equality holds and none of the consumers, for which the optimisation problems are described by Equations 2-16, has an incentive to adapt their electricity withdrawal and injection pattern from the grid by e.g. by installing more solar panels or using installed batteries in an alternate fashion. Different methods to solve the linked optimisations problems that are described by Equations 1-16 exist (see for example Gabriel et al., 2012). In this paper, a solution is found through the application of a simulation approach. Depending on the tariff structure applied, the coefficient of the network tariff (vnt or cnt) is increased until an equilibrium is attained. By starting from an initial low value (typically 0) of vnt or cnt we find the minimal coefficient under which cost recovery for the DSO holds. The flow chart of the algorithm underlying the proposed simulation approach is presented in Figure 1.

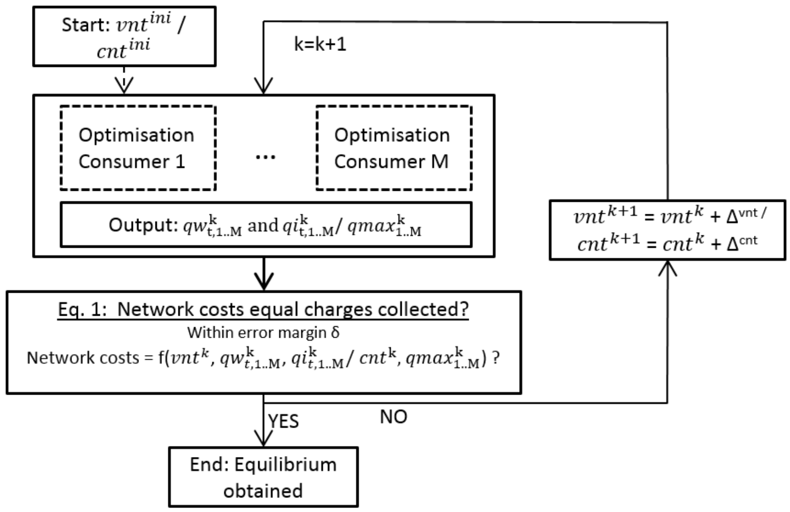


Figure 1: Flow of the calculations to obtain the equilibrium

The computational time needed to obtain a solution is sensitive to the number of unique consumers modelled and the length of the time series used to represent demand and PV yield.

4. Numerical example, result metrics and data

In this Section, firstly, the setup of the numerical example of the model is described. Secondly, the metrics to analyse the results are explained. Thirdly, the parameters constant for all four states of the world are presented and lastly, the parameter settings for these in the form of a technology cost matrix are presented.

4.1. Setup

For simplicity, only two consumer types are modelled: passive and reactive consumers. Both consumer types have the same original electricity demand from the grid. The sole difference between the two consumer types is that a passive consumer does not have the option to invest in solar PV and batteries, unlike a reactive consumer, who can opt to invest in DER. Passive consumers are uninformed about the possibility to invest in DER. They either do not have the financial means, are strongly risk averse or simply do not have space. Reactive consumers are economically rational, i.e. they minimise their costs to meet their electricity demand, and may invest in DER, if optimal. Note that the relative proportion of each consumer type is an important parameter for the sensitivity analysis of the results.

4.2. Proxies for efficiency and equity

Depending on the network tariff design in place, reactive consumers can offset their contribution to the sunk grid costs by investing in DER. In this case, the avoided contribution is reallocated to the passive consumers. However, the total costs to be recovered by the DSO remains the same, only the allocation of the contributions changes. More precisely, if a reactive consumer invests in DER technology, its electricity bill reduces due to the avoided energy costs *and/or* network charges. The reactive consumer will invest in DER if the difference between the reduction of the electricity bill and the DER investment cost is positive. The net reduction in the total electricity cost will be exactly this difference. The passive consumer does not invest in DER technology and will possibly see its electricity costs increase with the sunk costs reallocated by the reactive consumer. As an illustration, assume one reactive and one passive consumer. When no one invests in DER, the total electricity cost of all consumers is assumed the same as the consumers are identical. However, when investment in DER is allowed for a reactive consumer, the respective change in electricity cost can be:

- Change for reactive consumer = – avoided energy cost by the reactive consumer – avoided network charges by the reactive consumer + investment cost in DER
- Change for passive consumer = + avoided network charges by the reactive consumer

The net aggregated decrease or increase in total electricity cost for the two consumers, referred to as the change in system costs, will be:

- Change system costs = – avoided energy cost by the reactive consumer + investment cost in DER

Price signals are distorted if the avoided energy cost by the reactive consumer is lower than the investment cost in DER. This would mean that the system cost increases. In simple terms, 'the losers' (the passive consumers) lose more than 'the winners' (reactive consumers) win. The system cost is calculated in this model as the summation of the objective function of both consumer types weighted with their respective proportion $\mathrm{P_i}$[13]:

$$System\ cost = \sum_i \mathrm{P_i} * (energy\ costs_i + network\ charges_i + other\ charges + investment\ costs_i) \tag{17}$$

Fixed charges do not have a distortive effect in this model. Therefore, as a proxy for efficiency or 'non-distortionary', the system cost for a tariff structure is benchmarked with the system cost when fixed network charges are applied. A proxy for the equity is introduced by looking at the allocation of the sunk costs to the two consumer's types. It is assumed that in the most equitable situation the sunk costs allocated to both consumer types are the same, as their

[13] The proportion of a consumer group is defined by the number of consumers represented by a consumer group i ($\mathrm{N_i}$) divided by the total number of consumers connected to the distribution grid (N): $\mathrm{P_i} = \frac{\mathrm{N_i}}{\mathrm{N}}$

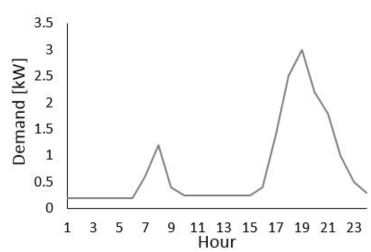
original electricity demand before installation of DER from the grid is identical. When a reactive consumer invests in DER part of the sunk costs can be reallocated to the passive consumer. The increase in network charges paid by the passive consumer compared to a situation where both consumer types pay the same fixed network charge is used as the proxy for equity.

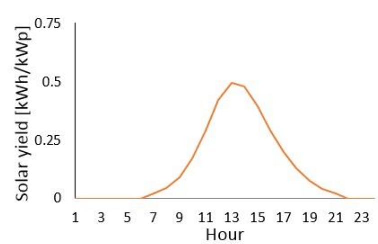
4.3. Data

In this stylised example the consumer demand and yield of a PV panel is represented using a time series of 24-hours with hourly time steps. (See Table 3 (middle and right)). The household demand for electricity shows a small peak in the morning and a stronger peak in the evening. The fulfilment of the demand is a hard constraint. The scaled annualised consumption of a consumer is 6.500 kWh with an annual peak of 3 kW. The relationship between the annual consumption and peak is based on Blank and Gegax (2014).[14] As a reference, in Europe average annual electricity consumption per household in 2015 ranged from 20.000 kWh (Sweden) to 1.400 kWh (Romania) (ACER, 2016). In the same year, the average electricity consumption per household in the USA was about 10.800 kWh (EIA, 2016a). This is a stylised example and the intention of this paper is not to analyse the impact of tariff design on consumers from a specific region. However, the adopted approach does not exclude such an analysis in the future. In Appendix B.1, the data used for a sensitivity analysis with longer time series and additional demand and solar yield profiles can be found.

Table 3: Technical DER Parameters (left), original demand profile (middle) and PV yield profile (right)

Parameters reactive consumer	Value
Lifetime PV	20 years
Lifetime battery	10 years
Discount factor PV and batteries	5 %
Maximum solar capacity installed	5 kWp
Maximum battery capacity installed	No limit
Efficiency charging & discharging	90 %
Leakage rate	2 %
Price received for electricity injected into the grid (% of wholesale price)	90 %





The yield per kWp PV installed scales up to 1160 kWh per year with the profile shown in Table 3 (right). This level is similar to the average yield in the territory of France (Šúri et al., 2007). As a reference, Formica and Pecht (2017)

[14] In that paper, a regression analysis using a small data sample of households in Alaska is done. The authors find that an increase in monthly energy use by 1,000 kWh would increase maximum monthly demand by 5.5 kW. For the sake of simplicity these findings are extrapolated to a yearly basis.

found a yield of 1300 kWh/kWp for a PV installation in Maryland, USA and Mason (2016) finds that in the UK the average yield equals 960 kWh/kWp. Remaining other relevant parameters are shown in Table 3 (left). Technical DER data is in line with Schittekatte et al. (2016). Finally, the price received for electricity injected into the central grid (also called the 'feed-in tariff') is set to 90 % of the assumed price paid for energy from the grid, excluding network cost or any other charges. The energy price paid for energy relates to the electricity wholesale price and includes a retailer margin.

In Table 4 the composition of the consumer bill is presented. This is the consumer bill in the default setting, i.e. a situation without investment in DER technology by any consumer. If reactive consumers decide to invest in DER, the relative proportion and absolute values of the bill components will change for both the reactive and the passive consumer. The consumer bill is based on information from the market monitoring report for electricity and gas retail markets by ACER (2016). There, the breakdown of the different components of the electricity bill for an average consumer in the EU for the year 2015 is presented. The energy component of electricity prices in the EU in 2015 is estimated to be 37%. In nominal terms, this means a cost of 0.074 €/kWh. Further, 26 % of the bill consisted of network charges and 13 % are RES and other charges. Finally, an important chunk (25%) of the bill consists of taxes. A value-added tax (VAT), averaging 15%, must be paid and additional (ecological) taxes, averaging 10 %, are raised on the use of power in some countries.

Taxes are integrated into the remaining three components: energy costs, network charges and other charges. The default electricity bill of the consumer consists of 45% energy costs, 35% network charges and 20% other charges. The energy price is set at 0.08 €/kWh consumed.[15] Other charges are recovered through a fixed fee and as such do not interfere with the analysis. However, this is not always the case, as described in Frondel et al. (2015). The question of how to collect such charges, or even whether they belong in the electricity bill at all, is out of the scope of this work. The network charges, the focus of this work, are recovered through the different network tariff designs.

[15] In this work, the energy cost component is modelled exogenously. In cases with high PV adoption this might be a strong simplification as a higher penetration of PV can have a depressing effect on wholesale prices (see e.g. Darghouth et al. (2016)).

Table 4: Consumer bill for in the default case, when no investment in DER by any consumer is made

Default consumer bill	Proportion of the bill	Cost per year	Recovery
Energy costs	45 %	520 €/year	0.08 €/kWh
Network charges	**35 %**	**404 €/year**	**Through the different network tariffs**
Other charges	20 %	231 €/year	Fixed fee (does not interfere)
Total electricity cost	Average of 0.18 € per kWh delivered	1155 €/year	

The total annual electricity cost, including also the network and other charges, equals 1155 €/year or 0.18 €/kWh delivered. This total cost is near to the average electricity cost for EU households in 2015 that was estimated around 0.21€/kWh (Eurostat, 2016). In the USA the average electricity cost in 2015 for residential use was lower, namely around 0.125€/kWh (EIA, 2016b).

Also a typical consumer bill varies widely over time and, additionally, is country context dependent. The energy cost component in the EU has fallen since 2012, both in nominal terms, from 0.08 to 0.074 €/kWh, and as a percentage of the final consumer bill (ACER, 2016). The proportion of the energy component of a typical residential electricity bill ranges from 78 % in Malta to solely 14-13 % in Norway and respectively Denmark. Not only the energy component but also the proportion of grid costs in the final bill was found to vary significantly. According to a recent European Commission (2015) report, the share of distribution cost paid by residential users in the EU ranges from 33% to 69% in the final consumer bill. High network charges are not always related to high costs of physical grids, but might be 'artificially' inflated. In some countries, costs have been added to the DSO's costs that are not directly tied to providing an incremental kWh of electricity, e.g. costs for energy efficiency programs and subsidies for installing distributed generation (Borenstein, 2016; European Commission, 2015; Huijben et al., 2016). In future work the sensitivity of the results to the country context will be investigated.

4.4. The technology cost matrix

The values of the key parameters for the different states of the technology cost matrix are displayed in Table 5. The numbers for the investment cost in residential PV are coherent with the low and high estimates of prices found in RMI (2015). As the cost of a kWh generated by 1 kWp of PV installed is a function of several parameters, the levelised cost of energy (LCOE) is calculated as an additional reference value.[16] The LCOE for the high and low PV cost scenario is equal to 0.18 €/kWh and 0.09 €/kWh respectively and these LCOE estimates are in line with the ranges presented

[16] In the model applied, the LCOE of PV is a function of the investment cost of the PV panel, lifetime, discount factor, the PV system performance ratio and the solar irradiation profile.

in Lazard (2016a). The same sources (Lazard, 2016b; RMI, 2015) are used to obtain the high and low investment cost scenario for lithium-ion battery packs. It is further assumed that the minimum time needed to fully (dis)charge the energy capacity of the battery is one hour. No investment subsidies for PV or batteries are introduced.

Table 5: Main parameter settings of the technology cost matrix

	High technology costs	Low technology costs
Investment cost PV	2600 €/kWp (LCOE: 0.18 €/kWh)	1300 €/kWp (LCOE: 0.09 €/kWh)
Investment cost batteries	600 €/kWh (full (dis)charge in 1 hour)	200 €/kWh (full (dis)charge in 1 hour)

Please note that high investment costs for PV panels could also be interpreted as installing those panels in parts of the world with less solar irradiance and vice-versa. It is harder to come up with a similar interpretation for the battery investment costs. However, the battery is used to shift power demand from the grid in time, a function which could also be provided by demand response.[17]

5. Results and discussion

The results obtained for the different tariff structures are displayed in Figure 2. The graph is split up into four quadrants, representing the four states of the world. The proportion of reactive consumers, able to invest in PV and batteries when economically rational is assumed to be 50 %. The proportion of reactive consumers is further discussed when the results are described. For each state of the world, the performance is shown of the three tariff structures for the efficiency proxy, on the horizontal axis, and for the equity proxy, on the vertical axis. The closer the result of a tariff structure is to the origin along one axis, the better its performance for the metric displayed on the other axis. Please note that in Appendix B.2. the results for longer and additional time series for demand and solar yield are shown and discussed briefly. In general, the results of the sensitivity analysis show the same trends as displayed on Figure 2. However, the results can be less outspoken in certain scenarios.

[17] Demand response is not modelled. The cost of demand response would be dependent on the value a consumer attributes to the need of power at a particular time. Such an analysis is out of the scope of this work.

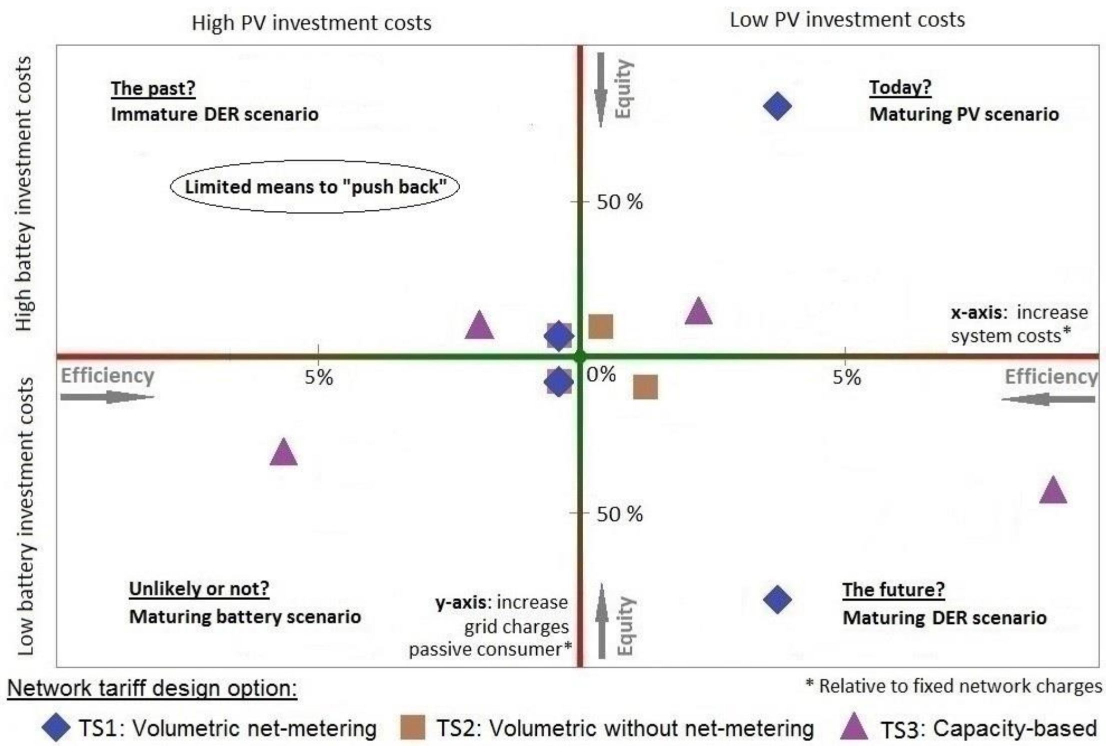


Figure 2: The results for the four scenarios of the technology matrix with 50 % reactive consumers connected to the grid. Results of the efficiency (horizontal) and equity (vertical) proxy are shown. The more the result of a tariff structure is situated near the origin along one axis, the better its performance for the metric on the other.

The results for the different tariff structures can be compared to each other in a specific state of the world. Also, the relative performance of a certain tariff structures in different state of the worlds can be assessed. This work does not attempt to discuss the trade-off between efficiency and equity. Only if a tariff structure dominates another tariff structure for both the efficiency and the equity metric, it can be said that one outperforms the other. In the next Subsections, the results are described per state of the world. The dynamics behind the results are described in detail for the 'Maturing DER scenario'. This Section ends with a short discussion on the implementation of capacity-based charges.

5.1. Immature DER scenario, the past?

Two observations are made in this reference state of the world. Firstly, the results show that applying volumetric network charges with net-metering, the network tariff design historically in place, does not create efficiency or equity issues for the recovery of the sunk costs. The same result is found for volumetric network charges without net-metering. This can be explained by consumers not having means to react to prices as PV is simply too expensive to invest in. A second observation is that with capacity-based network charges some inefficiencies, but very limited equity issues arise. This can be explained by investment in small but expensive batteries by the reactive consumers to shave their peak consumption. As the batteries are small, only a small proportion of the sunk costs are reallocated to the passive consumers.

5.2. Maturing battery and expensive PV scenario, unlikely scenario or not?

A state of the world with high PV investment costs and low battery costs is rather unlikely. However, this state of the world with associated technology cost could be the thought of as the future for places where electricity generated by PV is too expensive due to low levels of solar irradiation combined with few government subsidies. Alternatively, an unexpected battery R&D breakthrough could bring forward this scenario. Two observations from this state of the world are described below.

Firstly, results for volumetric charges with and without net-metering do not change. Net-metering does not incentivize investments in batteries for reactive consumers. [18] Under volumetric network charges without net-metering there is an incentive to install batteries. A consumer must pay network charges both for withdrawal and injection of energy into the grid. This means that a consumer is incentivised to self-consume his electricity generated on-site by PV. Consequently, when a consumer installs PV it can make sense to install additional batteries to limit the amount of electricity injected into the network when PV generation is high and demand low. The energy collected in the batteries can then be used to serve the electricity demand when the situation is reversed. As such, the exchange of electricity with the grid, and thus the network charges paid, will be limited. However, in this state of the world PV is expensive and therefore no PV is installed by the reactive consumer. As no PV is installed, also no batteries will be installed and therefore the results do not differ from those of the previous state of the world.

Secondly, increased inefficiencies and a more severe equity issue resulted with capacity-based charges when compared with the previously described state of the world. The proxy for efficiency, the system cost, is a function of two forces: the capacity of batteries installed and their costs. Reactive consumers install batteries with a higher capacity as these are rather inexpensive. However, since batteries are cheap, the increase in system costs is

[18] When energy prices or network charges would be time-varying also batteries adoption could result with volumetric charges without net-metering.

dampened. An equity issue results as the reactive consumers can shave their peak demand more significantly with the higher battery capacity installed per reactive consumer.

5.3. Maturing PV scenario, today?

Three observations can be made for this state of the world. Firstly, volumetric network charges with net-metering create severe equity issues and inefficiencies. Since reactive consumers install the maximum amount of PV of which the excess generation is fed into the grid, the netted-out electricity consumption of the reactive consumers from the grid is significantly lowered. Consequently, the network charge coefficient in €/kWh must increase to ensure cost recovery. This means that the network charges paid by the passive consumers increase strongly. Additionally, investment distortions are created with this network tariff structure. More precisely, the LCOE of PV for this scenario is slightly higher than the energy cost of electricity and the price received for injecting electricity into the grid. In the case a network tariff does not interfere with the volumetric (€/kWh) or capacity (€/kW) price signal, no investment in PV is expected from the rational cost minimising consumer. With volumetric network charges with net-metering in place, investing in PV becomes a lot more attractive as not only energy costs can be avoided but also network charges. These results confirm the findings of Eid et al. (2014). They concluded that net-metering creates significant equity issues for passive consumers and acts as an implicit subsidy for the adoption of PV.

A second observation is that the result for volumetric network charges without net-metering almost does not change when compared to the previously discussed scenarios. PV is inexpensive, and if reactive consumers install PV, they would avoid paying network charges for withdrawing electricity from the grid. However, the electricity demand is not always at the same level as the PV production and vice-versa. Therefore, the business case for a reactive consumer to install a large capacity of PV is not attractive, and only a very limited capacity of PV is installed. Batteries can increase the amount of electricity produced on-site that could be used for self-consumption. However, in this state of the world these are expensive and no batteries are installed.

The last observation is that the performance of capacity-based charges is impacted by a change in the PV investment cost while keeping the battery investment cost constant. This effect can also be observed when comparing the two states of the world with low battery costs and different PV investment costs. Lowered PV costs incentivise investment in PV under this tariff structure and consequently also investment in batteries becomes more attractive. This is rather surprising as can be seen from the demand and solar yield profile on Table 3 (middle and right) that the solar profile and peak demand are highly uncorrelated. This dynamic shows that there is added value in considering both investment possibilities in PV and batteries simultaneously when studying capacity-based charges in a setting with reactive consumers. Equity issues are limited as the capacity of batteries installed is small and the correlation of the solar yield profile and the peak demand of the consumer is low.

5.4. Maturing DER scenario, the future?

Three highlights are described for this state of the world. To begin with, Figure 2 shows that the results for volumetric charges with net-metering in this state of the world do not change when compared to the previously described state. This is expected as the only parameter changing between those two states is the battery investment cost, and with net-metering and no time-varying process in place, a reactive consumer has no reason to install batteries.

Secondly, the results for volumetric charges without net-metering change slightly. In this state of the world, the reactive consumers invest in PV and batteries. Inexpensive batteries increase the amount of electricity produced by PV that can be used for self-consumption. As such, the total amount of network charges paid by the reactive consumer decreases. However, the amount of avoided network charges is limited, and the installed capacities of both PV and batteries remain very small. This tariff structure could be regarded as an extreme case of the British tariff design as described by Green and Staffell (2017). In their paper, the authors investigate the business case of batteries and self-sufficiency for domestic electricity consumers. The obtained results are in line with their conclusion for GB. Namely that, even with low-cost storage available and a (volumetric) tariff design that seems to encourage the technology, energy arbitrage does not make consumer-based storage economic.

Thirdly, the results for capacity worsen significantly, both in terms of efficiency and equity, when comparing to the other states of the worlds. This result will be elaborated on more deeply to demonstrate why this is happening. In Figure 3 the results for efficiency and equity proxy with sensitivity for the proportion of reactive consumers connected to the grid is shown. For all three tariff structures, the magnitude of the inefficiencies and equity issues increases with an increased share of reactive consumers. This is relatively straightforward, because there are simply more reactive consumers with distorted investment incentives who are trying to reallocate the grid costs to a smaller share of passive consumers. This dynamic could be labelled as an effect of big numbers and is also captured by more static quantitative models as Hledik and Greenstein (2016)[19] and Simshauser (2016).

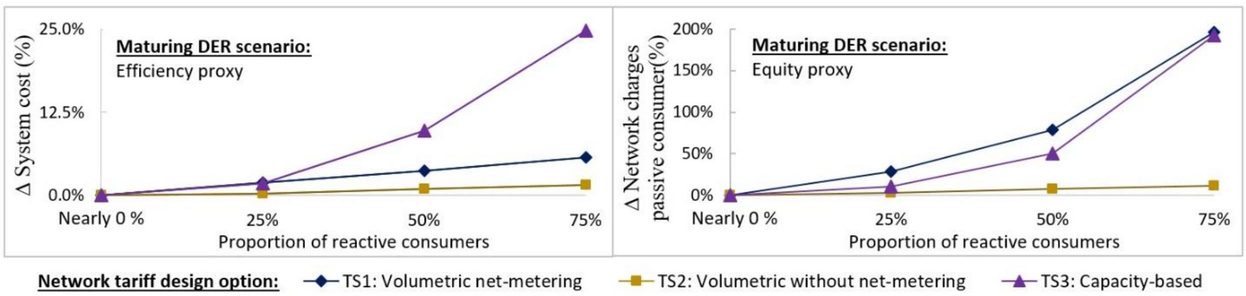


Figure 3: Results for the efficiency proxy (left) and the equity proxy (right) with sensitivity analysis for the proportion of reactive consumers.

However, a second effect makes the increase in inefficiencies and equity issues very non-linear and unpredictable. The origin of this effect is non-cooperative behaviour between consumers and the result is that *the capacity of DER technology installed per individual reactive consumer can increase with an increased share of reactive consumers connected to the grid*. In this scenario and under capacity-based charges, the optimal battery capacity installed per reactive consumer increased from 2.5 kWh with nearly no reactive consumers, to 5.5 kWh with 50 % reactive consumers connected to the grid.

Figure 4 helps to further explain the adverse effect of non-cooperative behaviour on the efficiency and equity proxy. In Figure 4 the annual electricity cost of the two consumer types, relative to the baseline case with non-distortive fixed network charges, is shown. Additionally, system cost, calculated as the weighted average electricity cost and used as a proxy for efficiency, is shown.[20] Please note that the scale of the vertical axis for the middle panel of Figure 4 differs from the other two panels.

[19] In their paper, the authors develop a preliminary understanding of the relationship between capacity-based charges and storage. A battery with a certain size is assumed and the cost of the battery for the consumer is not accounted for. The optimal sizing of the battery and the interaction between the sizing and the proportion of reactive consumers connected to the grid is not attempted, however, mentioned to be a valuable area of research.

[20] Indirectly also the results for the equity proxy can be calculated from Figure 4.

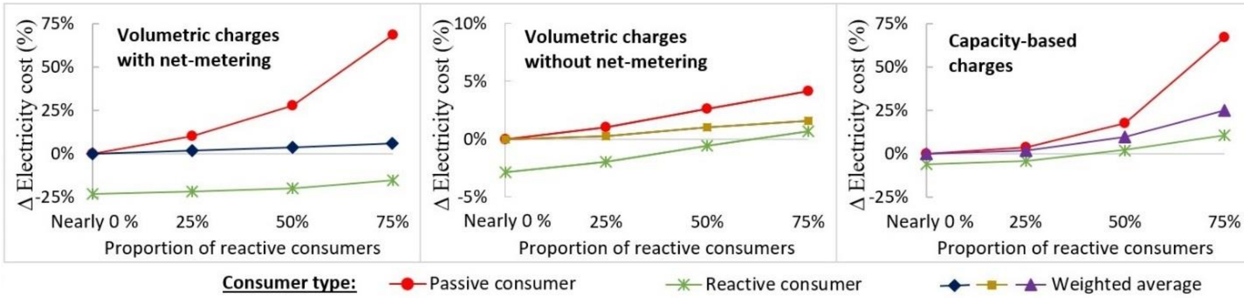


Figure 4: Difference in annual electricity cost per consumer type for the three network tariff structures compared to the application of non-distortive fixed network tariffs. Additionally, the weighted average electricity cost (or system cost) which serves as the proxy for efficiency is shown.

When the proportion of reactive consumers connected to the grid is very limited, a reactive consumer can lower his electricity bill under all tariff structures. Reactive consumers can profit the most under volumetric charges with net-metering by installing the maximum capacity of PV. The decrease in the electricity bill of the reactive consumer, compared to the baseline case, is the result of the low DER investment costs. As the proportion of reactive consumers is limited, the total grid costs reallocated to the numerous passive consumers and the rate increase of the network charge needed to ensure cost recovery for the DSO is minimal. Therefore, the increase in the electricity cost for the passive consumer is limited. It can also be observed that the electricity cost of an individual reactive consumer increases with an increased share of reactive consumers connected. It is surprising to see that under volumetric charges without net-metering and capacity-based charges the electricity cost of the reactive consumer surpasses the electricity cost for that same consumer in a situation where all consumers are passive and do not invest in DER at all. On first sight, this outcome might seem counter-intuitive: *Why would a consumer invest in DER when everybody, including himself, is better off when nobody invests in DER?*

This dynamic can be explained by the fact that cost-minimizing reactive consumers take uncoordinated investment decisions by following their own self-interest. The results of the model can be interpreted as a Nash equilibrium, defined as a solution of a non-cooperative game involving two or more players in which each player is assumed to know the equilibrium strategies of the other players, and no player has anything to gain by changing only his or her own strategy (Nash, 1951; Osborne and Rubinstein, 1994). In this context, a Nash equilibrium implies that no consumer has anything to gain by changing only his own operational and investment decisions. Concretely, for a certain share of reactive consumers, an individual consumer would not install more DER as in this case the additional investment does not justify the decrease in network charges and/or energy costs. On the other hand, for the same share of reactive consumers, an individual consumer would also not install less DER as that would mean his total electricity cost goes up as he would have to pay more network charges and/or energy costs. In a setting where all reactive consumers would jointly make an investment decision, it would be decided to install a lower amount of DER than in the case they make an individual decision. This would be an optimal solution as the overall efficiency would increase. With the game-theoretical model applied in this work, it is possible to capture and quantify the adverse effect of non-cooperative behaviour between reactive consumers.

Uncoordinated decision making does not only have an adverse effect on the aggregated electricity cost of all consumers but also on the electricity cost of the group of reactive consumers. In other words, reactive consumers are cannibalising their own 'profit' by competing against each other. *This adverse effect, which leads to a race (to the bottom) of DER adoption, can be minimised or enabled by adequate network tariff design.* For this scenario, the results show that capacity-based charges are more prone to enable this loop, which creates severe efficiency and equity issues. It can also be seen that this effect kicks in for volumetric charges without net-metering, however, less intense and delayed when compared to capacity based charges.[21] The same effect does not affect volumetric charges with net-metering for this scenario simply because the reactive consumer already had installed the maximum amount of PV capacity (5 kWp) when the proportion of reactive consumers was negligible.[22]

5.5. Implementation matters: on the limitations of capacity-based charges to recover sunk costs

With capacity-based charges in place, investment in batteries and PV are strongly (over)incentivised in some scenarios. This network tariff structure is found to be prone to adverse effects of non-cooperative behaviour, leading to an increased capacity of DER installed per individual consumer when the share of total reactive consumers increases. The reacting consumers are competing and try to reallocate the sunk cost burden to the passive consumers, but also to one another. Hledik (2014) and Hledik and Greenstein (2016) point out that there is no single

[21] Additional sensitivity runs were conducted and strong adverse effects of non-cooperative behavior were found for volumetric charges without net-metering in a scenario with very high grid costs (€ 1000 per consumer) and high energy cost (0.15 €/kWh.

[22] For more details on the interaction between net-metering and PV adoption see e.g. Cai et al. (2013) and Darghouth et al. (2016). In those works, models are used to simulate PV adoption and rate adjustments over 20 and 35 years, respectively.

type of capacity-based network charges, but that many variants exist. Depending on the implementation of the capacity-based charge results could resemble or depart from the outcomes presented.

In this work, a capacity-based network charge measuring the observed peak demand during one hour was used. A 24-hour deterministic profile including the demand peak was used in this work and results were annualised. By doing so it is assumed that the battery can perfectly anticipate when the peak demand takes place. Two design parameters of the capacity-based network charge can determine the level of (in)accuracy of the assumption of perfect foresight of the peak demand. Firstly, 'the ratchet or billing cycle' of a capacity-based charge, i.e. the peak demand is determined on a daily, monthly, seasonally or annual basis to calculate the network charges. Logically, the longer the period over which the peak demand is observed, the more inaccurate perfect foresight of the peak demand would be. Secondly, the duration over which the peak demand is measured, i.e. instantaneously, averaged over fifteen minutes, averaged over one hour, or averaged over several hours, etc. The shorter the period over which the peak measurement is averaged, the more inaccurate a perfect forecast of the peak demand is. Shorter averaging period increases uncertainty around the forecast. Thus 'badly designed' capacity charges for sunk cost recovery, e.g. based on the hourly peak demand over a monthly period, could resemble the results of this analysis. While capacity based charges based on the peak demand during 15-minutes with a seasonal or annual ratchet would perform better than the results shown in this analysis. However, if the investment cost of batteries is low enough or grid costs to be recovered through the tariff are high, similar dynamics would result, independent of the design of the capacity-based charge.

6. Conclusion

Low-voltage consumers cannot be considered as passive anymore after two technology breakthroughs: (1) PV enables domestic and commercial consumers to self-produce energy; (2) Batteries enable self-producers to choose both their grid energy and capacity parameters. The availability and costs of these new technologies strategically interact with tariffs to recover grid costs, as active consumers will react with their profit-maximising actions to any network tariff charged to them. In this paper, a game-theoretical model has been applied to assess whether:

(1) capacity-based network charges solve the efficiency problems experienced with volumetric charges with net-metering? And if,

(2) capacity-based network charges allow active consumers, investing in PV and batteries when incentivised, to be better off at the expense of passive, sometimes vulnerable, consumers?

Insights were gained with the help of three different distribution network tariff structures evaluated in four states of the world. This applied modelling approach allowed to capture the uncoordinated reaction of consumers to different tariff design by the adoption of DER technologies. Energy volumetric charges with net-metering, energy volumetric charges for both injection and withdrawal and capacity-based charges were assessed with a proxy for efficiency and equity. A central assumption was that grid costs to be recovered by the DSO were sunk, i.e. the adoption of DER technology by consumers does not influence the total grid costs to be recovered.

Regarding the first question, the results confirm that in a world with an increasing share of consumers connected to low voltage distribution networks reacting to price signals, simple netted out volumetric network charges to recover grid costs cannot be considered as the adequate network tariff design. Net-metering is an implicit subsidy for the adoption of PV. However, depending on the state of the world and its implementation, also capacity-based charges can severely distort the investment decisions of consumers. These results nuance the findings of the pro-capacity-based camp, e.g. Hledik and Greenstein (2016) and Simshauser (2016) and add a critical note to the observed trend towards being capacity-based tariffs replacing volumetric tariffs.

The observed dynamics confirm the suggestion made by Simshauser (2016), namely that if the capacity-based charge overstates the value of peak load it may pull-forward battery storage and create a new dimension to the sunk cost recovery problem. It was found that simply abolishing net-metering and applying so-called ‘bi-directional’ volumetric charges, an option also brought forward by Eid et al. (2014), can outperform capacity-based charges to recover sunk costs in a future scenario of low technology costs with high proportions of reactive consumers. This tariff design is found to be more robust against the adverse effects of non-cooperative behaviour and investment decisions are less distorted.

Regarding the second question, it was shown that both under volumetric charges with net-metering and capacity-based charges reactive consumers make uncoordinated investment decisions to push sunk grid costs to one another which can lead to overinvestment in DER and subsequently raise equity issues that. Equity issues are found acuter under net-metering. However, paradoxically, under capacity-based charges a situation can occur in which not only passive consumers, but also reactive consumers, end up paying more than in a situation where nobody invests in DER. This is due to competitive pressure among reactive consumers in allocating sunk cost. This effect was captured by modelling the grid cost recovery problem as a non-cooperative game between consumers, unprecedented in the existing body of literature.

By considering grid costs to be sunk, we focused on the limitations of capacity-based charges. Admittedly, this assumption presents a simplification in countries where the distribution network is in full expansion and therefore it will be relaxed in future work. By doing so, the total costs to be recovered by the DSO will become a function of network usage. In that setting, with low sunk costs and high future demand-driven investment, intelligently designed capacity-based charges could be of use. Lowered future grid costs due to intelligent grid charges could dampen the effects of non-cooperative behaviour. Another potential future research line would be to investigate the risk of grid defection when fixed charges would be increased strongly. Also, the effect of time-varying price signals, which would add value to the battery, would provide interesting insights.

7. Acknowledgements

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Appendix A: Overview of the used sets, parameters and variables

Sets
i : 1,..,N: Consumers
t: 1,..,tmax: Time steps with a certain granularity

Parameters
α: Proportion of grid investment to be recovered by volumetric charges [0-1]
β: Proportion of grid investment to be recovered by capacity-based charges [0-1]
NM: Parameter indicating whether net-metering [-1] or bi-directional volumetric charges are used [-1]
δ: Allowed band wherein the grid costs to be recovered by volumetric and/or capacity charges can differ from the grid charges collected as a percentage of total network costs [%]

Network costs: Total network costs to be recovered by the DSO [€]
FNT: Fixed network charge per connection, uniform over all consumers [€]
WDT: Scaling factor to annualise, dependent on length of the used time series and time step [-]
DT: Time step, as a fraction of 60 minutes [-]
N_i : Number of consumers represented by consumer (type) i
N : Total number of consumers connected to the distribution grid
$\mathrm{D}_{t,i}$: Original demand at time step t of agent i [kW]
MS_i : Maximum solar capacity that can be installed by agent i [kW]
MB_i : Maximum battery capacity that can be installed by agent i [kWh]
$\mathrm{SY}_{t,i}$: Yield of the PV panel at time step t of agent i [kWh/kWp]
EBP_t: Energy price to be paid by agent for buying from the grid [€/kWh]
ESP_t: Energy price received by agent for buying from the grid (Feed-in tariff) [€/kWh]
ICS: Investment cost for solar [€/kW]
ICB: Investment cost for batteries [€/kWh]
AFS: Annuity factor solar [-]
AFB: Annuity factor batteries [-]
BDR: Ratio of max power output of the battery over the installed energy capacity [-]
BCR: Ratio of max power output of the battery over the installed energy capacity [-]
EFD: Efficiency of discharging the battery [%]
EFC: Efficiency of charging the battery [%]
LR: Leakage rate of the battery [%]
SOC_0: Original (and final) state of charge of the battery [kWh]

Variables
Decision variable in the grid cost recovery constraint
vnt : Volumetric network tariff [€/kWh]
cnt: Power network charge [€/$\mathrm{kW}_{\mathrm{yearly\_peak}}$]

Decision variable of the consumer's optimisation problem
$qw_{t,i}$: Energy bought at time step t by agent i [kW]
$qi_{t,i}$: Energy sold at time step t by agent i [kW]
$qmax_i$: Yearly peak demand of agent I [kW]
$soc_{t,i}$: State of charge of the battery of agent i at step t [kWh]
$qbout_{t,i}$: Discharge of the battery of agent i at step t [kW]
$qbin_{t,i}$: Power input into the battery of agent i at step t [kW]
is_i: Installed capacity of solar by agent i [kW]
ib_i: Installed capacity of the battery by agent i [kWh]

Appendix B: Sensitivity analysis for demand and PV yield profiles

This Appendix has two aims. Firstly, to test the sensitivity of the results discussed in the body of the paper to the length of the time series for demand and PV yield. Second, to show the sensitivity of the results to different demand and PV yield profiles. The Appendix is build up out of two sections. B.1. describes the data used for the sensitivity analysis. Results are presented in B.2.

B.1. Data sensitivity analysis

Next to the reference demand and PV yield time series applied in the body of the paper, two additional time series for demand and two for the solar yield are build up. These time series all have a length of two weeks (336h) and obtained by randomising and scaling the original one-day reference profiles. In Table B.1, the key metrics of the additional time series for demand and PV yield are displayed and in Figure B.1 the time series are visualised.

Table B.1: Key metrics additional time series for demand and PV yield.

Demand profiles	*Yearly consumption [kWh]*	*Peak demand [kW]*	PV yield profiles	*Yearly PV yield [kWh/kWp]*
Low	3750	2.5	*Low*	960
Reference	6500	3	*Reference*	1160
High	11000	5	*High*	1360

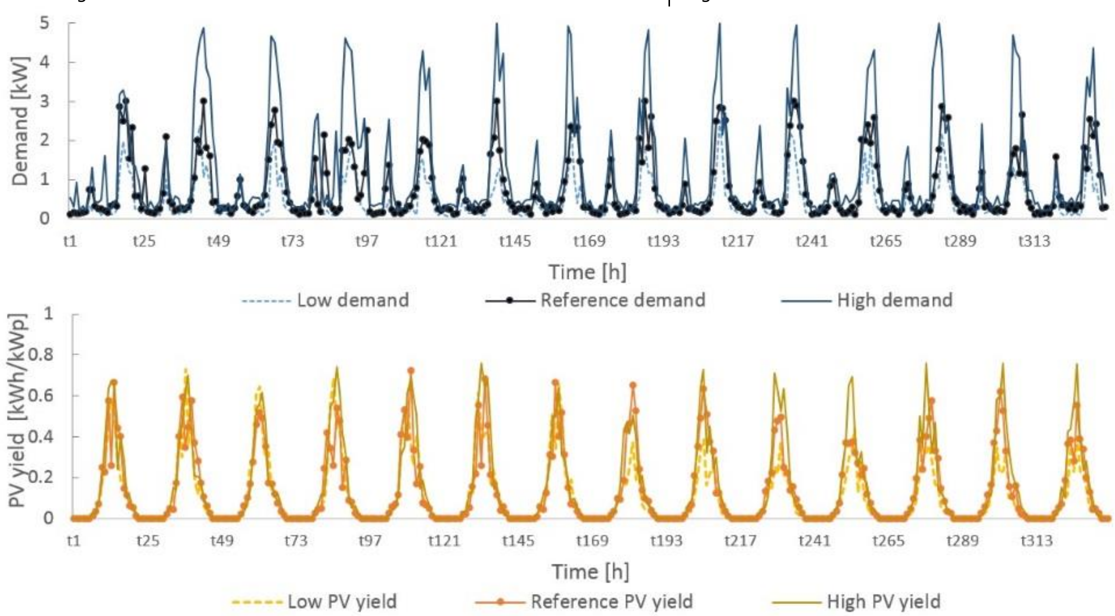

Figure B.1: Time series for demand (up) and PV yield (down).

B.2. Results sensitivity analysis

In Table B.2. the results with the runs of the one-day reference profiles which are used in the body of the paper are compared to the runs with the same profiles, but randomised and with a length of two-weeks. The results are shown for the four states of the world, all other parameters remained the same. The trends of the results are the same, the obtained values can change slightly in some states of the worlds for certain tariff structures. In general, higher variability in the time series leads to slightly less complementarity of PV and batteries, see e.g. the installed capacity of PV and batteries under TS2 and TS3 in the maturing DER scenario for the 24h and 336h time series. Also, from e.g. TS3 under the maturing battery and expensive PV scenario and TS3 under the maturing DER scenario, it can be seen that the metric for equity issues tends to decline slightly with longer time series. This can be explained by the fact that with longer time series slightly more investment in DER (leading to inefficiencies in some cases) is needed to reduce the grid charges of active consumers with the same amount than when shorter time series are used. In other words, it can be said that due to higher variability in demand and PV yield, the value of PV and/or batteries declines slightly for reactive consumers.

Table B.2: Results for the runs with the reference demand and solar profiles (24h and 336h) in the four states of the world.

	Immature DER			Maturing battery and expensive PV			Maturing PV and expensive battery					Maturing DER				
	TS1/ TS2	**TS3**		**TS1/ TS2**	**TS3**		**TS1**	**TS2**		**TS3**		**TS1**	**TS2**		**TS3**	
	24h/ 336h	24h	336h	24h/ 336h	24h	336h	24h/ 336h	24h	336h	24h	336h	24h/ 336h	24h	336h	24h	336h
Efficiency issue [%]	0	1.7	0.3	0	5.9	6.5	4.0	0.6	0.4	2.2	0.4	4.0	0.8	0.7	9.4	7.8
Equity issue [%]	0	7.9	1.5	0	32.7	29.1	80	5.9	4.0	9.5	1.7	80	6.7	5.8	48.5	34.7
PV reactive consumer [kWp]	0	0	0	0	0	0	5	0.6	0.5	0.6	0	5	0.9	0.7	2.6	0.8
Battery reactive consumer [kWh]	0	0.6	0.1	0	4.1	4.9	0	0	0	0.6	0.1	0	0.5	0.3	5.6	5.5

In Table B.3, the results for five additional runs under the different tariff structures are given. Four combinations are made with the new time series for demand and solar yield shown in Appendix B.1. Additionally, the run in which the high demand profile is combined with the high PV yield profile is ran twice. First, with an upper boundary of 5 kWp for the PV capacity installed by the reactive consumers. Second, with this upper boundary set to 10 kWp. 50 % of reactive consumers are assumed and the mature DER scenario (low investment cost for PV and batteries) is used. All other parameters remained the same. The relative performances of the tariff structures are in line with the results of the reference demand and PV yield series shown in the body of the paper.

Table B.3: Results for the additional runs under the different tariffs structures. Technology cost of maturing DER scenario.

	Low demand/ Low solar yield			Low demand/ High solar yield			High demand/ Low solar yield			High demand/ High solar yield (different max. PV)				
	TS1	**TS2**	**TS3**	**TS1**	**TS2**	**TS3**	**TS1**	**TS2**	**TS3**	**TS1**		**TS2**	**TS3**	
										5 kWp	10 kWp	5/10 kWp	5 kWp	10 kWp
Efficiency issue [%]	12.5	0.6	5.1	1.5	0.9	5.9	4.0	0.7	2.9	0.4	1.0	1.5	3.3	7.8
*Equity issue [%]**	100	3.8	34.0	100	7.7	42.7	27.6	3.7	16.9	44.6	100	9.6	22.3	40.4
PV reactive consumer [kWp]	5	0.3	0	5	0.5	2.6	5	1.0	0	5	10	1.7	5	6.9
Battery reactive consumer [kWh]	0	0	2.2	0	0.4	2.3	0	0.1	3.8	0	0	1.9	4.1	9.5

* An equity issue of 100 % (with 50% of reactive consumers) implies the grid charges for passive consumers are doubled because the reactive consumers are not paying any grid charges anymore. This can occur under volumetric charges with net-metering if reactive consumers export more electricity than they consume. It is chosen not to allow reactive consumers to have negative grid charges. However, the energy cost could become negative and results in a negative electricity bill when selling a high volume of electricity.