A reduction of distribution grid fees by combined PV and battery systems under different regulatory schemes

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***Abstract*—Depending on the chosen regulation, distributed generation reduces revenues for Distribution System Operators (DSOs) although costs for maintaining the system do not decrease – or even increase due to new load patterns such as peak generation of PV. We assess the impact of different forms of grid fees on household choices of PV and battery systems in a cost minimization framework and explore how those align with the requirements of DSOs. Fixed grid fees, independent of consumption and of peak demand of households, best allow for a full recovery of costs by DSOs. However, they pose a barrier to increasing distributed generation. Variable grid tariffs are not compatible with requirements of DSOs as they increase incentives for distributed generation but do not incentivize load shifting, thus increasing average and peak load at decreasing DSO revenues. Demand fees which are paid based on the peak load of households create incentives for decentralized storage. However, they may reduce revenues of DSOs significantly, while they do not necessarily decrease system costs to the same extent: peak load on the grid still remains high although the peak load of single households is reduced, due to changes in the correlation of loads of households after adopting battery technologies.**

***Index Terms*—Batteries, Photovoltaics, Supply and Demand, Power Grids**

I. INTRODUCTION

Distributed generation in households, in particular solar PV, decreases revenues for Distribution System Operators (DSOs) in most countries in the European Union, as network fees for households are based on variable consumption of electricity combined with a small fixed fee (refE et al., 2015). This is also the case for Austria, which is the focus of this study. Distributed generation substitutes energy from the grid and reduces DSO income through reduced revenues from consumption based tariffs. At the same moment, costs for the distribution grid operation remain constant or are even increased as peak loads on the network increase due to the feed-in of highly correlated PV generation. DSOs therefore increasingly demand from regulators to shift rates from variable consumption to fixed or demand rates to be able to recover costs [1], [2].

We compare three possible different tariff designs to assess how incentives for distributed generation and storage can be increased, while still maintaining revenues for DSOs: network fees can be completely based on consumption, which generates the problems of decreasing revenues for DSOs at stabilizing or even increased costs as the market share of distributed generation increases.

Tariffs can also be completely shifted to fixed rates, independent of the consumption or the maximum load in the household. The redistribution of costs, from consumption based to fixed, may however be considered unfair. Households with low consumption see their electricity rates significantly increased while high consuming households reduce their costs for electricity. Households cannot defer from a fixed rate, as they would have to completely disconnect from the electricity grid which is very costly when similar service quality is maintained.

As a third option, demand rates can be introduced. In that case, network fees depend on the peak demand of the particular consumer. Peak demand can be reduced if storage is introduced to households. Consumers can change their load profile to one that is less costly under the new regime by installing batteries which reduce their peak demand – and additionally integrate more of their own PV generation into the self-consumption of the household. The profitability of investments into decentralized electricity production of households therefore depends significantly on the chosen network tariff structure.

The adaptation of households to new tariff structures has two consequences for DSOs: first, revenue streams may change significantly, i.e. income from tariffs may decrease or increase compared to a baseline without change in tariffs. Second, a change in the load profiles after adaptation may also alter infrastructure costs of DSOs. In particular the average and the peak load on the network may be changed, which will affect future investment requirements and operational costs of the DSOs. When the adaptation of households to changed tariff structures is considered, new tariff schemes may therefore not fully cover costs implied by the adaptation to the scheme.

We apply a single-household optimization model which is able to choose between solar PV, batteries, and different distribution grid capacities to investigate the adaptation of cost-minimizing households to changed tariff structures. We use 15-minutes measured load profiles for 80 different households to assess the profitability of combined PV-battery-grid systems in comparison to grid-only systems. Additionally, we assess how the load is shifted by the battery system and how this affects the joint demand in the subsection of the distribution grid. We discuss the consequences for DSOs and conclude by giving policy recommendations.

II. Data & Methods

We first introduce the optimization model for the households and then show how individual household loads are related to the load on the subsection of the network. The empirical data used to solve the models and associated scenarios are presented subsequently.

A. Optimization model

A household with demand d_t faces costs for the amount of grid electricity x_g_t consumed $r_c \sum_t x\_g_t$, r_c being the electricity tariff, which is assumed to be time-independent[1]. Additionally, when a demand rate is applied, the household faces fixed costs depending on the peak consumption in a particular year $f_{grid}(x\_g^{cap})$. An additional fixed network fee does not change the investment decision into PV and batteries of the households, as the household's budget constraint is not considered here. To lower both, energy as well as variable grid tariffs, the household can install PV panels. We assume that the system is depending on weather conditions and production is therefore fixed at $x\_cap^{pv} * pv_t$, x_cap^{pv} being the installed capacity, and pv_t a production profile normalized to 1 kw_{peak}. The system costs $f_{pv}(x\_cap^{pv})$. Additionally, a battery system can be bought at cost $f_{battery}(x\_cap^{store})$. If distributed generation is installed in the household, the household may be able to sell surplus electricity x_p_t to the grid at a rate of r_p. The household therefore minimizes the following problem:

$$\min r_c \sum_t x\_g_t + f_{grid}(\mathrm{x\_g^{cap}}) + f_{pv}(x\_cap^{pv}) + f_{battery}(x\_cap^{store}) - r_p \sum_t x\_p_t$$

The following balancing restriction applies, i.e. demand has to meet supply, allowing for the curtailment of surplus electricity $curtail_t$:

$$pv_t * x\_cap^{pv} + x_{g_t} + x\_storage_t^{out} = d_t + x\_storage_t^{in} + x\_p_t + x\_curtail_t, \forall t$$

Parameter d_t denotes the fixed load in the household[2], while $x\_storage_t^{out}$ and $x\_storage_t^{in}$ denote the discharging and charging of batteries, respectively.

Storage is balanced with the help of the following equation, taking into account simplified linear storage efficiency σ, $x\_storage_t^{lev}$ indicating the current storage level:

$$x\_storage_{t+1}^{lev} = x\_storage_t^{lev} + \sigma x\_storage_t^{in} - x\_storage_t^{out}, \forall t$$

The storage can only store a particular amount of electricity, given by its storage capacity:

$$x\_storage_t^{lev} \leq cap^{store}, \forall t$$

The storage can only charge and discharge at a certain rate, which is defined as being the fraction δ of the purchased storage capacity:

$$x\_storage_t^{in} \leq \delta cap^{store}, \forall t$$
$$x\_storage_t^{out} \leq \delta cap^{store}, \forall t$$

Finally, the amount of electricity taken from and fed into the grid is limited by the capacity of the grid connection:

$$x\_g_t \leq x\_g^{cap}, \forall t$$
$$x\_p_t \leq x\_g^{cap}, \forall t$$

B. Cost for DSOs

Costs of the distribution grid for the DSO depend mainly on the peak capacity (we neglect here wear-out of equipment due to utilization). We can assume a linear relationship between peak capacity (in the subnet of the distribution grid) and costs, such as:

$$(1)\quad C(x_{peak}) = c_{fixed} + f_{cap}(x_{peak})$$

where $x_{peak} = \max\left(\sum_i x\_g_{t,i}, \sum_i x\_p_{t,i}\right)$. Costs are therefore constituted of a fixed part c_{fixed} and a variable part $f_{cap}(x_{peak})$. The load is either generated by consumption or by feed-in of PV generation.

The question arises how x_{peak} is related to the peak demand of the single households: the computation of the demand fee depends on that relation. In general, the diversity factor indicates how the peak load of a single household is related to the peak load in the (sub-)network. The diversity factor depends on the correlation of energy consuming processes, i.e. it is high for heating while it is lower for cooking devices [3]. We define it here as the relation of maximum load in the sub-grid and the sum of the maxima of the individual loads: $div = \frac{Max_t(\sum_{i=1}(Load_{i,t}))}{(\sum_{i=1} Max_t(Load_{i,t}))}$. Introducing the diversity factor, equation (1) can be written, in terms of peak load of single households, as:

[1] Some electricity rates in Austria differentiate prices between consumption during day and during night, which may make batteries more profitable. There are even time-dependent tariffs (such as from awattar.com). Those are neglected here.

[2] We neglect demand side reactions to changed prices as well as technical demand side management options here.

$C(grid) = c^{fixed} + f_{cap}(div \sum_i g_i^{cap})$

When adaptation of households is considered, div is not a fixed parameter but a variable. The introduction of solar PV will change div: solar PV generation in a subsection of a low-voltage grid is highly correlated, peaks in feed-in to the grid therefore also are highly correlated. It is not clear, however, if the diversity factor changes with the introduction of batteries. Depending on the operational mode of the battery, it may contribute to lowering the impact on the grid – or it may even increase the peak load. This means, that the costs of grid supply now depend on the generation and storage facilities installed in the subsection of the grid, as div becomes a function of PV and battery capacities, i.e. $div = f^{diversity}(cap_i^{pv}, cap_i^{store})$:

$$C(grid) = c^{fixed} + f^{cap}\left(f^{diversity}(cap_i^{pv}, cap_i^{store}) \sum_i g_i^{cap}\right)$$

We do not aim at determining in detail the costs in the subsection of the distribution grid, but aim into exploring how different policies affect adaptation of technologies in the households and how these change the overall load pattern on the subnetwork.

C. Load Data

Load data was measured in the period April 2010 - March 2011 for 1330 households in Upper Austria in 15 minutes intervals, using smart meters. None of the households had PV units installed. We selected a subset of households that consumed electricity under the same tariff structure (458 households). Within the datasets, some of the measured profiles had very low quality due to long incomplete periods of measurement. We chose 80 households with almost complete samples. Annual average consumption in the 80 households was 3,927 kWh, below the reported average of Austrian households of 4790 kWh for the year 2009/2010 [4]. We assumed that the 80 households are connected to the same low-voltage grid. Average load on the grid was 35 kW, while the peak load on the simulated subsection of the grid was 114 kW.

D. PV Data

PV data for the respective period (April 2010 – March 2011) and respective location (Linz in upper Austria) was derived from the model developed for PV-GIS [5]. Based on satellite images from DWD, which reports direct and diffuse irradiation, the horizontal irradiation was calculated. Considering temperature and shadowing based on a digital elevation model, the irradiation data was converted to timeseries of PV production, assuming an inclination of 35 degrees of PV modules, facing south-wards. This is very close to the optimum for the considered location. Sub-optimally installed PV systems are therefore not considered. Losses from inverters, cabling, and other system losses were assumed to sum up to 10% of production. PV production was modelled on an hourly basis only. To fit the more highly resolved load data, PV production in a particular hour was interpolated into four subhourly values. In the full year, the simulated system generates 1023 kWh per kw_{peak} of installed PV panel.

E. Scenarios

We optimized one year of operation for all households and assessed three different policy scenarios:

(1) Fixed: Implementation of a fixed network tariff, where consumption and peak demand are not taken into account in the tariff. This is the most adverse tariff structure with respect to the profitability of distributed generation and batteries.

(2) Variable: A continuation of the current Austrian tariff structure for households, which consists mainly of a variable grid tariff per kWh depending on consumption. This is the most favourable tariff for distributed generation, as an avoided kWh of electricity from the grid is worth the electricity rate plus the variable grid fee. As batteries can increase the self-consumption of generated PV electricity of households, the tariff also incentivizes battery storage to some extent.

(3) Demand: The introduction of a demand fee which is calculated on basis of the peak demand of the household. We assume a linear relationship between peak demand and costs for the households. In that case, there is an incentive for installing battery systems to lower the peak load in the household.

The values for variable and demand tariffs were tested for the range shown in TABLE 1. Fixed fees were chosen so that the compensation of DSOs equals the currently used variable fees.

Investment costs into PV and in particular into batteries are currently not competitive in any of the scenarios. To allow for the installation of those technologies in the simulated housholds, we assumed very low system costs of 1000€/kw_{peak} for PV panels and 200 € / kWh usable storage capacity of batteries.

TABLE 1: CHOSEN VALUES FOR POLICY SCENARIOS (PER HOUSEHOLD)

	Fixed (€/Year)	Demand fee (€/kW/Year)	Electricity Tariff (€/kWh)	Variable Grid Tariff (€/kWh)	Feed-in Tariff (€/kWh)
Fixed	120	-	0.14	-	0.05
Variable	-	-	0.14	0.02 – 0.30 (steps of 0.04)	0.05
Demand	-	20 – 160 (steps of 20)	0.14	-	0.05

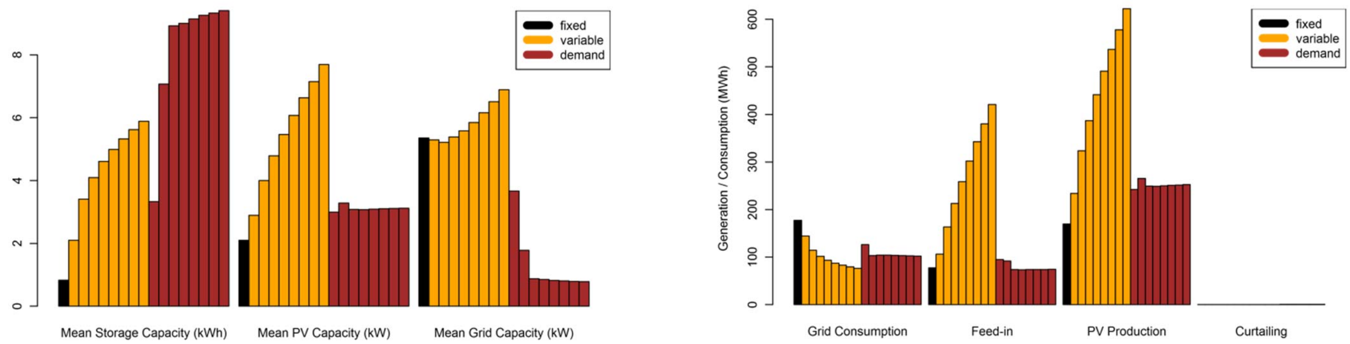

Figure 1: Left Panel: Average investments of households into distributed generation and peak grid capacity in the 17 policy scenarios. Right Panel: Grid consumption, feed-in into the grid, PV generation and curtailing in the 17 policy scenarios.

Currently, PV systems trade for around 1500€/kw$_{peak}$ for system sizes of 4 kw$_{peak}$ [6] and battery systems for about 800 €/kWh (Li-Ion battery systems, 90% roundtrip efficiency, a lifetime of 10,000 cycles) [7]. We assume a linear scaling of costs with capacity for both technologies, although this is not realistic as specific costs decrease significantly with increasing system size. However, it allows for a fully linear formulation of the optimization model which was necessary at this stage to reduce computational complexity.

The results of the optimization model strongly depend on the relation of PV to battery costs. We assume a stronger future cost decrease for batteries than for PV, as PV has travelled down the learning curve to a larger extent than batteries. Battery roundtrip efficiency is assumed to be 90%[7] , while we assume that the maximum charging and discharging power in kW is half the maximum storage capacity in kWh (i.e. δ =0.5). Investment costs are annualized, as we are only simulating one year of operation. We assume an interest rate of 3% and a lifetime of 20 years for the PV panels and 11 years for the batteries.

I. Results

Figure 1 (left panel) shows the average results of the optimization for all households. In all scenarios, the cost-minimal solution allows for an investment in PV and batteries in all three policy scenarios. However, investments into batteries are much higher in the demand fee scenario: this is a result of a reduction in demand fees when the peak load is decreased. Investment into PV is highest in the variable grid fee scenario.

In the demand fee policy the peak load of the simulated households is reduced to less than 1kW (from 5.66kW) on average when demand fees are increased. This is possible due to high battery capacities of up to 8kWh. However, there is a saturation effect at demand fees above 60€/kW: battery capacities do not further increase if fees rise above that level because additional storage capacities do not allow decreasing the peak load further. In the demand fee scenario, PV investments are lower than in the variable fee scenario because avoided costs from buying electricity from the grid are lower in the first. System sizes are consistently lower than 3kW$_{peak}$, while they reach up to 8kW$_{peak}$ in the variable fee scenario at very high variable grid fees.

Consumption of grid electricity decreases in all scenarios due to the installation of PV panels, (see Figure 1, right panel). Feed-in into the grid is highest in the variable fee scenario, as installed PV capacity is high and battery capacities are low. Feed-in into the grid remains almost constant for increasing demand fees in the demand fee scenario, as increasing PV generation is consumed in the households due to higher battery capacities. This is different for the variable grid fee scenario, where feed-in grows linearly with PV generation. In the demand scenario, a very small share of PV generation is curtailed to not exceed peak capacities.

Revenues for DSOs, costs of electricity supply for households and changes in the load pattern are shown in Table 2. In the fixed grid fee scenario, revenues of DSOs remain stable by definition. Total costs for households do not change, although some PV and storage capacity is installed. The peak load increases to 108%, while the average load on the network is increased to 106% due to PV generation.

In the variable grid fee scenario, an increase of fees does not necessarily lead to an increase in revenues. In the model, households start adapting to increased fees by installing larger PV capacities and batteries to increase auto-consumption and therefore decrease grid fees. At the same moment, the peak load in the grid increases significantly, as does the average load. The reason is the highly correlated feed-in of PV generation. Peak load increases relatively more than revenues of DSOs. Therefore, an increasing variable fee on grid consumption creates a vicious circle of increasing investment requirements for DSOs and increasing costs for households.

If a demand fee is implemented, the relative difference between the demand fee and battery costs matters. At the chosen parameter settings, a demand fee of 20€/kW/Year would not be sufficient to recover costs for DSO because the fee triggers investments into batteries and therefore lowers peak load in the households. Nevertheless, the combined peak load on the grid increases significantly as a consequence of increasing diversity factors due to PV production and storage. Costs for households are slightly lower than in the baseline scenario.

When the demand fee increases above 20€/kW/Year, households are incentivized to invest into larger battery capacities. Costs for households start to increase above the baseline scenario. At 60€/kW/Year a saturation effect can be observed: installed capacities neither of PV nor of batteries change.

TABLE 2: CHANGES IN COSTS AND LOAD PATTERNS ON DISTRIBUTION GRID

	Tariff Level	**Revenues DSO (% of Baseline)**	**Costs Households (% of Baseline)**	**Peak Load Grid (% of Baseline)**	**Average load on network (%of Baseline)**	**Diversity Factor**
Fixed (€/Year)	120	100	100	108	106	0.25
Variable	0.02	27	90	158	119	0.36
(€/kWh)	0.06	64	108	225	144	0.52
	0.10	95	123	277	166	0.62
	0.14	122	136	320	187	0.70
	0.18	147	148	371	206	0.77
	0.22	171	160	413	225	0.81
	0.26	194	171	451	243	0.84
	0.30	215	182	496	262	0.87
Demand	20	54	98	166	110	0.55
(€/kW/ Year)	40	53	111	131	90	0.90
	60	39	115	71	67	0.99
	80	50	118	70	66	0.99
	100	61	121	67	66	0.99
	120	71	123	65	66	0.99
	140	82	126	65	66	0.99
	160	93	129	64	66	0.99

At this level, revenues for the DSO are reduced to 39% of the baseline and costs for households are increased to 115%. At the same moment, the peak load is reduced to 71% and the average load to 67%. Increasing levels of the demand fee above 60€/kW/Year increases the revenues for the DSO while the other parameters remain constant, as households cannot adopt further to changing incentives.

The reduction in peak load of single households from an average of 5.66kW to 0.8kW in the more drastic scenarios does not translate to a similar reduction in peak loads on the grid level. Households adapt to changing grid fees by installing batteries. Therefore, under optimal control of the storage batteries, the load profiles of households show higher correlation, increasing the diversity factor.

Figure 2 shows the load profiles in 3 different policy scenarios and the baseload scenario for four seasons. While highly correlated PV production causes high (negative) peaks in load when the variable fee scenario is applied, those peaks are decreased significantly when the demand fee is applied as batteries store most of the overproduction.

I. CONCLUSIONS AND DISCUSSION

We have shown that changing the current tariff structure in the distribution grid from the currently applied mainly variable cost structure to demand fees is a possibility to better align household consumption patterns with requirements for the distribution grid. However, depending on future costs for storage systems, introducing demand fees causes households to decrease their own peak load significantly, while the peak load in the distribution grid does not decrease by the same amount. Therefore, costs for grids do not decrease as rapidly as revenues.

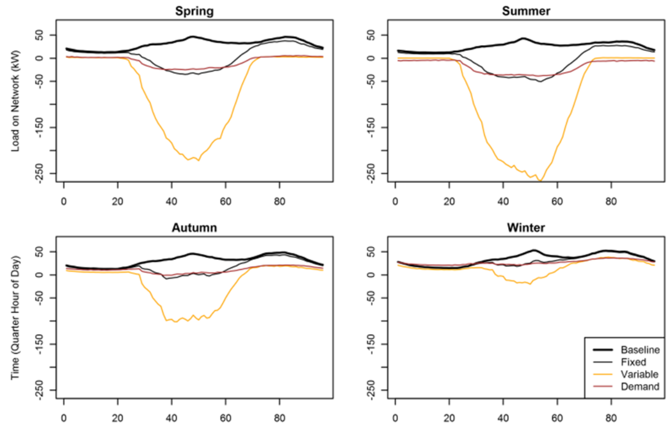

Figure 2: Load profiles on the grid for four different seasons and four different scenarios. The results for the scenario with a tariff level of 0.30€/kWh (Variable) and for the scenario with a tariff level of 160€/kW (Demand) are shown.

Fixed network fees can help in reducing the problem. However, they may be considered to be unfair (as consumers are equally contributing to network revenues, independent of their utilization) and they reduce incentives for low-carbon distributed generation significantly. Also, the systemic value of decentralized storage to distribution grid operators and the electricity system as a whole cannot be exploited. It can be considered to be a very defensive strategy therefore.

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