WORKING PAPER

A bilevel model for voluntary demand-side flexibility in distribution grids

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Abstract

This paper explores the price setting of demand-side flexibility, modelled as consumers' voluntary load reduction, in distribution grids. It develops a long-term equilibrium optimization model with a bi-level setting for voluntary demand-side flexibility. In the Upper Level (UL), the Distribution System Operator (DSO) maximizes welfare by deciding the level of network investments and setting the price for demand-side flexibility. The DSO also sets the distribution network tariff in order to recover the network investment and flexibility costs from the Lower Level (LL) consumers. LL's active residential and commercial consumers react to network tariffs and to the price offered for their flexibility by investing in rooftop solar and batteries and offering a certain volume of demand-side flexibility when requested by the DSO. The passive residential consumers also provide flexibility by decreasing their load, but they do not invest in rooftop solar or batteries. We find that voluntary demand-side flexibility increases welfare and allows significant network investment savings. We also find that the benefits can reach all types of consumers. Besides, it is opportune to apply price differentiation when setting the price for demand-side flexibility, where applicable.

Keywords

1. Introduction

Distribution grids will need to be expanded to accommodate increasing shares of renewable energy and keep up with the electrification of the transport sector (with electric vehicles) and the electrification of heating in buildings (with heat pumps). We can size future distribution grids based on the new consumption and production peaks that will emerge in different locations, or we can try to reduce peaks with price signals. Consumers receive multiple signals, such as signals from electricity market prices, network tariffs, and taxes and levies. In addition, DSOs started to contract flexibility. They can organize tenders for flexibility service providers, and they can also work with non-firm connection contracts for different types of customers. These contracts can be mandatory or voluntary. Both types of contracts have already been tested in different European countries (Beckstedde et al., 2020), but many regulatory issues remain.

The regulatory issues include the coordination between TSOs and DSOs ((Hadush and Meeus, 2018) and (Givisiez et al., 2020)), and the timing of flexibility tenders within the sequence of electricity markets (Meeus, 2020), the threat of strategic inc-dec games (Beckstedde et al., 2021), and the adaptation of the flexibility scheme to a specific context (J. P. Chaves et al., 2021). In this paper, we focus on another issue, which is the price setting for voluntary demand-side flexibility, modelled as voluntary reduction/curtailment of load. Spiliotis et al. (2016) and Abdelmotteleb et al. (2021) worked on voluntary demand-side flexibility, but they did not focus on price-setting. The first paper uses a single optimization with the price for flexibility as a parameter rather than a variable. The second paper also treats the price for flexibility as a parameter in what the authors refer to as an ad hoc model.

In this paper, we develop a long-term equilibrium optimization model with a bi-level set-up. In the Upper Level (UL), the Distribution System Operator (DSO) maximizes welfare by deciding on the level of network investments and setting the price for demand-side flexibility. The DSO also sets the network tariff at a level that allows recovering the network investment and flexibility costs from the Lower Level (LL). The LL's active residential and commercial consumers react to the net-work tariffs and the price offered for their flexibility by investing in rooftop solar and batteries and offering a certain volume of demand-side flexibility when requested by the DSO. The passive resi-dential consumers also provide flexibility, but they do not invest in rooftop solar or batteries.

In recent years, the application of bi-level equilibrium models to the electricity sector has proven to be very insightful ((Gabriel et al., 2013) and (Dempe et al., 2015)). Bi-level models have also been used to study regulatory issues related to distribution network investments. This started with the debate on distribution tariffs. Several authors used the bi-level set-up to show how consumers react to different types of tariffs, such as fixed, volumetric or capacity-based tariffs, with different levels of locational and spatial granularity. These studies have highlighted the importance of cost-reflective distribution tariffs to align consumers' interest with the system needs ((Schittekatte et al., 2018), (Govaerts et al., 2021), (Schittekatte and Meeus, 2020), (Pediaditis et al., 2021), and (Hoarau and Perez, 2019)). The model we developed in our previous paper, Nouicer et al. (2021), was the first to include the option for the DSO to curtail demand for a fixed compensation in a bi-level set-up. In that paper, we illustrated how demand-side flexibility and network tariffs could be complementary tools to save unnecessary network investments. However, we only considered a case with residential consumers, and we assumed that the DSO could curtail consumers for an ad-ministratively determined compensation. As it might not always be acceptable that the provision of demand-side flexibility is mandatory, we now consider a voluntary approach in this paper. In this voluntary approach, the DSO sets a price, and consumers then respond with the volume of flexibil-ity they are willing to offer at that price.

In other words, in this paper, we make a modelling contribution to the literature on bi-level equi-librium models that simulate the trade-off between flexibility and distribution network invest-ments. This model allows us to contribute to the regulatory debate on how to set the price for voluntary demand-side flexibility.

The remaining part of the paper is structured as follow. In section 2, we introduce the modelling approach and the mathematical formulation. In section 3, we detail and analyze the results of a numerical example. Finally, in the conclusion, we summarize our main findings and their policy implications.

2. Model: approach and mathematical formulation

We develop a stylized game-theoretical optimization model with a bi-level set-up ((Gabriel et al., 2013) and (Dempe and Zemkoho, 2020)). In the UL, the DSO, considered as perfectly regulated, maximizes welfare. It decides on the network investment level and the compensation to be offered to consumers to trigger the necessary demand-side flexibility levels. The DSO also sets the magnitude of network tariffs that are predominantly capacity-based to recover the grid investment and flexibility costs. Consumers optimize their individual welfare levels in the LL and voluntarily offer flexibility based on the implicit (network tariffs) and explicit prices signals (market-based flexibility). They can be active and invest in DERs, rooftop solar PV and batteries, or passive with no possibility for such DER investments. Commercial consumers are also able to invest in DERs. The flow chart of the model underlying the proposed approach is shown in Figure 1.

Figure 1: Flowchart for the interaction between the UL and the LL
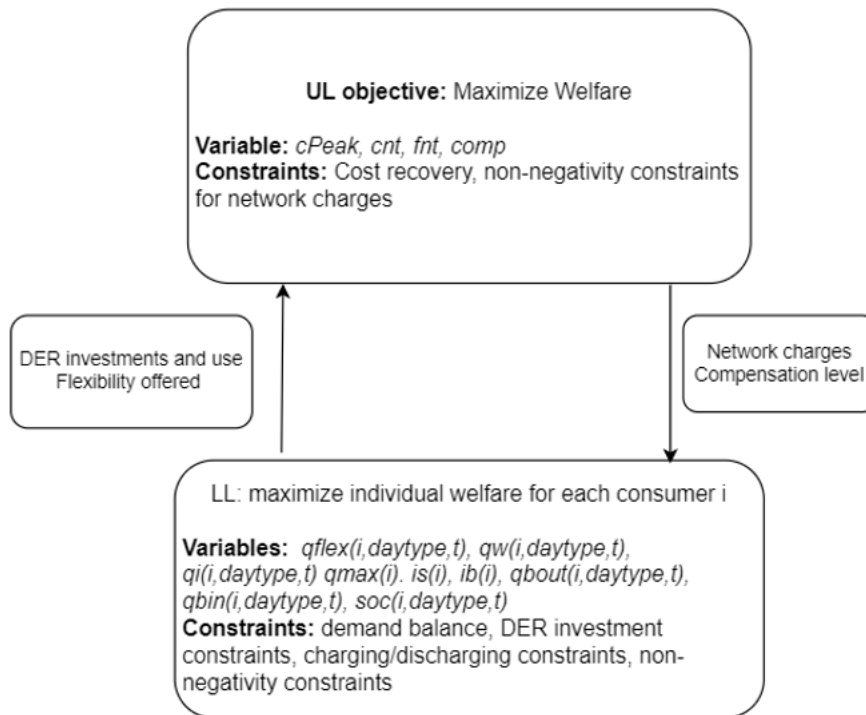
2.1. The Upper-level: the regulated DSO

The UL level optimization problem is a welfare maximization one, based on the decision variables: the compensation for flexibility as an alternative to network investment, comp, the magnitude of network tariff, being the capacity-based charge, cnt, and the fixed charge, fnt. The related objective function, Eq.1, is as follow:

Maximizes Netwelfare:

$$\text{Max} \qquad \text{GrossWelfare- TotalSystemCosts} \qquad\qquad (1)$$

Where:

$$GrossWelfare = \sum_{i=1}^{N} PC_i * \sum_{Daytype=1}^{M} \sum_{t=1}^{T}(D_{i,daytype,t} - qflex_{i,daytype,t}) * VoLL * WDT_{daytype} +$$
$$FlexibilityRevenue \tag{2}$$

$$FlexibilityRevenue = \sum_{Daytype=1}^{M} \sum_{t=1}^{T}(comp * qflex_{i,daytype,t}) * WDT_{daytype} \tag{3}$$

$$TotalSystemCosts = Flexibility\ costs + GridCosts + EnergyCosts + DERCosts + OtherFixedCosts. \tag{4}$$

With:

$$EnergyCosts = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \sum_{i=1}^{N}(qw_{t,daytype,i} * EBP_t - qi_{t,daytype,i} * ESP_t) * WDT_{daytype} \tag{5}$$

$$DERCosts = \sum_{i=1}^{N} is_i * AICS + ib_i * AICB \tag{6}$$

$$Flexibility\ costs = \sum_{Daytype=1}^{M} \sum_{t=1}^{T}(comp * qflex_{i,daytype,t}) * WDT_{daytype} \tag{7}$$

$$GridCosts = IncrGridCosts * (cPeak) \tag{8}$$

The $OtherFixedCosts$ are a fixed fee and do not interfere with the optimization process.

The gross welfare is calculated in Eq.2, which represents the actual electricity consumption, being the original demand ($D_{i,daytype,t}$) minus the flexibility procured levels ($qflex_{i,daytype,t}$), multiplied by the Value of Lost Load (VoLL) and annualized by the weighting factor, $WDT_{daytype}$. PC_i is the proportion of each type of consumer i. The original demand $D_{i,daytype,t}$ is indexed by consumer, i, hours of the representative day, t, and type of the representative day, $daytype$.

Eq.4 represents the total system costs that are the sum of four different elements. The aggregated energy costs are calculated by Eq.6 where $qw_{t,daytype,i}$ is the electricity quantity withdrawn from the grid and EBP_t is the corresponding withdrawal price, while $qi_{t,daytype,i}$ is the electricity injected in the grid with ESP_t the corresponding injection price.

The DER costs are calculated by Eq. 6 where is_i is the investment in solar PV (in kWp) and ib_i the investment in batteries (in kWh) by consumer i. AICS and AICB are two parameters for annualizing investment costs in solar PV and batteries, respectively.

The flexibility revenue represents the welfare surplus coming from the flexibility sold by all the consumers and is calculated by Eq.7. It is equal to the aggregated flexibility revenue of Eq.3, and therefore, both terms are cancelled out in the UL objective function. Eq.8 represents the grid investment costs that are a function of the maximum network coincident utilization peak, $cPeak$, and the parameter, IncrGridCosts, that is the cost of increase/decrease in the coincident peak per kW.

The $cPeak$, being the maximum of the demand and injection peaks, is calculated via the following equations 9 to 11.

$$cPeak = max\ (cPeakDemand, cPeakInjection) \tag{9}$$

$$cPeakDemand \geq \sum_{i=1}^{N} PC_i * (qw_{t,daytype,i} - qi_{t,daytype,i}) \quad \forall t, daytype \tag{10}$$

$$cPeakInjection \geq \sum_{i=1}^{N} PC_i * (qi_{t,daytype,i} - qw_{t,daytype,i}) \quad \forall t, daytype \tag{11}$$

The cost recovery of grid investment and flexibility procurement costs is imposed by the constraint in Eq.12. The regulated DSO sets the magnitude of the capacity and fixed components of the network tariffs to recover these costs.

$$\sum_{Daytype=1}^{M} \sum_{t=1}^{T} \sum_{i=1}^{N} PC_i * \left(comp * qflex_{i,daytype,t}\right) + IncrGridCosts * cPeak$$
$$= cnt * \sum_{i=1}^{N} PC_i * qmax_i + fnt \tag{12}$$

2.2. The lower level: consumers

The LL represents the individual consumers' optimization problems. They can be passive or active residential consumers, or commercial consumers in the latter part of the analysis. They react to the implicit price signal set via the DSO through the network tariffs and to the explicit one that is the demand-side flexibility compensation, also set by the DSO, and offer their flexibility in kWh accordingly. Active residential consumers and commercial ones can invest in DERs to maximize their individual welfare and be more independent from the electricity supplied via the grid. They can also choose to invest less in DERs if the set compensation is high enough that the revenues from demand curtailment outweigh the bill reduction benefits of investing in DER.

The LL optimization problem is expressed in Eq. 13 for each consumer:

$$\text{Maximise} \quad grossConsumerSurplus_i - costs_i \tag{13}$$

The gross consumer surplus is composed of two components and expressed in Eq.14: the first corresponds to the value of electricity consumption for each consumer, and the second is the revenue from the flexibility that every consumer gets based on his offered levels.

$$grossConsumerSurplus_i = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} (D_{t,,daytype,i} - qflex_{i,daytype,t}) * VoLL * WDT_{daytype} +$$

$$\sum_{Daytype=1}^{M} \sum_{t=1}^{T} \left(comp * qflex_{i,daytype,t}\right) \qquad \forall\, i \tag{14}$$

The second part of the consumers' objective functions is the total costs paid by each one. They are divided into four components, being energy costs, network charges, DER costs, and fixed costs. They are calculated in the following equations 15 to 17.

$$EnergyCost_i = \sum_{Daytype=1}^{M} \sum_{t=1}^{T} \left(qw_{t,daytype,i} * EBP_t - qi_{t,daytype,i} * ESP_t\right) * WDT_{daytype} \qquad \forall\, i \tag{15}$$

$$Gridcharges_i = cnt * qmax_i + fnt \qquad \forall\, i \tag{16}$$

$$DERCosts_i = is_i * AICS + ib_i * AICB \qquad \forall\, i \tag{17}$$

The fixed costs are a set of fees, e.g. VAT and taxes, that does not interfere with the LL optimization problems. The UL and LL remaining constraints are given in the appendix.

3. Case study and results

This section first introduces the numerical example for the numerical example. Second, we present the results obtained for this study case.

3.1 Case study

Table 1: Parameters in the numerical example

Parameter	Value
VoLL for residential consumers	9.6 €/kWh
VoLL for commercial consumers	3.96 €/kWh
Annual demand for residential consumers	9785 kWh
Annual demand for commercial consumers	12055 kWh
Frequency of critical days	10
Default Load (normal days)	Synthetic Load Profiles (SLP)
Incremental network expansion costs	400 €/kW, no sunk grid costs
Solar PV investment cost	1100 €/kWp
Battery investment cost	150€/kWh

3.1.1 VoLL values

The VoLL is defined by the electricity Regulation (EU) 2019/943 as an *'estimation in euro/MWh, of the maximum electricity price that customers are willing to pay to avoid an outage.'* In other words, it is the economic value that consumers put on electricity supply. For system operators, it is a reliability indicator that is used in grid planning (ACER, 2018). In 2020, ACER approved the methodology for calculating the VoLL developed by ENTSO-E (ACER, 2020). The methodology includes the possibility to define a sectoral VoLL, per type of consumers, residential and tertiary on the one hand, and commercial on the other hand.

Available studies for VoLL values' estimation show that there are sectoral variations for VoLLs, in addition to the differences across Member States. For the residential sector, the values vary be-tween 1.5 €/kWh in Bulgaria to 22.94 €/kWh in the Netherlands. High values of VoLL are due, among other things, to the fact that consumers have a high electricity dependence, e.g. for leisure time. For the non-residential or commercial sector, the values vary between the Member States and within a Member State, depending on the type of industrial or commercial activity. For the transport sector, for instance, the values range between 2.06 €/kWh in Hungary and 39 €/kWh in Ireland. For the textile sector, the values range between 0.36 €/kWh in Malta and 3.75 €/kWh in Slovakia. This variation in the values is linked to the electricity dependence for realizing the pro-ductive output For our numerical example, we opted for a VoLL of 9.6 €/kWh for the residential sector and 3.96 €/kWh for the commercial sector. This ratio between the residential and commer-cial VoLL is in line with the values in Belgium, Austria, Germany (ACER, 2018). Other factors can also impact the VoLL levels, such as the existence of a notice for the interruption event and the dura-tion of that event. A notice of one-day ahead is translated into a VoLL reduction of about 50% for residential consumers and to a lesser extent for non-residential consumers (ACER, 2018). The im-pact of the different level of VoLL have been analyzed in the context of mandatory curtailment in Nouicer et al. (2021).

Apart from VoLL, other metrics could be used to assess how consumers value an uninterrupted electricity supply. Ozbafli and Jenkins (2016) analyze the households' willingness-to-pay (WTP) for electricity supply. CEER (2010) lists the guidelines to estimate the cost of electricity supply

interruptions using the WTP and the willingness-to-pay (WTA). Nevertheless an important difference between WTA/WTP and VoLL is that WTA/WTP are measurements of the monetary value for which consumers are ready to pay/accept to avoid/undergo a reduction of their supply, and are usually normalized per unit of time, e.g. they can be expressed in €/hour. In turn, VoLL is normalized per unit of energy, e.g. €/kWh of electricity (ACER, 2018). Converting WTA/WTP is possible through a division by the (average) electricity consumed per unit of time, e.g. per hour (London Economics, 2013). Nevertheless, this can be more challenging in practice due to the unavailability of disaggregated consumption data at consumer's level as well as discrepancies between the values of WTA and WTP (CEER, 2010).

3.1.2 Demand parameters

We consider electricity load profiles for different days, i.e. a normal day and a critical day, and different consumers, i.e. residential and commercial consumers. We based our normal day profiles on the synthetic load profiles for the different types of consumers (Synergrid, 2019). For the critical days, which occur ten times a year, we magnified the consumption peaks of the normal day profiles. They represent days with high electricity consumption due to weather conditions or other non-frequent behavior leading to increased use of electricity.

We consider an annual electricity demand per household of 9785 kWh for the residential sector and 12285 kWh for the commercial sector. These relatively high consumption levels for residential consumers are due, inter alia, to the critical days' high demand shown in Figure 2. Annual electricity consumption varies between the countries worldwide, depending on the weather conditions and the use of electrical heating. In France, the average electricity consumption per household in the 1st quarter of 2020, was 4529 kWh (Fournisseurs d'électricité, 2021). Yet, for houses with a size of 120 sq m, more adequate for installing DERs, the average annual consumption is 12000 kWh (ENGIE, 2021). With the current trends of electrification of end-uses and the penetration of elec-tric vehicles, the final electricity demand would increase by 8.5% between 2015 and 2030 in Eu-rope, according to Agora Energiewende (2019), and based on the European Commission scenarios.

Figure 2: Profiles for normal and critical days for the different types of consumers
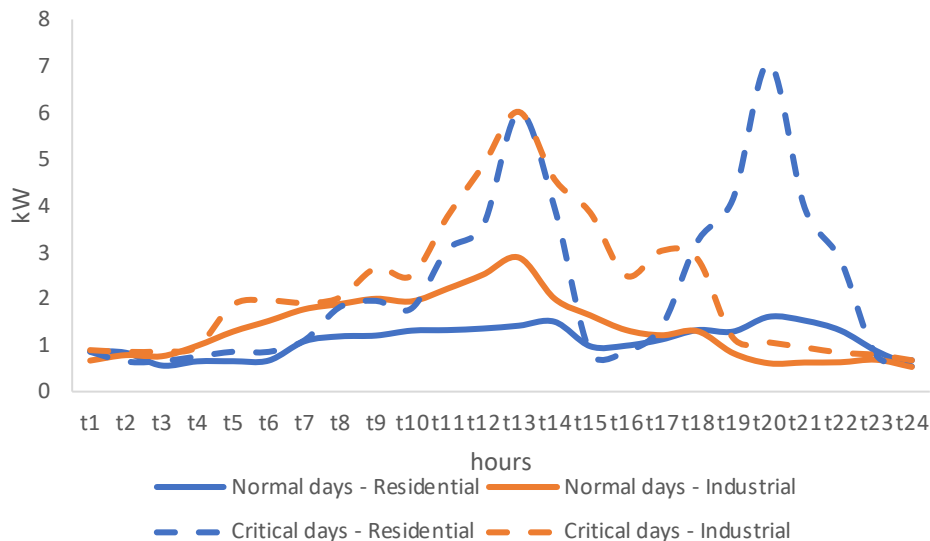
The residential load profiles have the so-called 'humped-camel shape' with an evening peak that is higher than the one at noon (Faruqui and Graf, 2018). The considered commercial consumers have a single peak in the middle of the day, around 1pm.

The contribution of residential demand to the system demand peak is important. In Europe, it contributes about 60% of the system peak (Torriti, 2020), while in some parts of the US, South Australia and New Zealand, it accounts for around 50% ((Gyamfi et al., 2013) and (EDF, 2013)). The contribution of the residential sector to the overall electricity demand is less important than its contribution to the peak. In Europe, it accounts for about one-third of the electricity demand (Torriti, 2020). For the critical days, we selected load profiles of residential consumers with an evening peak of ~7 kW, while the day peak is ~6 kW. Commercial consumers in our simulations have a predominant day peak of ~6 kW. For the model runs executed with only residential consumers, we opted for a 50%-50% distribution between prosumers and passive consumers, which is a situation that is expected in the near future. For instance, in Belgium, De Villena et al. (2021) find that, under enabling technological and economic incentives, up to 85% of the potential prosumers would become actual prosumers in Wallonia when a capacity component-based network tariff is set. In the cases with active residential, passive residential and commercial consumers, we opted for 33% for each of the three.

3.1.3 DER parameters

Prosumers can invest in rooftop solar PV panels and battery storage to maximize their individual welfare. Regarding the investment costs, we opted for a value for AICS, that is the investment cost in solar PV, of 1100 €/kWp (JÄGER-WALDAU, 2019) and for AICB, that is the investment cost in battery systems, of € 150 per kWh of installed capacity (European Commission, 2020). These values are in line with the current reduction trends of DER investment costs. In our case study, prosumers can invest up to 4 kW in solar PV panels and 6 kWh in battery systems.

3.1.4. Grid-related parameters

In our long-term equilibrium model, there are no sunk costs, and grid investments are assumed to be 100% driven by the coincident peak. This emphasizes the role of flexibility as an alternative for future investment in distribution grids. To set the value of the IncrGridCosts, we calculate the default grid costs, similar to MIT Energy Initiative (2016), which equals 400 €/kW. To recover the grid investment costs and the flexibility costs, the DSO sets the magnitude of the grid charges components. These charges are considered mostly capacity-based (cnt) with the possibility for the DSO to set up to 40€ of fixed grid charges (fnt).

3.2 Results

In this section, we first present the impact of different compensation levels for demand-side flexibility on the welfare and the different components of the invoice that consumers pay. We then let the model decide the optimal level of compensation. Subsequently, we look at the optimal under uniform pricing and under price discrimination. Finally, we do a sensitivity analysis in which we add an commercial consumer to the system to see how that changes the results.

3.2.1 Impact of different prices for demand-side flexibility

To understand the effects that drive the model towards a welfare-maximizing price for demand-side flexibility, we start by running the model iteratively for different compensation levels. In what follows, we explain what happens with three figures.

First, Figure 3 illustrates the evolution of gross welfare if we gradually increase the price for demand-side flexibility. The figure also illustrates the level of flexibility that is voluntarily offered by the consumers and procured by the DSO at these different prices (the volume of flexibility is expressed as a % of the total volume consumed in a year on the secondary y-axis). Note that gross welfare is the first term of Eq.1, which consists of two components: the consumers' valuation of electricity consumption (dark blue area of each bar), and the income that the consumers receive by

offering flexibility (striped blue area of each bar). As expected, consumers offer more demand-side flexibility for higher levels of compensation, and their income from these services also increases.

Figure 3: Gross welfare and flexibility offered for different levels of compensation
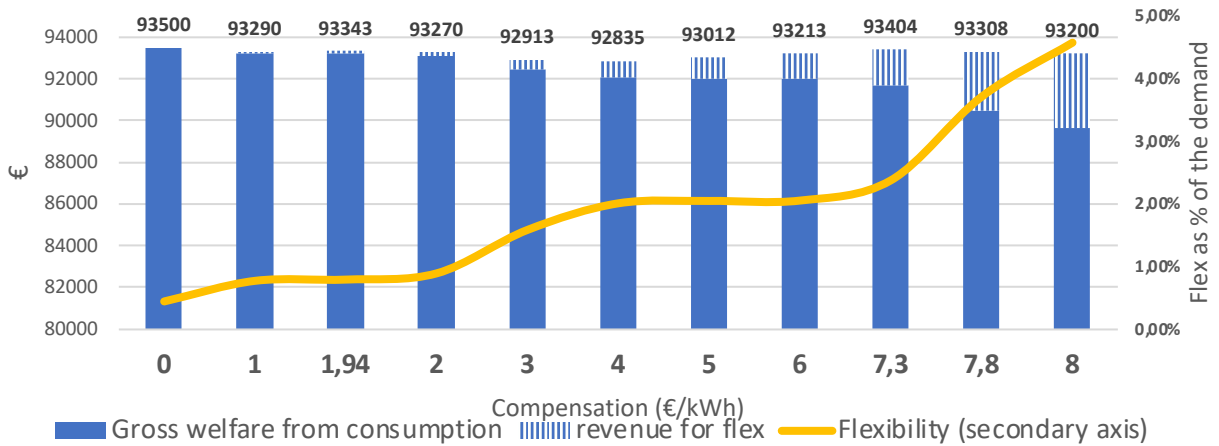
Second, Figure 4 illustrates the evolution of the invoice that consumers pay if we gradually increase the price for demand-side flexibility. The invoice consists of the energy sourcing costs, network charges, fixed charges, and annualized investment costs in DERs (solar PV and battery systems) minus the income from providing flexibility services.

In Figure 4, we show the level of network charges that are used to recover the network investment on the one hand and to recover flexibility costs on the other hand, in dotted bars and striped bars, respectively. The remaining part of the consumer invoice, being energy sourcing costs, the fixed charges, and the annualized investment costs in DERs, is shown in the dark blue area of the bars. Just like in the previous figure, this figure also includes the level of flexibility that is voluntarily offered by the consumers and procured by the DSO at these different prices. The figure reminds us that there are many interactions in this model. By offering a higher price for demand-side flexibility, the DSO can save network investments, which can help to lower network charges and increase the revenues consumers get from providing flexibility services. However, the DSO also allocates the costs of procuring flexibility via network tariffs to consumers. Therefore, the consumers' payment for network charges increases for high flexibility prices. The net effect on network charges and the total bill of consumers is positive for low demand-side flexibility prices but becomes negative for higher prices, i.e. higher than 4 € in this case.

Figure 4: Consumers' aggregated bill (y-axis) for different compensation prices (x-axis)
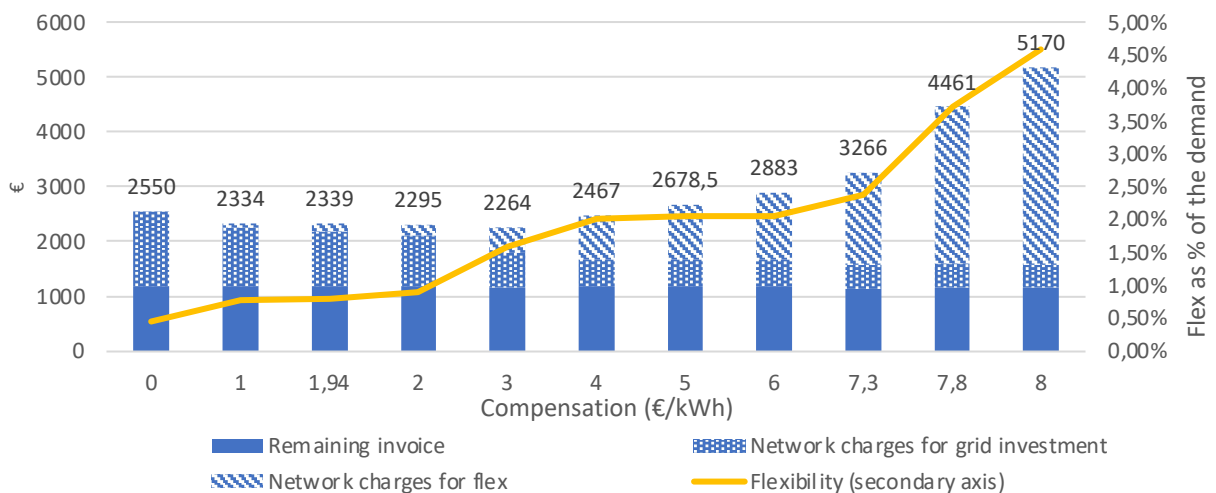
Third, Figure 5, illustrates the evolution of the net welfare if we gradually increase the price for demand-side flexibility. Note that the welfare is the objective function of the DSO in the UL and calculated in Eq.1. What happens with the welfare is, of course, the combination of the above two effects on gross welfare and the total system costs or the (aggregated) invoice for consumers. In the numerical example that we modelled, the welfare-maximizing price for demand-side flexibility is just below 2 €/kWh triggering 0.79% of voluntarily curtailed demand, as a percentage of their annual demand. This price is uniform for both types of consumers, referred to as uniform pricing for demand-side flexibility. We also notice that for a compensation equal to 0 €/kWh, the system welfare is close to the optimum level (Figure 5). In this case, consumers offer lower levels of demand-side flexibility (0.44%) to reduce network investment and consequently the network charges they pay. These limited levels of flexibility translate into a higher gross welfare (Figure 3), without impacting network charges part used to recover flexibility costs, explaining the close to optimum net system welfare.

Figure 5: System welfare for different levels of compensation
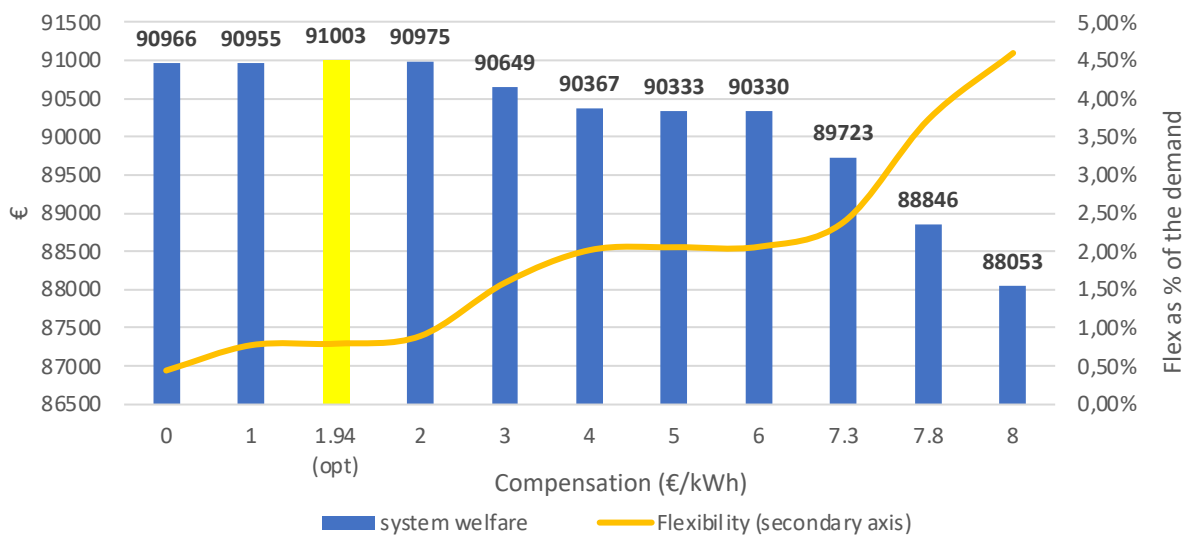
3.2.2 Welfare-maximizing prices for demand-side flexibility: uniform pricing versus price differentiation

In what follows, we first present the detailed results for using demand-side flexibility under uniform pricing. Then we compare them with the results for price differentiation. Finally, we assess the impact of the pricing approach on the distribution of costs and benefits between the two residential consumer types.

First, Table 2 and Figure 6 show the output of the model under uniform pricing, which means that the passive and active consumers are offered the same price for flexibility services. The welfare-maximizing price for demand-side flexibility is 1.94 €/kWh. This translates into a net welfare of 91003 € with a gross welfare of 93343 €, and costs of 2339 €. The consumers' aggregated revenue for demand-side flexibility, paid by the DSO, is 151 €. The reason why the compensation is set at a level lower than VoLL is the fact that compensation revenues are recovered via network tariffs (Eq.12). When the DSO offers high compensation to consumers, the gross welfare increase (Figure 3) and so do network tariffs levels used to recover flexibility costs to a higher extent (Figure 4). This impacts negatively net welfare (Figure 5). The optimal level of compensation is set in a way that mobilizes the necessary flexibility from consumers to save network investment without heavily increasing network charges and consequently system costs.

With this relatively limited compensation to curtail peak consumption during critical days, the DSO can save up to 50% of the network investments in our example. The active consumer, C1, provides slightly more of the total volume of demand-side flexibility than the passive consumer, C2, (53% versus 47%, for a flexibility revenue of €161.14 versus €142.03). Figure 6 illustrates the impact of the curtailment on the two types of consumers on a critical day. Prosumers invest in DERs (4 kW for solar PV and 6 kWh in batteries) and use their solar PV self-generated electricity to cover their day peak, while they use their battery storage to partly cover their evening peak. The voluntary curtailment happens both at the day and evening peak for the passive consumers. Both consumption peaks are reduced to the same level in our example.

Table 2: Results of the flexibility procurement

	No flex	Uniform pricing	
		C1	**C2**
Welfare (€)	90656	91003	
Flex level	-	0.79%	
Annualized network investment € (per consumer)	2001	1000.25(-50%)	
Compensation (€/kWh)	-	1.94	
Flex offered per agent		53%	47%
Flex revenue per agent (€)		161.14	142.03

Figure 6: Load profiles for the different types of consumers: left: prosumers, right: passive consumers
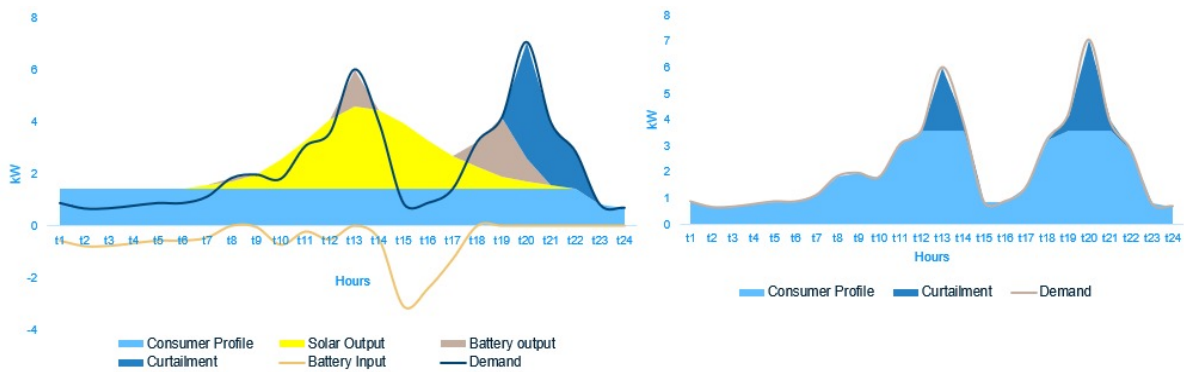

Second, Table 3 and Figure 7 show the results of the model with price differentiation, which means that the DSO is allowed to offer a different price for the flexibility services of the passive and active consumers. The net welfare of the solution with price differentiation is higher than in the case with uniform pricing. Under uniform pricing, the compensation needed to manage the passive consumers' peaks triggers bad behavior from the active consumers. The active consumers would be able to manage their own peaks with their PV and battery systems, but they anticipate that they can receive relatively high compensation for curtailment. With price differentiation, the DSO can offer an optimized lower compensation to the active consumers (0,23 €/kWh) than to the passive consumers (2,45 €/kWh). As illustrated in Figure 7, the most visible change is in the way the active consumers operate their batteries.

**Table 3: Comparison between a uniform and a differentiated compensation**

	Uniform		Differentiated	
			C1	C2
Welfare	91003		91037	
Flex level	0.79%		0.55%	
Annualized network investment € (per consumer)	1000.25(-50%)		1199.00 (-46%)	
Compensation (€/kWh)	1.94		0.23	2.45
Flex offered per agent	53%	47%	32%	68%
Flex revenue per agent (€)	161.14	142.03	7.92	178.27

Figure 7: Load profiles for the prosumer: left: uniform compensation, right: differentiated compensation
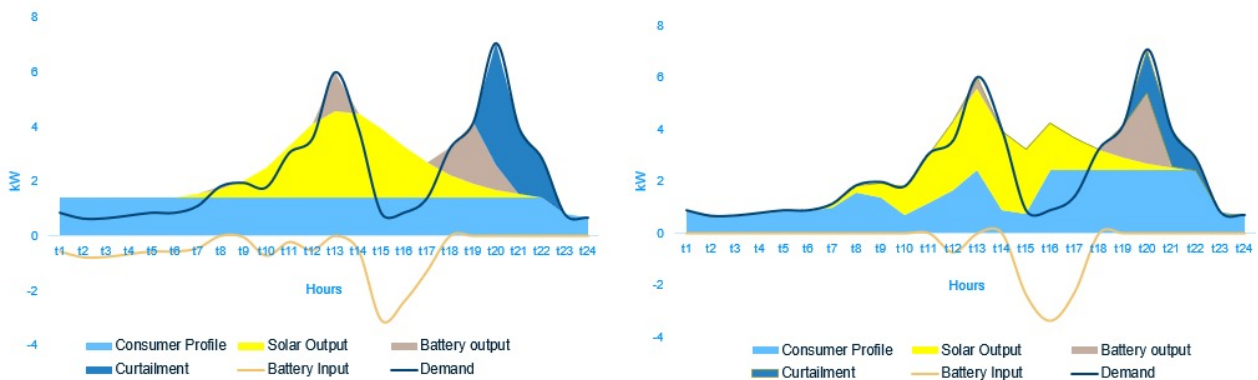
Third, Figure 8 compares the impact of the pricing approach on the distribution of costs and benefits between the two consumer types in our model. The academic literature on network tariffs concluded that cost-reflective distribution tariffs are more efficient, but not necessarily fair, see for instance Schittekatte and Meeus (2020) which measure fairness as increase in grid charges for passive consumers in comparison with a baseline and Neuteleers et al., (2017). Most of the benefits of cost-reflective tariffs are for the active consumers that invest in PV and battery systems. However, the table below illustrates that demand-side flexibility can help reduce the gap between active and passive consumers. We assess fairness, here, as the change in the relative gap between active and passive consumers invoices compared to the case where no flexibility is contracted. In our example, the gap reduces from 1685 euro to 1206 euro if we introduce demand-side flexibility with uniform pricing, and the gap reduces further to 478 euro if we can apply price differentiation.

Note that this, of course, assumes that we would be able to mobilize passive consumers to participate in these demand-side flexibility schemes that the DSO sets up. We think that this is a reasonable assumption, at least for some of them. Investing in PV and battery is indeed more time and resource-consuming than signing up for a smart connection agreement or other types of demand-side management schemes.

Figure 8: Consumers' bill and investment costs under the different flexibility schemes
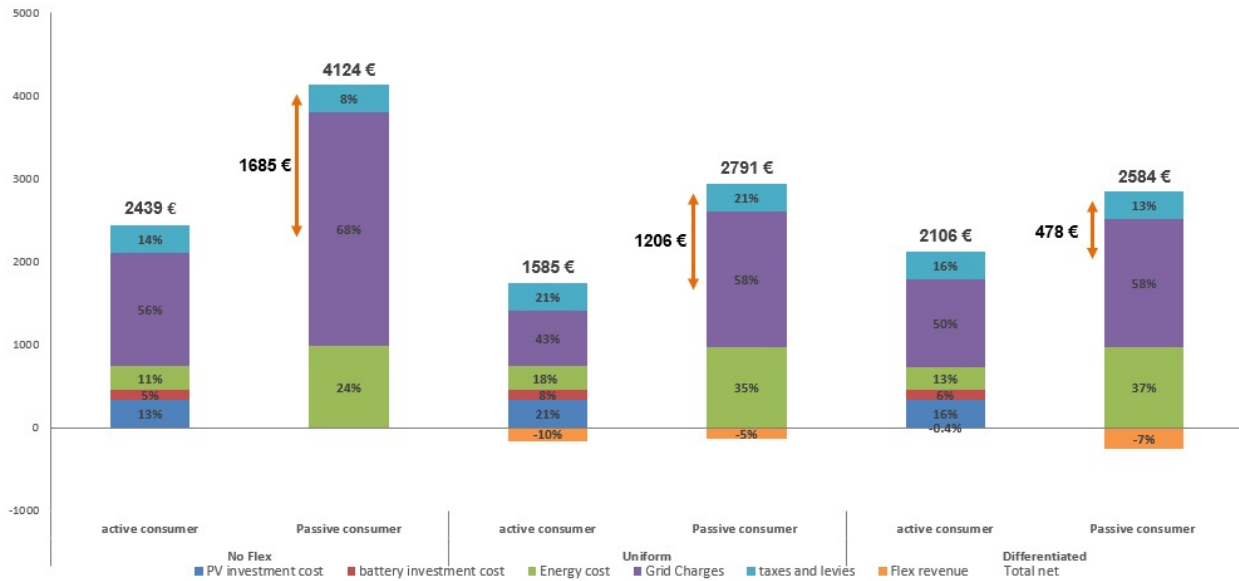
3.2.3. Sensitivity with a commercial consumer

Full price differentiation might not be feasible because it is difficult to distinguish passive and active residential consumers, and it might be considered discriminatory. For this reason, in what follows, we present an alternative that might be more feasible, which is to apply price discrimination for consumers connected at different voltage levels. To be able to run this sensitivity, we add a third type of consumer to the model, a commercial consumer with a VoLL equal to 3.96 €/kWh. Table 4 reports the results, where C1 refers to the prosumers, while C2 refers to passive consumers and C3 refers to commercial consumers. The findings are in line with the expectations. The results for demand-side flexibility with voltage price differentiation are better than the results with uniform pricing, but worse than the results with full price differentiation. Note also that the commercial consumer has a different load profile from the residential consumers (see Figure 2). In our system, the system peak, however, coincides with the residential peak, which is why the price differentiation between voltage levels is less beneficial than price differentiation among residential consumers. Note finally that the commercial consumer can game the compensation scheme, similar to the active residential consumer, which is why the price for demand-side flexibility is so low, much lower than the VoLL.

Table 4: Results with residential and commercial consumers

	No flex	Flex with uniform pricing			Flex with full price differentiation			Flex with voltage price differentiation		
		C1	C2	C3	C1	C2	C3	C1	C2	C3
Net welfare	75150	75281			75315			75308		
Flex level	-	0.5%			0.3%			0.4%		
Annualized network investment € (per consumer)	1469	849 (-43%)			1017 (-31%)			920 (-38%)		
Compensation (€/kWh)	-	1.4			0.25	1.72	0.1	1.48		0.08
Flex offered per agent	-	49%	46%	5%	17%	77%	4%	54%	42%	3%
Flex revenue per agent (€)		109.4	102.9	11.85	4.16	125.5	0.7	101.6	79.42	0.5

4. Limitation of the approach

In this section, we present some of the limitations of our approach that we identified, and we assess to which extent they underestimate or overestimate the potential of demand-side flexibility. The numerical results for our theoretical model depend on the data set considered. We use the obtained results to draw conclusions and show the impact of the associated parameters rather than finding exact values of general validity.

An example of overestimation is the demand profiles for residential consumers. Our data set uses similar load profiles of active and passive prosumers. This is translated into important flexibility levels procured from passive consumers. It could be argued that passive consumers consume less electricity than active ones. Yet, in our approach, we opt for average standardized profiles for normal days and critical days with higher consumption peaks, which happen a few times a year, for reasons that are similar for all types of consumers.

An illustration of underestimation is the load profiles of commercial consumers and their ability to invest in DER. In our approach, the commercial consumers can invest in rooftop solar PV panels to flatten their day consumption peak, which is triggered through the capacity-based network tariffs signals. Therefore the need to procure flexibility from commercial consumers is reduced as well as the related payment. Other types of consumers could be added, with different load profiles, such as commercial consumers. This may impact the flexibility offered by consumers, as they may have other types of load profiles.

However, the central role would remain the residential consumers for the uptake of demand-side flexibility due to important their contribution to the system demand peak.

5. Conclusion

In the conclusion, we summarize the paper's main contributions and the related findings below. First, for the modelling contribution, to the best of our knowledge, we are the first to model a voluntary scheme for flexibility, as an alternative to distribution investment, where the DSO sets the price for demand-side flexibility and the consumers respond by offering their flexibility. We modeled a uniform pricing as well as a differentiated pricing approach for the compensation offered by the DSO. We also compared the findings to the case where no demand-side flexibility is procured.

Second, for the policy contribution, we find that a voluntary demand-side flexibility scheme improves welfare. We also find that the welfare gains are significantly higher if price differentiation for the compensation of demand-side flexibility is applied. If price differentiation is an option, active consumers are offered a lower compensation than passive ones, which significantly reduces gaming by the former. As price differentiation might be difficult to apply to residential customers, we also looked at the possibility to differentiate between commercial and residential consumers and found that it is opportune to do so.

We also investigated how the welfare gains are distributed among different types of consumers. We wanted to know if the welfare gains are mainly for the active consumers, or also for the passive consumers. We found that a voluntary demand-side flexibility scheme reduces the fairness issue between the two types of residential consumers. If consumers that do not invest in DERs are activated via demand-side flexibility, they will also benefit from it. Also, we find that flexibility procurement with a differentiated compensation is fairer than a uniform one.

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Appendix

Appendix A: The MPEC model resolution

A1. MPEC Model formulation

SETS

i : 1,..,N: Consumers types, 1 for active and N for passive

t: 1,..,T: Time steps, hours, T=24h

Daytype: normal, critical

PARAMETERS (capitalized)

<u>Upper level</u>

PC_i: Proportion of consumer type i

VoLL: Value of lost load [€/kWh]

IncrGridCosts: Incremental annualized grid cost per kW, scaled per average consumer [€/kW]

$D_{i,daytype,t}$: Original demand at (t, daytype) of consumer i [kW]

$WDT_{daytype}$: annuity factors for the different costs [-]

<u>Lower Level</u>

Dt: time step, as a fraction of 60 minutes [-]

MS_i : Maximum solar capacity for consumer i [kW]

MB_i : Maximum battery capacity for consumer i [kWh]

$SY_{t,i}$: PV panel yield at time step t of consumer i [kWh/kWpeak]

EBP_t: Energy price for buying electricity from the grid [€/kWh]

ESP_t: Energy price received for injecting in the grid [€/kWh]

ICS: investment cost solar PV [€/kWp]

AFS: Annuity factor for solar PV investment

ICB : Investment cost battery [€/kWh]

AFB: Annuity factor for battery investment

BDRatio: Ratio of max power output of the battery over the installed energy capacity [-]

BCRatio: Ratio of max power input of the battery over the installed energy capacity [-]

ηout: Efficiency of discharging the battery [%]

ηin: Efficiency of charging the battery [%]

VARIABLES (starting with lower-case letters)

<u>Upper Level</u>

cnt: Capacity component of the network tariff [€/kW]

fnt: fixed component of the network tariff [€/consumer]

comp: Compensation for flexibility set by the DSO (could be uniform or differentiated by consumer i [€/kWh]

$cPeak$: The coincident peak demand resulting from the model optimization (the highest value of $cPeakDemand$ and $cPeakInjection$).

$cPeakDemand$: The coincident peak demand resulting from the model optimization

$cPeakInjection$: The coincident peak injection resulting from the model optimization

grossWelfare: The gross system welfare created from electricity consumption [€]

totalSystemCosts: Total annualized system costs, scaled per average consumer [€]

$systemGridCost$: Total annualized grid costs, scaled per average consumer [€]

$systemEnergyCosts$: Total annualized energy costs, scaled per average consumer [€]

$systemDERCosts$: Total annualized DER costs, scaled per average consumer [€]

Flexibilitycost: Total annualized flexibility costs, scaled per average consumer [€]

<u>Lower Level</u>

$qw_{i,daytype,t}$: Energy withdrawn at (t, daytype) by consumer i [kW]

$qi_{i,daytype,t}$: Energy injected at (t, daytype) by consumer i [kW]

$qflex_{i,daytype,t}$: Demand-side flexibility offered by consumers [kWh]

is_i: Installed solar PV capacity by consumer i [kW]

ib_i: Installed battery capacity by consumer i [kWh]

$qbout_{i,daytype,t}$: Discharge of the battery of consumer i at (t, daytype) [kW]

$qbin_{i,daytype,t}$: Charge of the battery of consumer i at (t, daytype) [kW]

$soc_{i,daytype,t}$: State of charge of the battery [kWh]

$grossConsumerSurplus_i$: The gross system welfare created from electricity consumption for consumer i [€]

$costs_i$: Annualized costs for consumer i [€]

$energyCosts_i$: Annualized energy costs for consumer i [€]

gridCharges_i: Annualized grid charges for consumer i [€]

DERCosts_i Annualised DER costs, for consumer i [€]

FULL CONSUMER CONSTRAINTS

1) $qw_{i,daytype,t} + is_i * SY_{i,daytype,t} + qbout_{i,daytype,t} - qi_{i,daytype,t} - qbin_{i,daytype,t} + qflex_{i,daytype,t}$

$\quad - D_{i,daytype,t} = 0$ $\qquad \forall\, t\,, daytype, i$ $\qquad (\mu1_{t,daytype,i})$

2a.) $soc_{i,daytype,t} - qBin_{i,daytype,t} * \eta in * dt + \frac{qBout_{i,daytype,t}}{\eta out} * Dt - soc_{i,daytype,t-1} * (1 - \varphi * Dt) =$

0 $\qquad \forall\, t \neq 1\,, daytype, i$ $\qquad (\mu2_{t,daytype,i})$

2b.) $soc_{i,normal,T} - soc_{i,normal,1} - qBin_{i,normal,1} * \eta in * Dt + \frac{qBout_{i,normal,1}}{\eta out} * Dt = 0$ $\quad \forall\, i$ $\qquad (\mu2_{1,normal,i})$

4.) $-qmax_i + qw_{i,daytype,t} + qi_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda1_{t,daytype,i})$

5.) $soc_{i,daytype,t} - ib_i \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda2_{t,daytype,i})$

6.) $qBout_{i,daytype,t} - ib_i * BDRatio \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda3_{t,daytype,i})$

7.) $qBin_{i,daytype,t} - ib_i * BCRatio \leq 0$ $\qquad \forall\, t\,, daytype, i$ $\qquad (\lambda4_{t,daytype,i})$

8.) $-qw_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda5_{t,daytype,i})/$

9.) $-qi_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda6_{t,daytype,i})$

10.) $-soc_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda7_{t,daytype,i})$

11.) $-qBout_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda8_{t,daytype,i})$

12.) $-qBin_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda9_{t,daytype,i})$

13.) $is_i - MS_i \leq 0$ $\qquad \forall i$ $\qquad (\lambda10_i)$

14.) $ib_i - MB_i \leq 0$ $\qquad \forall i$ $\qquad (\lambda11_i)$

15.) $-is_i \leq 0$ $\qquad \forall i$ $\qquad (\lambda12_i)$

16.) $-ib_i \leq 0$ $\qquad \forall i$ $\qquad (\lambda13_i)$

17.) $-qmax_i \leq 0$ $\qquad \forall i$ $\qquad (\lambda14_i)$ *implied by equations 4 and 10*

18.) $-qflex_{i,daytype,t} \leq 0$ $\qquad \forall\, t, daytype, i$ $\qquad (\lambda15_{t,daytype,i})$

A2. Model transformation

THE LAGRANGIAN FORMULATION

$$L = \sum_{i=1}^{N} \sum_{daytype}^{critical} \sum_{t=1}^{T} [- PC_i * (D_{i,daytype,t} - qflex_{i,daytype,t}) * VoLL * WDT_{daytype} - PC_i *$$

$$\sum_{t=1}^{T} (comp * qflex_{i,daytype,t}) * WDT_{daytype} + (qw_{i,daytype,t} * EBP_t - qi_{i,daytype,t} * ESP_t) * WDT_{daytype} +$$

$$cnt * qmax_i + fnt + is_i * AICS + ib_i * AICB + \sum_{daytype}^{critical} \sum_{t=1}^{T} \mu1_{i,daytype,t} * (qw_{i,daytype,t} + is_i * SY_{i,daytype,t} +$$

$$qbout_{i,daytype,t} - qi_{i,daytype,t} - qbin_{i,daytype,t} + qflex_{i,daytype,t} - D_{i,daytype,t}) + \mu2_{i,t \neq 1,daytype} *$$

$$(soc_{i,daytype,t} - qBin_{i,daytype,t} * \eta in * Dt + \frac{qBout_{i,daytype,t}}{\eta out} * Dt - soc_{i,daytype,t-1} * (1 - \varphi * Dt)) +$$

$$\mu2_{i,daytype,1} * (soc_{i,daytype,1} - SOC0 - qBin_{i,daytype,1} * \eta in * Dt + \frac{qBout_{i,daytype,1}}{\eta out} * Dt) + \lambda1_{i,daytype,1} *$$

$$(- qmax_i + qw_{i,daytype,t} + qi_{i,daytype,t}) + \lambda2_{i,daytype,t} * (soc_{i,daytype,t} - ib_i) + \lambda3_{i,daytype,t} *$$

$$(qBout_{i,daytype,t} - ib_i * BDRatio) + \lambda4_{i,daytype,t} * (qBin_{i,daytype,t} - ib_i * BCRatio) + \lambda5_{i,daytype,t} *$$

$$(-qw_{i,daytype,t}) + \lambda6_{i,daytype,t} * (-qi_{i,daytype,t}) + \lambda7_{i,daytype,t} * (-soc_{i,daytype,t}) + \lambda8_{i,daytype,t} *$$

$$(-qBout_{i,daytype,t}) + \lambda9_{i,daytype,t} * (-qBin_{i,daytype,t}) + \mu2_{i,daytype,t1} * (soc_{i,daytype,t1} - qBin_{i,daytype,t1} *$$

$$\eta in * Dt + \frac{qBout_{i,daytype,t1}}{\eta out} * Dt - SOC0) + \lambda10_i * (is_i - MS_i) + \lambda11_i * (ib_i - MB_i) + \lambda12_i * (-is_i) + \lambda13_i *$$

$$(-ib_i) + \lambda15_{t,daytype,i} * (-qflex_{i,daytype,t})$$

KKT conditions

$$\frac{\partial \Gamma}{\partial qw_{i,daytype,t}} = WDT_{daytype} * (EBP_t) + \mu1_{t,daytype,i} + \lambda1_{t,daytype,i} - \lambda5_{t,daytype,i} \qquad \forall i, daytype, t$$

$$\frac{\partial \Gamma}{\partial qi_{i,daytype,t}} = -WDT_{daytype} * ESP_t - \mu1_{t,daytype,i} + \lambda1_{t,daytype,i} - \lambda6_{t,daytype,i} \qquad \forall i, daytype, t$$

$$\frac{\partial \Gamma}{\partial qmax_i} = cnt - \sum_{daytype}^{critical} \sum_{t=1}^{T} \lambda1_{t,daytype,i} \qquad \forall i$$

$$\frac{\partial \Gamma}{\partial qflex_{i,daytype,t}} = (VoLL - comp) * WDT_{daytype} + \mu1_{t,daytype,i} - \lambda15_{t,daytype,i} \qquad \forall i, daytype, t$$

$$\frac{\partial \Gamma}{\partial soc_{i,daytype,t}} = \mu2_{i,daytype,t} - \mu2_{i,daytype,t+1} * (1 - \varphi * Dt) + \lambda2_{i,daytype,t}$$

$$- \lambda7_{i,daytype,t} \qquad \forall i, daytype \ t \neq \{T\}$$

$$\frac{\partial \Gamma}{\partial SOC_{i,daytype,t}} = \mu2_{i,daytype,1} - \mu2_{i,daytype,T} + \lambda2_{i,daytype,T} - \lambda7_{i,daytype,T} \qquad \forall i, daytype, t = \{T\}$$

$$\frac{\partial \Gamma}{\partial qBout_{i,daytype,t}} = \mu1_{i,daytype,t} + \frac{\mu2_{i,daytype,t}}{\eta out} * Dt + \lambda3_{i,daytype,t} - \lambda8_{i,daytype,t} \qquad \forall\, i, daytype, t$$

$$\frac{\partial \Gamma}{\partial qBin_{i,daytype,t}} = -\mu1_{i,daytype,t} - \mu2_{i,daytype,t} * \eta in * Dt + \lambda4_{i,daytype,t} - \lambda9_{i,daytype,t} \qquad \forall\, i, daytype, t$$

$$\frac{\partial \Gamma}{\partial IS_i} = ICS * AFS + \sum_{daytype}^{critical} \sum_{t=1}^{T} \mu1_{i,daytype,t} * SY_{t,i} + \lambda10_i - \lambda12_i \qquad \forall\, i$$

$$\frac{\partial \Gamma}{\partial IB_i} = ICB * AFB - \sum_{daytype}^{critical} \sum_{t=1}^{T} \lambda2_{i,daytype,t} - \sum_t \lambda3_{i,daytype,t} * BDRatio - \sum_t \lambda4_{i,daytype,t} * BCRatio +$$

$$\lambda11_i - \lambda13_i \qquad \forall\, i$$

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