The influence of local optimised energy communities on the European electricity market

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Abstract

The "Clean Energy for all Europeans" package of the European Union creates a legal basis to implement Energy Communities within Europe, to create investment incentives into local generation technologies and storages. This paper analyses the influence of energy communities on the European electricity market, just as vice versa. In order to show the influence and interactions between the local optima of the energy communities and the global goal of minimising costs and CO_2 emissions, two models are linked together in a scenario-dependent manner. A European market model calculates, based on exogenous demand,- and generation profiles of renewable energies, the optimal power plant dispatch in Europe and, associated with this, the expected electricity prices for the European electricity market. Following this, an energy community model optimises consumption and storage usage considering the hourly electricity price of the market as an exogenous time series. Since the global power plant dispatch is influenced by the demand profiles of the energy communities, and these in turn by the electricity prices on the spot market, there is a dependency between these two models. Investments made by the energy communities in Austria in PV systems and battery storages reduce the energy generation costs of the entire European energy market by 0.33% in the examined scenario for 2030. CO_2 emissions are reduced even more significantly by 2.9%.

Keywords: Energy System Decarbonisation, Energy Communities, Energy Market, Market model

Abbreviations

BG	Balancing Group
DC	Direct current

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DA	Day-ahead
EC	Energy Community
ENTSO-E	European Network of Transmission System Operators
MILP	Mixed-integer linear programming
NECP	National Energy and Climate Plan
NTC	Net transfer capacity
O&M	Operation and maintenance costs
PHS	Pumped hydropower storage
PTDF	Power transfer distribution factor
PV	Photovoltaic
RES-E	Renewable energy source electricity
RoR	Run-of-the-river hydroelectricity
VoLL	Value of lost load

1. Introduction

With its "Clean Energy for all Europeans" package and the Directive 2018/2001 the European Union has created a legal basis to enable renewable energy communities (EC) in the individual member states [1]. Reduced grid tariffs, fees and cancellation of green electricity fees within the EC create incentives for private investments into renewable energies. Thus, photovoltaic (PV) systems are more attractive from the owners' point of view, even if they cannot consume most of the generated energy by themselves. Consumers can reduce their dependence on the electricity market, offer their loads as demand-side-management flexibilities, e.g. heat pumps or electric vehicles, and thus benefit from lower grid fees and energy prices within the community. Selling PV generated energy within the EC improves the economic efficiency of investments, as the economic difference between self-consumption and feeding into the grid is significantly reduced by self-consumption within the EC. On the other hand, consumers buy this energy at lower energy and grid tariffs than they would on the spot market. Therefore, this economic benefit promotes rapid decarbonisation of the entire energy system, as there will be much more new private investments. According to Austrian law, specified in the "Erneuerbaren-Ausbaugesetz (EAG)" [2] a membership to an EC is open, e.g. for private households, small and medium-sized companies and municipalities.

1.1. State-of-the-art

The potential of costs savings of ECs for their participants is discussed in [3] by using mixed-integer linear programming (MILP) models, although this is not the primary motivation for participation [4]. While [5] provides different approaches for energy trade pricing models within ECs. Operation strategies of in particular storages to use arbitrage to gain economic benefits within a community are examined in [6]. On the other hand, the exploitation of demand-side flexibilities by companies can create further economic advantages by combining EC members with different, complementary demand behaviours [7]. [8] focuses on the impact of ECs on the utilisation of the distribution grid with different EC configurations and operation strategies. The integration of a grid-friendly behaviour of ECs by the implementation of a grid capacity based grid tariff is done in [9]. The integration of distributed small scale local generation units as aggregated devices into energy markets is evaluated by [10] for ancillary and flexibility markets. Investments into renewable energies and their influence between local energy communities and the energy market are evaluated in [11] by using a capacity expansion model.

1.2. Progress beyond state-of-the-art

The main focus of this paper are the interactions between local optimised ECs and the energy market over a time horizon of a whole year. Therefore, the European market model EDisOn [12] calculates, based on exogenous demand, - and generation profiles of renewable energies, the optimal power plant dispatch

in Europe and, associated with this, the expected electricity prices for the European electricity market. Within Austria, a detailed distribution grid model is used to see the local influences of the ECs. The FEMTO model [13] optimises consumption as well as storage usage within a specific energy community, considering the hourly electricity price of the market as an exogenous time series. Since the global power plant dispatch is influenced by the demand profiles of the ECs, and these in turn by the electricity prices on the spot market, there is a dependency between the two models (market model with elastic prices). To analyse the influence of ECs on the electricity market in terms of costs of electricity generation and CO_2 emissions, and to consider possible counteracting of local and global targets, different objective functions are considered.
From the ECs' point of view:

- Cost minimisation of the energy communities

From the market perspective

- Maximising social welfare (Cost minimisation of the European electricity market)

For this purpose, energy storages available within the ECs are optimised from the market's perspective and can also be used for the potential procurement of balancing energy. Therefore, the influence of ECs on the balancing energy market will be analysed (work in progress).

2. Nomenclature

Sets		
T	set of timesteps	index: t
BG	set of balancing groups	index: bg
H	set of households	index: h
EC	set of energy communities	index: ec
TH	set of thermal power plants	index: th
PS	set of hydro storages	index: ps
ST	set of other storages	index: st
L	set of transmission lines	index: l
Parameters		
$SRMC_{th}$	short run marginal costs of thermal power plant th	€/MWh
C_{th}^{start}	start-up costs of thermal power plant th	€
C^{hy}	generation costs of Run-of-River plants	€/MWh
C^{wind}	generation costs of wind turbines	€/MWh
C^{pv}	generation costs of PV systems	€/MWh
C^{ps}	generation costs of turbine operating hydro storages	€/MWh
VoLL	Value of lost load	€/MWh
D_{bg}	electrical demand without the EC residual demand in balancing group bg	MWh
D_h	electrical demand of household h	MWh
D^{2030NT}	electrical demand of the ENTSOE 2030 National Trends scenario	MWh
Γ_{bg}	Number of energy communities per balancing group bg	1
CAP_{th}^{max}	maximal power output of thermal power plant th	MW
CAP_{th}^{min}	minimal power output of thermal power plant th	MW
CAP^{pv}	installed power of photovoltaic devices	MW
$GenProfile^{pv}$	normalised generation profile of photovoltaic devices	(0;1)
P^{hy}	generation of Run-of-River plants	MWh
P^{wind}	generation of wind turbines	MWh
P^{pv}	generation of photovoltaic devices	MWh

$StorL_{ps}^{techn.min}$	minimal technical capacity of hydro storage ps	MWh
$StorL_{ps}^{techn.max}$	maximal technical capacity of hydro storage ps	MWh
$StorL_{ps}^{annualpattern}$	exogenous charging set-value of annual patterns of hydro storage ps	MWh
$CAP_{l}^{B\rightarrow A}$	power flow limitation of line l	MW
$CAP_{l}^{A\rightarrow B}$	power flow limitation of line l	MW
A	incidence matrix: balancing groups that are connected	-1;0;1
PTDF	power transfer distribution factor matrix	factor
Decision variables		
p_{th}	power generation of thermal power plant th	MWh
str_{th}	start-up of thermal power plant th	(0;1)
$spill^{hy}$	curtailment of Run-of-River plants	MWh
$spill^{wind}$	curtailment of wind turbines	MWh
$spill^{pv}$	curtailment of photovoltaic devices	MWh
nse	not supplied energy	MWh
p_{ps}^{tu}	turbine operation of hydro storage ps	MWh
p_{ps}^{pu}	pump operation of hydro storage ps	MWh
p_{st}^{out}	discharging of storage st	MWh
p_{st}^{in}	charging of storage st	MWh
x_{th}	start-up linearisation auxiliary variables of thermal power plant th	(0;1)
y_{th}	start-up linearisation auxiliary variables of thermal power plant th	(0;1)
z_{th}	start-up linearisation auxiliary variables of thermal power plant th	(0;1)
$storL_{ps}$	charging status of hydro storage st	MWh
$exch_{bg}$	power exchange over power lines between balancing group bg and all other connected balancing groups	MWh
$flow_{l}$	power flow over power line l	MWh
Energy Community - Parameters		
$P_{h}^{feed-in}$	Feed-in tariff of household h	€/MWh
$T^{ext.}$	external grid tariff	€/MWh
$F^{ext.}$	external fees	€/MWh
$T^{int.}$	internal grid tariff	€/MWh
$F^{int.}$	internal fees	€/MWh
Energy Community - Decision variables		
$p_{h}^{market_{buy}}$	procurement from the energy market	MWh

$p^{market_{sell}}$	PV energy sell to the energy market	MWh
$p^{EC_{buy}}$	procurement from other households within the same energy community	MWh
$p^{EC_{sell}}$	sale to other households within the same energy community	MWh
p^{out}	discharging of the battery storage	MWh
p^{in}	charging of the battery storage	MWh
$\beta^{buy}_{t,h}$	binary variable to avoid simultaneous feed-in and procurement	(0,1)
Model interaction variables		
P^{DA}	day-ahead market price	€/MWh
$D^{resid.}$	residual demand of one energy community	MWh

Table 1: Used parameters and decision variables

3. Model formulation

In order to analyse the influence and interactions between the electricity market and ECs, two models are combined (see figure 1). In the electricity market model, the total electricity generation costs for one year are minimised. After the optimisation is finished, the spot market price gets derived from the power plant dispatch via the dual variable of load coverage in each node. This price is thus determined by the level of demand and by the most expensive power plant used. It can be even negative if generation (especially Renewables) is higher than the actual demand. The spot market price, calculated as an hourly time series, serves as input for optimising the ECs. These, in turn, adjust their procurement from the energy market to the market prices. They prefer to buy energy when prices are lowest and cover the demand of the energy communities when electricity prices are high by using their storage facilities. So that changes the residual demand, i.e. the procurement or feed-in of the energy community to the market. This, in turn, influences the previously determined electricity prices. Therefore, the two models are iteratively optimised to show the influence of the elastic demand of the ECs.

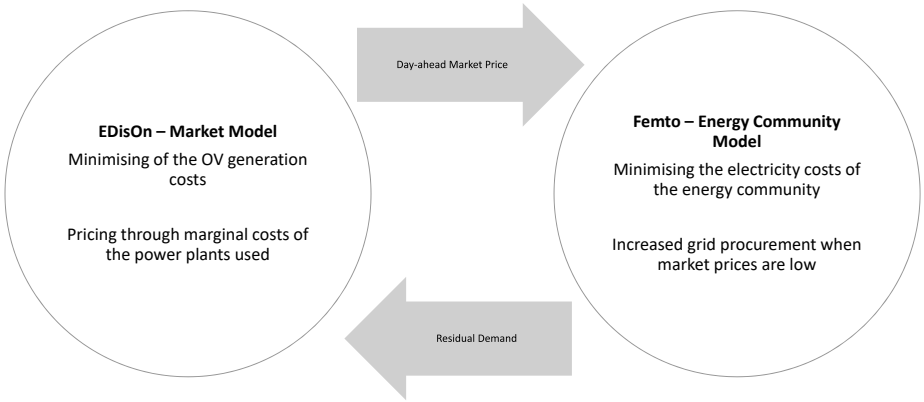

Figure 1: Dependence between the two models

The general demand $D_{t,bg}$, used within the market model, is calculated by using the ENTSOE 2030 National Trends scenario Demand $D_{t,bg}^{2030NT}$ and the demand profile of each household $D_{t,h}$ and the number of ECs per node Γ_{bg}.

$$D_{t,bg} = D_{t,bg}^{2030NT} - \Gamma_{bg} \cdot \sum_{h \in H_{ec}} D_{t,h} \tag{1}$$
$$\forall t \in T, \forall bg \in BG$$

3.1. Market Model - EDisOn

In the dispatch step, the electricity generation costs of the entire system are minimised (maximisation of social welfare), i.e. the use of thermal power plants, renewable energies and the use of storages are optimised in a rolling horizon optimisation with 365, day-ahead steps.

Figure 2 shows the nodes and transmission grid of the market-based dispatch process. The transmission lines between the nodes are thermal limited by their net transfer capacity (NTC), and the load flow over these lines is calculated using a direct current (DC) approximation.

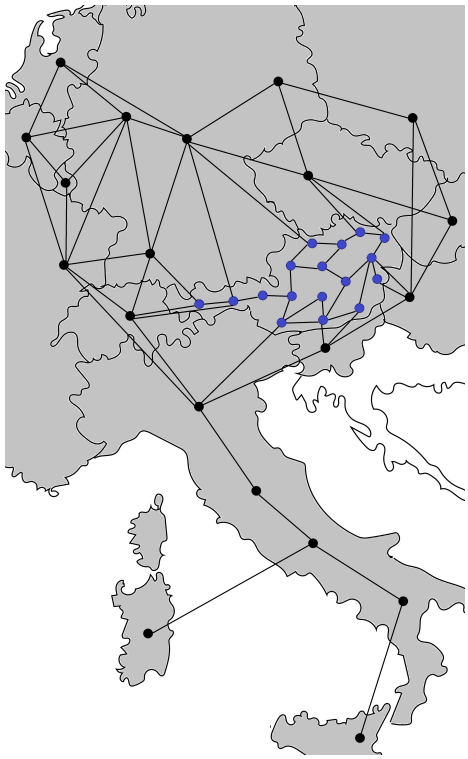

Figure 2: Nodes and transmission lines within the market-based cost minimisation

3.1.1. Objective function

The objective (2) minimises the overall electricity generation costs, that results from the usage of thermal power plants (3), renewable energies (4), pumped hydro storages (5) and costs for energy demand that will not be compensated (6).

$$\min_{C_{th},C_{RES},C_{Storage},C_{NSE}} C_{th} + C_{RES} + C_{Storage} + C_{NSE} \tag{2}$$

$$C_{th} = \sum_{t \in T} \sum_{th \in TH} \left(p_{t,th} \cdot SRMC_{th} + str_{th} \cdot C_{th}^{start} \right) \tag{3}$$

$$\begin{aligned} C_{RES} = & \sum_{t \in T} \sum_{ca \in CA} \sum_{bg \in BG} \left(P_{t,bg}^{hy} - spill_{t,bg}^{hy} \right) \cdot C^{hy} \\ & + \sum_{t \in T} \sum_{ca \in CA} \sum_{bg \in BG} \left(P_{t,bg}^{wind} - spill_{t,bg}^{wind} \right) \cdot C^{wind} \\ & + \sum_{t \in T} \sum_{ca \in CA} \sum_{bg \in BG} \left(P_{t,bg}^{pv} - spill_{t,bg}^{pv} \right) \cdot C^{pv} \end{aligned} \tag{4}$$

$$C_{Storage} = \sum_{t \in T} \sum_{ps \in PS} p_{t,ps}^{tu} \cdot C^{ps} \tag{5}$$

$$C_{NSE} = \sum_{t \in T} \sum_{ca \in CA} \sum_{bg \in BG} nse_{t,bg} \cdot VoLL \tag{6}$$

The costs of thermal power plants are made up of two cost components. On the one hand, costs proportional to their generated power via the SRMC and, on the other hand, costs for the start-up of these power plants. These are paid when a power plant starts to operate but was not in operation in the previous time step. Renewable energy generation and the turbine mode of pumped hydro storages are associated with operating and maintenance costs. Not supplied energy, demand that is not compensated, is penalised with a 10000 €/MWh fee.

3.1.2. Constraints

The energy demand has to be compensated in every balancing group (BG) for each timestamp (7). The decision variables to meet the demand are thermal power plant generation, renewable energy source electricity (RES-E) curtailment, storage usage, power exchanges to other nodes, and not supplied energy. The additional residual demand of ECs is implemented according to (1), as a demand profile that is calculated within the EC model in section 3.2.

The dual variable of this constraint gives the day-ahead (DA) price as an hourly profile, which gets used within the local optimisation of the ECs.

The demand at each node (equivalent to a BG in Austria) consists of two parts, the constant general demand $D_{t,bg}$ and the residual demand of the EC optimisation $D_t^{resid.}$. Within the first iteration, this residual demand corresponds to the sum of the demand of all households within the EC (1).

$$
\begin{aligned}
D_{t,bg} + \Gamma_{bg} \cdot D_t^{resid.} = & \sum_{th \in TH_{bg}} p_{t,th} + \sum_{ps \in PS_{BG}} (p_{t,ps}^{tu} - p_{t,ps}^{pu}) \\
& + \sum_{st \in ST_{BG}} (p_{t,st}^{out} - p_{t,st}^{in}) \\
& + P_{t,bg}^{hy} - spill_{t,bg}^{hy} + p_{t,bg}^{wind} - spill_{t,bg}^{wind} \\
& + P_{t,bg}^{pv} - spill_{t,bg}^{pv} - exch_{t,bg} + nse_{t,bg} \\
& : P_{t,bg}^{DA} \qquad \forall t \in T, \forall bg \in BG
\end{aligned} \tag{7}
$$

To consider the start-up costs of thermal power plants in the objective (2) thermal power plants are implemented in a linearised manner [14]. Furthermore the equations 8 - 11 limit the power plants' minimal and maximal technical capacity.

$$
p_{t,th} = x_{t,th} \cdot CAP_{th}^{min} + y_{t,th} \cdot (CAP_{th}^{max} - CAP_{th}^{min}) \tag{8}
$$

$$
x_{t,th} - y_{t-1,th} \leq str_{t,th} \leq 1 \tag{9}
$$

$$
y + z \leq x \leq 1 \tag{10}
$$

$$
x > 0, y > 0, z > 0, str > 0 \tag{11}
$$

$$
\forall t \in T > 1, \forall th \in TH
$$

The power generation of the renewable energies (e.g. equation 12 for PV systems) gets calculated by a yearly profile with a one-hour temporal resolution and their installed capacity at each node. The same generation profile is used on a local level for the optimisation of the ECs.

$$
P_{t,bg}^{pv} = CAP_{bg}^{pv} \cdot GenProfile_{t,bg}^{pv} \tag{12}
$$

$$
0 \leq spill_{t,bg}^{wind} \leq P_{t,bg}^{pv} \tag{13}
$$

$$
\forall t \in T, \forall bg \in BG
$$

The storage level of all types of storages has to be on the one hand between the technical minimum and maximum charging capacity (14). Pumped hydro storages, are additionally limited by an annual pattern (15). This constraint ensures that even while using a rolling horizon DA optimisation with 24 hour time frames each, the storages operate in a realistic operating behaviour. Thus, the storage charge follows an annual pattern that makes the most economic sense from the operator's point of view.

$$
StorL_{ps\ \&\ st}^{techn.min} \leq storL_{t,ps\ \&\ st} \leq StorL_{ps\ \&\ st}^{techn.max} \tag{14}
$$

$$
StorL_{t,ps}^{annualpattern} \cdot 0.75 \leq storL_{t,ps} \leq StorL_{t,ps}^{annualpattern} \cdot 1.25 \tag{15}
$$

$$
\forall t \in T, \forall ps \in PS, \forall st \in ST
$$

The power exchange (16 and 17) between the nodes is calculated by using a power transfer distribution factor (PTDF) matrix. This method presupposes that the voltage angle between neighbour nodes is small so that a DC approximation of the power flow can be used [15]. Matrix A is an incidence matrix, which describes which transmission line connects which balancing groups/nodes.

$$exch_{t,bg} = \sum_{l \in L} A_{l,bg} \cdot flow_{t,l} \tag{16}$$

$$flow_{t,l_{AC}} = \sum_{bg \in BG} PTDF_{l_{AC},bg} \cdot exch_{t,bg} \tag{17}$$

$$\forall t \in T, \forall bg \in BG, \forall l \in L$$

Transmission lines are limited by equation 18 and 19 using their NTC.

$$-CAP_l^{B \to A} \leq flow_{t,l} \leq CAP_l^{A \to B} \tag{18}$$

$$-CAP_l^{B \to A} \leq flow_{t,l} \leq CAP_l^{A \to B} \tag{19}$$

$$\forall t \in T, \forall l \in L \tag{20}$$

This is only an excerpt of the constraints used, the other ones regarding the usage of thermal power plants, storages, renewable energies and power exchange are described in detail in [12].

3.2. Energy Community Model - Femto

3.2.1. Objective function

The EC model minimises the operating costs of one EC for one year (21). Therefore the DA price, that the market model calculated, internal and external grid tariffs and fees are used as exogen parameters. At the moment, these grid tariffs only consist of an energy component, but the possibility to use power components is already implemented. For each household, it is possible to sell and buy energy within the EC, sell PV generated energy on the energy market at a constant feed-in price, or buy energy from the energy market at variable prices.

$$\min_{C_{market}, C_{grid_{ext.}}, C_{grid_{int.}}, C_{EC}} C_{market} + C_{grid_{ext.}} + C_{grid_{int.}} + C_{EC} \tag{21}$$

Energy procurement from the energy markets leads to energy costs according to the market price, while the feed-in of PV generated energy leads to a refund based on the constant feed-in tariff (22). Additionally for energy procurement from the market grid tariffs and fees proportional to the amount of energy are paid (23), while internal procurement results in lower grid tariffs and fees (24). In the case of internal trading between two households in an EC, the economic advantage that arises is divided fairly between both participants. This consists

of two components (25). The economic advantage of the energy costs is the difference between the DA price and the feed-in tariff, therefore their average value is the traded electricity price. The tariff savings between external and internal trading, are shared equally between both EC participants.

$$C_{market} = \sum_{t \in T} \sum_{h \in H} P^{DA} \cdot p_{t,h}^{market_{buy}} - P_{t,h}^{feed-in} \cdot p_{t,h}^{market_{sell}} \tag{22}$$

$$C_{grid_{ext.}} = \sum_{t \in T} \sum_{h \in H} \left(T^{ext.} + F^{ext.}\right) \cdot p_{t,h}^{market_{buy}} \tag{23}$$

$$C_{grid_{int.}} = \sum_{t \in T} \sum_{h \in H} \left(T^{int.} + F^{int.}\right) \cdot p_{t,h}^{EC_{buy}} \tag{24}$$

$$C_{EC} = \sum_{t \in T} \sum_{h \in H} \left(\frac{P^{DA} + P^{Feed-in}}{2} + \frac{T^{ext.} - T^{int.}}{2} \right) \cdot p_{t,h}^{EC_{buy}} \tag{25}$$

3.2.2. Constraints

The Demand of each household is compensated by local PV production, storage usage if available, energy procurement or sale from/to other households within the EC or the energy market.

$$D_{t,h} = P_{t,h}^{pv} + p_{t,h}^{out} - p_{t,h}^{in} + p_{t,h}^{market_{buy}} - p_{t,h}^{market_{sell}} + p_{t,h}^{EC_{buy}} - p_{t,h}^{EC_{sell}} \tag{26}$$
$$\forall t \in T, \forall h \in H$$

The PV module's generated power is calculated using the same generation profile as in the market model. This ensures that a PV device has the same hourly profile, whether used from a local or on the energy market perspective.

$$P_{t,h}^{pv} = CAP_h^{pv} \cdot GenProfile_t^{pv} \tag{27}$$

$$0 \leq spill_{t,h}^{pv} \leq P_{t,h}^{pv} \tag{28}$$
$$\forall t \in T, \forall h \in H$$

Only PV generated power and power from the battery can be sold within the EC.

$$0 \leq p_{t,h}^{EC_{sell}} \leq P_{t,h}^{pv} + p_{t,h}^{out} - p_{t,h}^{in} \tag{29}$$
$$\forall t \in T, \forall h \in H$$

Only PV generated power can be sold on the energy market.

$$0 \leq p_{t,h}^{market_{sell}} \leq P_{t,h}^{pv} \tag{30}$$
$$\forall t \in T, \forall h \in H$$

It is not allowed to buy energy from the market and sell PV generated energy at the constant feed-in tariff. This is ensured by using a binary variable $\beta_{t,h}^{buy}$.

$$p_{t,ec}^{market_{buy}} <= 10^6 \cdot \beta_{t,ec}^{buy} \tag{31}$$

$$p_{t,ec}^{market_{sell}} <= 10^6 \cdot \left(1 - \beta_{t,ec}^{buy}\right) \tag{32}$$

$$\forall t \in T, \forall ec \in EC$$

3.2.3. Model output

The local optimised EC model Femto interacts with the global optimised energy-market model EDisOn by the residual demand of the optimised EC. This residual demand contains the energy that the EC buys from the energy market and the feed-in of the locally produced energy to the market.

$$\sum_{h \in H} d_t^{resid.} = p_{t,h}^{market_{buy}} - p_{t,h}^{market_{sell}} \tag{33}$$

$$\forall t \in T, \forall h \in H$$

4. Results

4.1. Input data

The expansion of thermal power plants and renewable energies is used according to the National Energy and Climate Plan (NECP) of the individual member states of the European Union. Therefore, the National Trends 2030 scenario of the European Network of Transmission System Operators (ENTSO-E)[1] specifies the available generation technologies and the electricity demand ($D_{t,bg}^{2030NT}$). The costs used are listed in table 2.

CO_2 price	100 €/t
VoLL	10000 €/MWh
Wind/PV O&M costs	0.1 €/MWh
RoR O&M costs	0.01 €/MWh
PHS turbine costs	1 €/MWh

Table 2: Parameters of the market model

Each of the energy communities consists of eight households (dimensions according to [16]), with their individual generated load profiles (generated by the LoadProfileGenerator [17]). Of these, five are equipped with a PV system and three with battery storage (see table 3). The total annual energy consumption per EC is 39.5 kWh, with a PV generation of 26.4 kWh and a storage capacity of 16 kWh. Of these energy communities, 125000 are distributed among the 17 nodes in Austria using a load-based principle (34).

Household	Demand in kWh	Installed PV capacity in kW	Storage capacity in kWh
1	2940	5	-
2	3198	3	3
3	2099	-	-
4	2316	3	-
5	3625	-	-
6	3953	-	-
7	9506	8	8
8	11816	5	5
Total	39453	24	16

Table 3: Households per Energy community and their installed devices

$$\sum_{bg \in BG} \Gamma_{bg} = 125000 \tag{34}$$

[1] https://tyndp.entsoe.eu/maps-data

4.1.1. Scenarios

In order to show the influence of the ECs on the overall system, the market model and the model of the ECs are run iteratively several times in succession. For this purpose, electricity prices are calculated from a market perspective with an installed PV capacity of 9 GW and a battery storage capacity of 2.9 GWh in Austria. The energy communities, in turn, optimise themselves with their own (additional) PV plants (3 GW) and storage (2 GWh). In order to classify the influence of the locally optimised ECs, two additional reference scenarios are considered. Firstly, the business-as-usual "BAU" scenario with 9 GW PV and 2.9 GWh storage. This is the scenario that considers the baseline without the investment incentives of the ECs. Secondly, the "market optimal" scenario optimises the entire generation plants and flexibilities from a market perspective i.e. calculates the globally cost-minimised dispatch. In this scenario in Austria, 12 GW of PV devices and 4.9 GWh of battery storages are used. The iterative solutions of the model coupling (market & EC it. 1-5) will be located between these two solutions with their objective functions.

- "BAU": Business as Usual scenario: market model: 9 GW PV & 2.9 GWh battery storage
- "market optimal": optimum from the market perspective: 12 GW PV & 4.9 GWh battery storage
- "market & EC it. 1-5": Model combination: 9 GW PV & 2.9 GWh battery storage (market perspective), 3 GW PV & 2 GWh battery storage (EC perspective)

4.2. Electricity generation costs

Considering the five iterative scenarios "market & EC it. 1-5" shows no significant differences with multiple iterations. Therefore only the last iteration ("market & EC it. 5") is considered in the evaluations. Compared to the BAU scenario, the additional investments through the use of energy communities reduce total electricity costs by 0.33% from 70.1 to 69.87 billion € per year (see figure 3). While the market optimum, at 69.78 billion €, would result in savings of 0.46%. The lost social welfare gain of 90 million € is offset by savings from the ECs perspective of 50 million €, and the investment incentives.

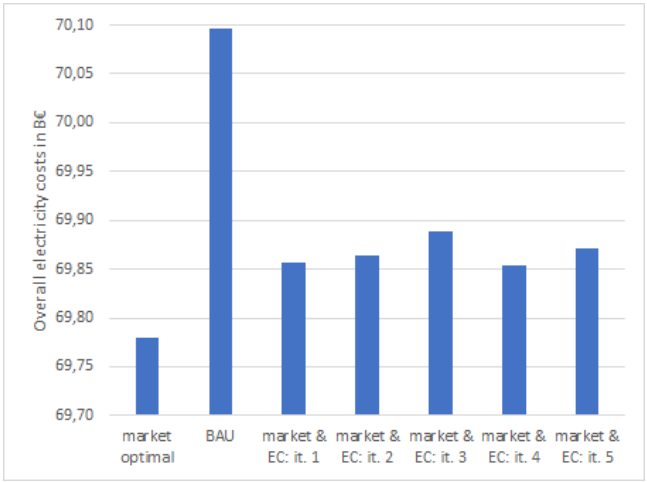

Figure 3: Overall electricity generation costs

Table 4 shows 6.6% costs savings of the eight households without setting up an EC ("Baseline costs") and with an EC ("EC costs"). Whereby there is significant less PV feed-in and less external grid usage. The savings are divided into 267 € for grid tariffs and fees and 128 € for energy costs. These energy costs savings are because of the internal PV self consumption and storage usage.

	Baseline costs in €	EC costs in €
Market Buy	3352	2802
Market Sell	-898	-476
EC Buy	-	707
EC Sell	-	-707
Grid ext.	1850	1533
Grid EC	-	232
Fees	1709	1527
Total	6013	5618

Table 4: Energy costs for one set of households with/without forming an EC

4.3. CO2 emissions

The CO_2 emissions are significantly lower with the usage of energy communities in comparison to the business-as-usual scenario (0.3%), but only a little lower than in the market-optimum scenario (0.32%)(see figure 4).

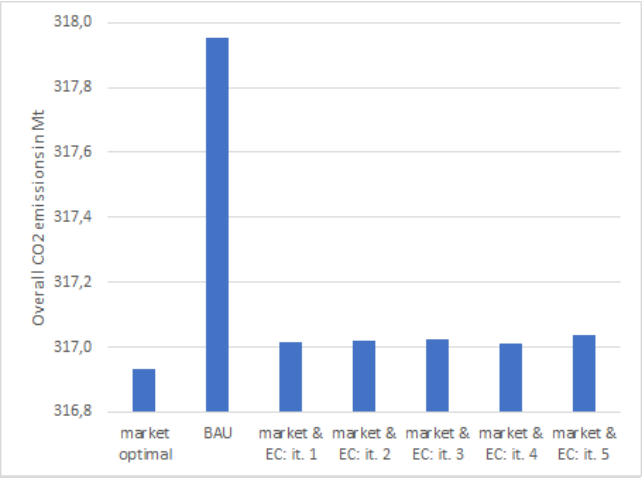

Figure 4: Overall CO2 emissions

On the other hand CO_2 emissions within Austria behave in an opposite way. These are 0.18% lower with ECs than from the optimal market perspective.

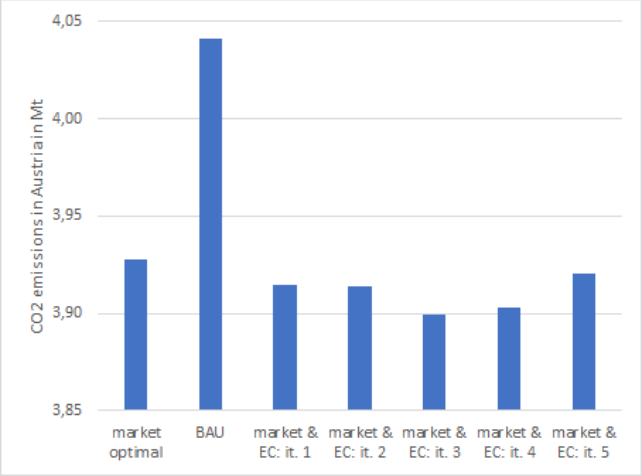

Figure 5: CO2 emissions in Austria

Although the market model's objective function minimises the overall system's costs, the CO_2 price used indirectly reduces the use of power plants with higher emissions. Therefore, oil, coal and lignite are primarily reduced, while gas-fired power plants and biomass cover demand peaks. In the "market optimal" scenario, with the higher flexibility of battery storages, compared to "market & EC it. 5", less lignite is used in the Czech Republic and Germany, and less coal-fired power plants in the Netherlands and Germany. In total, their

use is reduced by 0.13 TWh. Due to the larger capacity of the global optimised battery storages in Austria, the peak demand of the optimised electricity market is increasingly compensated for by the combination of battery storages and gas-fired power plants in Austria. Their use is increased by 0.2 TWh compared to the "market & EC it. 5" scenario. In the case of ECs, these global flexibilities are partly missing, and therefore the use of gas power plants is reduced in Austria during the night (see figure 6), as is the export of energy. Therefore, the use of ECs results in local reduced CO_2 emissions in Austria, while these increase in the overall system.

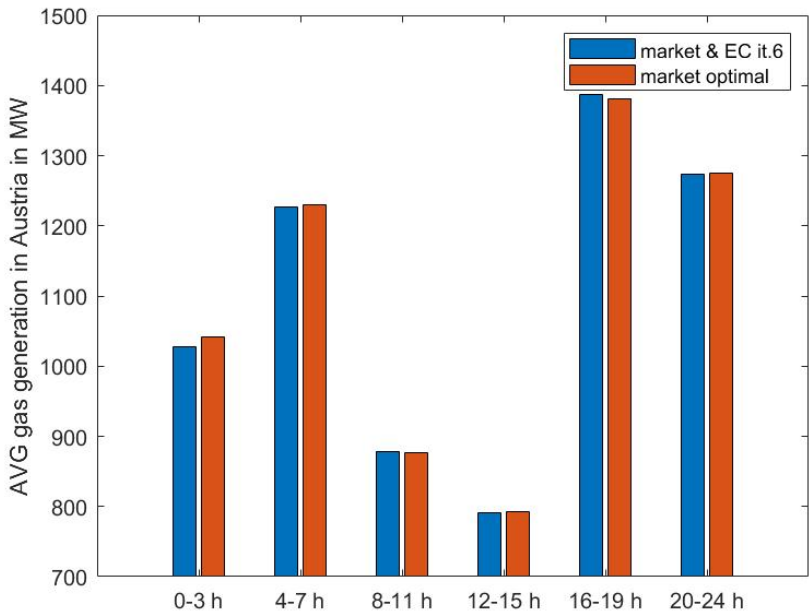

Figure 6: Generation through gas fired power plants in Austria

In Austria, the use of the Energy Community shifts the demand to periods with low electricity prices (especially 8 a.m. - 3 p.m.) and reduces them in return in the evening from 4 - 12 p.m (see figure 7).

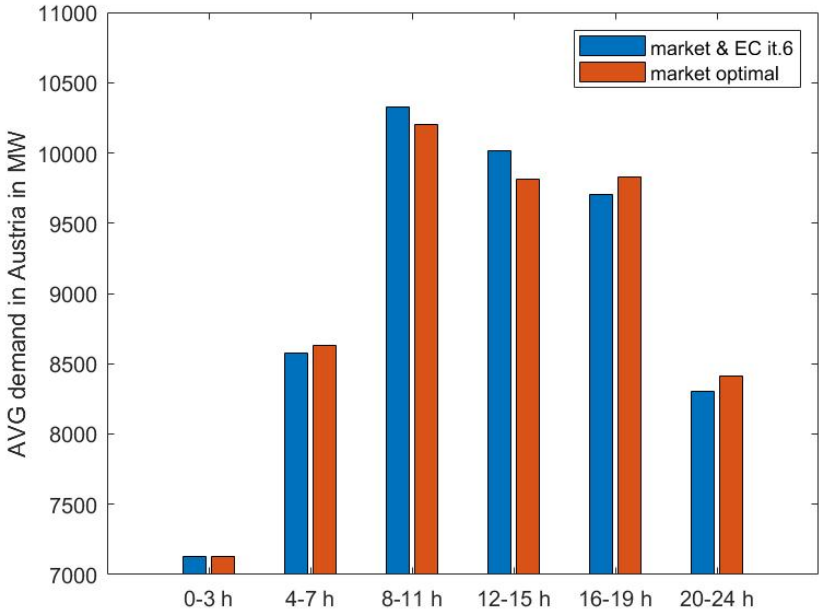

Figure 7: Demand in Austria

5. Conclusion

The results show that the widespread use of ECs leads to a significant reduction in global CO_2 emissions. These savings result from the additional investment incentives into PV systems and battery storages, which are optimised locally. However, if these are operated in an optimised manner from a market perspective, this only leads to a slightly higher emission reduction. In Austria, locally, the emissions with self-optimised ECs are even lower than from the optimal market perspective. This is due to the high degree of expansion of renewables, which means that gas-fired power plants are often only used to cover demand peaks of neighbouring countries. Their coal fired power plants would emit more CO_2 than Austrias gas turbines. The additional investment incentive provided by ECs leads to significant cost savings both from the perspective of the overall system and the perspective of the members of an EC.
Further work should investigate the changed residual demand and utilisation of the transmission grid when they are operated with minimal residual power. Possibilities for this are given by power components of the grid tariffs and a changed objective function. Furthermore, the influence of energy communities on the procurement of balancing energy is to be shown, especially in a comparison between storage operation from the market's point of view and from the point of view of the ECs.

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