Exploring Regulation Policies in Distribution Networks through a Multi-Agent Simulator

Miguel Manuel de Villena*, Raphael Fonteneau*, Axel Gautier†, and Damien Ernst*
*Department of Electrical Engineering and Computer Science, Montefiore Institute, University of Liege
†LCII, Department of Economics, HEC Liege, University of Liege
Email: {mvillena, raphael.fonteneau, agautier, dernst}@uliege.be

***Abstract*—This paper presents a multi-agent simulator that describes the interactions between the agents of a distribution network (DN), and an environment. The agents are the users of the DN and the electricity distribution system operator. The environment is the set of rules (tariff design, technology costs, or incentive schemes) that impacts the agents interactions. For a given environment, we can simulate the evolution of the agents and the environment itself. We assume the electricity consumers are rational agents that may deploy distributed renewable energy installations if they are cost-efficient compared to the retail electricity tariff. The deployment of such installations may alter the cost recovery scheme of the distribution system operator, by inducing a change in the way the user use of the grid. By modelling the cost recovery mechanism of the distribution system operator, the system simulates the evolution of the retail electricity tariff in response to such a change in the aggregated consumption and production.**

I. Introduction

Over the last few decades, proactive policy making has supported a major paradigm shift in the power generation sector, resulting in a progressive energy transition from fossil fuels to renewable energy sources [1]. Such an energy transition is shaping the future of the electricity system: in this context, numerous incentive mechanisms are fostering a notable integration of **d**istributed **r**enewable **e**lectricity (DRE) generation technologies, such as solar photovoltaic panels (PV), into the distribution networks (DN). However, those incentive mechanisms might have been used without the adequate understanding of the underlying problems they may entail: since DN are not engineered to absorb large amounts of distributed electricity generation [2], the inclusion of a vast volume of DRE may cause severe technical problems [3]. Additionally, regulatory problems may appear also as a result of DRE adoption [4]. In our work we focus on the latter, which range from the over-compensation of DRE owners to the potential failure of the cost recovery mechanisms of the distribution system operators (DSO) [5].

This paper aims at presenting a methodology for assessing the potential regulatory problems stemming from a set of regulation rules (including the incentive mechanisms) that stimulates a heavy DRE adoption. Thus, with this methodology we may take any set of regulation rules as inputs, and compute their impact on a DN. Such an impact is measured with two metrics: (i) the evolution of the retail electricity price (simply retail price from now on) over time, and (ii) the evolution of the proportion of DRE-owners and non-DRE owners in the DN over time. The set of rules that drives these evolutions is known as an environment, and consists of three elements, as explained in [6]:

- *tariff design*: this consists of the type of charges applied to the customers for their grid use (e.g. volumetric tariffs, or capacity tariffs);
- *technology costs evolution*: this includes the prices for generation and storage technologies; and
- *incentive mechanism*: this is the combination of technologies and/or support schemes that help DRE become economically competitive, (e.g. a monetary aid awarded to the DRE owners over the lifetime of the DRE).

To simulate the impact of a given environment on a DN, we need to introduce a set of agents who will interact with it, over a finite time horizon. There are three types of agents:

- *DRE owners*: users of the DN that own a DRE installation (also known as prosumers);
- *non-DRE owners*: users of the DN that do not own a DRE installation (also known as consumers); and
- *distribution system operator (DSO)*: operator of the DN.

As a result of the agents interactions with the environment, the DN will evolve in a dynamical system. At every time step of this system, the two mentioned metrics will be computed, enabling the observation of such an evolution.

The methodology presented in this paper is based on a multi-agent discrete-time dynamical system formalisation that models the interactions of a some agents with an environment, and computes the resulting evolution of the DN. From this evolution, we may compare different environments. Our main contributions are:

- We provide a description of our multi-agent discrete-time dynamical system formalisation. Such a formalisation allows us to test different environments, in particular we introduce (i) two tariff designs, and (ii) two incentive mechanisms. This is detailed in Section II.
- We show the simulator functioning by testing different environments. This is presented in Section IV.

II. Methodology

In our multi-agent discrete-time dynamical system, we model the electricity users as rational agents who are —in principle— exposed to retail prices, and that may invest in optimally sized DRE installations, provided that these are cost-efficient compared to the retail price. As a result of users deploying DRE installations, the DSO cost recovery mechanism may be altered, inducing a change in the distribution component of the retail price (distribution tariff from now on) for the subsequent time-step of the dynamical system. These two effects (DRE adoption and distribution tariff evolution), are computed at every time-step of a discrete-time dynamical system in which the interactions of the agents with the environment will drive the evolution of the DN. Thus, in this methodology we: (*A*) start by explaining how the interactions between the agents and the environment occur, (*B*) elaborating then on the different introduced environments, and (*C*) and finalising by providing a description of the agents modelling.

A. Interactions

The interactions between the agents and the environment are computed at every time-step of our dynamical system. These interactions depend on the nature of the agent, namely:

- the DRE owners interact by trading electricity with the DN. These trades occur in the form of imports: DN $\rightarrow$ user, and/or exports: DN $\leftarrow$ user;
- the non-DRE owners interact also by trading electricity with the DN. In this case these trades occur only in the form of imports: DN $\rightarrow$ user.
- the DSO interacts by computing a distribution tariff that allows it to break-even.

Through these interactions, the agents incur costs and collect revenues. The relation between costs and revenues will drive the evolution of the DN. Computing these interactions, at every time-step, involves calculating: (1) the yearly electricity costs of the users, (2) the yearly electricity revenues of the users (if any), and (3) the new distribution tariff determined by the DSO according to its cost recovery mechanism. These calculations depend on the environments, which are defined next.

B. Environments

In the presented multi-agent system, we introduce a number of options to build an environment:
Depending on the *tariff design*:

- *a1* - Volumetric: electricity trades are paid for/collected according to volumes of energy [€/kWh].
- *a2* - Volumetric and capacity: two terms, the first one is volumetric [€/kWh], and the second one is based on a fixed charge per capacity contracted by the user [€/kWp].

Depending on the *technology costs*:

- *b1* - Linearly decreasing trend over time.

Depending on the *incentive mechanism*: in particular we focus on the compensation mechanism. By compensation mechanism we refer to the manner the electricity trades between the users and the DN are recorded [7]. We consider two distinct compensation mechanisms, as described in [5]:

- *c1* - Net-metering (NM): system consisting of one meter that records the imports by running forwards, and the exports by running backwards, this entails that both directions be assigned with the same monetary value, namely the retail tariff. Furthermore, the total exports are upper bounded by the total imports for a determined billing period, per user.
- *c2* - Net-purchasing (NP): system consisting of two separate meters for the imports and the exports respectively, this implies that the imports are paid for at retail tariff, whereas the exports are paid at a selling price.

Constructing an environment necessitates choosing one element per option. Consequently, with these settings we can create four different families of environments:

- *e1 = a1+b1+c1*
- *e2 = a1+b1+c2*
- *e3 = a2+b1+c1*
- *e4 = a2+b1+c2*

Each of these families depends on the retail price, the capacity price, and/or the selling price. Consequently, it is possible to create any number of environments by setting different values of these three prices.

The three calculations introduced in subsection II-A (costs of the users, revenues of the users, and cost recovery mechanism of the DSO) depend on the family of environments. Let $\mathcal{N} = \{1, \ldots, N\}$ denote the set with the time-steps of our discrete-time dynamical system. And let $\mathcal{I} = \{1, \ldots, I\}$ denote the users of the DN.

a) Family of environments e1: the electricity costs of the users are computed according to equation (1). The revenues of the users are $\phi_{i,n} = 0$ for this environment, since under net-metering the produced electricity is not sold to the grid. Finally the DSO computation of the new distribution tariff for the following time-step is computed according to equation (2).

$$\psi_{i,n} = \max\left\{0, \left(\rho_{i,n}^{(-)} - \rho_{i,n}^{(+)}\right) \cdot \Pi_n^{(in)}\right\} \quad \forall i, n \in \mathcal{I} \times \mathcal{N} \quad (1)$$

$$\Pi_n^{(dis)} = \frac{\Omega_n^{(d)} + \Delta_{n-1}^{(d)}}{\widehat{D}_n} \quad \forall n \in \mathcal{N} \quad (2)$$

with $\Delta_{n-1}^{(d)} = \widehat{R}_n^{(d)} - R_n^{(d)}$, where $R_n^{(d)}$ are the actual measured revenues, and $\widehat{R}_n^{(d)}$ are the expected revenues computed (before the period) according to equation (3).

$$\widehat{R}_n^{(d)} = \Pi_n^{(dis)} \cdot \sum_{i=1}^{I} \rho_{i,n}^{(-)} \quad \forall n \in \mathcal{N} \quad (3)$$

b) Family of environments e2: the electricity costs and the revenues of the users are computed according to equations (4) and (5) respectively. The DSO computation of the following distribution tariff is performed as in environment *e1* (see equations (2) and (3)).

$$\psi_{i,n} = \rho_{i,n}^{(-)} \cdot \Pi_n^{(in)} \quad \forall i, n \in \mathcal{I} \times \mathcal{N} \quad (4)$$

$$\phi_{i,n} = \rho_{i,n}^{(+)} \cdot \Pi_n^{(sp)} \quad \forall i, n \in \mathcal{I} \times \mathcal{N} \quad (5)$$

c) Family of environments e3: the electricity costs of the users are computed by means of equation (6). The users revenues are $\phi_{i,n} = 0$ (same rationale as before). The DSO computation of the distribution tariff follows equation (7).

Furthermore, in this case there is a capacity tariff which the DSO may adjust at every time-step (see equation (8)).

$$\psi_{i,n} = \max\left\{0, \left(\rho_{i,n}^{(-)} - \rho_{i,n}^{(+)}\right) \cdot \Pi_n^{(in)}\right\} + \Pi_n^{(cap)} \quad \forall i,n \in \mathcal{I} \times \mathcal{N} \tag{6}$$

$$\Pi_n^{(dis)} = \frac{\Omega_n^{(d)} + \Delta_{n-1}^{(d)}}{\widehat{D}_n} \quad \forall n \in \mathcal{N} \tag{7}$$

$$\Pi_n^{(cap)} = \frac{\Omega_n^{(c)} + \Delta_{n-1}^{(c)}}{\widehat{C}_n} \quad \forall n \in \mathcal{N} \tag{8}$$

with $\Delta_{n-1}^{(c)} = \widehat{R}_n^{(c)} - R_n^{(c)}$ and $\Delta_{n-1}^{(d)} = \widehat{R}_n^{(d)} - R_n^{(d)}$, where $R_n^{(c)}$ and $R_n^{(d)}$ are measured once the period is completed, $\widehat{R}_n^{(c)}$ is determined by means of equation (9), and $\widehat{R}_n^{(d)}$ is computed as in the family of environments *e1* (see equation (3)).

$$\widehat{R}_n^{(c)} = \Pi_n^{(cap)} \cdot I \quad \forall n \in \mathcal{N} \tag{9}$$

d) Family of environments e4: the electricity costs of the users are computed with equation (10). The revenues of the users are computed as in the family of environments *e2* (equation (5)). The distribution tariff is computed as in environment *e3* (see equations (3), (7), (8), and (9)).

$$\psi_{i,n} = \left(\rho_{i,n}^{(-)} \cdot \Pi_n^{(in)}\right) + \Pi_n^{(cap)} \quad \forall i,n \in \mathcal{I} \times \mathcal{N} \tag{10}$$

TABLE I
NOTATION

$\rho_{i,n}^{(-)}$	total imports of user i at period n
$\rho_{i,n}^{(+)}$	total exports of user i at period n
$\psi_{i,n}$	electricity costs of user i at period n
$\phi_{i,n}$	revenues of user i at period n
$\Omega_n^{(d)}$	costs of the DSO (volumetric) at period n
$\Omega_n^{(c)}$	costs of the DSO (capacity) at period n
$\Delta_{n-1}^{(d)}$	imbalance of the DSO (volumetric) of period $n-1$
$\Delta_{n-1}^{(c)}$	imbalance of the DSO (capacity) of period $n-1$
$\widehat{R}_n^{(d)}$	expected revenues of the DSO (volumetric) at period n
$\widehat{R}_n^{(c)}$	expected revenues of the DSO (capacity) at period n
$R_n^{(d)}$	actual revenues of the DSO (volumetric) at period n
$R_n^{(c)}$	actual revenues of the DSO (capacity) at period n
$\widehat{D}_n$	expected demand of the users at period n
$\widehat{C}_n$	expected peak demand of the users at period n
$\Pi_n^{(sp)}$	users selling price at period n
$\Pi_n^{(cap)}$	capacity price at period n
$\Pi_n^{(in)}$	retail price at period n *
$\Pi_n^{(dis)}$	distribution tariff at period n *
λ_n	costs of energy, transmission, and taxes *

* The relation between $\Pi_n^{(in)}$ and $\Pi_n^{(dis)}$ follows this equation: $\Pi_n^{(in)} = \Pi_n^{(dis)} + \lambda_n \quad \forall n \in \mathcal{N}$.

All of the presented equations depend on different parameters: $\rho_{i,n}^{(-)}$, $\rho_{i,n}^{(+)}$, $\Omega_n^{(d)}$, $\Omega_n^{(c)}$, $\widehat{D}_n$, and $\widehat{C}_n$. These parameters are computed when modelling the agents of the system. The other parameters in table I ($\Pi_n^{(sp)}$, and λ_n) are inputs of the model. The rest of table I are variables whose computations have been presented in this section ($\psi_{i,n}$, $\phi_{i,n}$, $\Delta_{n-1}^{(d)}$, $\Delta_{n-1}^{(c)}$, $\widehat{R}_n^{(d)}$, $\widehat{R}_n^{(c)}$, and $\Pi_n^{(in)}$).

C. Agents of the system

Once we have introduced the different environments, and how the interactions with these occur, we can describe how the agents are modelled. In our system we have three types of agents: DRE owners, non-DRE owners, and DSO. The first two are the users of the DN, whereas the third one is the operator of the DN.

1) DRE owners: these users are modelled relying on an optimisation framework instantiated in the form of a linear program (LP). This LP minimises the levelized cost of electricity ($LCOE$) of the DRE installation. The $LCOE$ is the average total cost to deploy and operate a DRE installation, divided by the total energy consumed by the user over the project lifetime. With this LP we can extract, at every time-step, the values of $\rho_{i,n}^{(-)}$ and $\rho_{i,n}^{(+)}$. The LP formalisation is presented in the next section (Section III).

2) non-DRE owners: at the initialisation of the system, we assume zero installed DRE capacity for all the users (i.e. all users are non-DRE owners). Then at every time-step, the system updates the proportion of users who have deployed a DRE installation. Thus, we define two groups of non-DRE owners: *group A*: denoting the users who may deploy a DRE installation, and *group B*: comprising the users who cannot invest in a DRE installation due to technical or economic constraints. We model these two groups differently:

a) group A: we resort to the same LP we use to model the DRE owners. However, in this case we use it to extract the $LCOE$ of the potential DRE installation a user of this group could deploy. By comparing this $LCOE$ with the retail price, a gradient-like driver is created: if the $LCOE$ is lower than the retail price, the user will have a probability $p > 0$ of actually deploying the DRE installation that leads to such an $LCOE$. Once a user from group A deploys a DRE installation, it is modelled as a DRE owner until the end of the simulation. If a user *group A* does not deploy a DRE installation at a particular time-step, it is modelled in the same fashion as *group B* users, for this particular time-step. However, at the subsequent time-steps, this user will have a new opportunity of deploying a DRE installation.

b) group B: we compute the yearly electricity demand of every user, which is covered entirely by the DN.

3) DSO: the last of the agents is modelled by computing, at every time-step, its cost recovery mechanism, as introduced previously. Then, the DSO will calculate a new distribution tariff for the subsequent time-step that allows it to break-even. To compute this cost recovery mechanism, the following parameters are required: $\Omega_n^{(d)}$, $\Omega_n^{(c)}$, $\widehat{D}_n$, and $\widehat{C}_n$.

$\Omega_n^{(d)}$: costs of the DSO related with the volume of energy distributed to the users of the grid. At the initialisation of the system, we assume a balanced system where the costs of the DSO are fully recovered by its revenue. Thus, we assume the initial costs equal to the initial revenues (aggregated demand of all users times the distribution tariff). At every time step the revenues may decrease due to the DRE deployment. Hence, we measure the total actual revenues of the DSO ($R_n^{(d)}$). Assuming

that the cost recovery mechanism recovers all the previous economic imbalances, we use these revenues as costs of the DSO for the subsequent time-step ($R^{(d)}_{n-1} = \Omega^{(d)}_n$).

$\Omega^{(c)}_n$*:* costs of the DSO related with the capacity required by the users of the grid. Similarly to the previous case, we assume a balanced initial state where the costs of the DSO are fully recovered by its revenue. Thus, we assume the initial costs equal to the initial revenues (aggregated capacity fees of the users). At every time step, the DRE deployment may cause the fees to vary, altering the actual revenues from capacity fees ($R^{(c)}_n$). These revenues are used as DSO costs for the subsequent time-step ($R^{(c)}_{n-1} = \Omega^{(c)}_n$).

$\widehat{D}_n$*:* expected volume of energy distributed at every time-step. It is computed before the initialisation of the period, and corresponds to the last observed aggregated demand (D_{n-1}) of the users, thus $D_{n-1} = \widehat{D}_n$. Hence, this does not take into account the DRE installations that may have been deployed from $n-1$ to n.

$\widehat{C}_n$*:* expected aggregated peak demand of the users at every time-step. As in the previous case, it is computed before the initialisation of the period, and corresponds to the last observed aggregated peak demand (C_{n-1}) of the users, thus $C_{n-1} = \widehat{C}_n$. The DRE installations potentially deployed at the previous period are not taken into account.

III. LP Formalisation

In this section we formalise the optimisation framework in the form of an LP, used to model the DRE owners and the *group A* of the non-DRE owners. On the one hand, the DRE owners are modelled to compute their electricity trades, which were introduced in the previous section as imports and exports. On the other hand, the non-DRE owners of *group A* are modelled to determine their minimised $LCOE$, obtained for an optimally sized DRE installation.

The optimisation horizon is set to $Y \in \mathbb{N}$ years which are divided into 8760 time-steps ($Y \times 8760$). Let $\mathcal{T} = \{0, \ldots, T-1\}$, with $T = 8760$, represent a time discretisation of one year (in hours). Moreover let $\mathcal{Y} = \{0, \ldots, Y-1\}$, represent the years of the optimisation. All of the parameters and variables presented in this section depend on $\mathcal{N}$. Furthermore, this LP runs for every individual user in set $\mathcal{I}$.

Let χ represent the investment costs as a linear function of technology prices and sizing configuration. These costs are computed according to the following equation:

$$\chi = p \cdot P^{(pv)} + \frac{Y}{B} \cdot b \cdot P^{(bat)} \tag{11}$$

where p represents the optimal PV size in kWp, b is the optimal battery size in kWh, $P^{(pv)}$ and $P^{(bat)}$ are the technology prices (PV and battery respectively), and B is lifetime of the battery.

The yearly costs of operation are represented by ξ_y, and computed by means of the following equation.

$$\xi_y = \mu_y + m_y + \zeta_y \quad \forall y \in \mathcal{Y} \tag{12}$$

where μ_y are the yearly electricity costs, m_y represents the yearly costs of operation and maintenance, and ζ_y stands for the recovered costs. The electricity costs depend on the family of environments: for family *e1* we use equation (13), for *e2* we use equation (14), for *e3* we use equation (15), and for the family of environments *e4* we make use of equation (16):

$$\mu_y = \max\left\{0, \sum_{t=0}^{T-1} \left(\rho_t^{(-)} - \rho_t^{(+)}\right) \cdot \Pi^{(in)}\right\} \quad \forall y \in \mathcal{Y} \tag{13}$$

$$\mu_y = \sum_{t=0}^{T-1} \rho_t^{(-)} \cdot \Pi^{(in)} \quad \forall y \in \mathcal{Y} \tag{14}$$

$$\mu_y = \max\left\{0, \sum_{t=0}^{T-1} \left(\rho_t^{(-)} - \rho_t^{(+)}\right) \cdot \Pi^{(in)}\right\} + \Pi^{(cap)} \quad \forall y \in \mathcal{Y} \tag{15}$$

$$\mu_y = \left(\sum_{t=0}^{T-1} \rho_t^{(-)} \cdot \Pi^{(in)}\right) + \Pi^{(cap)} \quad \forall y \in \mathcal{Y} \tag{16}$$

where $\rho_t^{(-)}$ are the hourly imports, and $\rho_t^{(+)}$ represents the hourly exports. $\Pi^{(in)}$ and $\Pi^{(cap)}$ are the retail and the capacity price. These prices are fixed across the entire LP horizon, and correspond to the n^{th} prices determined by the discrete-time dynamical system. The operation and maintenance costs m_y are computed according to equation (17) [8].

$$m_y = \frac{1}{200} \cdot p + \frac{1}{100} \cdot b \quad \forall y \in \mathcal{Y} \tag{17}$$

Finally, the recovered costs are also environment dependent. In light of this, families of environments *e1* and *e3* have $\zeta_y = 0$, whereas for families *e2* and *e4* we use equation (18).

$$\zeta_y = -\left(\sum_{t=1}^{T} \rho_t^{(+)} \cdot \Pi^{(sp)}\right) \quad \forall y \in \mathcal{Y} \tag{18}$$

The energy balance of the system depends on the imports $\rho_t^{(-)}$, exports $\rho_t^{(+)}$, the electricity produced by the PV array k_t, the hourly demand $U_t^{(d)}$, the maximum hourly production $U_t^{(p)}$, the energy flow into the battery $j_t^{(-)}$, the energy flow out of the battery $j_t^{(+)}$, the efficiency of charge η^c and discharge η^d the batteries, and the depth of discharge of the batteries dod. The energy flows into and out of the battery also depend on the variation of the state of charge (soc) between $t-1$ and t. Thus, the following equations control the energy balance, taking into account the state of charge of the batteries:

$$\rho_t^{(+)} - \rho_t^{(-)} = k_t - U_t^{(d)} - j_t^{(-)} + j_t^{(+)} \quad \forall t \in \mathcal{T}, \tag{19}$$

with:

$$k_t = p \cdot U_t^{(p)} \quad \forall t \in \mathcal{T} \tag{20}$$

$$j_t^{(-)} \leq b \cdot F^{(-)} \quad \forall t \in \mathcal{T} \tag{21}$$

$$j_t^{(+)} \leq b \cdot F^{(+)} \quad \forall t \in \mathcal{T} \tag{22}$$

$$b \cdot dod \leq soc_t \leq b \quad \forall t \in \mathcal{T} \tag{23}$$

$$soc_t = \begin{cases} soc_{t-1} - \dfrac{j_t^{(+)}}{\eta^{(d)}} + j_t^{(-)} \cdot \eta^{(c)} & \forall t \in \mathcal{T} \setminus \{0\} \\ soc_0 \in [b \cdot dod, b] \text{ for } t = 0 \end{cases} \tag{24}$$

Finally, let $LCOE$ denote the general objective function that represents the levelized cost of electricity. This objective function is minimised in this optimisation.

$$LCOE = \frac{i_0 + \sum_{y=0}^{Y-1} \dfrac{\xi_y}{(1+r)^y}}{\sum_{y=0}^{Y-1} \dfrac{d_y}{(1+r)^y}} \tag{25}$$

where the yearly demand of the system is defined as $d_y = \sum_{t=0}^{T-1} U_t^{(d)}$, and r represents the discount rate.

IV. Test case

To illustrate our multi-agent discrete-time dynamical system, an example is presented. In this example, we simulate one environment of each family of environments. Thus, we create four environments, according to the four described families:

- Env. A: corresponds to the family of environments *e1*. We propose a volumetric tariff with a compensation mechanism consisting of net-metering. In this case, the distribution tariff is initially set to $\Pi_0^{(dis)} = 0.09$ €/kWh.
- Env. B: corresponds to the family of environments *e2*. This case is based on a volumetric tariff with a compensation mechanism consisting of net-purchasing. As in the previous case, the distribution tariff is initially set to $\Pi_0^{(dis)} = 0.09$ €/kWh. The selling price is fixed to $\Pi_n^{(sp)} = 0.08$ €/kWh (constant over the simulation).
- Env. C: corresponds to the family of environments *e3*. We create this case with a distribution tariff with two components: volume and capacity. The first component represented with a volumetric fee conveyed to the users by means a distribution tariff which is initially set to $\Pi_0^{(dis)} = 0.045$ €/kWh. The second component is a capacity fee, set initially to $\Pi_0^{(cap)} = 223$ € for installations up to 10 kWp, this term will not evolve in our simulation, since we do not let the users adjust their peak demand.
- Env. D: corresponds to the family of environments *e4*. As in the previous case, there are two terms. The capacity term is the same as case C ($\Pi_0^{(cap)} = 223$ € for installations up to 10 kWp which cannot evolve in our simulations). The distribution tariff term is initially set to $\Pi_0^{(dis)} = 0.045$ €/kWh. Furthermore, the selling price is fixed to $\Pi_n^{(sp)} = 0.08$ €/kWh.

The value of λ_n is fixed to 0.13 €/kWh for all cases. The technology costs are initially set to $P^{(pv)} = 1500$ €/kWp and $P^{(bat)} = 300$ €/kWh; they are assumed to evenly decrease at every period n by 0.07%. The optimisation horizon Y is set to 20 years. The efficiencies are set fixed to $\eta^{(c)} = 0.95$ and $\eta^{(d)} = 0.95$. Finally the dod is fixed to 10%.

At the initialisation of the system, all the users are non-DRE owners. Hence, to represent every agent in the proposed multi-agent tool, the model includes two groups of medium size residential users (peak demand of around 3 kW). *Group A*: modelling the heterogeneity of DN users involves the representation of every user as an individual agent. To introduce them in the simulation, the multi-agent model necessitates their electricity demand profile and their production profile. In the analysed test case, we create different synthetic demand profiles with the help of the CREST model [9]. As for the production profile, we count on real PV measurements expressed in kW/kWp. *Group B*: the remaining customers of the DN must be modelled only in terms of net energy off-take.

At every time-step of the multi-agent system simulation, we keep track of the deployed DRE units, as well as of the distribution tariff adjustment. Thus, we can determine the evolution of the deployed capacities of PV and battery. Moreover, it is possible to compute the evolution of the distribution tariff for each case. Two figures depict the two metrics considered: the evolution of DRE deployment and optimal size: Figure 1; and the evolution of the distribution tariff: Figure 2, for the four distinct environments.

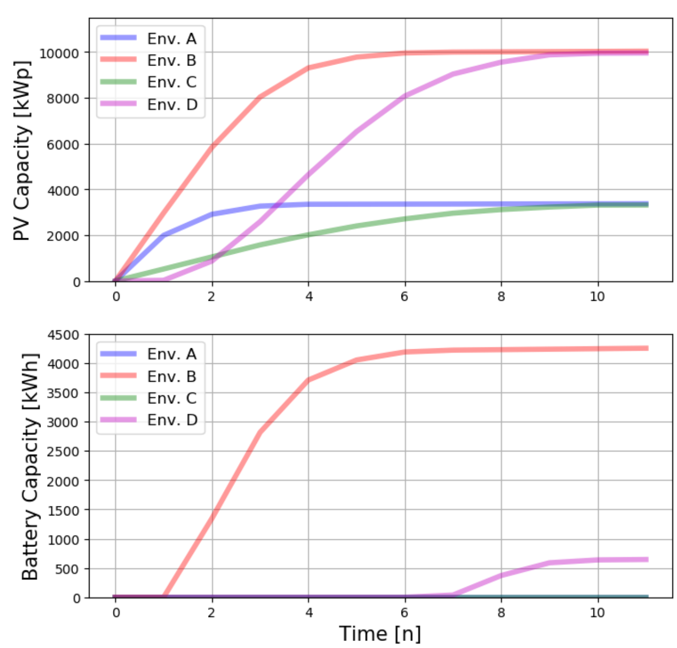

Fig. 1. Cumulative PV and battery capacities of the deployed DRE, over the presented discrete-time dynamical system. The economically optimal size of the deployed DRE installations is influenced in a large extent by the environment. In this figure, we observe these different users behaviours under four distinct environments.

Regarding the size of the installations, we observe two different behaviours of the four environments:

- A and C do not deploy batteries, these two environments

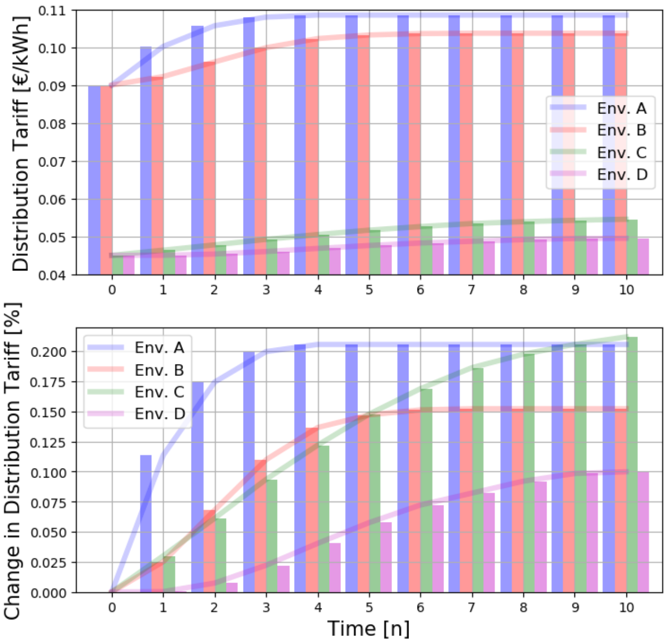

Fig. 2. Evolution of the distribution tariff. The deployment of DRE units induces an increase in the distribution tariff. Such an increase features a different extent depending on the environment.

rely on NM as incentive mechanism, therefore not deploying batteries since, with this system, batteries and imports are perfect substitutes. Since there is no incentive to sell electricity (see equations (13) and (15)), the PV capacity is adjusted to simply cover their peak demand.

- B and D deploy some batteries to become more self-sufficient, reducing the imports. PV deployment results 2.5 times larger than in the other two environments, since there exists an incentive to sell electricity (see equations (14) and (16)). The difference between B and D lies in the fixed capacity term, which makes difficult the recovery of the installation costs for case D.

Regarding the distribution tariff, the upper sub-figure in Figure 2 indicates that introducing a capacity term (Env. C and D) will considerably reduce the effect of an increasing distribution tariff, induced by the DRE deployment. However, when inspecting the lower sub-figure in Figure 2 (change in distribution tariff relative to the initial state), we can observe that the increase in the distribution tariff occurs predominantly in those environments with NM as incentive mechanism (Env. A and C), demonstrating the unfitness of this compensation mechanism to cope with DRE deployment.

V. Conclusion

This paper has presented a multi-agent simulator to describe the interaction between distribution networks and consumers, for any regulatory technical environment. In this system, electricity consumers interacting with a single distribution network are modelled as rational agents that may invest in optimised distributed renewable energy installations. The distribution tariff is adapted according to cost recovery mechanism of the DSO (must break-even), that depends on the distributed renewable energy that is produced and consumed in the distribution network.

To illustrate the performance of the multi-agent system, we have designed and simulated four different examples based on the four families of environments introduced in this paper. The simulator allows to illustrate the impact of the regulation policies on many aspects: (i) the evolution of the electricity distribution tariff; (ii) the evolution of DRE deployment; and (iii) the optimised configurations of distributed renewable energy installations (production and storage capacities).

Preliminary results show a more volatile distribution tariff when net-metering is chosen as incentive mechanism, as a result of the deployment of distributed renewable energy units. This remains true also when a capacity term is added to the distribution costs. These results can be further explored in a future work, by scaling up the simulator introducing a larger user diversity.

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