A Grid Cost Recovery Bilevel Model with Centralized and After-the-Meter Distributed Electricity Generation

Salvador Doménech Martínez[1], Fco. Alberto Campos Fernández[1], José Villar Collado[2], Michel Rivier Abad[1]
[1] Instituto de Investigación Tecnológica, Escuela Técnica Superior de Ingeniería ICAI, Universidad Pontificia de Comillas
Santa Cruz de Marcenado, 26 – 28015, Madrid, Spain.
[2] INESCTEC, Campus da FEUP, Dr Roberto Frias, 4200-465 Porto, Portugal
Contact email: sdomenech@iit.comillas.edu

***Abstract*—Under the expected decarbonization of the power system (where high voltage network use is diminished due to the expected increase of self-satisfied DG), the economical sustainability of the electrical grid activities might put at risk without increasing the electricity tariffs. New models are therefore necessary to properly address and study the design of these tariffs under this zero-emission scenario. In this paper a mathematical bilevel model is proposed to achieve this aim. While the objective of the upper level is to obtain the long-term evolution of the tariffs needed to sustain the grid activities, the second level focuses on the representation of the electricity generation activity. In particular, in the lower level a generation expansion problem is formulated by means of the maximization of the traditional GENCOs' profits and the minimization of the DG' costs, both simultaneously and in the sense of Nash, taking into account the energy and reserve commodities, the network tariffs of DG customers and the classical UC constraints. Since the proposed model is a non-convex bilevel mathematical problem that has been applied to a realistic large scale power system, the resolution methodology is based on a sensible heuristic. It uses parallel computing for each solution evaluation of the first level while satisfying the equilibrium conditions of the second level and without setting its KKT conditions. The case studies…..**

***Index Terms*—Bilevel models, Nash equilibrium, generation expansion, distributed generation, parallel computing, heuristic optimization.**

NOMENCLATURE

Acronyms

CG	Centralized Generation
DG	Distributed Generation
CV	Conjectural Variations
GENCOs	Generation Companies
KKT	Karush-Kuhn-Tucker conditions
EPEC	Equilibrium Problem with Equilibrium constraints
MPEC	Mathematical Problem with Equilibrium Constraints
PSO	Mathematical Problem with Equilibrium Constraints
SPV	Solar Photovoltaic

Sets

C	Customer segments
G	GENCOs
Y	Years
$\underline{Y}$	Years where decisions are made
$\underline{P}$	Discretization indexes of the power term tariff
$\underline{E}$	Discretization indexes of the energy term tariff

Sets and indexes

s	Agent, $s \epsilon C \cup G$
c	Customer segment, $c \epsilon C$

$\underline{c}$	Reference customer, $\underline{c} \epsilon C$
g	GENCO, $g \epsilon G$
t	Generation unit
h	Hour
$y, \underline{y}$	Year
$\underline{p}$	Discretization index of the power term tariff
$\underline{e}$	Discretization index of the energy term tariff

Parameters (uppercase and greek)

CR_y	Regulatory grid costs [€]
$IC_{t,s,y}$	Investment costs [€/MW]
$D_{c,h,y}$	Customer's base demand [MWh]
$VC_{t,g,y}$	Variable cost of CG [€/MWh]
DI_t	Available power coefficient [MW/MW]
CI	Percentage to increment the demand peak [%]
$\theta^{\delta}_{g,h,y}$	GENCOs energy conjectures [€/MWh/MW]
$TP0_c$	Power term tariff in the first year [€/MW]
$TE0_c$	Energy term tariff in the first year [€/MWh]
$TP_{c,y}(\underline{p})$	Discretization of the power term tariff [€/MW]
$TE_{c,y}(\underline{e})$	Discretization of the power term tariff [€/MWh]
$cp^*_{c,y}(\underline{p}, \underline{e})$	Optimal contracted power [MW]
$dq^*_{c,h,y}(\underline{p}, \underline{e})$	Optimal customer's net demand from the grid [MWh]
$d^*_y(\underline{p}, \underline{e})$	Difference between regulatory incomes and cost [€]
d^*	Minimal difference of $d^*_y\left(\underline{p}, \underline{e}\right)$ [€]

Variables (lowercase and greek)

$tp_{c,y}$	Power term tariff [€/MW]
$te_{c,y}$	Volumetric buying/selling term tariff [€/MWh]
$cp_{c,y}$	Customer's contracted power [MW]
$p_{t,s,y}$	Installed power [MW]
$dq_{c,h,y}$	Customer's net demand from the grid [MWh]
$eq_{c,h,y}$	Power injected into the grid [MWh]
$q_{t,s,h,y}$	Generated power [MWh]
$\lambda^S_{h,y}$	Electricity market price [€/MWh]
λ^L_y	Capacity market price [€/MW]
$\lambda^L_{h,y}$	Hourly capacity payment [€/MWh]

I. Introduction

The expected decarbonization of the power system and the reduction of the investment costs of some power generation technologies (see [1] and [2] for SPV grid parity studies) is providing consumers the opportunity to satisfy part of their electricity needs through DG, based on the installation of small-scale renewable generation units and batteries. However, the integration of DG into existing electrical networks has associated several technical, economic and regulatory questions. While the distribution grid will play a much more active role (see [3]), the use of the transmission grid is expected to be reduced, putting at risk its economic viability. Effectively, under a large penetration of DG, incomes from access tariffs paid by the customers are expected to drop while, to ensure backup CG when DG intermittent generation falls, the corresponding investment, operation and maintenance costs of the transmission grid are not.

Regulation of the power sector is in charge of deciding the appropriate access tariffs to recover the costs of the transmission grid (see [4]). Since most of these costs are almost fixed, independently of the energy flowing, the regulator may need to increase the access tariffs to compensate the income loss caused by the increasing of the DG investments. However, an increase in access tariffs incentivize more customers to invest in DG (additional load-defection), reducing the energy supply from the transmission grid, and triggering further increases in access tariffs, leading to the so-called death spiral [5]. Not much has been written in relation with the study of these behaviour under this new zero-emission paradigm, though different regulations are being

implemented [6]. There is also a lack of models that can be used by the regulator to address the problem of the tariff design in this context by explicitly considering the impact of the tariffs on the electricity generation activity (DG and CG investments, mix of technologies, wholesale market prices, etc). Indeed, most of the papers considers policy decisions as external passive inputs (see for example [7] and [8]), despite their great impact on the global balance of the power sector and on the market results themselves.

Since DG and electricity markets follow the regulator tariff decisions, bi-level Stackelberg models (see [9]) can be considered as sensible approaches to represent the impact between the tariffs and the DG-CG investments and the market outputs. Bi-level models have been used in many fields to solve different types of nested problems (see [10] for a review). In the power sector, they were applied to study the transmission network expansion [11], the optimal control of smart-grids, [12]; the distributed energy resources, [13] and [14]; the market biding strategies, [15]; the electricity pricing with demand respond, [16] and [17]; or the generation expansion, [18], [19] and [20]. However, not much has been found to analyse regulatory decisions such as tariffs. Only [21] presents a bi-level problem with the regulator at the leader problem, whose objective is to maintain earnings from regulated tariffs, and the customers at the follower problem, which objective is to minimize DG investments' costs satisfying the demand. However [21] cannot be applied to realistic systems with combined CG and DG investments, different types of consumers, storage technologies or network losses. Moreover, in [21] the contracted power of DG is assumed to not react with DG investments, which is quite naive. This paper presents an improved version of [21] to tackle all these issues, which can be used to analyse the death spiral and how the CG and DG investments respond to tariffs (and vice-versa) in realistic power systems. It is based on a bilevel model where the aim in the first level is to obtain the long-term evolution of the tariffs needed to sustain the transmission grid activities. The second level is formulated in [22] as a CV equilibrium and focuses on the generation expansion problem by the maximization of the GENCOs' profits and the minimization of the DG consumer costs. Based on [23], the equilibrium considers the energy and reserve commodities, the network access tariffs of DG customers, a simplified approximation of the grid losses, the classical UC thermal constraints and a weekly-simplified hydro unit management.

Regarding the resolution of bilevel models, in [24] a very extensive and interesting review of resolution techniques for bilevel (even trilevel) models is presented, classifying them into 3 main categories: 1) the vertex enumeration approaches; 2) the KKT approaches involving branch-and-bound algorithms and complementary pivot algorithms, in which the upper-level problem includes the lower-level's optimality conditions (leading to MPEC or EPEC); and 3) the penalty function approaches (see [24] for more details). In terms of applications to the electricity sector, as far as the authors know, only the KKT approach have been used (just to name a few, see [21], [25], [26] and [17]), using the strong duality theorem (see for example [14]) or piecewise linear approximations ([27]) to linearize the nonlinear objective function of the resulting MPEC. However, the KKT approach is very time-consuming when solving large-scale problems, like the ones solved in this paper, with mass of variables and constraints (and therefore mass of derivatives to compute and maintain). Moreover, due to the non-convexity of the problem, multiple local optima might come up, and optimal solutions cannot always be guaranteed even with the most powerful algorithms. In these cases, and to overcome the above mentioned issues, a range of heuristic algorithms have been developed that do not need the lower-level's optimality conditions (like evolutionary, PSO and chaos, neural network, genetic or tabu based algorithms, see [24]). However, even with these heuristics, finding a reasonable solution to these complex high-dimensional, multimodal problems, often requires lot of iterations to converge. Since, when solving a realistic case study, a single iteration, which entails an evaluation of the second level, may take up several minutes, the computational efficiency is clearly jeopardized. This paper proposes one possible resolution approach to remedy the downside of these heuristics by computing in parallel the resolution of the second level trying out many different possible solutions of the first level. This heuristic combined with a sensible discretization of the feasible region of the model's first level could make this method more desirable in practice.

The main contributions of this work are:

- Formulation of a mathematical bilevel model that can be used by regulators to address the problem of finding the future electrical tariffs that ensure the economic viability of the transmission grid in a power system, considering, among others, the reaction of DG and CG investments.
- A computational-feasible resolution method based on parallel evaluation of the mentioned reaction that avoid derivatives and which leads to very reasonable execution time even when solving realistic case studies.
- Analysis of resolution time and results of a Spain-like case study for the period 2019-2039…...

This paper is structured as follows. Sections II formulates the proposed bilevel model and III describes the resolution method proposed. Section IV presents a case study devoted to validating some of the main contributions of the proposed model, and finally section V draws the main conclusions and describes future works.

II. The Cost Recovery Bilevel Model

This section presents the formulation of the bilevel model proposed in this paper for the transmission grid cost recovery problem.

A The first Level: the Tariff Optimization Model

As it is well known, the design of the access tariffs is of major importance and depends on what the regulator is trying to achieve, [28] (for example some tariff policies support that tariffs should be designed in such a way that they promote economically efficient or environment-friendly installations to support, and not impede, the energy transition). In this paper, the first level of the proposed bilevel model focuses on the design of the access tariffs to cover the transmission grid costs along a period of years. To this aim, the access tariffs must be specified by groups of customers according to different criteria (for example, based on similar consumption patterns, similar location-related circumstances, similar voltages levels, etc., [29]). In this paper the customers have categorized according, firstly, to their type (residential, industrial or commercial customers) and, secondly, to their economic activity (metallurgy, chemistry, mining, wood/paper, food, hotels and restaurants, services, etc.) or household type (block, single-family, etc.). It is assumed that customers belonging to the same category (or segment) behave similarly. Moreover, it is also assumed that grid-tied is the most attractive option (both financially and in terms of security of supply, when compared to off-grid alternatives), i.e., that grid defection is the worst-case scenario for the regulator and the grid. The next generic tariff structure has been considered (see [30] and [31]):

- A power related term, $tp_{c,y}$ [€/MW], that customers pay for their contracted power $cp_{c,y}$.
- An energy related term, $te_{c,y}$ [€/MWh], proportional to the customer segment's energy consumed or sold from or to the grid.

This structure is aligned with current EU tariff structures ([32]) that consider that the network costs constitute most of the total costs of the system, which are determined by two fundamental variables: a customer's installed contracted power and the energy consumed.

Under these assumptions and considering the above tariff structure, the objective function of the first level problem can be formulated as follows:

$$\min_{tp_{c,y},te_{c,y},d_y \geq 0} \sum_{y} d_y \tag{1}$$

s.t.

$$\sum_{c} tp_{c,y} \cdot cp^{*}_{c,y} + \sum_{c,h} te_{c,y} \cdot dq^{*}_{c,h,y} + d_y = CR_y \tag{2}$$

$cp^{*}_{c,y}$ and $dq^{*}_{c,h,y}$ being the contracted power and the energy bought from the grid by each customer that are optimal from the point of view of the second level, when $tp_{c,y}$ and $te_{c,y}$ are the decision made in the first level. Parameter CR_y is the cost incurred by the customers' use of the grid (the cost for the use by GENCOs is deflated) and variable d_y is the difference between such a cost and the incomes from the tariffs, for each year y$\in Y$, which is minimized.

In terms of distributing the tariffs among the customers, there exists in the literature two different main approaches that can be used ([28]): the application of long-term marginal costs and the causality principle. Although the former aims to achieve a better economic signal, it entails difficulties in its implementation since it requires the detailed representation of the grid. For this reason, the most usual solution applied in practice is the causality principle that ensure that every customer pays their fair share in terms of the cost they produce to the grid, ensuring equity. Regarding this topic, it is assumed in this paper a constant causality principle ensuring that the same fair share of the first year is kept throughout the temporal horizon. This rule avoids more complex analyses like for example the possibility of having cross-subsidies between customer categories. Therefore, it must be hold:

$$\frac{tp_{c,y}}{tp_{c',y}} = \frac{TP0_c}{TP0_{c'}} \qquad (tp_{c,y} \rightarrow te_{c,y}) \tag{3}$$

which is mathematically equivalent to the following expression where only tariffs of a reference client $\underline{c}$ is optimized, reducing the set of decision variables:

$$tp_{c,y} = \frac{TP_{c,y0}}{TP_{\underline{c},y0}} \cdot tc_{\underline{c},y} \qquad (tp_{\underline{c},y} \rightarrow te_{\underline{c},y}) \tag{4}$$

Finally, it is assumed that tariffs might only change in some predetermined years, $\underline{y} \in \underline{Y} \subseteq Y$, i.e., for any y$\in Y$:

$$tp_{\underline{c},y} = \begin{cases} tp_{\underline{c},y0}, y0 \le y < min\left\{\underline{y} \in \underline{Y}\right\} \\ tp_{\underline{c},\underline{y}}, \underline{y} \le y < min\left\{\underline{y}' \in \underline{Y} : \underline{y}' > \underline{y}\right\}, \underline{y} \in \underline{Y} \ (tp_{\underline{c},y} \to te_{\underline{c},y}) \\ tp_{\underline{c},max\left\{\underline{y} \in \underline{Y}\right\}}, y \ge max\left\{\underline{y} \in \underline{Y}\right\} \end{cases} \quad (5)$$

Thus, the optional evolution of the tariffs throughout the temporal horizon leads to a tariff staircase function, which is rather realistic and simplify the understanding of the tariff structure.

A The Second Level: the CG-DG Equilibrium Model

1) The CG-DG objective functions

The second level is described in detail in [23]. Forgetting, by simplicity, the discount rate and assuming that the buying and selling terms of the tariffs are identical, the objective function of each GENCO and each customer to be optimized simultaneously in the sense of Nash are:

$$\text{Max}\left\{\sum_{y}\left[\sum_{t,h}\left(\left(\lambda^{S}_{h,y} - VC_{t,g,y}\right)\cdot q_{t,g,h,y}\right) + \sum_{t}\left(\left(\lambda^{L}_{y}\cdot DI_{t} - IC_{t,g,y}\right)\cdot p_{t,g,y}\right)\right]\right\}, \forall g \quad (6)$$

$$\text{Min}\left\{\sum_{y}\left[tp_{c,y}\cdot cp_{c,y} + \sum_{t} IC_{t,c,y}\cdot p_{t,c,y} + \sum_{h}\left(\left(\lambda^{S}_{h,y} + \lambda^{L}_{h,y} + te_{c,y}\right)\cdot dq_{c,h,y} - \left(\lambda^{S}_{h,y} + \lambda^{L}_{h,y} - te_{c,y}\right)\cdot eq_{c,h,y}\right)\right]\right\}, \forall c \quad (7)$$

By one hand, the first term of each GENCO objective function in (6) is the energy market profit, while the second one is the capacity market profit, computed both as the market incomes, minus the costs. By the other hand, the first term of each customer objective function in (7) is the cost of the power access tariff, the second represents the DG investment costs, and the third adds up the purchasing and selling energy costs and incomes from or to the grid.

2) The CG-DG linking constraints

The linking constraints that set the game are:

$$\sum_{t} q_{t,c,h,y} + dq_{c,h,y} = D_{c,h,y} + eq_{c,h,y} \quad (8)$$

$$\sum_{t,g} q_{t,g,h,y} = \sum_{c} dq_{c,h,y} - \sum_{c} eq_{c,h,y} : \lambda^{S}_{h,y} \quad (9)$$

$$\sum_{t,g} DI_{t}\cdot p_{t,g,y} = (1+CI)\cdot \max_{h}\left(\sum_{c} dq_{c,h,y} - \sum_{c} eq_{c,h,y}\right) : \lambda^{L}_{y} \quad (10)$$

The first constraint is the balance constraint for each customer, the second meet the demand with CG in the energy market while the third is devoted to meet the peak demand in the capacity market.

1) The CG-DG remaining constraints

Finally, the remaining constraints of the game are:

$$dq_{c,h,y} + eq_{c,h,y} \le cp_{c,y} \quad (11)$$

$$q_{t,s,h,y} \le p_{t,s,y}, s \in C \cup G \quad (12)$$

The first constraint imposes that the energy bought or sold by each customer must not surpass the contracted power, while the second guarantees that the production for either DG or CG never exceeds the installed capacity.

Finally, as mentioned in [23], the hourly CG and DG operation and investments constraints and also the classical UC constraints must be also included. They coincide with those described in [33].

III. The Resolution Method

This section describes an algorithm for the resolution of the proposed bilevel model formulated in the previous section.

1) A parallel computational search for the first level

As mentioned above, the only decision variables of the first level are the tariff terms $tp_{\underline{c},\underline{y}}$ and $te_{\underline{c},\underline{y}}$ for the chosen reference client $\underline{c}$ and years $\underline{y} \in \underline{Y}$. Even like that, the set of feasible solutions to try out is infinite and entails a computational burden that is not acceptable in the finding of an optimal solution. For this reason, only a discrete set $\{TP_{\underline{c},\underline{y}}(\underline{p}), \underline{p} \in \underline{P}\}$ of possible values for $tp_{\underline{c},\underline{y}}$ and $\{TE_{\underline{c},\underline{y}}(\underline{e}), \underline{e} \in \underline{E}\}$ for $te_{\underline{c},\underline{y}}$ will be evaluated through the following algorithm:

Step 1. For each possible pair $(\underline{p},\underline{e}) \in \underline{P} \times \underline{E}$, solve the second level of the problem (as it will be described in the next subsection) assuming that $tp_{\underline{c},\underline{y}} = TP_{\underline{c},\underline{y}}(\underline{p})$ and $te_{\underline{c},\underline{y}} = TE_{\underline{c},\underline{y}}(\underline{e})$, and obtaining from (4) and (5) the remaining values $TP_{c,y}(\underline{p})$ and $TE_{c,y}(\underline{e})$ of the tariffs $tp_{c,y}$ and $te_{c,y}$ for the rest of customers and years. Note that parallel computation can be used in this step to solve all these problems in parallel. Let us denote $cp^*_{c,y}(\underline{p},\underline{e})$ and $dq^*_{c,h,y}(\underline{p},\underline{e})$ the obtained optimal contracted power and energy bought from the grid by each client, respectively.

Step 2. If $d^*_y(\underline{p},\underline{e})$ is d_y once cleared it from (2) considering $cp^*_{c,y}(\underline{p},\underline{e})$ and $dq^*_{c,h,y}(\underline{p},\underline{e})$ and the tariffs values of $(\underline{p},\underline{e})$, the optimal solution is obtained by computing the lowest value d^* of $\sum_y d^*_y\left(\underline{p},\underline{e}\right)$ when varying $(\underline{p},\underline{e})$ throughout $\underline{P} \times \underline{E}$, i.e.:

$$d^* = \min_{(\underline{p},\underline{e}) \in \underline{P}\times\underline{E}} \left\{ \sum_y d^*_y\left(\underline{p},\underline{e}\right) \right\}$$
$$d^*_y\left(\underline{p},\underline{e}\right) = CR_y - \sum_c TP_{c,y}\left(\underline{p}\right) \cdot cp^*_{c,y}\left(\underline{p},\underline{e}\right) + \sum_{c,h} TE_{c,y}(\underline{e}) \cdot dq^*_{c,h,y}\left(\underline{p},\underline{e}\right) \tag{13}$$

2) An equivalent cost minimization model for the second lebvel

As it is proved in [23], if tariffs are known (they are in this resolution method since the first level fixes them to $TP_{c,y}(\underline{p})$ and $TE_{c,y}(\underline{e})$ for each pair $(\underline{p},\underline{e})$), a price-response CV approach, [34], can been applied to the game of the second level, and the Nash optimality conditions can be solved by the following quadratic minimization problem:

$$\text{Min} \left\{ \begin{array}{l} \sum_g \left(\begin{array}{l} \sum_{h,y} \left(\begin{array}{l} \sum_t VC_{t,g,y} \cdot q_{t,g,h,y} + \\ \theta^S_{g,h,y} \cdot 0.5 \cdot \left(\sum_t q_{t,g,h,y} \right)^2 \end{array} \right) \\ + \sum_y \left(\begin{array}{l} \sum_t IC_{t,g,y} \cdot p_{t,g,y} + \\ \theta^L_{g,y} \cdot 0{,}5 \cdot \left(\sum_t DI_t \cdot p_{t,g,h,y} \right)^2 \end{array} \right) \end{array} \right) \\ + \sum_c \left(\begin{array}{l} \sum_y TP_{c,y}\left(\underline{p}\right) \cdot cp_{c,y} + \sum_{t,y} IC_{t,c,y} \cdot p_{t,c,y} \\ + \sum_{h,y} \left[\begin{array}{l} TE_{c,y}(\underline{e}) \cdot \left(dq_{c,h,y} + eq_{c,h,y}\right) \\ \theta_{c,h,y} \cdot 0.5 \cdot \left(eq_{c,h,y} - dq_{c,h,y}\right)^2 \end{array} \right] \end{array} \right) \end{array} \right\} \tag{14}$$

Subject to (8)-(12), and where (see [23] for more details):

$$\frac{\partial \lambda^S_{h,y}}{\partial\left(\sum_t q_{t,g,h,y}\right)} = -\theta^S_{g,h,y} \tag{15}$$

$$\frac{\partial\left(\lambda^S_{h,y} + \lambda^L_{h,y}\right)}{\partial dq_{c,h,y}} = -\theta_{c,h,y} = -\frac{\partial\left(\lambda^S_{h,y} + \lambda^L_{h,y}\right)}{\partial eq_{c,h,y}} \tag{16}$$

$$\frac{\partial \lambda^L_y}{\partial\left(\sum_t p_{t,g,y}\right)} = -\theta^L_{g,y} \tag{17}$$

IV. Case studies and results

Aquí lo de siempre, a qué Sistema se aplica, el horizonte, una descripción general de los distintos subapartados….

A. *Scenarios' description*

Importante este apartado para describir en detalle qué escenarios se han analizado.

B. *Input data*

Lo de siempre: poner subapartados con parámetros relevantes, o hacer referencia a datos de fuentes públicas o a otros papers (como podría ser el paper 2 de la tesis de Salva).

C. *Results*

La organización de este apartado dependerá de en qué resultados nos estemos fijando.

D. *Computational results*

Pongo los resultados computacionales aparte porque el modelo no es de optimización. Aquí hay que explicar con más detalle que en otros papers en los que hemos trabajado número de variables y restricciones del primer nivel y número de variables y restricciones del segundo nivel. Ordenador usado, todo lo que puedas decir de los hilos y tus movidas informáticas, número de núcleos, características del ordenador, tiempos de ejecución de las fases (si existen) del algoritmo de resolución, si se usa resolución en diferentes ordenadores, cómo es la grid, qué características tienen los ordenadores usados, y todo lo que se te ocurra para embellecer esto.

V. Conclusions

This paper proposes a bilevel optimization model that can be used in policy studies to address the problem of finding the electrical tariffs that cover the grid regulated costs in the long-term, considering the reaction of the electricity generation activity. The regulators' objectives are represented in the first level, while the second stage targets the simultaneous maximization (in the sense of Nash) of the CG profits and the minimization of DG costs, when investing in new generation assets. This model might provide new leverages to the regulator to analyze the main drivers that allow to maintain a centralized approach or increase decentralization.

Another contribution of this paper is the resolution method of the bilevel model that is based on a parallel resolution of the equilibrium of the second level, trying out different feasible tariffs in the first level, which leads to quasi-optimal solutions in very reasonable times, even solving large scale study cases.

The case studies, resulting from the application of the model to the Spanish system, show that:

- .

The authors are currently working on .

References

[1] G. C. Christoforidis, A. Chrysochos, G. Papagiannis, M. Hatzipanayi, and G. E. Georghiou, "Promoting PV energy through net metering optimization: The PV-NET project," in *2013 International Conference on Renewable Energy Research and Applications (ICRERA)*, 2013, pp. 1117–1122.

[2] "pv_gpm_2_residential_2013.pdf." .

[3] K. Balamurugan, D. Srinivasan, and T. Reindl, "Impact of Distributed Generation on Power Distribution Systems," *Energy Procedia*, vol. 25, pp. 93–100, Jan. 2012.

[4] "Microsoft Word - R-2008-129 AJE Optimal network tariffs and allocation of costs.doc - Optimal network tariffs and allocation of costs.pdf." .

[5] K. W. Costello and R. C. Hemphill, "Electric Utilities' 'Death Spiral': Hyperbole or Reality?," *Electr. J.*, vol. 27, no. 10, pp. 7–26, Dec. 2014.

[6] A. Picciariello, J. Reneses, P. Frias, and L. Söder, "Distributed generation and distribution pricing: Why do we need new tariff design methodologies?," *Electr. Power Syst. Res.*, vol. 119, pp. 370–376, Feb. 2015.

[7] S. Doménech, F. A. Campos, J. Villar, and M. Rivier, "An equilibrium approach for modeling centralized and distributed generation expansion planning," *Rev. EPSR 2019*.

[8] F. Martín-Martínez, A. Sánchez-Miralles, M. Rivier, and C. F. Calvillo, “Centralized vs distributed generation. A model to assess the relevance of some thermal and electric factors. Application to the Spanish case study,” *Energy*, vol. 134, pp. 850–863, Sep. 2017.
[9] S. Dempe, *Foundations of bilevel programming*. Springer, 2002.
[10] B. Colson, P. Marcotte, and G. Savard, “An overview of bilevel optimization,” *Ann. Oper. Res.*, vol. 153, no. 1, pp. 235–256, Apr. 2007.
[11] M. Jenabi, S. M. T. Fatemi Ghomi, and Y. Smeers, “Bi-Level Game Approaches for Coordination of Generation and Transmission Expansion Planning Within a Market Environment,” *IEEE Trans. Power Syst.*, vol. 28, no. 3, pp. 2639–2650, Aug. 2013.
[12] F. Delfino, R. Minciardi, F. Pampararo, and M. Robba, “A bi-level control architecture for the optimal operation of smart grids,” in *2014 IEEE Conference on Control Applications (CCA)*, 2014, pp. 855–860.
[13] S. Bahramara, M. Yazdani-Damavandi, J. Contreras, M. Shafie-Khah, and J. P. S. Catalão, “Modeling the Strategic Behavior of a Distribution Company in Wholesale Energy and Reserve Markets,” *IEEE Trans. Smart Grid*, vol. 9, no. 4, pp. 3857–3870, Jul. 2018.
[14] M. Zugno, J. M. Morales, P. Pinson, and H. Madsen, “A bilevel model for electricity retailers’ participation in a demand response market environment,” *Energy Econ.*, vol. 36, pp. 182–197, Mar. 2013.
[15] J. D. Weber and T. J. Overbye, “A two-level optimization problem for analysis of market bidding strategies,” in *1999 IEEE Power Engineering Society Summer Meeting. Conference Proceedings (Cat. No.99CH36364)*, 1999, vol. 2, pp. 682–687 vol.2.
[16] E. Alekseeva, L. Brotcorne, S. Lepaul, and A. Montmeat, “A bilevel approach to optimize electricity prices,” *Yugosl. J. Oper. Res.*, vol. 29, no. 1, pp. 9–30, 2019.
[17] A. KOVÁCS, “Bilevel programming approach to demand response management with day-ahead tariff,” *J. Mod. Power Syst. Clean Energy*, vol. 7, no. 6, pp. 1632–1643, Nov. 2019.
[18] S. Wogrin, E. Centeno, and J. Barquin, “Generation Capacity Expansion in Liberalized Electricity Markets: A Stochastic MPEC Approach,” *IEEE Trans. Power Syst.*, vol. 26, no. 4, pp. 2526–2532, Nov. 2011.
[19] S. J. Kazempour, A. J. Conejo, and C. Ruiz, “Strategic Generation Investment Using a Complementarity Approach,” *IEEE Trans. Power Syst.*, vol. 26, no. 2, pp. 940–948, May 2011.
[20] S. Wogrin, “Generation expansion planning in electricity markets with bilevel mathematical programming techniques,” Comillas Pontifical University, Madrid, 2013.
[21] C. Cervilla, J. Villar, and F. A. Campos, “Bi-level optimization of electricity tariffs and PV distributed generation investments,” in *European Energy Market (EEM), 2015 12th International Conference on the*, 2015, pp. 1–5.
[22] S. Doménech, F. A. Campos, J. Villar, and M. Rivier, “Joint energy and capacity equilibrium for centralized and distributed generation,” *Rev. EPSR 2019*.
[23] S. Doménech, F. A. Campos, J. Villar, and M. Rivier, “Joint Energy and Capacity Equilibrium for Centralized and After-the-Meter Distributed Generation,” *Rev. EPSR 2019*.
[24] J. Lu, J. Han, Y. Hu, and G. Zhang, “Multilevel decision-making: A survey,” *Inf. Sci.*, vol. 346–347, pp. 463–487, Jun. 2016.
[25] B. F. Hobbs, C. B. Metzler, and J.-S. Pang, “Strategic gaming analysis for electric power systems: an MPEC approach,” *IEEE Trans. Power Syst.*, vol. 15, no. 2, pp. 638–645, May 2000.
[26] A. Ramos, M. Ventosa, and M. Rivier, “Modeling competition in electric energy markets by equilibrium constraints,” *Util. Policy*, vol. 7, no. 4, pp. 233–242, Feb. 1999.
[27] M. T. Vespucci, M. Innorta, and G. Cervigni, “A Mixed Integer Linear Programming model of a zonal electricity market with a dominant producer,” *Energy Econ.*, vol. 35, pp. 35–41, Jan. 2013.
[28] J. Reneses and M. P. Rodríguez Ortega, “Distribution pricing: theoretical principles and practical approaches,” *Transm. Distrib. IET Gener.*, vol. 8, no. 10, pp. 1645–1655, Oct. 2014.
[29] M. P. Rodríguez Ortega, J. I. Pérez-Arriaga, J. R. Abbad, and J. P. González, “Distribution network tariffs: A closed question?,” *Energy Policy*, vol. 36, no. 5, pp. 1712–1725, May 2008.
[30] Ignacio, J.Pérez-Arriaga, *Regulation of the Power Sector*, Srpinger. .
[31] M. P. Rodríguez Ortega, J. I. Pérez-Arriaga, J. R. Abbad, and J. P. González, “Distribution network tariffs: A closed question?,” *Energy Policy*, vol. 36, no. 5, pp. 1712–1725, May 2008.
[32] “Eurolectric: ‘Network tariff structure for a smart energy system,’” 2013.
[33] S. Domenech, Campos, F. A., J. Villar, and M. Rivier, “An Equilibrium Approach for Modeling Centralized and Distributed Generation Expansion Planning,” *Work. Pap. IIT-18-018A*, 2018.
[34] C. A. Díaz, Fco. A. Campos, and J. Villar, “Existence and uniqueness of conjectured supply function equilibria,” *Int. J. Electr. Power Energy Syst.*, vol. 58, pp. 266–273, Jun. 2014.