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Coordination of Generation and Transmission Development through Generation Transmission Charges - A Game Theoretical Approach

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Abstract—Transmission charges aim to recover the cost of transmission network investments and provide efficient locational signals to new generators. In this paper, we investigate the effect of these charges on the development of new generation capacities in the system. Generation expansion planning is decided by strategic generation planners (SGPs) trying to maximize their profits, while transmission line investments are planned by a central planner and regulatory body aimed at minimizing the overall operation and network investment costs of the system. Regulatory transmission charges (RTCs) are calculated according to the marginal responsibility of generation investment on transmission network investment costs. An iterative algorithm is proposed to model the interaction taking place between the central planner and SGPs. The developed methodology is applied to a 2-node illustrative example and the IEEE-RTS96, and effects of RTCs on investment decisions of SGPs are analyzed.

Index Terms—Generation expansion planning; Game theory; Marginal transmission charges.

NOMENCLATURE

Sets:

- G_z Set of generating units owned by the strategic planner z
- L_C Set of transmission lines to be expanded
- V_z Set of available decisions for portfolio z

Parameters:

- C_g Fuel cost (\$/MWh) of unit g
- W_s Duration (h) of load level s in the year
- D_{ns} Active load level (MW) at bus n in load level s
- EL_ℓ Expansion cost (\$/MW/year) of transmission line l
- EG_g Expansion cost (\$/MW/year) of generating unit g
- F_ℓ Capacity (MW) of transmission line l
- H_{nl} Matrix of power transfer distribution factors
- M Sufficiently large number
- P_g Capacity (MW) of generating unit g
- RTC_g Regulatory transmission charge (\$/MW/year) for generator g

Indices:

- g Index for generating units
- ℓ Index for transmission lines

- n Index for buses
- s Index for load levels
- v Index for strategies
- z Index for strategic generation planners

Variables:

- sc Social cost (\$/year) of the system
- $\hat{f}_\ell$ Expanded capacity (MW) of transmission line l
- $\hat{p}_g$ Expanded capacity (MW) of generating unit g
- p_{gs} Power generation (MW) of unit g in load level s
- π_z Profit (\$/year) of strategic generation planner z
- η_{ns} Price of electricity (\$/MWh) at bus n in load level s
- θ_s Lagrange multiplier (\$/MWh) of power balance equation in load level s
- $\bar{\mu}_{\ell s}$ Lagrange multiplier (\$/MWh) of upper limit for power flow of transmission line l in load level s
- $\underline{\mu}_{\ell s}$ Lagrange multiplier (\$/MWh) of lower limit for power flow of transmission line l in load level s
- $\bar{\lambda}_{gs}$ Lagrange multiplier (\$/MWh) of upper limit capacity of generating unit g in load level s
- $\underline{\lambda}_{gs}$ Lagrange multiplier (\$/MWh) of lower limit capacity of generating unit g in load level s

I. INTRODUCTION

THE expansion and operation of generation is in the hands of market agents (generation companies) in those systems where the electricity sector has been deregulated. However, the development and operation of both transmission and generation are mutually dependent. Hence, due to the fact that both activities are in different hands (those of the transmission system operator and generation companies, respectively), achieving their efficient functioning requires that coordinating signals are sent to generators (and market agents in general) so that they take into account the existence of the network in the operation and investment decisions they make. Marginal electricity pricing theory provides a satisfactory solution to the coordination of generation and transmission operation in the form of Locational Marginal Prices (LMPs), or nodal prices, see [1]. Thus, LMPs, and other coordinating signals based on them, like wheeling transmission charges, have been employed to achieve an efficient coordination of generation and transmission operation under imperfect competition both in the short term, or operation time frame, see [2] and [3], and when computing the development of generation and

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transmission, see [4] and [5]. However, achieving an efficient coordination of the generation and transmission expansion requires that generation companies take into account, not only the impact that their operation and investment decisions shall have on the short term (operation) value of the transmission capacity, but also the overall impact that these decisions shall have on network investment costs. Note that efficient short term operation signals (LMPs or wheeling charges) are only able to recover a small fraction of the investment cost of a real transmission grid that is optimally adapted, as authors in [6] show. Consequently, additional transmission charges, sometimes called complementary charges, are needed to make generators internalize in their investment decisions the full transmission network development cost they cause.

However, in most systems of the world, generators pay shallow connection charges (only including the cost of direct connection facilities) and Use of the System (UoS) charges corresponds only to a small fraction of the cost of the bulk transmission grid, or no part of the cost of this grid at all, see [7]. A notable exception to this are countries in South America, where a significant number of systems, like Argentina and Chile, levy UoS charges on generators that recover a large fraction of the cost of the bulk grid. Reasons for limiting the fraction of grid development costs applied on generators include the fact that, if not given the appropriate structure, transmission charges could interfere with efficient generation operation decisions and harm the competitive position of some of these generators, see [8].

Despite what is the normal practice in transmission charges, and given that generation investment decisions may have a relevant impact on network development costs, providing generation companies with economic signals (complementary transmission charges) leading the former to internalize in their investment decisions the impact that these decisions are deemed to have on network development costs is desired. If appropriately designed, applying complementary transmission charges results in an increase in the efficiency of the overall development of the generation and the grid. This is especially relevant when network investments to undertake are significant, as it is the case in most regional markets where large investments in renewable generation are envisaged. In this case, reductions in investment costs may be significant. Besides, a fair and efficient allocation of network costs among market agents or systems may avoid the opposition of relevant stakeholders to the construction of new network lines that are much needed in the region.

There are some regions, like Nordic countries, where there is a long tradition of cooperation among systems in the development of their grids, [9], [10]. In the Nordic region, regulation enacted promotes the sharing among national systems of the cost of network reinforcements that influence the trade of energy at regional level. If possible, the cost of these reinforcements shall be paid proportionally to the benefits that countries obtain from them. However, there is no obligation to apply this regulation and, whenever an agreement is not reached among countries, new transmission lines must be paid by the country where they are built. Lastly, this only affects the sharing of the cost of these lines among countries. Countries

are free to determine how to allocate the fraction of the cost of a new line they have to pay to local generators and loads. Thus, if countries do not allocate costs of a new line according to cost causality, final transmission charges paid by agents may have lost most of their locational content. In Central America, a similar network cost allocation system based on network usage by international transactions applies, though in this case, the application of the regional network cost allocation method is enforced by regulation, see [11].

Some attempts to apply meaningful, locationally differentiated transmission charges at agent level have taken place in power systems like the Argentinean one, with the so-called areas of influence, or Marginal Participations method, [12]. However, results computed with this are heavily dependent on the selection of the balancing node in the system, deemed to balance any injection or withdrawal of power by agents when computing the responsibility of the latter in the network use, [13]. Hence, despite being useful for the Argentinean power system, where the balancing node can easily be located in the Capital Buenos Aires, as the single major load center in the country, its application in other more meshed power systems may not be very satisfactory. All in all, there are very few examples of a meaningful application of efficient network charges to drive generation investment decisions.

However, unless fair and efficient¹ charges are applied which aligns network charges paid by new generators with the grid costs caused by the installation of these generators, as already pointed out, network investment costs to integrate renewable generation may significantly increase and some agents, groups of them, or countries may block the construction of needed reinforcements if they feel only a fraction of the cost of these new assets is paid and that is not commensurate with the benefits they will obtain from them. This, in our view, is affecting the development of cross-border transmission lines in Europe, which is lagging behind the needs of the European system, [14], [15].

The application of efficient energy prices, i.e., nodal, or locational marginal ones, allows the efficient recovery of a fraction of network investment costs, [16], [17]. However, as authors in [18] demonstrate, nodal pricing can recover only a small portion of transmission costs because of the lumpy nature of investments and the economies of scale present in the transmission activity. Therefore, it is necessary to allocate the remaining fraction of the cost of transmission grid to its users through the so-called complementary charges. As suggested, complementary charges can be applied on several groups of actors, i.e., generators or consumers. These charges can adopt a wide range of structures, i.e., based on energy produced, installed capacity, or demand level, [19]. Even more, they can be calculated according to a wide variety of approaches. In principle, these charges should signal the responsibility of agents in the construction of lines, although this has been

¹Inefficiencies in the computation of transmission charges occur when charges applied on new generators do not reflect the responsibility of generators in network investment costs, which is intimately linked to the benefits these generators obtain from network investments relative to the benefits other agents in the system are obtaining from these same transmission investments. This may result in a development of generation that may impose significantly larger network investment costs than the optimal ones.

discarded in most countries, [20], [21].

Among the many methods to allocate network costs to users when computing network charges, Postage Stamp type methods apply the same charge per MW of generation capacity installed, or MWh of energy injected, regardless of the loading on the transmission system, the profile of each agent, or its location, [22]. Therefore, these methods do not make a distinction among transmission users based on their responsibility in the development of transmission system, [22]. There is a wide variety of Usage-based charging methods, [23], [24], resulting in widely different charges. They aim to allocate the fraction of the cost of each line not recovered from the application of energy prices according to the usage that agents make of this line. But the usage made of a line by each agent cannot be indisputably computed. Besides, network usage is nothing but a proxy to the benefits that agents obtain from network investments, which are the real driver behind these investments, see [8].

Allocation methods based on the responsibility of network users on grid investments can be deemed to result in efficient signals if appropriately implemented. Within this family of methods, we have considered in our analysis nodal charges (varying across network nodes) that are proportional to the marginal impact of a change in the generation capacity installed in each node on network development costs, or the marginal impact of generation capacity on the cost of transmission services. This type of methods have been largely discussed in [6], [12], [25]–[27], and resemble in its conception philosophy the Investment Cost Related Pricing methodology applied in the UK, see [28]. However, due to the implementation made of this principle in the UK, the method applied there actually computes the marginal use of the grid by each agent when a certain, common, balancing node is deemed to respond to changes in the power injection by each generator. Thus, this method shares some weak points, already highlighted, with the Areas of Influence method applied in Argentina.

Regulatory transmission charges (RTCs) applied on generators that we compute are proportional to the marginal impact of an increase in the size of each generator on the network investment costs computed by the central network planner when optimizing the development of the grid. At the same time, RTCs are scaled (using a single proportionality factor) so as to recover a pre-determined fraction of the network costs from their application (the one that is decided to be levied on new generation in the system). This proportionality factor may be deemed a degree of freedom to be used by the regulator to fine tune charges applied so that they induce efficient investment decisions by agents. When computing network investments, the central planner deems generation investments declared by market agents as given. However, RTCs applied on generation may condition the corresponding companies' investment decisions, since overall network costs afforded by a company rightfully depend on its investment decisions in the long term. In fact, some authors [4], [29]–[34] have proven the importance of considering the interactions between generation and transmission investments. However, there is a lack of research on the use of transmission charges as a signal driving

the coordination of generation and transmission expansion to increase the efficiency of the overall development of the system. Previous works on the coordination of generation and transmission investments ignore the possibility to apply complementary transmission charges on new generation to drive generation investments. We model the effect of the application of RTCs on the interaction between generation and transmission investments. RTCs are proportional to the marginal responsibility of new generators on network investment costs.

Reflecting analytically the impact of generation investment decisions on RTCs faced by the corresponding generation company in the generation investment problem would be very complex. This would involve including optimality conditions of the transmission expansion planning problem into the generation expansion planning problem. At the same time, the transmission expansion planner should take into account the effect of his investment decisions on the generation investment strategy chosen by the company. Then, generation capacity constraints of the transmission expansion planning problem would be formulated in terms of some dual variables of this same transmission expansion planning problem. All this would make the overall equilibrium problem highly non-linear.

Therefore, we propose to compute the overall equilibrium solution following an iterative approach whereby the generation expansion problem faced by strategic generation planners (SGPs) and the network expansion problem faced by the central network planner are solved separately over and over again, each time considering updated values of complementary transmission charges, RTCs, applied on new generators, until optimal solutions computed in both problems are consistent between them as well as with RTCs applied. As shown by recent works on the computation of the expansion of transmission, either alone or combined with the expansion of generation [35]–[39], the planning of the expansion of the transmission grid is a very complex problem. Given that the focus of our work is not transmission expansion planning itself, but its coordination with generation expansion through network charges, we have modeled the former problem in a simplified way.

This article is structured as follows. First, the problem representing the efficient planning of the system is formulated in Section II-A, then, the strategic planning of the development of generation portfolios by SGPs is presented in Section II-B, while the method applied to compute RTCs is addressed in Section II-C together with the algorithm implemented to compute the equilibrium investment strategies by SGPs and the network planner. Simulation results from the application of the considered RTCs in a 2-node illustrative example and the IEEE-RTS96 are discussed in Section III. We conclude in Section IV.

II. THE METHODOLOGY

A. Efficient Planning of Generation and Transmission

At the beginning of this section, the formulation for efficient planning of generation and transmission is presented. This model is used as a benchmark to assess the efficiency of

the results computed in a decentralized market context both when considering transmission charges paid by generators and when not considering them. Efficient planning means that one entity decides about the planning scheme of the system. This corresponds to the planning problem solved in vertically integrated power systems. The objective function of this model is to minimize the system social cost (this comprises both generation and network investment costs and operation ones).

$$\begin{aligned} \text{Minimize}_{\hat{p}_g, p_{gs}, \hat{f}_\ell \geq 0, \ell \in L_c} \quad & sc = \sum_{\ell \in L_c} \hat{f}_\ell E L_\ell + \sum_g \{ \hat{p}_g E G_g \\ & + \sum_s W_s C_g p_{gs} \}. \end{aligned} \quad (1a)$$

subject to:

$$\sum_n D_{ns} = \sum_g p_{gs}; \quad \forall s. \quad (1b)$$

$$0 \leq p_{gs} \leq P_g + \hat{p}_g; \quad \forall g, s. \quad (1c)$$

$$\begin{aligned} - (F_\ell + \hat{f}_\ell) \leq \sum_n H_{n\ell} (p_{gs} - D_{ns}) \leq (F_\ell + \hat{f}_\ell); \\ \forall \ell, s. \end{aligned} \quad (1d)$$

As seen in this formulation, the operating constraints are the balance constraint between demand and supply (1b), capacity constraints of the generators (1c), and those of transmission lines (1d), all of which are written based on a DC power flow ($g \leftarrow n$ refers to the connection of unit g to node n). At each node, the lost load is modelled as a fictitious generator with its marginal cost equal to the value of lost load at that node. Several operation situations (snapshots) have been considered in the formulation of the transmission and generation expansion planning problem, as represented by index s . This allows us to include not only the most stressful situation from the point of view of the grid, but also additional operating situations that may be relevant. Since the focus of this paper is on the coordination of transmission and generation planning, and for the sake of simplicity, only scenarios formed by the different demand levels on the evolution of the system in the future is being considered. Also, a simplified model of the transmission and generation expansion is introduced in which the investment decisions are modeled as extra capacities for the lines and for the generating units, [4], [34], [40]. We assume that an increase in the capacity of a line does not change the topology of the network. This formulation is compatible with the idea proposed in this paper for calculating RTCs, based on the marginal effect of increases in the generation capacity in each node on the cost of transmission reinforcements required. This is discussed in Section II-C. This assumption is acceptable for meshed networks in analyses covering a relatively short-term horizon, where topological changes to the grid and additions to the capacity of existing lines are expected to be small. Further work is foreseen to extend the model to properly take into account larger topological changes. A literature review of the power system expansion models and solution methods can be found in [41].

The resulted model is linear optimization problem which can be solved by available commercial softwares.

B. SGPs Problem

1) *Optimization Problem of One SGP*: Each SGP maximizes its profit by deciding on its investment actions, $\hat{p}$, assuming that other SGPs' investment actions are given. As seen in (2a), the objective function of SGP includes the profits from selling power in the market (the first term) minus the investment cost, which includes RTCs paid by SGP (the second term). The interaction between SGP and the joint market is modelled as a leader-follower game, [42]. The leader is SGP and the follower is the joint market. This is a bilevel optimization problem as represented below:

$$\begin{aligned} \text{Maximize}_{\hat{p}_g \geq 0} \quad & \sum_{g \in G_z} \{ \sum_{s, g \leftarrow n} W_s (\eta_{ns} - C_g) p_{gs} \\ & - \hat{p}_g (E G_g + RTC_g) \}. \end{aligned} \quad (2a)$$

subject to

$$\text{Minimize}_{p_{gs} \geq 0} \quad \sum_{g, s} W_s C_g p_{gs}. \quad (2b)$$

$$\text{subject to} \quad (1b), (1c), (1d). \quad (2c)$$

where η_{ns} is the price of electricity at bus n in load level s , which is calculated through the Lagrange multipliers of the lower level problem as follows:

$$\eta_{ns} = (1/W_s) [\theta_s - \sum_\ell H_{n\ell} (\mu_{\ell s} - \bar{\mu}_{\ell s})]; \quad \forall n, s. \quad (3)$$

The price in expression (3) is calculated by partially differentiating the Lagrangian of the lower-level problem of the SGP with respect to demand, D_{ns} . It models the marginal impact of an increment of the demand at node n , load level s on the operation cost. Since the operation cost includes W_s as the duration of the related snapshot (operating situation), the whole term is divided by W_s .

In the lower level, the market operator optimizes the short-term dispatch in each load level based on the monitored costs of generating units and subject to the network constraints. As there is no constraint connecting load levels, variable operation costs can be summed up in the objective function, as in the optimization problem (2b)-(2c). We convert this optimization problem to a mixed-integer linear programming problem using the Karush-Kuhn-Tucker approach, [43], and the strong duality, [44]. The dual problem of (2b)-(2c) is as follows:

$$\begin{aligned} \text{Maximize}_{\lambda_{gs}, \bar{\lambda}_{gs}, \mu_{\ell s}, \bar{\mu}_{\ell s} \geq 0, \theta_s} \quad & \sum_{n, s} \theta_s D_{ns} + \sum_{g, s} \bar{\lambda}_{gs} (P_g + \hat{p}_g) \\ & + \sum_{\ell, s} \{ (\mu_{\ell s} - \bar{\mu}_{\ell s}) \sum_n H_{n\ell} D_{ns} - (\mu_{\ell s} + \bar{\mu}_{\ell s}) (F_\ell + \hat{f}_\ell) \}. \end{aligned} \quad (4a)$$

subject to:

$$\begin{aligned} W_s C_g - \theta_s + \bar{\lambda}_{gs} - \lambda_{gs} - \sum_\ell H_{n\ell} (\mu_{\ell s} - \bar{\mu}_{\ell s}) &= 0; \\ g \leftarrow n, \forall g, s. \end{aligned} \quad (4b)$$

Since the problem in (2b)-(2c) is convex, strong duality holds and primal objective function at the optimal point is

equal to the dual objective function:

$$\begin{aligned} \sum_{g,s} \{W_s C_g p_{gs} - \bar{\lambda}_{gs}(P_g + \hat{p}_g)\} &= \sum_{n,s} \theta_s D_{ns} \\ &+ \sum_{\ell,s} \{(\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s}) \sum_n H_{n\ell} D_{ns} - (\underline{\mu}_{\ell s} + \bar{\mu}_{\ell s})(F_\ell + \hat{f}_\ell)\}. \end{aligned} \quad (5)$$

Satisfying the strong duality condition (5) at the same time with the primal feasibility constraints (1b),(1c),(1d), and the dual constraint (4b), the optimal solution to both the primal and the dual problems is found. In this way, we can insert the short-term dispatch problem as equilibrium constraints to the SGP problem as follows.

$$\begin{aligned} \text{Maximize } \sum_{\hat{p}_g \geq 0} \{ \sum_{g \in G_z} \sum_{s, g \leftarrow n} W_s (\eta_{ns} - C_g) p_{gs} \\ - \hat{p}_g (EG_g + RTC_g) \}. \end{aligned} \quad (6a)$$

$$\text{subject to } (1b), (1c), (1d) \quad (6b)$$

$$W_s C_g - \theta_s + \bar{\lambda}_{gs} - \lambda_{gs} - \sum_\ell H_{n\ell} (\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s}) = 0; \quad (6c)$$

$$g \leftarrow n, \forall g, s. \quad (6c)$$

$$\begin{aligned} \sum_{g,s} \{W_s C_g p_{gs} - \bar{\lambda}_{gs}(P_g + \hat{p}_g)\} &= \sum_{n,s} \theta_s D_{ns} \\ &+ \sum_{\ell,s} \{(\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s}) \sum_n H_{n\ell} D_{ns} - (\underline{\mu}_{\ell s} + \bar{\mu}_{\ell s})(F_\ell + \hat{f}_\ell)\}. \end{aligned} \quad (6d)$$

$$\bar{\lambda}_{gs}, \lambda_{gs}, \underline{\mu}_{\ell s}, \bar{\mu}_{\ell s} \geq 0; \quad \forall g, \ell, s. \quad (6e)$$

Non-linearity in (6a) can be linearized by using stationary condition (6c) and the expression for price in (3),

$$W_s (\eta_{ns} - C_g) p_{gs} = (\bar{\lambda}_{gs} + \lambda_{gs}) p_{gs}. \quad (7)$$

and the fact that λ_{gs} is non-zero when the production is zero and $\bar{\lambda}_{gs}$ is non-zero when the production is equal to the maximum limit. Therefore,

$$W_s (\eta_{ns} - C_g) p_{gs} = \bar{\lambda}_{gs} (P_g + \hat{p}_g). \quad (8)$$

Right hand side of (8) is also seen in the strong duality condition equation, (6d).

The added capacity of generating units, $\hat{p}$, is in the discrete steps, although, it is clearly not continuous and cannot be discretized in very small steps. Even when the refurbishment of a power plant may result in a limited increase of its generation capacity, taking investments in generation as a quasi-continuous variable does not make physical sense. The investment step size is a feature of the generation unit rather than an input factor to be decided by the modeler when applying the solution method. Therefore, $\hat{p}$ can be discretized using binary expansion $\hat{p}_g = \sum_{k \in K} a_k x_{gk} P_g$, where $a_k = \frac{1}{2^{Card(K)-k}}$ and $x_{gk} \in \{0, 1\}$. Thus, the right-hand side of (8) is linearized using the disjunctive approach [45] and introducing a new variable t_{gks} as follows:

$$-M(1 - x_{gk}) \leq t_{gks} - \bar{\lambda}_{gs} P_g \leq M(1 - x_{gk}). \quad (9)$$

$$-M x_{gk} \leq t_{gks} \leq M x_{gk}. \quad (10)$$

This results to

$$\bar{\lambda}_{gs} (P_g + \hat{p}_g) = \bar{\lambda}_{gs} P_g + \sum_k t_{gks} a_k. \quad (11)$$

Therefore, the problem of each SGP can be written as a mathematical problem with equilibrium constraints (MPEC) as follows:

$$\begin{aligned} \text{Minimize } \pi_z = \sum_{\hat{p}_g \geq 0} \{ \sum_{g \in G_z} \sum_s \{ \bar{\lambda}_{gs} P_g + \sum_k t_{gks} a_k \} \\ - \hat{p}_g (EG_g + RTC_g) \} \end{aligned} \quad (12a)$$

$$\text{subject to } (1b), (1c), (1d) \quad (12b)$$

$$W_s C_g - \theta_s + \bar{\lambda}_{gs} - \lambda_{gs} - \sum_\ell H_{n\ell} (\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s}) = 0; \quad (12c)$$

$$g \leftarrow n, \forall g, s.$$

$$\begin{aligned} \sum_{g,s} \{W_s C_g p_{gs} - \bar{\lambda}_{gs} P_g + \sum_k t_{gks} a_k\} &= \sum_{n,s} \theta_s D_{ns} \\ &+ \sum_{\ell,s} \{(\underline{\mu}_{\ell s} - \bar{\mu}_{\ell s}) \sum_n H_{n\ell} D_{ns} - (\underline{\mu}_{\ell s} + \bar{\mu}_{\ell s})(F_\ell + \hat{f}_\ell)\}. \end{aligned} \quad (12d)$$

$$\bar{\lambda}_{gs}, \lambda_{gs}, \underline{\mu}_{\ell s}, \bar{\mu}_{\ell s} \geq 0; \quad \forall g, \ell, s. \quad (12e)$$

$$\hat{p}_g = \sum_{k \in K} a_k x_{gk} P_g; \quad \forall g. \quad (12f)$$

$$-M(1 - x_{gk}) \leq t_{gks} - \bar{\lambda}_{gs} P_g \leq M(1 - x_{gk}); \quad \forall g, k, s. \quad (12g)$$

$$-M x_{gk} \leq t_{gks} \leq M x_{gk}; \quad \forall g, k, s. \quad (12h)$$

2) *Interaction of SGPs: The Extremal-Nash Equilibrium (ENE) concept is employed in this paper to model the system market power, [46], [47]. The ENE formulation is a two-level optimization problem. The inner level finds all Cournot-Nash equilibria of the game and the upper level finds the extremum-Nash equilibrium. This concept tackles the issue of multiple-Nash equilibria in Cournot games, [48]. The complete formulation is written as follows:*

$$\text{Minimize } sc = \sum_{\hat{p}_g \geq 0} \{ \hat{p}_g EG_g + \sum_s W_s C_g p_{gs} \}. \quad (13a)$$

$$\text{subject to } (12b) - (12h) \quad (13b)$$

$$\begin{aligned} \pi_z = \sum_{g \in G_z} \{ \sum_{s, g \leftarrow n} \{ \bar{\lambda}_{gs} P_g + \sum_k t_{gks} a_k \} \\ - \hat{p}_g (EG_g + RTC_g) \}; \quad \forall z. \end{aligned} \quad (13c)$$

$$\pi_z \geq \pi_z^v; \quad \forall z, v \in V_z. \quad (13d)$$

Constraint (13d) is the Nash equilibrium constraint. Satisfying (13b)-(13d) gives all the Nash equilibria of the problem and the objective function of the problem (13a) makes sure that the Nash equilibrium with the lowest social cost (this includes generation investment and operation cost) will be selected. The optimization problem (13a)-(13d) is a mixed-integer linear program (MILP) which can be solved by available commercial softwares.

C. RTCs

1) *Formulating RTCs:* There are various ways to calculate RTCs. The goal of all these approaches is to allocate all or part

of the transmission investment costs to the different users of the transmission system, [49]. In this paper, these charges are calculated in a way that a) they are proportional to the marginal impact of generation investment $\hat{p}_g$ on transmission investment costs for a network that is optimally adapted to generation and load in the system and b) they recover the fraction α of transmission investment costs. Note that fraction α of the transmission investment cost is recovered through RTCs applied on new generation installed. RTCs provide locational signals to new generations in order to influence their decision to minimize the system social cost of the system. It is assumed that the rest of the transmission investment cost is recovered in other ways (e.g., from congestion rents, connection charges applied on demand, etc.) Therefore:

$$RTC_g = \beta \frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g}. \quad (14)$$

$$\sum_g \hat{p}_g RTC_g = \alpha \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell. \quad (15)$$

Conditions a) and b) are reflected in (14) and (15), respectively. In this paper, we have mainly studied the possibility of influencing strategic decision of SGPs through RTCs in order to drive a more efficient development of the system, rather than aiming to complete the recovery of the cost of transmission expansion through RTCs. In this respect, we have reported the results of using different α s in Section III.

However, as stated in the introduction, LMPs can recover only a small portion of transmission costs and, as argued in [22], complementary network charges applied on both generators and consumers should complete the recovery of the total transmission cost. In our paper, α defines the portion of the transmission development cost recovered through RTCs applied on SGPs. It is assumed that the rest of the transmission expansion cost is recovered by fixed charges applied on the load and congestion rents, etc. Consequently, in order to be coherent with this assumption, parameter α should never be larger than one minus the fraction of the cost of network investments recovered from LMPs, which in real life systems normally is below 20%, see [6].

To calculate $\frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g}$, one MW of generation capacity is added to the related generation unit and the transmission planning problem formulated below is solved.

$$\text{Minimize } \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell + \sum_{g,s} W_s C_g p_{gs}. \quad (16a)$$

$$\text{subject to } (1b), (1c), (1d) \quad (16b)$$

Note that $\hat{p}_g$ is the result of SGPs' problem formulated in (13) and is given in (16). The problem above forms a linear problem which can be solved by available commercial softwares.

New transmission capacity built as resulting from (16) is marked $\hat{f}_\ell^*$. The partial derivative $\frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g}$ is approximated by the difference in transmission investment costs of expansion schemes $\hat{f}_\ell^*$ and $\hat{f}_\ell$.

$$\frac{\partial \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell}{\partial \hat{p}_g} \approx \sum_{\ell \in L_c} \hat{f}_\ell^* EL_\ell - \sum_{\ell \in L_c} \hat{f}_\ell EL_\ell. \quad (17)$$

Having the value for partial derivatives, β can be calculated by imposing the equality in (15). Equation (15) makes sure that the fraction α of the transmission investment costs is recovered through RTCs calculated per MW and multiplied by SGPs added capacities.

2) *Coordination of Generation and Transmission Expansion Planning Using RTCs*: In order to compute the equilibrium between SGPs, when subject to cost reflective RTCs, and the central planner's network investment decisions, the following iterative algorithm is proposed. Note that $\hat{P}_{g-final}$ is the final expanded capacity of generating units.

Step 0: RTCs are initialized (to zero) and all SGPs' new investment decisions are initialized to a value that cannot be adopted by investment decisions (e.g., sufficiently large number M) $\hat{P}_{g-final} = M$, that at least two iterations of the algorithm are run and coherence between RTCs computed (not the original value provided to them) and generation and transmission investments are ensured when convergence is achieved.

Step 1: SGPs' generation investment problems are solved considering last RTCs computed while ignoring the network capacity limits. Network capacity limits are ignored because the available capacity of network lines, as resulting from the network expansion plan that is consistent with generation investment decisions being computed in this step, has not been determined yet. This step aims to compute the generation investment decisions made by generation companies when only influenced by RTC signals (given that transmission lines may be reinforced in later steps of the algorithm).

Step 2: The central planner network investment problem is solved assuming generation investments computed in Step 1 as given. This aims to compute the network expansion plan best adapted to generation investments computed in Step 1. This network expansion plan shall, in turn, condition SGPs' investment decisions by setting network capacity limits considered by SGPs in the investment decisions (next Steps).

Step 3: Generation and Transmission investment decisions by SGPs and the network planner are refined taking this time into account a sensible estimate of the required capacity of network elements. This is undertaken in Steps 3 and 4 as follows (Finely tuned investments in generation and transmission capacity are employed to update RTCs in Step 5, if needed). In Step 3, SGPs investment decision problems are solved again, this time taking into account the network capacity limits computed in Step 2 together with RTCs. If the investment decisions by SGPs, $\hat{p}_{g-step3}$, do not change with respect to those computed in Step 3 in the previous iteration (i.e., if $\hat{p}_{g-step3} = \hat{P}_{g-final}$), convergence has been achieved and the algorithm ends. Otherwise, $\hat{P}_{g-final}$ is set to $\hat{p}_{g-step3}$ ($\hat{P}_{g-final} = \hat{p}_{g-step3}$).

Step 4: The central planner network investment problem, is solved considering generation investments computed

in Step 3 ($\hat{P}_{g-final}$ or $\hat{p}_{g-step3}$, which are the same).
 Step 5: RTCs are updated according to the network investments obtained in Step 4. Return to Step 1.

III. CASE STUDY

To assess the developed approach on RTCs and coordination of generation and transmission investments, two case studies are analyzed in this section. First, a 2-node illustrative example representing two areas is studied. Second, the IEEE-RTS96, [50], is simulated and the computational performance of the proposed algorithm is tested. The CPLEX solver in GAMS is used to solve the optimization problems.

A. 2-node Illustrative Example

The single-line diagram of the 2-node illustrative example is depicted in Fig. 1. Each node represents an area the generators of which are planned by a SGP, SGP1 and SGP2 for the nodes A and B, respectively. The weekly load profile in [50] with the peak load represented in Fig. 1 is considered for computing the operating cost of the system. A higher body decides about the expansion of the line between the two nodes, i.e., areas. As seen in the figure, there is a large load in node A and the unit in node B has lower (variable) production costs than the one in node A. Therefore, there is a great need for investment both on the generation and transmission sides.

Fig. 1: Single-line diagram of the 2-node illustrative example; OC: Operation Cost, Cap.: Capacity, IC: Investment Cost, IO: Investment Options (in MW applied only in decentralized planning)

The initial values considered for RTCs are zero. For the value of α (fraction of the transmission investment cost recovered through RTCs applied on new generations) equal to 0.4, the proposed algorithm achieves convergence, i.e., reaches a stable result after three iterations meaning the result in iteration #3 is the same as the one in iteration #2. The resulting generation and transmission investments in iteration #1 and iteration #2, as well as the system social cost, are compared with the result of the centralized (efficient) expansion planning in Table I. The corresponding RTCs are reported in Table II. In iteration #1, generation capacity is built in both nodes. However, the calculated RTC is zero for node A and is very high for node B (28261 \$/MW) compared to its generation investment cost. Note that one MW increase of the generation investment in node B results in about one MW investment in the connection line while one MW investment in generating unit of node A does not affect the transmission investment. This would result in 59.66 M\$ and 40.75 M\$ profits for SGP1 and SGP2, respectively. However, as seen in the result of iteration #2, based on charges in iteration #1, SGP2 decreases its investment while SGP1 increases its investment. This result is consistent with the new RTCs computed in iteration #2, so

TABLE I: Generation and Transmission Expanded Capacities and the System Social Cost for Different Iterations ($\alpha = 0.4$) and the Centralized Planning of the 2-node Illustrative Example; EC: Expanded Capacity, SC: System Social Cost

Runs	Units EC (MW)		Lines EC (MW)	SC (M\$)
	U1	U2	A-B	
Iteration #1	50	75	53	78.91
Iteration #2	100	25	3	76.1
Centralized Planning	150	30	0	74.64

SGPs do not change their actions and their final profits are 69.59 M\$ and 40.63 M\$ for SGP1 and SGP2, respectively. The energy not served (ENS) is the same for both iterations (17125 MWh), however, the final system social cost is 76.1 M\$, which is 3.6% lower than the system social cost in iteration #1. This shows the effectiveness of the calculated RTCs to improve the efficiency of the system development and to make it closer to the efficient result of centralized expansion. Finally, U1 does not pay anything and U2 pays 0.24 M\$ of the transmission investment costs.

Applying RTCs equal to zero, as corresponding to the first iteration of the proposed algorithm for the computation of RTCs, results in investments decided by the generation company located in the exporting node being well above the optimal level and, consequently, also investments in transmission capacity connecting both nodes being above the level that would result from the centralized joint expansion planning. When, in the second iteration of the algorithm, RTCs applied make the generation company U2 pay 40% of the cost of the transmission capacity required to export its power production to node A, U2 finds it profitable to decrease substantially its investments in generation capacity with respect to the first iteration, while investments by U1 (those in the importing node) increase substantially. Consequently, investments in transmission capacity decrease substantially as well. In this case, strategic generation investments by U1 and U2 and transmission capacity investments are closer to those resulting from the centralized expansion planning, i.e., the optimal ones. This results in a significant reduction in total system costs (about 2.81 M\$) with respect to the first iteration of the algorithm (first row in Table I), where RTCs equal to zero are applied. Convergence is achieved after this second iteration.

Changing parameter α determining the fraction of network investment costs paid by generation does not result in a reduction of the efficiency of system expansion (or the efficiency of the coordination between generation and transmission developments) with respect to the case where no RTCs are applied on generation. Values of α lower than 0.4, i.e., 0.3, 0.2, and 0.1, result in infinite iterations between two states with the results similar to the two iterations reported in Table I. In other words, with lower values of α , RTCs levied in iteration #1 on U2 are still large enough for SGP2 to reduce the capacity expansion of U2, but its RTC in iteration #2 is not large enough for SGP2 to keep its decision, and he goes back to investment decisions computed in the iteration #1.

B. The IEEE-RTS96

In this section, the cost allocation algorithm is simulated on the IEEE-RTS96. This system has 24 buses and 38 trans-

TABLE II: RTCs for the Different Iterations ($\alpha = 0.4$) of the 2-node Illustrative Example

Iteration #	Units RTCs (\$/MW)	
	U1	U2
1	0	28261
2	0	4784

TABLE III: Characteristics of the Generating Units of SGPs of the IEEE-RTS96

SGP# (Unit#)	Capacity (MW)	Node	Fuel Cost (\$/MWh)	Investment Cost M\$/MW/year
SGP1 (U1)	76	3	10	0.02
SGP2 (U2)	76	7	10	0.02
SGP2 (U3)	197	12	5	0.05
SGP3 (U4)	155	20	6	0.05

mission lines. The technical information such as power flow input data, transmission line capacities, and the weekly load data for this system are given in [50]. The single line diagram of the network is depicted in Fig. 2. For our analysis, we have divided this system into two areas, the north and the south, shown in Fig. 2, according to the two voltage levels in this system. The south area in the picture has more load and the north area has more generating capacity. Transmission investments considered concern the connection lines between these two areas, each line with 0.05 M\$/MW/year investment cost. The load level of the original IEEE-RTS96 is multiplied by a factor of 1.5, with 600 \$/MWh being the value of lost load. SGPs and their generating units, which can be upgraded, are listed in Table III. Investment options, as in the 2-node example, are zero, 0.25, 0.5, and 0.75 times the capacity of the generating units.

Fig. 2: Single-line diagram of the the IEEE-RTS96.

Analogously to the 2-node example system, considering initial values of RTCs equal to zero and the value of α equal to 0.4, the algorithm achieves convergence in three iterations and after 47 minutes of running time. Most of the running time is devoted to solving the MIP problem of SGPs in steps 1

TABLE V: RTCs for the Different Iterations ($\alpha = 0.4$) of the IEEE-RTS96

Iteration #	Units RTCs (\$/MW)			
	U1	U2	U3	U4
1	1836.9	1797.7	34246.7	50647.5
2	1835	1700.1	34211.8	50595.9

and 3 of the algorithm presented in Section II-C2. The results for generation and transmission investments as well as RTCs are reported in Tables IV and V, respectively. ENS amounts to 1574 MWh in iteration #1 and 1497 MWh in iteration #2. While the ENS increases by 5% in iteration #2, the System social cost decreases from 285.28 M\$ in iteration #1 to 278.11 M\$ in iteration #2. The decrease achieved in the system social cost is 7.17 M\$, i.e., 2.5% of the system social cost. Having this result, we can calculate the transmission investment costs paid by each generation company in each area. From the total cost of transmission expansion, 0.2 M\$ is paid by U1 and U2 in the area with higher load (the south area), and 7.57 M\$ is paid by U3 and U4 in the area with higher generation (the north area). The fact that companies in the north area make larger payments is not only related to the larger generation investment taking place in the north area, but also because of the higher RTCs applied there compared to the south area.

An important observation here is that imposing RTCs calculated in iteration #1, SGP2 decides to increase the size of the new capacity built in U2. This is because of the effect of the strategic behavior of SGPs on investments. If SGP2 does not change its decision (or reduce the expanded capacity of U2), with the new RTCs, the other players change their actions and SGP2 is worse off. In other words, even though the RTC for U2 increases, the equilibrium of the stated problem lies in a point where generation capacity built for U2 is larger. Then, the previous point of equilibrium in iteration #1 is not the Nash equilibrium anymore, meaning that at least one of the SGPs has an incentive to change its investment strategy assuming other SGPs do not change theirs. This example shows how the strategic behavior of SGPs might lead to results that are difficult to anticipate.

Next, we change the value of some input vectors to show that applying RTCs to generators might have a negative effect on the social welfare of the system. For this, we increase the value of α to 0.5. The new results are presented in Tables VI and VII. As one can see, the system social cost increases by 8.37 M\$ from iteration #1 to iteration #2. Then, in this case, RTCs are harmful. The reason for this is that, in iteration #2, as a result of transmission charges applied, SGP2 decides not to invest in U3 and, instead, increases its investment on U2 by 19 MW. Then, the total generation investment in the system decreases by 30.25 MW, and this results in an increase in the system social cost (U3 has the lowest fuel cost while U2 has the highest one). This result shows that RTCs can be ineffective when there is already under-investment in transmission capacity when not applying RTCs on generators ($RTC_s = 0$).

The results of the model developed, when applied to some case studies, show that the theoretical effect of RTCs on the development of the system, increasing its efficiency, is

TABLE IV: Generation and Transmission Expanded Capacities and the System Social Cost for Different Iterations ($\alpha = 0.4$) and the Centralized Planning of the IEEE-RTS96; EC: Expanded Capacity, SC: System Social Cost

Runs	Units EC (MW)				Lines EC (MW)					SC (M\$)
	U1	U2	U3	U4	3-24	9-11	9-11	10-11	10-12	
Iteration #1	57	38	49.25	116.25	121.525	32.724	69.215	62.657	100.19	285.28
Iteration #2	57	57	49.25	116.25	120.518	33.529	69.773	63.125	100.406	278.11
Centralized Planning	33.1	199.9	132.2	251.1	130.69	52.03	84.407	78.082	111.549	218.06

TABLE VI: Generation and Transmission Expanded Capacities and the System Social Cost for Different Iterations ($\alpha = 0.5$) and the Centralized Planning of the IEEE-RTS96; EC: Expanded Capacity, SC: System Social Cost

Runs	Units EC (MW)				Lines EC (MW)					SC (M\$)
	U1	U2	U3	U4	3-24	9-11	9-11	10-11	10-12	
Iteration #1	57	38	49.25	116.25	121.525	32.724	69.215	62.657	100.19	285.28
Iteration #2	57	57	0	116.25	114.843	18.176	54.391	54.154	91.357	293.65
Centralized Planning	33.1	199.9	132.2	251.1	130.69	52.03	84.407	78.082	111.549	218.06

TABLE VII: RTCs for the Different Iterations ($\alpha = 0.5$) of the IEEE-RTS96

Iteration #	Units RTCs (\$/MW)			
	U1	U2	U3	U4
1	2296.1	2247.2	42808.4	63309.4
2	2667.8	2414.7	0	69252.7

TABLE VIII: Comparing the Results for the Different Values of α for the IEEE-RTS96; SC: Social Cost

Value of α	Iteration #	SC (M\$)
0	2	285.28
0.1	3	286.374
0.2	5	293.65
0.3	NA*	NA
0.4	3	278.11
0.5	3	293.65
0.6	NA	NA
0.7	4	286.374
0.8	4	296.589
0.9	4	296.593
1	3	296.589

* NA: Not Available (infinite iteration).

contingent on the level of market power generators hold and are able to exercise. Not applying RTCs on generation turns out to result in larger generation investments than those decided by generation companies when they are subject to network charges. Thus, when, in the absence of network charges, their profit maximization strategies lead generators in exporting areas to build more generation capacity than needed, as in the 2-node case-example discussed above, applying cost-reflective RTCs leads these generators to reduce their investments in new capacity and, consequently, drives a more efficient development of the system (affecting both generation and transmission expansion). However, when, in the absence of RTCs applied on generation, the strategic behavior of SGPs leads them to build a lower amount of cheap generation capacity (the most cost competitive generation exporting power to other areas of the system) than the optimal level of investments in this capacity, applying cost-reflective RTCs not only is unable to trigger more efficient generation investments (directing these investments towards better locations or driving the generation technology mix closer to the optimal one), but, instead, reduces the amount of investments in cost competitive generation further, thus reducing the overall efficiency of the development of the system and increasing system social costs (as it can be concluded from the numerical results computed for the IEEE-RTS96 system considering a value of parameter $\alpha = 0.5$). When agents behave competitively, i.e., under perfect competition assumptions, applying cost reflective RTCs always results in an increase in the efficiency of the development of the system.

Table VIII shows the output of the proposed algorithm, i.e., the number of iterations and the social cost of the system, for several values of α from 0 to 1. As seen, the only value of α for which RTCs applied increase the efficiency of system expansion (decrease the system social cost compared to $\alpha = 0$, i.e., $RTCs = 0$) is $\alpha = 0.4$. It can be concluded that the value of α , which is decided by the regulator, is an important factor and can affect the system development significantly.

Having reliable information about the profit made by SGPs, the regulator can set the value of α accordingly to maximize the positive effects of RTCs.

IV. CONCLUSION

This paper proposes and analyzes an approach to impose transmission charges, named RTCS, in order to coordinate transmission expansion (coordinated by a central planner with the minimization of the social cost as the objective) with generation expansion (conducted by strategic generation planners, named SGPs, that maximize their profit). RTCs are calculated based on the marginal effect of generation investment on transmission expansion costs. An iterative algorithm is proposed to model the equilibrium between SGPs' investment decisions and the central planner's network investment decisions, where coordination takes place through RTCs. The algorithm is applied to compute the system development equilibrium in a 2-node illustrative example and the IEEE-RTS96. The results show that the theoretical effect of RTCs on the development of the system, increasing its efficiency, is contingent on the level of market power generators hold and are able to exercise. Therefore,

- RTCs should be designed carefully taking this into account. This is future research work to be addressed by authors of this paper.
- The strategic behavior of SGPs distorts also (among other things) the efficient coordination of generation and network expansion through RTCs. Measures to control

and reduce the level of market power held and exercised by SGPs are needed also to achieve a better coordination of generation and transmission developments.

In order to model the interaction between generation and transmission expansion planning strategies, and their eventual coordination through RTCs, we have adopted a simplified representation of the transmission and generation expansion planning problems, where only scenarios formed by the different demand levels on the future evolution of the system are being considered and for which the investment decisions are modeled as extra capacities for the lines and for the generating units. We assume that an increase in the capacity of a line does not change the topology of the network. Besides, another main limitation of the work carried out is related to the inability to achieve convergence of the algorithm proposed for the computation of RTCs for some of the possible values of parameter α . This means for some values of α , computing the effect that RTCs proposed would have on the development of the system would not be possible. Another limitation concerns the size of the system where RTCs proposed can be computed. The number of generation companies considered, that of potential investments to be undertaken by them, and the number of potential reinforcements to the network should be kept within certain limits to be able to solve the resulting problem. As for the future lines of research, alternative transmission charging schemes to the one proposed should be explored specially other transmission charging methodologies based on network usage by generators, like Average Participations or Marginal Participations [13]. Further work is also foreseen to extend the model to properly take into account larger network topological changes.

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