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Proactive transmission expansion planning with storage considerations

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ABSTRACT

Under the current European market environment, transmission companies have to decide network expansion by maximizing social welfare. However, generation companies (GENCOs) decide their capacity expansion with the aim of maximizing their own profit. This process, in addition to the increasing penetration of renewable energy, storage and distributed generation, might represent a rupture between short and long-term signals. Therefore, this paper proposes a bi-level formulation for the generation and transmission coordination problem (GEPTEP). We consider a proactive framework in which a centralized TSO represents the upper level while the decentralized GENCOs, that trade in the market, represent the lower level. As a novel feature, an enhanced representative period framework is employed, which allows us to consider operation in both short and long-term storage technologies. A case study is presented to compare the results between perfect and imperfect competition in the market.

1. Introduction

1.1. Motivation

Under the current European deregulated market, centralized TSOs have to decide network investment by minimizing total operation cost (or maximizing total welfare), while decentralized GENCOs decide their expansion by maximizing their own profit. This process creates contradictory incentives that can result in a misalignment of short and long-term signals. Moreover, when the ideal cost-minimizing generation capacity investment assumed by the TSOs differs from reality, (due to strategic market interactions between GENCOs), then the transmission expansion plan could end up not being the cheapest option for society. The question that we try to answer in this paper is: if instead of assuming perfect competition a TSOs foresees strategic market outcomes, can this be beneficial for society? In order words, we want to analyze and compare, under a proactive framework approach, how the decisions of either perfect competition or Cournot in the operation and generation investment can affect the transmission decisions and the total welfare that the TSO aims to maximize.

For instance, if we consider that a TSOs takes its investment decision first, we would expect that, in order to achieve lower operation costs, a TSOs would invest as much as possible in transmission lines. This decision could be explained because, for the long-term, the magnitude of transmission investment is lower than generation investment. However, GENCOs might prefer lower investments in transmission capacity and higher investment in generation capacity in order to benefit from short-term price increases resulting from transmission congestions. These effects, in addition to the increasing penetration of renewable energy, storage and distributed generation, result in greater differences between short-term incentives (dependent on intermittency of renewable sources) and long-term decisions (dependent on seasonality).

In this sense, we are interested in modeling how the competition in the electricity market affects and is affected by the long-term decisions in both generation and transmission expansion planning. Particularly, given that GENCOs interact with each other in a market driven framework while transmission is operated in a centralized way.

1.2. Literature review

Transmission and generation expansion planning have been very relevant topics in power systems. Both problems, separately, have gathered a great amount of research that has focused on studying the consideration of bigger networks, more detailed operation and the introduction of renewables, batteries and distributed generation. However, the analysis of these problems separately might disregard important existing links between generation and transmission. Therefore, the centralized co-optimization of the Transmission Expansion Planning and the Generation Expansion Planning (GEPTEP) is a relevant analytical framework to decide capacity investment given the interactions between both actors.

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1.2.1. Co-optimization models

A comprehensive literature review on co-optimization GEPTEP models can be found in Ref. [1]. The authors classify optimization models depending on how time and network are represented, which economic sectors are included and whether a policy or planning model is considered. Under the previous classification, we are interested in a detailed planning model of the power system that responds to the new complexities introduced by renewable generation and storage technologies. In the mathematical model proposed in this paper we formulate renewables as a non dispatchable technology, and, we allow the model to spill renewable energy if it is cost-optimal.

Regarding the modeling of storage capacity expansion, co-optimization models for transmission and storage can be found in Refs. [2,3]. In these articles, the authors highlight, for the case of storage expansion planning, that co-optimization leads to lower system costs compared to independent optimization problems. Additionally, in Refs. [4,5] authors develop a storage size and siting analysis. Authors in Ref. [4] show that the conditions of siting depend on the type of storage technology and [5] concludes that in order to guarantee recovery of investment a minimum profit constraint should be included.

Additionally, it has been established in Ref. [6] the importance of a correct representation of short-term operation for long-term decisions. In particular, authors in Ref. [6] show that this is especially true for storage technologies which can operate both in short (batteries) and long (hydro) term. Thus, authors in Ref. [6] present a thoughtful comparison of the available time representation modeling frameworks and apply them to a storage investment model. As a result [6], proposes a representative-period model with transition matrix and cluster indices. This framework is an extension of the usual representative days, by considering transitions between representative periods to be able to model inter-period constraints rather than only intra-period constraints. In this paper, we will follow this approach to represent time, slow and fast storage constraints.

Until now, we have described the centralized and coordinated GEPTEP framework. However, in the current market environment, the centralized co-optimization of a vertically integrated utility is a limited analytical tool that cannot answer the additional questions regarding the sequential and strategic interactions between investment and operation decisions in the electricity market. For this reason, equilibrium models, and, in particular, bi-level or multi-level problems have appeared in the literature as an alternative to study competitive and strategic decisions between agents.

1.2.2. Co-planning equilibrium models

Thus, regarding strategic-equilibrium models (which in GEPTEP context we will refer as co-planning equilibrium models), a literature review can be found in Refs. [7,8]. In these papers, models are classified depending on the solution method, the hierarchical structure of the model, the type of equilibrium and whether perfect or imperfect competition is considered.

In terms of the hierarchical structure in the Electric Power System, the agents of the system can be classified typically into three groups: GENCOS, TSO and Market Operation (MO). Accordingly, the GEPTEP problem is usually defined as a three level model. Under this framework, investment decisions are decided in the upper level GEP (or TEP) given the investment decisions in the middle level TEP (or GEP) and subject to the spot market (MO) in the lower level. It is important to clarify that, when the anticipation of the market outcome is considered, the GEPTEP problem would have three levels. However, the consideration of three separate levels introduces more complexities into the problem and consequently into its solving techniques.

Frequently, by applying different techniques, these three levels (**TEP** s.t GEP s.t market) of decisions are reduced to two levels as shown in Refs. [9,10]. However, these techniques imply that the mathematical structure of the problem will change from a mathematical program with equilibrium constraints (MPEC) to an equilibrium program with equilibrium constraints (EPEC) model. Alternatively, we can still consider an MPEC by having the TSO in the upper level, and simultaneous decisions of GENCOs and MO in the lower level (where market operations are guaranteed by TSO by maximizing congestions rents in the market). This would lead, in the lower level, to a spatial equilibrium market model as seen in Refs. [11–13]. Additionally, authors in Ref. [14] model a proactive bi-level approach but only the perfectly competitive case is considered and storage technologies are not modeled. Thus, in this paper, we will stick this MPEC structure by considering two levels: TEP in the upper level, and both GEP (including storage technologies) and MO decisions *simultaneously considered* in the lower level. In particular, bi-level modeling is based in a leader-follower approach that can be applied in Power Systems to represent hierarchical decisions between transmission and generation expansion planners. In terms of GEPTEP models, either proactive (TEP moves first) or reactive models (GEP move first) can be studied. This classification was first introduced by Ref. [10] in the seminal paper on bi-level GEPTEP. Authors in Ref. [10] consider a strategic model and demonstrate theoretically how proactive planning leads to greater social welfare compared to the reactive approach.

Most of the literature in co-planning equilibrium models for GEPTEP deals with the proactive approach. Indeed, in Ref. [15] a summary of some of the existing proactive models can be found. Authors in Ref. [16] extend the theoretical work done in Ref. [10] where only different investment plans were evaluated. Thus, in Ref. [16] a first complete model is proposed, however, in contrast to Ref. [10], they relax the Cournot assumption and they consider perfect competition in the electricity market to guarantee convexity in the lower level. Moreover, authors in Ref. [17] also define three levels; they assume perfect competition in the market in the lower level, strategic generation expansion in the middle level and transmission expansion in upper level.

Compared to Refs. [16,17] adds uncertainty in the demand and applies it to a real-size model. Additionally [18], extends this framework and proposes a model with Cournot strategic decisions in the market. Finally [19], relaxes Cournot assumption and proposes a two-level approach in the market outcome by considering an interaction between ISO market clearing problem and GENCOs optimal bidding strategies, resulting in a four-level model. However [18,19], propose heuristic techniques that do not guarantee a global optimum solution.[1] In contrast to the above references, we consider a two-level Cournot framework via conjectured responses, by considering MO and investment of GENCOs at the same level. This is done based on the work of [20] which shows that a bi-level model where investment decisions are followed by market decisions can, under certain circumstances, be simplified into a single-level model using conjectural variations. Additionally, we will we will compare the bi-level results both for the perfect competition and Cournot competitions cases.

In spite of the greater welfare achieved by the proactive approach, more recently authors in Ref. [21] develop a three-level reactive model where storage investment is included. Moreover [22], proposes a new comparison between the proactive and the reactive approach. In contrast to Ref. [17], authors in Ref. [22] propose the elimination of multiple equilibria by considering pessimistic and optimistic TSOs. Nevertheless, the choice of either hierarchical approach depends on the regulatory framework of the case study. For instance, in the European context, ENTSOe plays the role of a centralized agent in which regional coordination takes place; thus, a proactive approach will be more accurate.

Additionally, as mentioned above, we will focus on the modeling of storage technologies, and to our knowledge only [21] has considered detailed storage expansion in hierarchical models. However [21],

[1] It is important to note that, when strategic behavior is considered, multiple Nash equilibria can arise.

disregards hydro storage in his model, given that, in the existing literature, not adequate framework has been developed to jointly represent short and long-term storage technologies. We overcome this shortcoming by applying the aforementioned approach based on [6]. Additionally, authors in Ref. [21] develop a tri-level reactive model where investment in merchant storage is considered in the upper level, while transmission expansion and market are modeled in the middle and lower level respectively. As opposed to Ref. [21], in this paper both batteries and hydro storage are joined in a single lower level under a proactive approach, which has been proven to lead higher welfare compare to the reactive approach [10].

1.2.3. Modeling options

Finally, for transmission expansion planning, binary variables are the most recommended to successfully represent the lumpiness condition of transmission investment. In contrast, the representation of generation expansion planning decisions can be relaxed and still achieve accurate results, as shown in Refs. [7,15,16,23]. This consideration responds to the need of convexity conditions in the lower levels for multi-level approaches. Therefore, under a bi-level framework authors usually represent generation decisions with integer variables when transmission expansion is not considered, as seen in Refs. [8,9,24]. To our knowledge only [22] considers investment binary variables in both levels of a GEPTEP by solving the problem with a Moore Bard Algorithm. Start-up/shut-down or minimum stable-load-type conditions could also be considered in our model in order to make it more realistic. However, since those decision require binary variables in the lower level, introducing these constraints in our bilevel framework is not straight-forward. One option of accounting for these operating constraints might be by relaxing their integrality; however, the corresponding results would have to analyzed very carefully, and moreover, this would increase even more the size and complexity of the problem. To our knowledge, none of the bi-level models in the literature considers these constraints. We will explore this interesting topic in future research.

Furthermore, different options can be found to model the network. For instance, policy models such as [25–27] consider a transshipment model to simplify operation. This modeling is applied as an alternative to DC or AC modeling as they increase exponentially computational effort. However, operation models normally consider DC network but a limited time horizon. For the moment, a DC approach will be used. It is important to mention that the usual lossless DC approach can lead to multiple equilibria even for a basic configuration of the network. Thus, for future work, the consideration of a linear loss model can easily avoid this multiple equilibria problem and include a wider variety of configurations of the problem.

Moreover, we do not consider uncertainty in this paper. Conceptually speaking, introducing uncertainty would be a simple extension of our model, i.e. by means of stochastic programming for example. However, in our long-term investment problem we face different sources of uncertainty that can be either short long-term uncertainties, and that potentially should be addressed with different techniques such as robust optimization or stochastic programming in order to adequately capture to nature of each source of uncertainty (e.g. renewable production, policy decisions, price of fuels, demand evolution, etc.). However, this is out of the scope of this paper. In Section III, the mathematical formulation of the one-level and bi-level models is presented. In Section IV, we present a study case to compare centralized and decentralized models. In Section V, we conclude.

2. Model formulation

This section is divided in two parts. In Sub-Section 2.1. the market responsive framework is formulated and in 2.2 the proactive model is developed. Notation can be found at the end of the document.

2.1. Conjectured-price market

The market responsive framework, without the consideration of generation and transmission investment, is now formulated. We will follow the model proposed in Ref. [28]. For the sake of simplicity, we consider only one period, and only one GENCO per node. Considering one GENCO per node implies that the residual demand is seen by only one GENCO, and therefore each GENCO decides both price and quantity to be produced (considering transmission prices also, please see B2) as seen in as seen in Refs. [9–11]. Moreover, elasticity is assumed to be linear where *pDemand* represents the inelastic part of the demand and *pDslope* represents how it reacts to prices.

If Demand is given by equation (1) and if every GENCO maximizes its profit as in (2), then market conditions are given by (3)

$$vDemand_d = pDemand_d - pDslope_d * vProd_{gad(g,d)} \quad \forall\, g \tag{1}$$

$$Profit_g = \lambda_{gad(g,d)} * vProd_g - pFCost_g * vProd_g \quad \forall\, g \tag{2}$$

$$\frac{\partial Profit_g}{\partial vProd_g} = \lambda_{gad(g,d)} + vProd_g * \frac{\lambda_{gad(g,d)}}{\partial vProd_g} - pFCost_g = 0 \quad \forall\, g \tag{3}$$

Let us define $\theta_g = \frac{\partial\lambda}{\partial vProd_g}$ as the conjecture that is assumed to be known for every GENCO. *If* $\theta_g = 0$ we consider the Perfect Competition case (PC), and if $\theta_g = \frac{1}{pDSlope}$ we consider the Cournot Oligopoly case (CO).

2.2. Proactive model (PM)

First, we present the proactive framework in which TSO proposes investments and the GENCOs react to this decision, in this case perfect information and elastic demand are considered. Fig. 1 shows the proposed framework, where TSO is in the Upper Level (see Section 2.2.1) and GENCOs are in the Lower Level (see Section 2.2.2). Then, in Section 2.2.3, the lower level is re-formulated as a set of non-linear equations by considering its Karush-Kuhn-Tucker (KKT) conditions. Finally, in Section 2.2.4, the structure of the linearized one-level proactive problem is presented, allowing us to solve this problem as a one-level Mixed Integer Linear Program (MILP).

2.2.1. Upper level

The objective function (4) minimizes the investment cost in transmission lines (LI) and generation (GI) plus the total operation cost (OC). Each equation is defined for $p \in \Gamma_{rp,p}$.(except 20). Please note $\Gamma_{rp,p}$ indicates, from the whole year, which are the hours that constitute each representative days. Equation (8) states that if a line is built, it will continue functioning during the time horizon.

$$\underset{vNewLineydd'}{\text{Minimize}} \quad GI + LI + OC \tag{4}$$

Subject to (5)–(8), and Lower Level constraints.

$$GI := \sum_{gyd} (Y - y + 1) \times pInvC_g \times (vNewGen_{ygd} - vNewGen_{y-1,gd}) \tag{5}$$

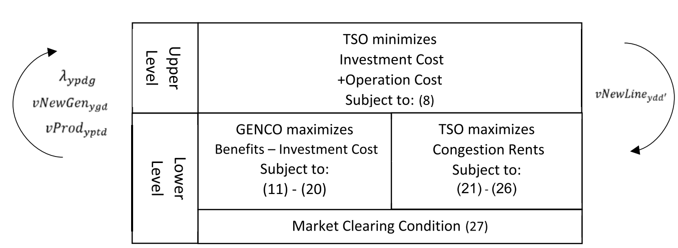


Fig. 1. Model hierarchy.

$$LI:=\sum_{ydd'}(Y-y+1)\times pInvC_{dd'}\times(vNewLine_{ydd'}-vNewLine_{y-1,dd'}) \quad (6)$$

$$OC:=\sum_{y,(p,rp)\in\Gamma_{rp,p},t,d} pW_{rp}\times pFCost_t\times vProd_{yptd} \quad (7)$$

$$vNewLine_{y-1,dd'}\le vNewLine_{ydd'}\ \ \forall\ (d,d')\in LC\ \ \forall\ y \quad (8)$$

2.2.2. Lower level

This model considers the market clearing conditions, the usual operating constraints and a detailed storage operation modeling. At this level, we have both the market clearing and generation investment decisions. On the one hand, GENCOs seek to maximize benefits defined as Operation Incomes (OI) minus Operation Cost (OC) and Generation Investment (GI). On the other hand, the TSO wants to maximize congestions rents. We consider that both players act simultaneously on the lower level.

It is important to note that the lower level is single-level equilibrium model with two types of players (GENCOs, and, TSO) who take generation capacity investment and production decisions (GENCOs), and, corresponding power flow and voltage angle decisions (TSO) simultaneously. This implies that there is no anticipation of market outcomes in generation capacity decisions by GENCOs. In any case, since we are able to adapt the degree of competition in the market in our model, choosing a less competitive market might "compensate" for this non-anticipation [29]. Therefore, we consider a spatial equilibrium model where generators compete a la COURNOT and react naively to the transmission congestions as in Ref. [30]. This generalizes the work done in Ref. [20].

Finally, we assume that there is only one GENCO per node, but we might have several generation units per GENCO. Moreover, we consider only one unit per GENCO and thus index g represents both generators and company.

2.2.2.1. GENCO problem.

The dual variables of each set of equations appear after colons.

$$arg\ \underset{LL}{\text{Maximize}} OI-OC-GI \quad (9)$$

$$LL:=\{vNewGen_{ygd},\ vProd_{yptd},\ vCon_{yphd},\ vSpill_{yphd}\}$$

$$OI:=\sum_{y,(p,rp)\in\Gamma_{rp,p},t,d} pW_{rp}\times(\lambda_{ypd\in(GAD)})\times vProd_{yptd\in(GAD)} \quad (10)$$

Subject to (5), (7), (10), (11)–(20).

Equation (27) represents the nodal power balance (or market clearing condition) in which demand must equal local generation plus power inflows and minus power outflows. The dual variable λ_{ypd} related to this set of constraints correspond to the Locational Marginal Prices (LMP).

$$0\le vProd_{ypgd}\le pMaxProd_g:\ \bar{\rho}_{ypgd},\ \underline{\rho}_{ypgd}\ \ \forall\ g\in GED,\ \forall\ ypd \quad (11)$$

$$0\le vWind_{ypwd}\le pMaxWind_{wnp}$$
$$:\ \overline{\rho w}_{ypgd},\ \underline{\rho w}_{ypgd}\ \ \forall\ w\in GED,\ \ \forall\ ypd$$

$$0\le\ vProd_{ypgd}\le pMaxProd_g\times vNewGen_{ygd}$$
$$:\ \bar{\omega}_{ypgd},\ \underline{\omega}_{ypgd}\quad \forall\ g\in GCD,\ \forall\ ypd \quad (12)$$

$$0\le\frac{vCon_{yphd}}{pEfficiency_h}\le pMaxCons_h$$
$$:\ \bar{\kappa}_{yphd},\ \underline{\kappa}_{yphd}\quad \forall\ h\in GED,\ \ \forall\ ypd \quad (13)$$

$$0\le\frac{vCon_{yphd}}{pEfficiency_h}\le pMaxCons_h\times vNewGen_{yhd}$$
$$:\ \bar{\eta}_{yphd},\ \underline{\eta}_{yphd}\quad \forall\ h\in GCD,\ \ \forall\ ypd \quad (14)$$

$$-vNewGen_{y-1,gd}+vNewGen_{ygd}\ge 0$$
$$:\ \underline{\beta}_{ygd}\qquad \forall\ ygd \quad (15)$$

$$0\ge -vNewGen_{ygd};\ 0\ \le MaxGen_g-vNewGen_{ygd}$$
$$:\ \bar{o}_{ygd},\ \underline{o}_{ygd}\qquad \forall\ ygd \quad (16)$$

$$pMinLevel_h\le vLevel_{yphd}\le pMaxLevel_h$$
$$:\ \bar{\mu}_{yphd},\ \underline{\mu}_{yphd}\qquad \forall\ yphd \quad (17)$$

$$0\ \ \le\ \ vSpill_{yphd}:\ \underline{\mu}'_{yphd}\qquad \forall\ yphd \quad (18)$$

$$vLevel_{yph_fd}=vLevel_{y,p-1,h,d}+vLevel_{y=1,p=1,h,d}+pInflow_{yph_fd}-vSpill_{yph_fd}$$
$$-\ vProd_{yph_fd}+vCon_{yph_fd}$$
$$:\ \psi_{yphd}\ ,\ \forall\ h_f\in GED,\ \ p<pf,\quad \forall\ yphd, \quad (19)$$

$$vLevel_{yphd}=vLevel_{y,p-M,h,d}+vLevel_{y=0,p=1,h,d}$$
$$+\sum_{p'}^{p}\sum_{p''}\left(pInflow_{yp''hd}-vSpill_{yp''hd}-\ vProd_{yp''hd}\right.$$
$$\left.+\ vCon_{yp''hd}\right):\ \psi'_{yphd}\qquad \forall\ h\in GED,\ \ p<pf,\quad \forall\ yd,$$
$$with\ p`=p-M+1\ and\ p\ \in Ps,\ \ p''\in H(p',\ p'')\ \ Ps$$
$$=\left\{ps|\frac{ps}{M}\in Z^{+}\right\} \quad (20)$$

Equations (11), (13), (16)–(18), (21) represent the upper and lower bounds of the existing elements of the system. While equations (12) and (14) represent the lower bounds of the candidate new elements in the system. Equations (21) and (22) represent the DC formulations of the network for existing lines, while equations (23)–(26) represent the DC formulations for new lines. In (23)–(26), a Big M approach has been used to linearize the product between investment decisions and angles. Finally, equations (19) and (20) represent the storage balance conditions as proposed in Ref. [31]. On the one hand, equation (20) is considered for long-term storage i.e. hydro when only interday balance is considered. With this equation, reservoir management is followed up across the entire year, as opposed to the rest of constraints in which only intraday operations are included. For the hydro case the parameter ***pInflow*** represents the water inflows in the year (in energy), ***vCon*** represents pumping decisions and ***vProd*** the production decisions of the hydro unit. On the other hand, equations (20) and (19) are jointly considered to represent short-term storage when intraday operation is relevant i.e. batteries. In this case, we do a daily energy balance of the battery but also a i.e weekly balance to consider the transition between the representative days. For batteries, ***pInflow*** is set to 0, and ***vCon*** and ***vProd*** represent charging and discharging of the battery. While the detailed formulation and explanation of this representation of storage is presented in Ref. [23], we briefly explain it here for clarity.

The reservoir energy balance is verified for a given time window. For instance, consider 4 representative periods, a 168 h (one week) window and two weeks as shown in Fig. 2. Thus, the reservoir balance equation (20) will be verified at the end of every week e.g. at M1 and M2. Thus, the interday balance is the sum of inflows and consumption minus spillage and production for every "representative hour" (p"), which represents each hour of the year (p'). In addition, they are summed over the window M until hour ($p\ \in Ps$). Please note that $H(p'',p')$ maps each hour of the year to its corresponding hour in the

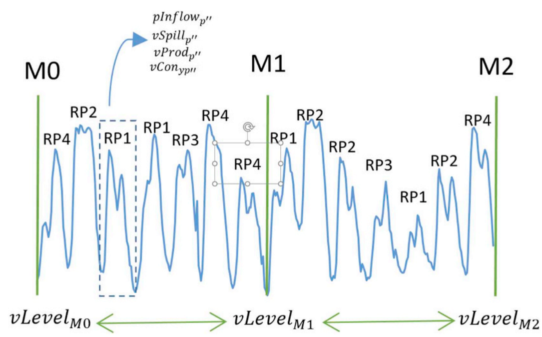


Fig. 2. Interday energy balance.

appropriate representative day (i.e the first 24 h of the year can be represented by hours 5545–5568 of RP4), and is not to be confused with $\Gamma_{rp,p}$ that tells us which hours of the year are the representative ones (i.e RP4 is made of hours 5545–5568).

2.2.2.2. TSO problem. We assume that the (TSO) that wants to maximize congestions rents from price differences.

$$arg \underset{vFlows_{ypdd'}, vTheta_{ypd}}{\text{Maximize}} \sum_{y,p,d} (\lambda_{ypd\in(GAD)} - \lambda_{ypd'\in(GAD)}) \times vFlows_{ypdd'}$$

s.t

$$pMaxFlows_{dd'} \geq vFlows_{ypdd'} \geq -pMaxFlows_{dd'}$$
$$: \bar{\phi}_{ypdd'}, \underline{\phi}_{ypdd'} \quad \forall (d, d') \in LE, \forall yp \quad (21)$$

$$vFlows_{ypdd'} = pSB \times \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}}$$
$$: \phi_{ypdd'} \quad \forall (d, d') \in LE, \forall yp \quad (22)$$

$$vFlows_{ypdd'} \geq -pMaxFlows_{dd'} XvNewLine_{ydd'}$$
$$: \underline{\zeta}_{ypdd'} \quad \forall (d, d') \in LC, \forall yp \quad (23)$$

$$- vFlows_{ypdd'} \geq -(pMaxFlows_{dd'} \times vNewLine_{ydd'})$$
$$: \bar{\zeta}_{ypdd'} \quad \forall (d, d') \in LC, \forall yp \quad (24)$$

$$- vFlows_{ypdd'} \geq \left(-pSB \times \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} - pMaxFlows_{dd'}(1 - vNewLine_{ydd'})\right)$$
$$: \bar{\tau}_{ypdd'} \quad \forall (d, d') \in LC, \forall yp \quad (25)$$

$$vFlows_{ypdd'} \geq \left(pSB \times \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} - pMaxFlows_{dd'}(1 - vNewLine_{ydd'})\right)$$
$$: \underline{\tau}_{ypdd'} \quad \forall (d, d') \in LC, \forall yp \quad (26)$$

2.2.2.3. Market clearing.

$$\sum_{g\varepsilon GAD} vProd_{ypgd} + \sum_{g\varepsilon GAD} vWind_{ypwd} + \sum_{d'\varepsilon LA} vFlows_{ypdd'} - \sum_{d'\varepsilon LA} vFlows_{ypd'd} + \sum_{g\varepsilon GAD} \frac{vCon_{yphd}}{pEfficiency_{h\varepsilon GHD}} = pDemand_{ypd}$$
$$: \lambda_{ypd} \quad \forall y, p, d \quad (27)$$

The simultaneous consideration of the GENCO, TSO, and market clearing condition represent the wholesale market for the case of perfect and imperfect competition (depending on the conjectural variation described in II.A).

2.2.3. Lower level KKT conditions

An equivalent formulation for the lower level optimization problem is presented. KKT conditions are the following:

- Primal feasibility conditions. TSO: (21)–(27) and Gencos: (11)–(20)
- Dual feasibility conditions. TSO: (28)–(29) and Gencos: (30)–(36)
- Complementary slackness conditions[2]

Dual feasibility conditions (Each equation is defined for $p \in \Gamma_{rp,p}$, except for equations (32)–(36).):

$$\phi_{ypdd'\in LE(d,d')} + \underline{\phi}_{ypdd'\in LE(d,d')} - \bar{\phi}_{ypdd'\in LE(d,d')} + \underline{\zeta}_{ypdd'\in LC(d,d')} - \bar{\zeta}_{ypdd'\in LC(d,d')} + \bar{\tau}_{ypdd'\in LC(d,d')} - \underline{\tau}_{ypdd'\in LC(d,d')} + \lambda_{ypd'\in(GAD)} - \lambda_{ypd\in(GAD)} = 0 : vFlows_{ypdd'} \quad \forall\ ypdd' \quad (28)$$

$$\sum_{d\in LE(d,d')} \frac{pSB}{pReactance_{dd'}} * \phi_{ypdd'} - \sum_{d'\in LE(d,d')} \frac{pSB}{pReactance_{d'd}} * \phi_{ypd'd} + \sum_{d\in LC(d,d')} \frac{pSB}{pReactance_{dd'}} * \bar{\tau}_{ypdd'} - \sum_{d'\in LC(d,d')} \frac{pSB}{pReactance_{dd'}} * \underline{\tau}_{ypd'd} - \sum_{d'\in LC(d',d)} \frac{pSB}{pReactance_{d'd}} * \bar{\tau}_{ypd'd} + \sum_{d\in LC(d,d')} \frac{pSB}{pReactance_{d'd}} * \underline{\tau}_{ypdd'} = 0 : vTheta_{ypd}, \forall\ ypd \quad (29)$$

$$\sum_{gyd} (Y - y + 1) * pInvC_g + \sum_{gyd} (Y - y + 1) * pInvC_g + pMaxProd_g * \bar{\omega}_{ypgd} + \underline{\beta}_{ygd} - \underline{\beta}_{y+1,gd} - \bar{o}_{ygd} + \underline{o}_{ygd} = 0$$
$$: vNewGen_{ygd} \quad \forall\ ygd \in GCD \quad (30)$$

$$- vDemand_{ypd} + pDemand_d - pSlope * vProd_{yptd} = 0$$
$$: vDemand_{ypd} \quad \forall\ ygd \in GAD \quad (31)$$

For equations (32)–(36) we define $p'' = p' + 1 - M$ $Pa = \{p|p \in \Gamma_{rp,p}\}$, $Ps = \left\{ps|\frac{ps}{M} \in Z^+\right\}$, $and\ Pt = Ps \cup Pa$

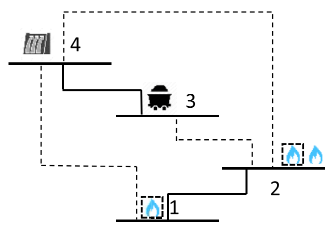
$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p},d} pW_{rp} * \left(-FuelCost_{tp} + vProd_{yptd} * \frac{\partial\lambda_{ypd\in(GAD)}}{\partial vProd_{yptd_g}}\right)\right) + \lambda_{ypd\in(GAD)} - \bar{\rho}_{ypgd\in(GED)} + \underline{\rho}_{ypgd\in(GED)} - \bar{\omega}_{ypgd\in(GCD)} + \underline{\omega}_{ypgd\in(GED)} + \sum_{p'}^{p'} (\psi_{yph}) = 0, \quad :vProd_{ypgd} \ \forall\ y, hd \in (GED)\ \forall\ p' \in H(p', p) /\ p \in Pa,\ p' \in Ps \quad (32)$$

$$\bar{\kappa}_{yphd} - \underline{\kappa}_{ygphd} + \psi_{yph_fd} + \sum_{p'}^{p'} (\psi'_{yph}) = 0, \ : vCon_{yphd} \quad \forall\ p' \in H(p', p),\ p \in Pa,\ p' \in Ps,\ \forall\ y, hd \in (GED) \quad (33)$$

$$-\bar{\mu}_{yphd} + \underline{\mu}_{yphd} + \sum_{p'}^{p'} \psi_{yph} = 0 \ : vSpill_{yphd} \quad \forall\ p' \in H(p', p)\ p \in Pa,\ p' \in Ps, \forall\ y,\ hd \in (GED) \quad (34)$$

$$\lambda_{ypd\in(GED)} + \overline{pw}_{ypgd}, \underline{pw}_{ypgd} \quad \forall\ ypwd \in (GED) \quad (35)$$

[2] Linearized conditions can be found in ANNEX.



Node	Max/Min (MWh)	GENCO (g, tec)	Fuel Cost (€/MWh)	Capacity (MW)
2	572/303	(C2,CCGT)	31	550
3	286/151	(C3,Coal)	54	588
4	429/227	(C4,Hydro)	0	500

	Reservoir (GWh)		Inflows (MWh)	
	Max	**Min**	**Max**	**Min**
Hydro	240	60	0.8	0.1

Fig. 3. System characteristics.

$$-\bar{\mu}_{yphd} + \underline{\mu}_{yphd} + \psi_{yp\in Pa,h_f d} + \psi_{y,p+1\in Pa,h_f d} + \psi'_{yp\in Ps,hd} - \psi'_{y,p+M|p\in Ps,hd} = 0 \quad :vLevel_{yphd}\ \forall\ p \in Pt,\ \forall\ yhd \in GED \tag{36}$$

Please note that all the previous equations are linear, therefore the only nonlinearities are those introduced by the complementarity conditions. Consequently, this set of KKT conditions can be solved either as an NLP or formulated and solved as an MPEC. Nevertheless, we can only guarantee to find a local optimum when solving NLP or MPEC and, in some cases, no solution might be found. In order to tackle the limitations of this approach, a bi-level MILP problem is formulated to obtain a global optimum solution.

2.2.4. Bi-level MILP formulation

The bi-level problem is formulated as a MILP. For this purpose, we apply the Fortuny-Amat linearization technique first proposed in Ref. [32] to transform complementarity conditions into linear constraints. Therefore, the MILP problem is given by the box below. Details of the linearization of complementarity slackness conditions are included in the Appendix. It is important to note that a Big-M parameter is defined for each block of equations. We do this to tune the parameters depending on the nature of the constraint in order to avoid numerical errors.

Objective function (4)
Subject to:
Upper level constraints: (5)–(8)
Primal feasibility constraints: (11)–(20)
Dual feasibility constraints: (28)–(36)
Linearized complementarities: (39)–(51)

3. Case study

3.1. Data

The system, as shown in Fig. 3, is composed of 4 nodes, with demand in each node. We consider 3 generation companies (C2, C3, C4), 3 existing generators, and 2 candidate generators for companies C2 and C3 (candidate generator in node 1 belongs to C3 and candidate generator in node 2 belongs to company 2). For the network configuration, we consider two scenarios: Green-Field Scenario (GF): In this scenario, we assume that no network is in place and investments have to be done from scratch. Brown-Field Scenario (BF): In this scenario, we have the network depicted in Fig. 3. Therefore, we have 2 existing and 3 candidate lines. Continuous lines in Fig. 3 represent existing units and existing transmission lines. Dotted lines represent candidate units and candidate transmission lines. We also include fuel cost and capacity of the existing generators. Additionally, for the hydro unit we have the maximum and minimum reserve levels of the hydro reservoir as well and the maximum and minimum hourly inflows into the reservoir. Finally, to keep this case study simple we disregard wind spillages and we consider a net total demand.

In Tables 1 and 2 we can find the operation and investment cost of

Table 1
Candidate lines.

From Node	To Node	Reactance [p.u]	Annual Inv Cost (M€)	Capacity (MW)
3	4	0.03	0.375	200
1	2	0.03	0.375	200
1	4	0.03	0.375	200
2	3	0.03	0.375	200
2	4	0.03	0.375	200

Table 2
Candidate generators.

(G, TEC)	Node	Annual Inv Cost [k €/MW]	Fuel Cost (€/MWh)	Capacity (MW)
(C2,CCGT)	2	29	27	667
(C3,CCGT)	1	40	28	500

candidate units and lines (we include all lines as candidates for GF case) as well as their location and maximum capacity. Additionally, for this study case, 4 representative days (24 h each) are chosen, a window of 168 h is selected and the model is run for a 1-year horizon. We chose 4 days based on the study done in [6], where a comparison of CPU time compared to objective function error was done for a different number of representative days. Compared to their study we chose less days because of the complexity introduced by Big-M constraints into bi-level models. Additionally, the model is generic and can be solved for a multi-year horizon, however, given the complexities of bi-level models and the new formulation for long and short-term storage, we decided to consider only 1 year to focus in depth on the basic planning results.

Additionally, we consider two different competition cases both from GF and BF scenarios. We consider the Perfect Competition (PC) case with $\theta_g = 0$ and the Cournot Oligopoly (CO) case with $\theta_g = 0.008$, please see Section II.A. The model is coded in GAMS, solved with GUROBI and run on a computer with 3.4 GHz processor and 32 GB of RAM. For the GFS the PC case takes 145 s and the CO case 2000 s with a 0% integrality gap. For the BF case the PC model takes 969s and CO takes 1158s for a 1% integrality gap.[3]

3.2. Operation and investment results

First, we analyze investment decisions. Tables 3 and 4 show transmission and generation capacity expansion. First of all, we observe that the degree of competition in the market affects optimal TEP decisions.

[3] The window considered highly affects computational time. For BF case we set a 85 h window and we let the program run for 10000 s but the gap did not decrease from 5%.

Table 3
Transmission expansion.

		Generation Company	Generation Exp (MW)	Annual Inv Cost (M€)
GF	PC	C3, CCGT	560	16.80
	CO	C3, CCGT	545	16.36
BF	PC	C2, CCGT	360	
		C3, CCGT	57.5	13.10
	CO	C3, CCGT	350	10.52

Table 4
Generation expansion.

		Lines Invested	Capacity (MW)	Annual Inv Cost (M€)
GF	PC	(2–4) (3-2) (3–4)	600	0.37
	CO	(3-2)(3–4)	400	0.75
BF	PC	(2–4) (3-2)	400	0.75
	CO	(3-2)	200	0.37

This indicates that a bi-level model provides insights that a single-level model is not able to yield. Moreover, from Tables 3 and 4 we can see that for both GF and BF scenarios capacity expansion is higher in the PC case compared to the CO case. This is reasonable because, in a perfectly competitive environment, GENCOs cannot react strategically because they do not have market power and therefore the TSO tends to over-invest to guarantee lower operational costs. Inversely, in a Cournot oligopoly framework, GENCOs have market power and tend to under-invest in order to increase their profits, a phenomenon observed often [20,29]. Please note that in the CO case the generator at node 1 remains isolated, this is a direct consequence of the elasticities chosen at each node. If a less elastic demand were chosen at node 1, the model would decide to connect it to the network. Below we will analyze system costs and efficiency by introducing the welfare measure.

In order to analyze the efficiency of each framework we use the welfare. We compute the Social Welfare as the summation of the Consumer Surplus (CS) and the Producer Surplus (PS). Please note that the calculation of the CS is the usual expression that results from the integral of the utility of the demand.

$$CS = \sum_{A} \frac{pDemand}{pSlope} vProd_{yptd} - \frac{1}{2pSlope} * vProd_{yptd}^{2} - \lambda_{ypd(GAD)} * vProd_{yptd} \quad (37)$$

$$PS = \sum_{A} \lambda_{ypd(GAD)} * vProd_{yptd} - pFCost_t * vProd_{yptd} - \sum_{ygd} pInvC_g * (vNewGen_{ygd}) - \sum_{ydd'} pInvC_{dd'} * (vNewLine_{ydd'}) \ A = \{(y, p, t, d) | y \in Y, (p, rp) \in \Gamma_{rp,p}, t \in T, d \in D\} \quad (38)$$

Table 5 contains the Total Costs of the System (TCS), Operational Costs (OC), System Demand (SD) and the Relative Operational Costs per TWh produced (ROC). Table 6 contains Social Welfare (SW), Producer Surplus (PS), Relative Produce Surplus (RPS), Total Investment (TI) and Demand Supplied per MW of Investment (DSI), computed as the ratio between SD and TI, for each one of the scenarios and cases. At first glance, we obtain some counterintuitive results. For both GF and BF scenarios PC total costs are higher than CO total costs, however, as seen in Table 5 this is mainly true because in the PC case more SD is met compared to CO. Therefore, if we compute the ROC, we obtain that ROC in PC is lower than in the CO case. This supports the hypothesis, mentioned above, that higher investment in PC leads to lower ROC while a lower investment in CO leads to higher ROC.

We can see in Table 6, surprisingly, that CO welfare is higher than PC welfare. This suggests that, for sequential games, the absence of perfect competition in the market can be beneficial to society as a whole. In fact, similar results have been observed in Ref. [20]. Authors

Table 5
Costs.

		TSC (M€)	TIC (M€)	OC (M€)	SD (TWh)	SPD (GW)	ROC M€/TWh
GF	PC	210	17.2	148	9.15	1.88	16.19
	CO	191	17.1	144	8.77	1.95	16.49
BF	PC	187	13.9	143	8.99	1.54	16.00
	CO	172	10.9	146	8.79	1.24	16.66

Table 6
Welfare.

		SW (M€)	PS (M€)	RPS [p.u]	TI (MW)	DSI (MWh/MW)
GF	PC	1282	294	0.22	1160	7.88
	CO	1405	394	0.28	945	9.27
BF	PC	1088	324	0.29	617	10.99
	CO	1113	379	0.34	550	15.95

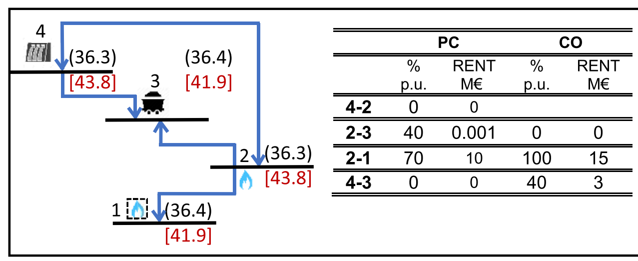


Fig. 4. Flows direction and congestion BrownField.

Fig. 5. Market share.

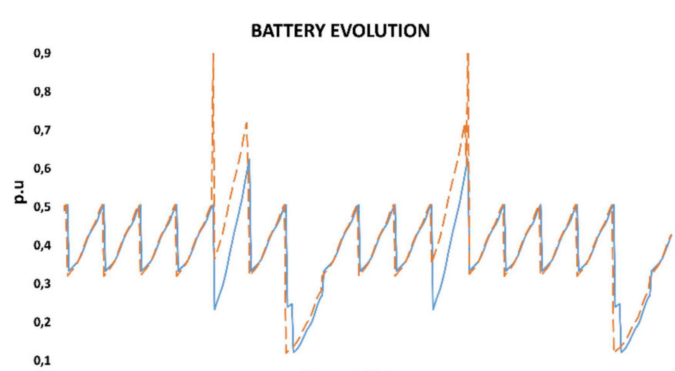


Fig. 6. Battery usage.

Table 7
SBF capacity expansion.

	IL	TCI (MW)	IG & S	GCI (MW)	TI (MW)	SD (GWh)	PSD (GWh)	DSI (MWh/MW)	WF (M€)	RWF (M€)
PC	2–4	200	C2, B	36,4	236.4	7	1.37	29	813	116
CO	–	0	C2, B	37.7	0	4.5	0.87	119	742	164

in Ref. [20] show that, when operation is anticipated by capacity expansion, social welfare results are case-dependent and therefore we can obtain cases with higher efficiency in Cournot competition than in perfect competition. Even though market power increases (seen as producer surplus increases) total welfare is still higher in the CO case.

For this purpose, we have computed the relative producer surplus (RPS) as the ratio between PS and welfare. As seen in Table 6 in both GF and BF cases RPS is greater in CO than in PC. This result indicates that more market power can actually be beneficial to society depending on the case at hand. This can be explained by the fact that the amount of demand supplied by one MW of investment (DSI) is greater in CO than in PC case, as seen the last column of Table 5. Somehow, the investment that is taken under CO is more efficient as it supplies more demand relatively speaking. This fact can also be explained by the network effects occurring in a non-arbitrage Cournot spatial model as seen in Fig. 5. In such a case, flows can be inverted given that, as mentioned in Ref. [13], the elasticity at some nodes incentivizes generators to reduce prices, and with the absence of a marketer this leads to non-cost based price differences. Therefore, this may cause that reduced transmission capacity increases welfare in some cases.

Additionally, the RPS for CO in BF scenario is greater than RPS for CO in GF scenario. This can be explained because the given network in BF is not optimal and not perfect, and therefore companies are capable of exercising a greater market power. Moreover, it is also true for the inverse case. The relative consumer surplus RCS = (1-RPS) in PC is greater than in CO case for both GF and BF scenarios. Additionally, RCS for PC case in GF scenario is greater compared to the PC case in BF scenario, in accordance to the fact the PC leads to an optimal setting and therefore consumer surplus is greater.

Moreover, In Fig. 4 we can study how companies' market share varies in the different scenarios. We compute it as the relative production of each company over total production. In each scenario, the inner circle refers to the PC case while the outer circle refers to the OC case. On the one hand, in GF, the market share of each company under PC and CO are very close, strategic behavior does not defers from perfect competition. This can be explained because in the GF scenario, the leader TSO decides over most capacity and can lead to a closer competitive market under the CO case. On the other hand, the market share changes drastically from PC to OC under BF scenarios. This is due to the initial configuration of the network in BF. The fact that in the BF line (1–2) is already built (which otherwise would not be) makes company 2 and 3 to be more cost efficient. In addition, in the CO case it leads to an increase, of companies 2 and 3, of relative market power compared to company 4.

In Fig. 5 we show the directions of the power flow for the Brownfield case. In the black upper brackets and the lower red brackets, we present the average prices (€/MWh) per node for the PC and the CO case respectively. The arrows in Fig. 5 represent the direction of the flows through the lines. This direction is the same during all hours, except for line (4-2) (which is only built in the PC case) where flows appear in both directions. In the CO case line (2–3) is never congested, (2-1) is always congested and (4-3) is congested 40% of the time of the year. For the PC case lines (4-2) and (4-3) are never congested while (2–3) and (2-1) are congested 4% and 75% of the time respectively. As we can see, in the PC case lines are less congested and average prices are closer. As expected in the PC case, flows on average go from low price nodes to high prices nodes. However, in the CO case the direction of power flows are inverse and go from high prices to low prices, a counterintuitive results already seen in Ref. [13]. As mentioned above, this can happen because the elasticity at some nodes incentivizes generators to reduce prices, and with the absence of a marketer, this leads to non-cost based price difference.

3.3. Storage results

Finally, we analyze an additional scenario with storage investment. We take the same system configuration as in Fig. 3, but we replace the CCGT candidate generator in node 1, with a Battery (B) belonging to company 4. We call this new scenario Storage Brown Field (SBF) in contrast to the previous Brown Field Scenario with CCGT candidates (now CBF). We consider a battery with 250 MWh of installed capacity, 50 MW of maximum charge/discharge and investment cost of 400 k €/MW. Table 7 contains Invested Lines (IL), Transmission Capacity Investment (TCI), Invested Generation (IG), Storage (S) Generation Capacity Invested (GCI), Total Investment (TI) defined as TCI + GCI, System Demand (SD) and Demand Supplied per MW Installed (DSI). As we can see in Table 7 DSI is higher for both PC and CO compared to CBF scenario. This means that the joint TEP and GEP investment in the storage case is more efficient than TEP and GEP in the base case. Additionally, DSI in CO is much higher than in PC, which suggests that, in this case, storage investments are more efficient in CO than in PC.

Moreover, Fig. 6 shows the usage of the battery (normalized by maximum capacity), we select the period of the year from h3600-h4200. As we can see, for the CO case the battery level is kept higher than PC case. The discharge cycles[4] are similar but in CO the battery reaches higher levels for both upper and lower bounds, this makes the percentage of energy produced by battery (over total production) in CO case 19% compared to a 13% on the PC case. Therefore, in CO the installed battery is used more than under PC. However, in CO prices are higher because COAL (with higher variable costs) is the new peaking unit, which replaces CCGT in PC. These results lead to a greater total welfare in PC compared to CO as seen in Table 7. Additionally, taking into account that the Demand Supplied by Investment (DSI) is much higher in CO than PC, again the Relative Welfare (RW) is greater in CO than PC.

4. Conclusions

In this paper, we develop an analytical framework to study the strategic interaction between a centralized transmission planner and decentralized GENCOs. As a novelty, we apply an enhanced representative-period framework that permits us to introduce both long-term and short-term operation constraints to study the yearly evolution of the energy stored. Additionally, we compare the investment and welfare results in a proactive transmission expansion framework where the TSO anticipates either perfect or Cournot competition in the market. We obtain some counterintuitive results where Cournot

[4] Please note that the battery cycles are daily because of our choice of representative periods as days. Therefore, as mentioned in Ref. [6] if the true period of the cycles (for a fully hourly model) are longer than 1 day, they can be misrepresented by the representative periods approach.

competition in bi-level models, under some circumstances, can be beneficial to society as a whole. We also see that a Greenfield planning leads to lower market power compared to a Brownfield planning. For future work, stochasticity can be introduced in order to model renewables accurately. Additionally, this can help to enrich the analysis of strategic competition between production and investment decisions. Finally, a linearized loss approximation or AC approach can be introduced to eliminate multiple solutions and to have more accurate dispatch results.

Acknowledgements

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Notation

A. Sets/Indices

$y \in Y$	year
$p \in P$	periods
$rp \in RP$	representative periods
$\Gamma_{rp,p}$	set of correspondence between *rp* and *p*
p	final period
$d \in D$	nodes
$g \in G$	generator unit *g*
$t(g) \in T$	thermal units
$h(g) \in H$	storage units
$hf(h) \in HF$	short-term storage units
$hs(h) \in HS$	long-term storage units
$GAD(g, d)$	set of all possible *g* located at node *d*
$GED(g, d)$	set of existing g located at node *d*
$GCD(g, d)$	set of candidate g located at node *d*
$LA(d, d')$	set of all possible lines from node *d* to *d'*
$LE(d, d')$	set of existing lines from node *d* to *d'*
$LC(d, d')$	set of candidate lines from node *d* to *d'*
Hpp'	Univocal correspondence between period *p* and *p'* $\in \Gamma_{rp,p}$

B. Parameters

$pMaxProd_g$	Maximum capacity of technology *g*	MW
$pMaxFlow_{dd'}$	Maximum flow in line *dd'*	MW
$pReactance_{dd'}$	Reactance of line *dd'*	[p.u]
$pFCost_t$	Fuel cost of technology *t*	€/MWh
$pFixCost_t$	Fix operation cost of thermal generator *t*	€
$pInvC_g$	Annualized investment cost *g*	€/MW
$pInvC_{dd'}$	Annualized investment cost of line *dd'*	€
$pDemand_{ypd}$	Demand Intercept at year *y* period *p* at node *d*	MW
$pDSlope$	Demand Slope	€/MW
$pEfficiency_h$	Efficiency of storage unit *h*	[p.u]
$pInflow_{ph}$	Energy inflows for period *p* storage *h*	MWh
$pMaxLevel_h$	$pMinLevel_h$Max/Min reservoir level of storage unit *h*	MW
$pMaxCons_h$	Maximum consumption of storage unit *h*	MW
M	Time window	h
pW_{rp}	Weight of each representative day	[p.u]
pSB	Base Power	MW

C. Variables

$vProd_{ypgd}$	Production at year *y* period *p* of generator *g* at node d	MW
$vNewGen_{ygd}$	Investment status at year *y* of generation unit g at node d	{0,1}/MW
$vNewLine_{ydd'}$	Investment status at year *y* of line connecting node *d* to *d'*	{0,1}/MW
$vFlows_{ypdd'}$	Flows at year *y* at period *p* from node *d* to *d'*	MW
$vTheta_{ypd}$	Voltage angle at year y period p node *d*	p.u.
$vDemand_{ypd}$	Demand at year y period *p* at node *d*	MW
$vLevel_{yphd}$	Level at year *y* period *p* of storage unit h at node *d*	MW
$vCon_{yphd}$	Consumption at year *y* period *p* of storage unit h at node *d*	MW
$vSpill_{yphd}$	Spillage at year *y* period *p* of storage unit h at node *d*	MW

Appendix

Each set of equation corresponds to the linearization of a complementarity condition. Equality constraints are not included. $\overline{Mdual}$, $\underline{Mdual}$: Refer to big M parameters corresponding to each dual variable for upper and lower bounds respectively. $\overline{Ydual}$, $\underline{Ydual}$: refer to binary variables corresponding to each dual variable for upper and lower bounds respectively

$$
\begin{aligned}
& vProd_{ypgd} \leq \underline{M\rho} * \underline{Y\rho}_{ypgd} \\
& \underline{\rho}_{ypgd} \leq \underline{M\rho} * \left(1 - \underline{Y\rho}_{ypgd}\right) \\
& vProd_{ypgd} - pMaxProd_g \leq \overline{M\rho} * \overline{Y\rho}_{ypgd} \\
& 0 \leq \bar{\rho}_{ypgd} \leq \overline{M\rho} * \overline{Y\rho}_{ypgd} \\
& \forall\ gd \in GED, \quad \forall\ yp
\end{aligned}
\tag{39}
$$

$$
\begin{aligned}
& Wind_{ypwd} \leq \underline{M\rho w} * \underline{Y\rho w}_{ypgd} \\
& \underline{\rho w}_{ypgd} \leq \underline{M\rho w} * \left(1 - \underline{Y\rho w}_{ypgd}\right) \\
& \overline{\rho w}_{ypgd} \leq \overline{M\rho w} * \overline{Y\rho w}_{ypgd} \\
& Wind_{ypwd} - pMaxWind_{wnp} \leq \overline{M\rho w} * \overline{Y\rho}_{ypwgd} \\
& \forall\ wd \in GED, \quad \forall\ yp
\end{aligned}
\tag{40}
$$

$$
\begin{aligned}
& 0 \leq vProd_{ypgd} \leq \underline{M\omega} * \underline{Y\omega}_{ypgd} \\
& 0 \leq \underline{\omega}_{ypgd} \leq \underline{M\omega} * (1 - \underline{Y\omega}_{ypgd}) \\
& vProd_{ypgd} - pMaxProd_g * vNewGen_{ygd} \leq \overline{M\omega} * \overline{Y\omega}_{ypgd} \\
& \bar{\omega}_{ypgd} \leq \overline{M\omega} * \overline{Y\omega}_{ypgd} \\
& \forall\ gd \in GCD, \ \forall\ yp
\end{aligned}
\tag{41}
$$

$$
\begin{aligned}
& \frac{vCon_{yphd}}{pEfficiency_h} \leq \underline{M\kappa} * \underline{Y\kappa}_{ypgd} \\
& \underline{\kappa}_{yhpd} \leq \underline{M\kappa} * (1 - \underline{Y\kappa}_{ypgd}) \\
& \frac{vCon_{yphd}}{pEfficiency_h} - pMaxCons_h \leq \overline{M\kappa} * \overline{Y\kappa}_{ypgd} \\
& \bar{\kappa}_{yhpd} \leq \overline{M\kappa} * (1 - \overline{Y\kappa}_{ypgd}) \\
& \forall\ hd \in GED, \ \forall\ yp
\end{aligned}
\tag{42}
$$

$$
\begin{aligned}
& 0 \leq \frac{vCon_{yphd}}{pEfficiency_h} \leq \underline{M\eta} * \underline{Y\eta}_{yphd} \\
& 0 \leq \underline{\eta}_{yhpd} \leq \underline{M\eta} * \left(1 - \underline{Y\eta}_{yphd}\right) \\
& 0 \leq \frac{vCon_{yphd}}{pEfficiency_h} - pMaxCons_h(vNewGen_{yhd}) \leq \overline{M\eta} * \overline{Y\eta}_{yphd} \\
& 0 \leq \underline{\eta}_{yghpd} \leq \overline{M\eta} * (1 - \overline{Y\eta}_{yphd}) \\
& \forall\ gd \in GCD, \quad \forall\ yp
\end{aligned}
\tag{43}
$$

$$
\begin{aligned}
& -vFlows_{ypdd'} + pMaxFlows_{dd'} \leq \underline{M\phi} * \underline{Y\phi}_{ypdd'} \\
& \underline{\phi}_{ypdd'} \leq \underline{M\phi} * \left(1 - \underline{Y\phi}_{ypdd'}\right) \\
& -vFlows_{ypdd'} - pMaxFlows_{dd'} \leq \overline{M\phi} * \overline{Y\phi}_{ypdd'} \\
& -vFlows_{ypdd'} - pMaxFlows_{dd'} \leq \overline{M\phi} * \left(1 - \overline{Y\phi}_{ypdd'}\right) \\
& \forall\ (d, d') \in LE, \ \forall\ yp
\end{aligned}
\tag{44}
$$

$$vFlows_{ypdd'} + pMaxFlows_{dd'} * vNewLine_{ydd'} \le \underline{M\zeta} * \underline{Y\zeta}_{ypdd'}$$

$$\underline{\zeta}_{ypdd'} \le \underline{M\zeta} * \left(1 - \underline{Y\zeta}_{ypdd'}\right) \tag{45}$$

$$\forall\ (d, d') \in LC, \forall\ yp$$

$$-\ vFlows_{ypdd'} + (\ pMaxFlows_{dd'} * \ vNewLine_{ydd'}\ ) \le \overline{M\zeta} * \overline{Y\zeta}_{ypdd'}$$

$$\bar{\zeta}_{ypdd'} \le \overline{M\zeta} * (1 - \overline{Y\zeta}_{ypdd'})$$

$$\forall\ (d, d')\ \in LC, \forall\ yp \tag{46}$$

$$-\ vFlows_{ypdd'} + \left(\begin{array}{c} pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} \\ + pMaxFlows_{dd'}(-1 + vNewLine_{ydd'}) \end{array} \right) \le \overline{M\tau} * \overline{Y\tau}_{ypdd'}$$

$$\bar{\tau}_{ypdd'} \le \overline{M\tau} * (1 - \overline{Y\tau}_{ypdd'}) \tag{47}$$

$$\forall\ (d, d')\ \in LC, \forall\ yp$$

$$vFlows_{ypdd'} + \left(\begin{array}{c} -\ pSB * \frac{vTheta_{ypdd'} - vThetha_{ypdd'}}{pReactance_{dd'}} \\ -\ pMaxFlows_{dd'}(1 - vNewLine_{ydd'}) \end{array} \right) \le \underline{M\tau} * \underline{Y\tau}_{ypdd'}$$

$$\underline{\tau}_{ypdd'} \le \underline{M\tau} * (1 - \underline{Y\tau}_{ypdd'}) \tag{48}$$

$$\forall\ (d, d')\ \in LC, \forall\ yp$$

$$-\ vNewGen_{y-1,gd} - vNewGen_{ygd} \le \underline{M\beta} * \underline{Y\beta}_{ygd}$$

$$\underline{\beta}_{ygd} \le \underline{M\beta} * \left(1 - \underline{Y\beta}_{ygd}\right) \tag{49}$$

$$\forall\ gd \in GCD, \quad \forall\ yp$$

$$vNewGen_{ygd} \le \underline{M\omicron} * \underline{Y\omicron}_{ygd}$$

$$\bar{\omicron}_{ygd} \le \underline{M\omicron} * (1 - \underline{Y\omicron}_{ygd})$$

$$MaxGen_{g} - vNewGen_{ygd} \le \underline{M\omicron} * \underline{Y\omicron}_{ygd} \tag{50}$$

$$\bar{\omicron}_{ygd} \le \overline{M\omicron} * (1 - \overline{Y\omicron}_{ygd})$$

$$\forall\ gd \in GCD, \quad \forall\ yp$$

$$pMinLevel_{h} - vLevel_{yphd} \le \underline{M\mu} * \underline{Y\mu}_{yphd}$$

$$\underline{\mu}_{yph} \le \underline{M\mu} * \left(1 - \underline{Y\mu}_{yphd}\right)$$

$$vLevel_{yphd} - pMaxLevel_{h} \le \overline{M\mu} * \overline{Y\mu}_{yphd} \tag{51}$$

$$\bar{\mu}_{yph} \le \overline{M\mu} * (1 - \overline{Y\mu}_{yphd})$$

$$\forall\ gd \in GCD, \quad \forall\ yp$$

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