What is the cost of disregarding market feedback in transmission expansion planning?

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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. A case study is presented to evaluate different policy planning objectives. Additionally, the planning results of the bi-level framework (considering both perfect competition and Cournot oligopoly in the lower level) are compared with a traditional cost minimization framework.**

Keywords—GEP, TEP, co-planning, Cournot, proactive

I. Introduction

A. Motivation and Background

Under the current European deregulated market, centralized TSOs have to decide network investment by minimizing total operation cost, 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), 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 a simple cost minimization approach, a TSO foresees strategic market outcomes, can this be beneficial for society? In other words, we want to compare how the operation and investment decisions under perfect or Cournot competition can affect the transmission decisions and the total welfare.

For instance, if we consider that a TSO takes its investment decision first, we would expect that, in order to achieve lower operation costs, a TSO would build more lines compared to the case where GENCOs take investment decision first (it is important to note that this does not contradict the fact that, in specific cases in the short-term, using fewer lines can result in lower operation costs due to transmission switching). 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 and long-term decisions.

B. Relevant Literature

In recent years, a lot of research has been conducted on what we call co-planning equilibrium models. In this type of models, the agents of the system can be classified typically into three groups: GENCOs, TSO and Market Operator (MO). Accordingly, the GEPTEP problem is usually defined as a three level model, where 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 (GENCOs and MO) in the lower level. This three-level equilibrium structure implies solving a complex EPEC equilibrium. Alternatively, as for the case of this paper, we can consider an MPEC by having the TSO in the upper level (TEP), and simultaneous decisions of GENCOs (GEP) and MO in the lower level. In order to model imperfect competition in the lower level we consider a conjectured response framework. This is done based on the work of [1] which shows that a bi-level model, where investment decisions are followed by market decisions, can be simplified into a single-level model using conjectural variations.

Additionally, we focus on the modeling of storage technologies. To our knowledge only [2] and [3] have considered detailed storage in hierarchical models. In particular, authors in [2] 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. On the other hand, authors in [3] consider battery expansion in the lower level and choose a pessimistic Transmission Company and prove some subsequent uniqueness properties. However, both [2] and [3] consider perfect competition and disregard hydro storage in their models, given the complexity to jointly optimize short- and long-term storage technologies. We overcome this shortcoming by applying the enhanced representative periods approach proposed by [4]. 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 to higher welfare compared to the reactive approach [5].

Finally, authors in [6] consider a stochastic bi-level model with a merchant transmission investor in the upper level and wind expansion and market operation in the lower level, where Cournot competition is considered. Finally, authors in [7] apply the same structure but they consider storage expansion and Cournot competition in the lower levels. Both works [6], [7] find counterintuitive results when considering Cournot competition in the lower level compared to a perfect competition case.

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C. Contributions and Organization

The contributions of this paper are twofold: first of all, we extend the model formulation proposed in [7] by considering different objective functions. By doing so, we allow a social planner TSO to explore different possible investment options and to compare them to a welfare maximizing benchmark. Second, we propose a framework that allows us to quantify the additional cost, also referred to as regret, of employing a traditional centralized planning approach disregarding market feedback as opposed to a bi-level proactive framework. The remainder of this paper is organized as follows: section II presents the mathematical formulation of the bi-level model and it introduces the regret computation; section III presents a case study, and finally, section IV concludes the paper.

II. FORMULATION

The formulation of this problem is based on the work done in [7]. Therefore, here we present only the bi-level equilibrium representing the GEPTEP co-planning problem. In [7], this equilibrium (which is convex, because all constraints are linear) is re-formulated as a Mixed Integer Program (MIP), by replacing the lower level equilibrium constraints by its equivalent KKT conditions, and then by linearizing the resulting non-linearities. Due to space limitations, the KKT conditions and the linearized complementarities are omitted and can be found in [7]. Before presenting the formulation of the bi-level model, we first explain the market responsive framework to be used in the lower level. Then, we introduce the Bi-level Proactive Model (PM), then we introduce the Cost Minimization Model (CMM), which is traditionally used for transmission expansion planning and finally the regret computation framework is presented. Please find the nomenclature in the Annex.

A. Market Responsive Framework

Following the work of [8], we consider an affine relation between prices and demand as shown in (1), i.e., demand is elastic, where *pDemand* represents the inelastic part of the demand and *pDslope* represents the slope of this function, which can be interpreted as how demand reacts to prices. Therefore, for a given node the demand would be given by (1).

$$vDemand_d = pDemand_d - pDslope_d * \lambda_{gad(g,d)} \;\forall d \quad (1).$$

We furthermore define a conjectural variation $\theta_g = \partial\lambda gad(g,d)/\partial vProd_g$ that is assumed to be known for every GENCO g . This conjecture corresponds to each GENCO's belief on how much they can impact market prices by varying its production $vProd_g$ ($vCon_h$ for storage units). If $\theta_g = 0$ this represents perfect competition (PC), and if $\theta_g = 1/pDSlope$ (inverse of the slope of the residual demand curve) it represents the Cournot oligopoly (CO). This conjecture allows us to model different degrees of competitive behavior.

B. Bi-level Proactive Model (PM)

First, we present the proactive framework in which a social planner TSO (from now on TSO) - this can be understood as an entity where both TSO and regulator are considered the same entity - proposes investments and GENCOs react to its decisions. Perfect information (this assumption can be relaxed considering uncertainty either with stochastic or robust programing) and elastic demand are assumed. Figure 1 shows the bi-level framework, where the TSO takes TEP decisions in the upper level subject to the lower level. Likewise, the lower level represents the market equilibrium where GENCOs take GEP and operating decisions, while the system operator (SO) makes sure that the power flow decisions are feasible. . In the upper level, the TSO can either minimize total cost, or maximize total welfare.

Upper Level	TSO or social planner (decides TEP) 1) Minimizes Total Cost 2) Maximizes Welfare	
Lower Level	GENCOs (decide GEP and operation) Maximize Benefits	SO (decides power flow) Maximizes Congestion Rents
	Market Clearing Condition	

Figure 1: Bi-level Framework.

1) Upper Level: TEP

The social planner TSO considers two different objective functions at the upper level: total system cost minimization, or welfare maximization. Each of these objective functions leads to a different bi-level model: CM-PM and WM-PM. Note that having different objective functions allows the social planner to explore the range of optimal investments and how different they are given the welfare social optimum benchmark.

a) Cost Minimizing Bilevel Proactive Model (CM-PM)

In this case, we consider that the social planner TSO follows a traditional objective and aims to minimize the total system cost. Therefore, this objective is represented by (4), where central planner TSO minimizes the Total Cost (TC) composed by Line Investment Costs (LI), Generation Investment Costs (GI), and Operation Cost (OC).

$$\underset{vNewLineydd'}{\text{Minimize}} \quad TC = GI + LI + OC \quad (2)$$

Subject to (3)- (6) , and Lower Level equilibrium.

$$LI := \sum_{ydd'} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \quad (3)$$

$$GI := \sum_{gyd} (Y - y + 1) * pInvC_g * \left(vNewGen_{ygd} - vNewGen_{y-1,gd}\right) \quad (4)$$

$$OC := \sum_{y,(p,rp)\in\Gamma_{rp,p},t,d} pW_{rp} * pFCost_t * vProd_{yptd} \quad (5)$$

$$vNewLine_{y-1,dd'} \le vNewLine_{ydd'} \;\forall(d,d') \in LC \;\forall y \quad (6)$$

b) Welfare Maximization Proactive Model (WM-PM)

We can also consider that the social planner TSO maximizes the total welfare, calculated as the Utility of the Demand (UD) minus total costs. This approach allows us to compare how this objective can change the capacity expansion decisions. Therefore, the actual objective function would be given by (7). Note that we do not allow for de-investment as imposed by equation (6). Equation (8) represents the utility of demand resulting from the area under the demand curve.

$$\underset{vNewLineydd'}{\text{Maximize}} \quad UD - (GI + LI + OC) \quad (7)$$

Subject to (3) - (6), (8), and Lower Level equilibrium

$$UD: \sum_{y,(p,rp)\in\Gamma_{rp,p},d} \left(pDemand_{ypd} * vDemand_{ypd} - \frac{vDemand_{ypd}{}^2}{2} \right) \quad (8)$$

2) Lower Level: market equilibrium

The lower level represents the market equilibrium where consumers maximize the utility of the demand, GENCOs maximize their profits (deciding generation investment and operation of generating assets) and a SO wants to maximize congestions rents (deciding power flows and voltage angles). The consumers, GENCOs and SO's optimization problems are linked by the market clearing condition (30). This market structure implies that GENCOs do not anticipate market outcome in their expansion decisions. 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 [9].

The previous description implies that the market is modeled as a spatial equilibrium model where GENCOs compete strategically and react naively to the transmission congestions as in [10]. Additionally, we assume that there is only one GENCO per node, but we might have several generation units per GENCO. For this case, we consider only one unit per GENCO and thus the index g represents both generator units and companies.

Moreover, in the formulation of the market model we use enhanced representative days [4] to represent the temporal structure. The novelty of this temporal representation is that it allows us to capture both short- and long-term storage technologies accurately due to the intra- and inter-day storage constraints, which are explained in detail in [4] and upon which we comment briefly later on. From now on, each equation is defined for $p \in \Gamma_{rp,p}$.(except (23)). Please note that $\Gamma_{rp,p}$ indicates which hours, from the whole year, belong to each representative day.

a) Consumer: Demand Utility maximization

The consumers try to maximize the utility of the demand, by deciding demand. Their optimization problem is given by:

$$Max_{vDemand_{ypd}} \, UD$$

Subject to (8) and (9)

$$vDemand_{y,p,d} \geq 0 \; \forall ypd \quad (9)$$

b) GENCO: Profit Maximization Problem

$$arg \; \underset{GV}{\text{Maximize}} \, OI - OC - GI \quad (10)$$

Subject to (4), (5), (12) , (13) - (23).

$$GV: \{vNewGen_{ygd}, vProd_{ypgd}, vCon_{yphd}, vSpill_{yphd}\} \quad (11)$$

$$OI := \sum_{y,p,rp,g,d} pW_{rp} * (\lambda_{yp,d\in(GAD)}) * (vProd_{yp,gd\in GAD} - vCon_{yp,hd\in GAD}) \quad (12)$$

$$0 \leq vProd_{ypgd} \leq pMaxProd_g \;\; \forall yp, \forall gd \in GED \quad (13)$$

$$0 \leq \; vProd_{ypgd} \leq pMaxProd_g * vNewGen_{ygd} \;\; \forall yp, \forall gd \in GCD \quad (14)$$

$$0 \leq \frac{vCon_{yphd}}{pEfficiency_h} \leq pMaxCons_h \;\; \forall yp, \forall hd \in GED \quad (15)$$

$$0 \leq \frac{vCon_{yphd}}{pEfficiency_h} \leq pMaxCons_h * vNewGen_{yhd} \;\; \forall yp, \forall hd \in GCD \quad (16)$$

$$-vNewGen_{y-1,gd} + vNewGen_{ygd} \geq 0 \quad \forall y, \forall gd \in GCD \quad (17)$$

$$0 \geq -vNewGen_{ygd} \quad \forall y, \forall gd \in GCD \quad (18)$$

$$pMinLevel_h \leq vLevel_{yphd} \leq pMaxLevel_h \; \forall yp, \forall hd \in GED \quad (19)$$

$$pMinLevel_h * vNewGen_{yhd} \leq vLevel_{yphd} \leq pMaxLevel_h * vNewGen_{yhd} \;\; \forall yp, \forall hd \in GCD \quad (20)$$

$$0 \;\leq\; vSpill_{yphd} \;\; \forall yp, \forall hd \in GAD \quad (21)$$

$$vLevel_{yph_fd} = vLevel_{y,p-1,hf,d} + pIniLevel_{y=1,p=1,hf,d} - vProd_{yph_fd} + vCon_{yph_fd} \quad (22)$$
$$\forall h_fd \in GAD, \forall yp, p < pf$$

$$vLevel_{yphsd} = vLevel_{y,p-M,hs,d} + pIniLevel_{y=1,p=1,hs,d} + \sum_{p'}^{p} \sum_{p''} (pInfl_{yp''hsd} - vSpill_{yp''hsd} - vProd_{yp''hsd} + vCon_{yp''hsd}) \quad (23)$$
$$\boldsymbol{\forall y, \forall hs, d \in GAD, \forall p, p < pf, \; with \; p` = p - M + 1 \; and \; p \in Ps, p'' \in H(p', p'') \;\; Ps = \left\{ps | \frac{ps}{M} \in Z^+\right\}}$$

Equation (12) represents the operational incomes of GENCOs, equations (13) , (15), (19) and (21) represent upper and lower bounds of the existing elements of the system. While equations (14), (16) and (20) represent the lower and upper bounds of the candidate generation investments in the system. Equation (17) avoids de-investments and (18) defines the non-negativity of new generation. Finally, equations (22) and (23) represent the storage balance conditions as proposed in [4].

On the one hand, equation (23) is considered for long-term storage, i.e. hydro, where only interday balance is considered. In 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 vCon represents pumping decisions and vProd the production decisions. On the other hand, equation (22) is considered to represent short-term storage when intraday operation is relevant, i.e. batteries. Variables vCon and vProd represent charging and discharging. While the detailed formulation and explanation of this representation of storage is presented in [4], 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 hour (one week) window and two weeks as shown in Figure 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 appropriate representative day (i.e the first 24 hours 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).

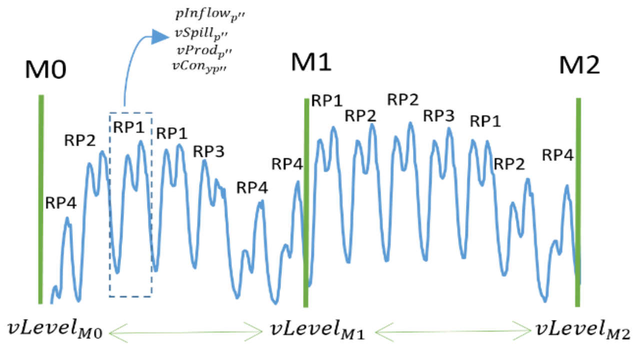

Figure 2: Interday Energy Balance.

c) SO

We assume that the SO wants to maximize congestions rents from price differences by deciding power flows.

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

Subject to (24)-(29), where

$$pMaxFlows_{dd'} \geq vFlows_{ypdd'} \geq -pMaxFlows_{dd'} \quad \forall yp, \forall (d,d') \in LE \tag{24}$$

$$vFlows_{ypdd'} = pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} \quad \forall yp, \forall (d,d') \in LE \tag{25}$$

$$vFlows_{ypdd'} \geq -pMaxFlows_{dd'} * vNewLine_{ydd'} \quad \forall yp, \forall (d,d') \in LC \tag{26}$$

$$-vFlows_{ypdd'} \geq -(\ pMaxFlows_{dd'} * vNewLine_{ydd'}\ ) \quad \forall yp, \forall (d,d') \in LC \tag{27}$$

$$-vFlows_{ypdd'} \geq \left(-pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} - pMaxFlows_{dd'}(1 - vNewLine_{ydd'})\right) \quad \forall yp, \forall (d,d') \in LC \tag{28}$$

$$vFlows_{ypdd'} \geq \left(pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} - pMaxFlows_{dd'}(1 - vNewLine_{ydd'})\right) \quad \forall yp, \forall (d,d') \in LC \tag{29}$$

Equations (24) and (25) represent the DC formulation of the network for existing lines, while equations (26)-(29) represent the DC power flow formulations for new lines.

d) Market Clearing

$$\sum_{g\epsilon GAD} vProd_{ypgd} + \sum_{d'\epsilon LA} vFlows_{ypdd'} - \sum_{d'\epsilon LA} vFlows_{ypd'd} + \sum_{h\epsilon GAD} \frac{vCon_{yphd}}{pEfficiency_h} = vDemand_{ypd} \quad \forall y,p,d \tag{30}$$

The simultaneous consideration of the GENCOs, Consumers, SO, 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). The complete formulation to solve this equilibrium can be found in [7]. Additionally, we implement a regularization method to compute Big Ms as proposed in [11].

C. Cost Minimization Model (CMM)

Finally, we would like to compare the previously proposed bi-level model with a traditional GEPTEP cost minimization framework.

This framework reflects what TSOs apply for real expansion planning. TSOs usually consider inelastic demand and perfect competition. Additionally, they consider either an exogenous GEP or they plan GEP considering also centralized generation expansion decisions, i.e GEPTEP problem. Given that we consider inelastic demand and perfect competition, the CMM would be given by the following one-level optimization problem:

$$\underset{vNewLine_{ydd'},GV,vFlows_{ypdd'},vTheta_{ypd}}{\text{Minimize}} \quad TC = GI + LI + OC \tag{31}$$

Subject to (3)-(6), (13) -(29). The only exception is that in (30), $vDemand$ is considered to be fixed and therefore the market responsive framework is disregarded.

D. Regret Computation

We propose the following framework to evaluate the advantages of considering a Bi-level model instead of a Single Level cost minimization model (CMM). In reality, markets are not perfect, however; TSOs assume perfect competition when taking their investment decisions, as reflected in the CMM model. We would like to quantify what is the cost not considering that GENCOs are strategic players that maximize their own profits, rather than players that minimize system costs.

To that purpose, we solve the proactive bi-level model PM model (either a CM or WM) and we compare the results to the CMM model. In particular, first, we solve the PM model and we refer to it as *Optimal PM*. Second, for the exact same system demand obtained by the *Optimal PM*, we solve the CMM, which obtains TEP and GEP that might differ from the ones previously obtained by PM. We refer to this model as the *Naïve CMM*; it is "naïve" because it does not reflect the strategic behavior of GENCOs.

Hence, TEP and GEP obtained by the Naïve CMM might be erroneous given that they assume perfect competition, which is not always the case. Third, we fix the TEP solution obtained by the naïve CMM, and re-run the PM model (i.e., solving the lower level) in order to see how much the "wrong" TEP decision is going to distort the market equilibrium and GEP decisions. We refer to this model as the *Actual CMM* because it accounts for decision errors made by a cost minimization approach. Therefore, the regret of using a CMM approach is computed as total cost of the *Actual CMM* minus the total cost of the *Optimal PM*.

III. Case Study

A. Data

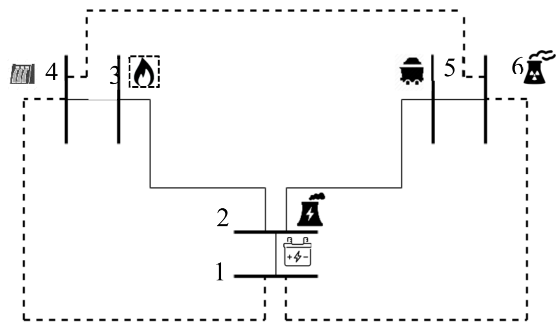

Figure 3: System Characteristics.

The system depicted in Figure 3 is composed of 6 nodes. There is demand at each node and existing generation units at each node except at node 3 where there is a candidate generator. Table I shows the characteristics of the generators and the average maximum and minimum demand per node. Additionally, the system is composed of 5 existing transmission lines (with a 200 MW capacity), and 3 candidate lines as seen in Table II. We consider 2 representative days (24h each) and a moving window of 168h to represent hydro storage. The planning horizon is 1 static year (8760h).

Table I: Demand and Generation Data

From Node	To Node	Reactance [p.u]	Total Investment Cost (M€)	Capacity (MW)
1	6	0.03	10	150
6	3	0.05	10	150
1	4	0.07	10	150

Table II: Candidate Lines

Node	GENCO	Fuel Cost (€/MWh)	Capacity (MW)	Demand Max/Min (MW)
1	Battery	0	100	369/209
2	Fuel Oil	54	441	578/328
3	CCGT*	37.31	450	337/191
4	Hydro	160	300	545/309
5	Coal	49.7	588	401/227
6	Nuclear	15	771	307/174

B. *Results*

1) *Comparison of different TSO objective functions*

In Table III we show the results of the bi-level model that minimizes total system cost, i.e., CM-PM, and compare it to the welfare maximizing results WM-PM. In both cases, we consider a perfectly competitive market. This section demonstrates that even under perfect competition, the optimal TEP investment can vary depending on the objective chosen by the social planner.

Table III: Economic Outputs

	Units	CM-PM	WM-PM
Welfare	(M€)	1758.4	1896
TEP Cost	(M€)	19.5	30
TEP	Lines	6_1/6_3	ALL
GEP Cost	(M€)	19.5	18.2
GEP	MW	437.6	410.3
Operation Cost	(M€)	328	392.1
Total Cost	(M€)	367.5	440
Total Demand	(TWh)	253.2	278

As expected, the CM-PM has a lower total cost than WM-PM and WM-PM has a greater welfare than CM-PM. The previous result can be explained given the incentive that the TSO has to maximize the utility of the demand. Therefore, the TSO tries to meet more demand, which in this case is achieved by allowing more TEP, but still creating more welfare

Figure 4 shows the average prices per node resulting from each model. Prices in square brackets and parentheses correspond to WM-PM and CM-PM respectively. The direction of the power flows are the same in both models; power flows go from low price nodes to high price nodes as indicated by the blue arrows. Additionally, prices in WM-PM are greater or equal than in CM-PM, however, as mentioned before, this can be explained because both welfare and demand are higher WM-PM.

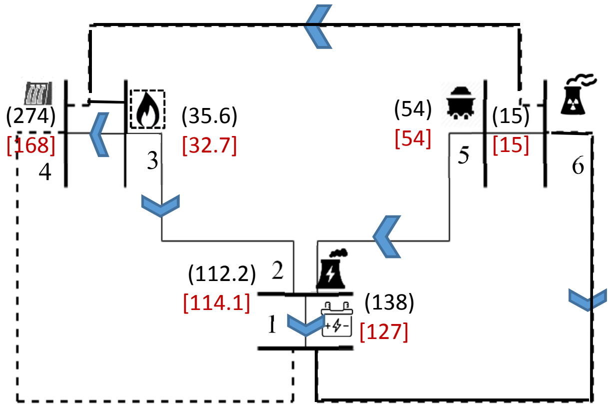

Figure 4: CM-PM and WM-PM Flows and Prices

2) *Regret Computation*

In this section, we compute the regret of not considering strategic market feedback when taking TEP decisions as mentioned in section II.D. We consider the CM-PM case with Cournot competition. The results for the WM-PM case are similar, but they are omitted due to space limitation.

Table IV: Bi-level (CM-PM) vs Cost Minimization (CMM)

	Units	Optimal PM	Naïve CMM	Actual CMM
Welfare	M€	809.19	587	809.26
TEP Cost	M€	10	20	20
TEP	Lines	6-3	6-1/6-3	6-1/6-3
GEP Cost	M€	9.55	9.8	9.51
GEP	MW	214.8	220.9	214.2
Oper. Cost	M€	206.4	102	206.13
Total Cost	M€	225.95	131.8	235.64
Total Demand	TWh	119.33	119.33	119.46
Regret	M€			9.8
Relative Cost	M€/TWh	1.89	1.10	1.97
Relative Regret	M€/TWh			0.08

In Table IV we can see that a *Naïve CMM* approach would invest in two lines, expecting that, with a perfectly competitive market, 220.9 MW of generation would be built. However, under a Cournot market framework, the *Optimal PM* would build one line and the GENCOs would actually build more capacity, i.e., 214.8 MW. This leads to a total cost of 131.8 M€ for the *Naïve CMM* which is almost half of the total cost of the *Optimal PM* (given that the *Naïve CMM* is not considering the reality of having a Cournot market equilibrium). Therefore, in order to compute the regret, we fix the TEP investment resulting from the *Naïve CMM*, and run again the PM model, this actually leads to a higher total system cost of 235.7 M€ as given by *Actual CMM*. Thus, compared to a 225.9 M€ total cost of the *Optimal PM*, there is an absolute 9.8 M€ regret (and a 0.08 M€/MWh relative regret considering the total demand) that could have been avoided if a market feedback of GENCOs investment decisions and operations had been taken into account. This means that the traditional cost minimization approach employed by many TSOs actually ends up leading to a 0.08 M€/MWh higher cost for society.

Finally, it is important to note, that for the case of *perfect competition,* the planning regret is *zero*. This means that (even if the market anticipation is not taken into account in a cost-minimization approach) the TEP results are robust, in the sense that the final operation cost, given the GEP from the *Actual CMM*, would be the lowest possible. However, in the case of non-perfect competition, the *Naïve CMM* might yield a different sub-optimal TEP than the bi-level PM model, causing for a potential regret in the millions.

IV. CONCLUSIONS

In this paper, we present a bi-level model to decide transmission expansion planning taking into account that generation capacity and operating decisions are taken by strategic agents in a market framework. Our model allows for exploring different objectives for the TSO. In a case study, we show that taking planning decisions with mere cost minimization models, ends up leading to a higher cost for society, than taking these investment decisions with bi-level models that properly capture strategic behavior and market feedback.

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APPENDIX - NOTATION

A. Sets / Indices

$y \in Y$	year
$p, \in P$	periods (hours in the year)
$ps \in Ps$	Moving window periods
$rp \in RP$	representative periods
$\Gamma_{rp,p}$	set of correspondence between rp and p
p	final period
$d, d' \in D$	nodes
$g \in G$	generator unit *g*
$t(g) \in T$	thermal units
$h(g) \in H$	storage units
$hf(h) \in HF$	fast short-term storage units (batteries)
$hs(h) \in HS$	slow long-term storage units (hydro)
$GAD(g, d)$	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 perio*d p* and *p*' $\in \Gamma_{rp,p}$

B. Parameters

$pMaxProd_g$	Maximum capacity of technology g	MW
$pMaxFlows_{dd'}$	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	€
$pInvC_g$	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^2/€
$pEfficiency_h$	Efficiency of storage unit *h*	[p.u]
$pInfl_{yphsd}$	Energy inflows for year *y* period *p* storage *hs* at node d	MWh
$pMaxLevel_h$ $pMinLevel_h$	Max/Min reservoir level of storage unit *h*	MW
$pMaxCons_h$	Maximum consumption of storage unit	MW
M	Time window	h
pW_{rp}	Weight of each representative day	[p.u]
pSB	Base Power	MW
θ_g	Conjectural variation of GENCO g	€/MW^2

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 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
λ_{ypd}	Prices at year *y* period *p* node *d*	€/MW

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