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TRANSMISSION EXPANSION PLANNING UNDER IMPERFECT COMPETITION

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Abstract

Using old tools to solve modern problems can be costly. This might be the case for the generation and transmission expansion planning problem (GEPTEP), which has been solved with sufficient accuracy under the paradigm of a centralised decision-making utility. In particular, most E.U. energy system models assume perfect competition or perfect foresight, which do not adequately reflect the current paradigm and, thus, may lead to flawed market regulations. Therefore, what happens if we keep using cost-minimization tools in modern decentralised markets, with new technologies, new market participants (merchant transmission investor, merchant renewable generators) and increasing potential to exercise market power?

In this thesis, we try to answer this question by proposing a comprehensive proactive bi-level model, that considers sequential investment decisions, imperfect competition, and elastic demand, and comparing it with the equivalent of a centralised planning utility. To comply with this objective, in Paper I (summarized in Chapter 2.1), we present a comprehensive literature review on GEPTEP models, both for co-optimization models (vertically integrated utilities in a centralised environment) and co-planning models (under a market environment with competing generators and imperfect competition). Compared to previous works, we carry out a detailed classification of co-planning models and their underlying equilibrium models. We explicitly differentiate their hierarchical and regulatory structure with their equivalent reduced structure, and we classify the distinctive approaches used to represent the market. From this review, we identified the characteristics of our reference market model to be compared with the centralised industry benchmark problem.

Paper II (summarized in Chapter 2.2) proposes a proactive bi-level model that considers sequential investment decisions, with the transmission company as the leader and generators as followers, this structure can be applied to the current European context, where ENTSOE plays the role of a centralised agent that proposes future planning pathways, to which national generation companies react. Additionally, we consider imperfect competition via conjectural variations, and the introduction of specific short- and long-term storage operation and investment conditions. We solve this problem by converting the underlying equilibrium problem into a set of equations using the Karush Khun Tucker conditions and by linearizing them according to (Fortuny-Amat & McCarl, 1981). Among others, we found that when considering imperfect competition in the market, some counterintuitive results can arise, i.e., allowing trade between areas (building new lines) can decrease total welfare.

Finally, in Paper III (summarized in Chapter 2.3), we extend the model in Paper II to formulate a merchant transmission investor. We propose a methodology that would ultimately allow us to answer our first question. How costly is it to use old tools for new problems? We present two case studies (a 3-node and a modified IEEE 24-node). Some of the main conclusions are the following i) Disregarding strategic market feedback can lead to a non-negligible welfare loss. In particular, this welfare loss could be worse when we have batteries in the mix, as it implies disregarding the effects that the flexibility of batteries can have on the exercise of market power. ii) Merchant transmission investors lead to a worse-off situation, with lower welfare and higher prices. We found that in some cases, a merchant investor can lead to the same welfare loss as disregarding strategic market feedback. Most importantly, this sub-optimal planning output also leads to a significant distortion of the optimal generation mix, affecting the system's robustness in terms of responsiveness to intermittent resource availability.

Abbreviations

BESS	Battery Energy Storage Systems
ENTSOE	European Network of Transmission System Operators for Electricity
EPEC	Equilibrium Problem with Equilibrium Constraints
EU	European Union
GENCOs	Generation Companies
GEP	Generation Expansion Planning
GEPTEP	Generation Expansion Planning & Transmission Expansion Planning
KKT	Karush–Kuhn–Tucker
MPEC	Mathematical Programming with Equilibrium Constraints
NLP	Non Linear Programming
RE	Renewable Technology
TEP	Transmission Expansion Planning
TSO	Transmission System Operator
US	United States of America

Contents

List of papers

I. **Gonzalez-Romero, I.-C.**, Wogrin, S. and Gómez, T. (2020), Review on generation and transmission expansion co-planning models under a market environment. IET Gener. Transm. Distrib., 14: 931-944. https://doi.org/10.1049/iet-gtd.2019.0123.[1]

II. **Gonzalez-Romero, I.-C.**, Wogrin, S. and Gómez, T. (2019), Proactive transmission expansion planning with storage considerations. Energy Strategy Reviews, 24: 154-165, https://doi.org/10.1016/j.esr.2019.02.006.[2]

III. **Gonzalez-Romero, I.-C.**, Wogrin, S. and Gómez, T. (2021), Transmission and storage expansion planning under imperfect market competition: Social planner versus merchant investor. Energy Economics, 103 : 105591, https://doi.org/10.1016/j.eneco.2021.105591.[3]

Other relevant publications and conferences

I. Conference: **I. -C. Gonzalez-Romero**, S. Wogrin and T. Gómez. Decentralised storage and renewable investments in transmission expansion planning: a bi-level approach. Session: Energy, Environment and Climate1. International Federation of Operational Research Societies (IFORS)/(Virtual). Seoul (South Korea). Jun 2021.

II. Book Chapter: S. Wogrin, S. Pineda, D.A. Tejada, **I.C. Gonzalez-Romero**, Transmission expansion planning outside the box: a bilevel approach, in *Transmission expansion planning: the network challenges of the energy transition*. Editors Lumbreras, S.; Abdi, H.; Ramos, A.. Ed. Springer. Cham, Switzerland, 2020.

III. Conference: **I. -C. Gonzalez-Romero**, S. Wogrin and T. Gómez, "Considering market feedback in transmission expansion planning with storage and renewable technologies" 12th Trans-Atlantic Infraday Conference -TAI 2019. University of Maryland. Washington (United Stated of America). Oct 2019.

IV. Conference Paper: **I. -C. Gonzalez-Romero**, S. Wogrin and T. Gómez, "What is the cost of disregarding market feedback in transmission expansion planning?," *2019 International Conference on Smart Energy Systems and Technologies (SEST)*, 2019, pp. 1-6, doi: 10.1109/SEST.2019.8849107

V. Conference: **I.C. González-Romero,** S. Wogrin, T. Gómez, Proactive bi-level GEPTEP with storage considerations, 24th Young Energy Economists and Engineers Seminar - YEEES 2018, Delft (The Netherlands). 12-13 Abril 2018.

[1] Isaac-Camilo Gonzalez-Romero: Conceptualization, Formal analysis, Investigation, Writing – original draft, Writing - Review & Editing. Sonja Wogrin: Conceptualization, Methodology, Supervision, Funding acquisition, Writing - Review & Editing. Tomás Gomez: Validation, Resources, Writing - Review & Editing.

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1 Introduction

The decarbonization of the society is a central objective for most governments, in particular, the EU aims at achieving carbon neutrality by 2050, where the energy sector contributes to 75% of EU's greenhouse emissions. In the power sector, it is essential to assure the phasing out of coal, decarbonization of gas and the penetration of renewable energy technologies in the context of a liberalised energy sector.

In most E.U. member states, power companies would adopt renewable energy technologies only if they contribute to their profit-maximizing objectives. Furthermore, since renewable energy technologies like wind and solar power are typically intermittent, uncertain, and geographically dispersed, their viability will depend on their proper integration into the existing transmission network. However, grid expansion and generation expansion decisions are taken by separate entities with differing and even conflicting objectives. For example, i.e., welfare-maximizing regulated transmission system operators (TSOs) decide transmission expansion, while liberalised profit-maximizing generation companies decide generation expansion and operation. These contradictory objectives create some complexities that most E.U. energy system models assume perfect competition or perfect foresight, which do not adequately reflect the current paradigm and, thus, may lead to flawed market regulations.

Therefore, under the current European liberalised market, national transmission companies have to decide network investment by minimizing total operation cost (or maximizing total welfare), while competing generation companies (GENCOs) decide their expansion by maximizing their profit. This process creates contradictory incentives that can result in a misalignment of short-term operation and long-term investment signals. Moreover, when the ideal cost-minimizing generation capacity investment assumed by transmission companies differs from reality (due to strategic market interactions between GENCOs), the transmission expansion plan could not be the lowest option for society. For instance, if we consider that a TSO takes its investment decision first (proactive approach), 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 decisions first (reactive approach). This decision could be explained because, in the long term, the total cost in transmission investment is lower than that of 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.

In particular, GENCOs potential strategic behaviour is more relevant nowadays, given that construction times for transmission lines are consistently higher than construction times for new distributed generation technologies. It has been proved theoretically that a proactive approach leads to higher total welfare than its reactive counterpart (Sauma & Oren, 2007). However, in practice, most of the TSOs in the world follow a reactive approach (Spyrou et al., 2017). Nevertheless, some other approaches are actually close to proactive planning. For example, the U.S. government approved a regulation that includes the concept of anticipative (proactive) transmission planning in order to achieve higher social welfare (FERC, 2011). In Chile, a law that enforces the consideration of coordination between transmission and generation has also been approved (Ministerio Energía, 2016). Additionally, in the current European context, ENTSOE plays

the role of a centralised agent that proposes future planning pathways, in which regional coordination takes place (Huppmann & Egerer, 2014), to which national generation companies react. Thus, under such regulatory contexts, a proactive planning approach would be suitable.

This whole market setup is additionally affected by the high penetration of renewable energy. In fact, renewable energy introduces several challenges into market operation, e.g., renewable energy sources such as wind and solar photovoltaic are strongly intermittent, have a nearly zero variable cost, and their investment costs have been continuously decreasing in the last years. This situation would require to be counterbalanced with the increase in flexibility either by Demand Side Management (DSM) measures, reinforcement of the grid or the introduction of a new technology in the market, i.e., Battery Energy Storage Systems (BESS). Although energy storage technologies are already embedded in energy systems through the form of pumped hydro, this new player can help to reduce the intermittency in the systems and even be complementary to thermal generation. In 2018, the BESS worldwide deployment doubled 2017, led by Korea, China, the U.S., and Germany (IEA, 2020). Therefore, in this thesis, we will study the policy implications in transmission expansion planning of recognizing the potential strategic behaviour in the market in a context of high renewable penetration and new storage technologies.

1 Background

1.1 Generation and Transmission Expansion Planning

The capacity expansion problem has been of major importance in power systems, given the capital intensity and the variety of technologies available in the electricity sector, an optimization tool is necessary to try to achieve the least cost expansion solution. The traditional structure of power systems was a centralised environment where a vertically integrated utility was in charge of deciding both Transmission Expansion Planning (TEP) and Generation Expansion Planning (GEP), among other issues. However, computational limitations lead these problems to be solved separately. In this sense, these stand-alone investment optimisation problems have gathered a great amount of research that has recently focused on studying the consideration of bigger networks, more detailed operation and the consideration of renewable generation, batteries, distributed generation and their corresponding support schemes. For a complete review of these separate problems please refer to (Hemmati et al., 2013).

With the evolution of computational capability, the joint consideration of both problems became possible, allowing to capture the important links between generation dispatch and transmission supply along with their siting and sizing decisions. These models, usually known as Generation Expansion Planning and Transmission Expansion Planning (GEPTEP) co-optimisation models, represent the vertically integrated utility in a centralised environment, that aims to minimise total system cost. This cost minimisation framework is equivalent to maximizing the total welfare of the system when three assumptions are fulfilled; i) perfect competition, ii) simultaneous operating and investment decisions, and iii) perfect information. As a consequence of considering the links between generation and transmission, this co-optimisation framework results in a lower system cost compared to a separate GEP / TEP optimisation approach as shown in (Conejo et al., 2016), (Krishnan et al., 2016),(Hu et al., 2012).

However, this co-optimisation framework, cannot answer additional questions regarding sequential and strategic decisions that emerge in a decentralised market environment. With market environment, we refer to the fact that the vast majority of power systems today are organised via a liberalised market in which private companies compete amongst each other (in generation and retail). Therefore, the investment and operation decisions under a market environment are quite different from centralised planning. In a liberalised electricity market environment, generation expansion and operation are decided in a competitive way where every generation company (GENCO) takes its own decisions by aiming to maximise total profits, while the transmission planning keeps being centralised.

In this sense, the liberalisation of electricity markets has introduced new dynamics that lead to conflicting interests between the different decision makers in the electric power system. The behaviour of GENCOs can be modelled by means of game theory to represent their strategic interactions as a Nash equilibrium. Moreover, if we would like to consider the sequence between investment and operation for this strategic agents, hierarchical models (bi-level) permit us to

represent such structures. Bearing this in mind, hierarchical equilibrium models represent an adequate tool to study how different agents in GEPTEP problems behave under such a market environment.

In this context, we move from the term “co-optimisation” to the term “co-planning”. We introduce this term, given that these models are not, in essence, a single optimisation problem. Thus, co-planning models, help us to understand how Transmission Companies (TRANSCOs) and Generation Companies (GENCOs) take strategic and sequential decisions. For example, consider the case where transmission expansion decisions are made first, and subsequently, under a market framework, GENCOs make their expansion decisions (or possibly the other way around). In this sense, equilibrium models, in particular, bi-level or multi-level problems help us model this kind of interactions. It is important to note that strategic behaviour does not only occur in the operation but also in the investment decisions. Nowadays, this is particularly true because of the shorter construction times of generation units (mainly for renewable technologies) and longer times for transmission lines (either as a result of stricter environmental restrictions or more demanding communities) permit GENCOs, for instance, to site their units strategically in such a way that they induce congestions in the network that lead to higher operational incomes for GENCOs.

A key issue in generation and transmission expansion planning is the choice of which investment decision is considered to be taken first. Does the transmission planner take its decisions after the generation has been sited or do the generation companies plan their investments after transmission assets have been decided? What comes first, the chicken or the egg? To solve this problem, we have to make an assumption on the sequence in which investment decisions are made. These choices are the proactive and reactive transmission planning approaches. Authors in (Sauma & Oren, 2006) propose a proactive planning approach as a framework in which the network planner has the ability to influence generation investment and spot market behaviour. In terms of the hierarchy, it means that TRANSCO is the leader and the GENCOs that anticipate market outputs are the followers. Respectively, under a reactive planning approach, the network planner assumes that generation capacities are given and then it optimises based only on the spot market equilibrium. Reactive planning is thus represented by a model with multi-leaders GENCOs and one or several TRANSCOs as followers. Authors (Sauma & Oren, 2006) consider an oligopoly structure and demonstrate theoretically how proactive planning leads to greater social welfare in comparison to reactive planning.

In practice, as mentioned in (Spyrou et al., 2017) most of the TRANSCO companies in the world follow a reactive approach, and none of them has applied a strictly proactive approach as the one proposed in (Sauma & Oren, 2006). In such proactive approach, GENCOs submit their plans to the respective TRANSCO and they plan the reinforcements according to those generation plans. This planning process has been, by default, the most natural procedure to repond to the private decision-making of generator companies (which come along with capital intensive investment).

However, as mentioned in (Pozo et al., 2017) there are some other approaches that are close to proactive planning. In such an approach, the TRANSCO should anticipate the possible investments in generation and decide its transmission reinforcements in order to maximize the total welfare in the system. This procedure might even more applicable in a context of several

small investors (in various power systems the number of GENCOs have increased due to an easier access and lower capital intensity of renewables investments). Additionally, in terms of stability of the system, TRANSCO are starting to anticipate GENCOs investment with a longer time horizon, to assure the necessary conditions to achieve a reliable system operation.

For example, a regulation was approved in the US that includes the concept of anticipative (proactive) transmission planning to obtain a higher social welfare (FERC, 2011). Initially, such approach did not find a strong support but in 2021 several organizations supported the Advance Notice of Proposed Rulemaking (ANOPR) on regional transmission planning, that includes a clear need for proactive transmission expansion planning to achieve an efficient level of transmission investment to ensure just, reasonable, and equitable rates (this might imply building idle capacity that will serve as a signal to GENCOs and influence their investment decisions). In Chile, a regulation that enforces the consideration of coordination between transmission and generation has also been approved (Ministerio Energía, 2016). Additionally, in the current European context, ENTSOE plays the role of a centralised agent that proposes future planning pathways, in which regional coordination takes place, and then nationally generation companies can react to its decisions. Thus, under this regulatory context a proactive planning approach would make more sense.

1.2 Equilibrium problems

Going beyond the assumption of perfect competitive markets, non-cooperative game theory serves us to define and study the strategic interactions among rational decision makers, which leads initially to some equilibrium models, such as Nash Equilibrium, where each player's decisions is the best reply to the other's player strategies (Jørgen Jacobsen, 1996).

When discussing the equilibrium structure of GEPTEP models we distinguish among several different cases, all of which are depicted in Figure 1. The first classification we have to make is whether the nature of the game is simultaneous or sequential. With simultaneous games, we refer to equilibrium structures where all decision variables are assumed to be taken simultaneously, i.e., TEP investment, GEP investment, market operating decisions are all taken at the same time. A sequential or hierarchical structure refer to the type of games where one set of decisions is taken before the other in a Stackelberg manner.

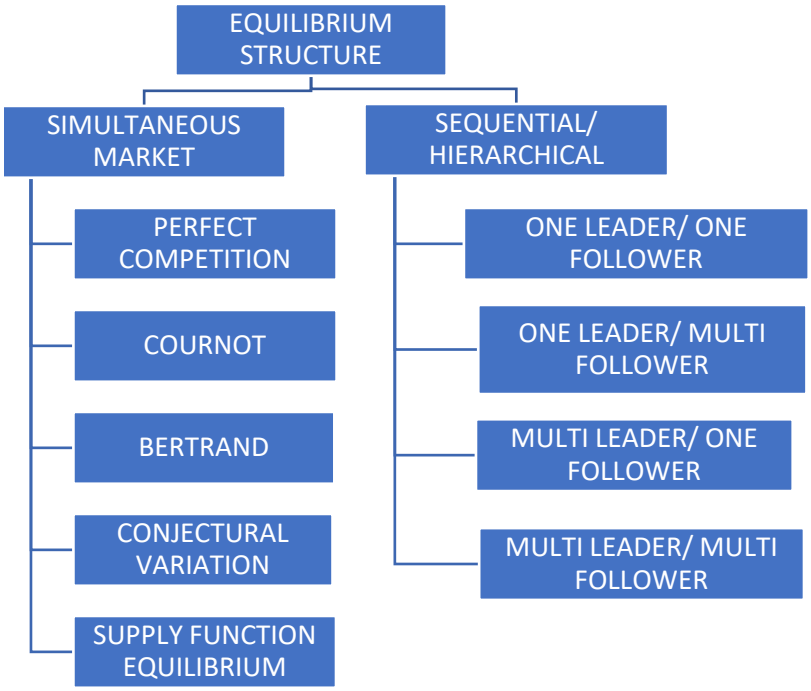

Figure 1: General Mathematical Structure of Equilibrium Models

In this thesis we focus on sequential games, which inherently model a decision-making hierarchy a la Stackelberg (Von Stackelberg, 2011).

Table I: Classification of hierarchical multilevel models

	Leaders	Followers
OLOF	ONE	ONE
OLMF	ONE	MULTIPLE
MLOF	MULTIPLE	ONE
MLMF	MULTIPLE	MULTIPLE

Stackelberg (Von Stackelberg, 2011) simulates a market where there is a leading firm and multiple followers. This game is defined as an equilibrium where the decisions of the leader are taken considering the best reaction of the followers that, at the same time, take their decisions knowing how the leader would react anticipating their own decisions. In this sense, bi-level programming generalises the Stackelberg model, by extending the number of players (and the type of decisions) in the game.

In particular, when a bi-level problem is defined as an OLMF game its mathematical structure is seen as an MPEC or as a simple bi-level programming problem. As seen in Figure 2, the OLMF is a type of mathematical structure in which a single optimisation problem (Upper Level) is constrained by several simultaneous optimisation problems (Lower Level) that represent an equilibrium. In Figure 2,, x and y represent lower and upper-level decision variables respectively.

$$Max\ F(x, y)$$

$$Subject\ to:$$

$$\begin{array}{lll} Max\ f(x_1, y) & Max\ f(x_2, y) & \dots\ Max\ f(x_n, y) \\ subject\ to & subject\ to & \dots\ subject\ to \end{array}$$

$$\begin{array}{lll} g_1(x_1, y) \leq 0 & g_2(x_2, y) \leq 0 & \dots g_n(x_n, y) \leq 0 \\ x_1, y \geq 0 & x_2, y \geq 0 & \dots \quad x_n, y \geq 0 \end{array}$$

Figure 2: Bi-level problem with an OLMF structure

In some cases, this lower-level equilibrium can be converted into a single optimisation problem. Nevertheless, even if this is possible, the resulting complete problem cannot be solved directly by classical optimisation techniques because an optimisation problem is constrained by another optimisation problem. Therefore, in order to solve a bi-level problem, with an OLMF structure, we can follow the next steps. First, the set of lower-level optimisation problems can be converted into a set of non-linear and non-convex constraints by applying the Karush-Kuhn-Tucker (KKT) (if the optimisation problem is convex) conditions. As seen in Figure 3, the resulting optimisation problem is constrained by the primal feasibility constraints, the dual feasibility constraints and the Complementarity Conditions (CC).

$$Max\ y\ F(x, y)$$
$$Subject\ to:$$

Dual
$$\partial L/\partial x_1 = 0 \quad \partial L/\partial x_2 = 0 \quad \dots \quad \partial L/\partial x_n = 0$$

CC
$$\lambda_1 g_1(x_1, y) = 0 \quad \lambda_2 g_2(x_2, y) = 0 \dots \lambda_n g_n(x_2, y) = 0$$

Primal
$$\begin{array}{llll} g_1(x_1, y) \leq 0 & g_2(x_2, y) \leq 0 & \dots & g_n(x_n, y) \leq 0 \\ x_1, y \geq 0 & x_2, y \geq 0 & \dots & x_n, y \geq 0 \end{array}$$

Figure 3: OLMF problem with Lower Level KKT Conditions

The resulting set of constraints is non-linear and non-convex given the complementarity conditions of the problem. This lower level has the structure of a Mixed Complementarity Problem (MCP), and therefore the whole problem has the structure of an MPEC. Please note that bi-level (OLMF) problems are particular cases of MPECs. Now we list the most used techniques to solve these kinds of problems. As mentioned in (Pineda et al., 2018), these techniques can be divided into dedicated (efficient algorithms that ensure global optimality but require significant additional coding) and non-dedicated algorithms. Some of the non-dedicated algorithms are (that can be implemented directly using commercial software): NLP/ MPEC, Regularisation, Penalisation, and MIP KKT- DUAL.

The only non-convexity in Figure 3 introduced by the complementarity conditions this problem solvable using an ordinary NLP solver (or specific solvers, such as PATH, can solve this problem more efficiently). We call this methodology the NLP/MPEC problems. Unfortunately, both nonlinear and MPEC solvers cannot guarantee a global optimal solution to the MPEC, given that all feasible points are non-regular (Pineda et al., 2018), and consequently, solution methods can easily get stuck in a local optimum or not even find a feasible solution. The regularisation(Pineda et al., 2018) relaxes the complementarity condition of the MPEC problem. Instead, the set of equations for $g_n(x_n, y) \leq t$ are solved. Then the NLP problem for small values of t is iteratively solved. The solution of each iteration will be the initial point of the following iteration; this process

is faster but only provides a local optimum point solution for the MPEC. As an alternative we have the penalisation (Pineda et al., 2018) which is similar to the regularisation. Conversely, in this case, the complementarity conditions are penalised in the objective function by a parameter that is reduced along the iterations until a sufficiently small value of the parameter is reached. As before, the solution of each iteration will be the initial point of the following iteration.

Finally, in the MIP KKT- DUAL alternative, the non-linear problem described in Figure 3 can be converted into a MILP (when the upper-level objective function is linear) by linearizing the complementarity conditions. This linearisation can be achieved by applying the methodology proposed by Fortuny-Amat in (Fortuny-Amat & McCarl, 1981) or by the discretisation method proposed in (Pereira et al., 2005). In the first case, a disjunctive formulation is applied to transform complementarity constraints into binary constraints. This is done by splitting the original constraint into two disjunctive constraints limited by a large enough parameter. This is usually known as the Big M constraints. This method is, by far, the most used method to solve bi-level problems. However, most of the papers that use it do not explicitly mention a method to determine the Big-M values. In fact, as mentioned in (Pineda & Morales, 2018), if these values are small, suboptimal solutions can appear, and conversely, too large Big-Ms can lead to numerical issues (when different variable magnitudes are reflected in dual variables), such as unstable solutions or large execution times.

Additionally, instead of applying the whole set of KKT conditions, the complementarity conditions can be replaced by the strong-duality conditions (where the objective function of the dual problem equals the objective function of the primal problem), which together with its primal and dual feasibility conditions, leads to an equivalent primal-dual formulation. In (Arroyo, 2010) a comparison of the KKT and the primal-dual formulation is presented and applied to a vulnerability analysis of the power system. The authors find that the primal-dual approach is more efficient because the size of the problem is highly reduced. In this thesis we apply the MIP KKT-DUAL methodology, which presents some scalability concerns and has to be carefully applied considering the potential issues that can arise if the bounds are either too tight or too big. However, it is a good enough approach to run small and medium size problems.

1.3 Objectives

Given the strategic interactions between various actors in the power sector, e.g., consumers, GENCOs, TRANSCOs or merchant investors (MIs), and policymakers, a game-theoretic analysis will be developed to gain insights about market design and societal impacts. Furthermore, since energy policies have implications for entire sectors as well as across borders, the interaction between diverse types of decision-makers will be analysed. Towards that end, in this thesis, a state-of-the-art analysis based on optimization and game theory is proposed; it provides insights on market design and the uptake of renewable energy technologies.

1.3.1 Main Objective

The main objective of this thesis is to develop a long-term bi-level model to address optimal transmission expansion under imperfect competition. The model should consider an imperfectly

competitive market framework in which generation expansion (both thermal and renewable energy technologies) and production decisions are taken. This main objective is achieved with three particular specific objectives:

1.3.2 Specific Objectives

- *O1. Long-term benchmark analysis:*
  Development of a long-term deterministic expansion planning model, that co-optimises generation and transmission expansion, representing the usual operation (generation dispatch, DC power flows, demand balance, etc.) and investment decision (continuous generation expansion and binary transmission expansion). This model assumes perfect competition and foresight, additionally is meant to serve as a benchmark to be compared with a strategic equilibrium model.

- *O2. Long-term technology R&D and adoption analysis:*
  Development of a bilevel optimization model that analyses the task of a proactive transmission expansion planning problem. The proactive transmission planner is subject to an imperfect market equilibrium in which we have an adequate representation of RE operation and technology costs to determine investment strategies from the perspective of strategic generation companies.

- *O3. Policy analysis of strategic investment decisions:*
  Development of a policy approach that addresses optimal transmission expansion under different objectives (either social welfare maximization from a social planner or profit maximization from a merchant perspective) and different market frameworks (perfect competition or strategic behaviour) in which thermal and renewable generation companies take expansion and operation decisions.

Figure 4 shows the interrelation among the different objectives. Objectives O1 and O2 aim at defining and developing the existing benchmark framework applied in most power systems in the world (O1) and the proposed bilevel equilibrium framework that considers strategic behaviour in the market (O2). Finally, these two frameworks are compared to analyse the implications of planning the system under an overly simplistic model compared to a comprehensive long-term adoption model (O3). We can consider diverse market design approaches with liberalised GENCOs or merchant transmission investors.

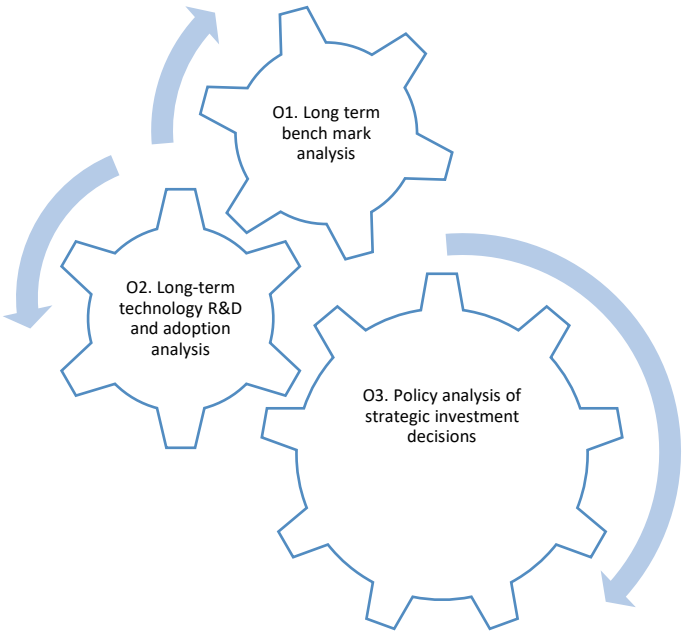

Figure 4: Relationship between the specific objectives

2 Thesis Outline

This thesis consists of three published journal papers. as shown in Figure 5: the conclusions of the review of the state-of-the-art help defining the type of models to be tackled O1 and O2; then in the second paper the actual formulation of the benchmark and the bilevel model to fulfil O1 and O2 are presented; finally, in the third paper a policy framework is proposed to compare and to evaluate the models resulting from the fulfilment of O1 and O2.

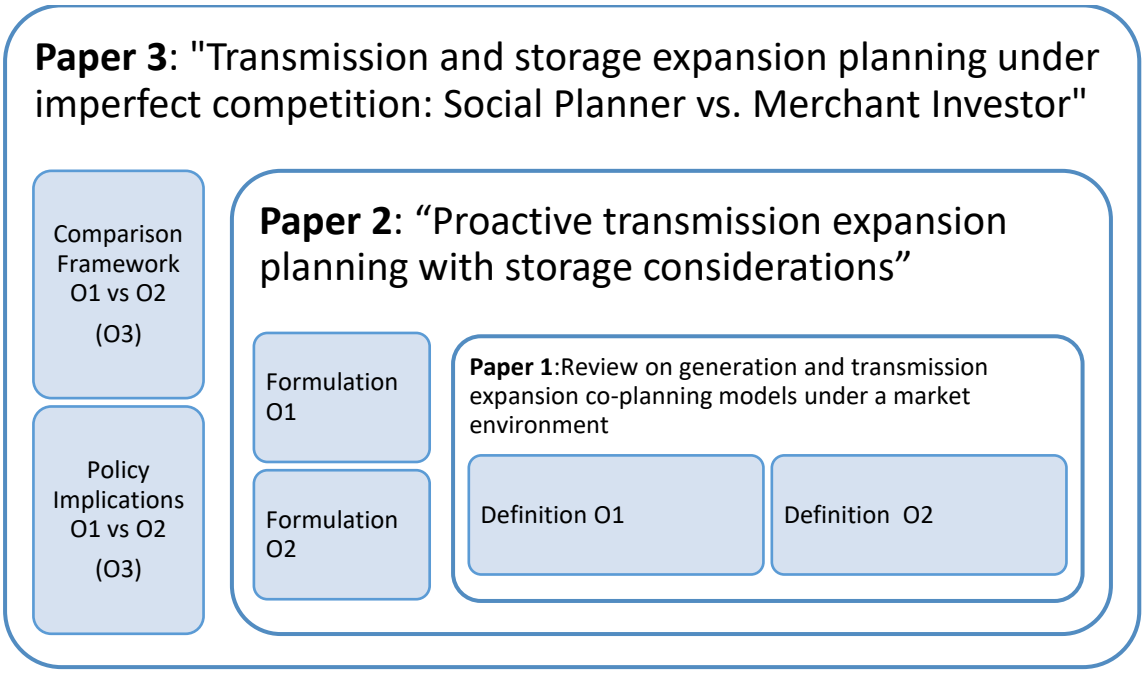

Figure 5: Paper's contribution to thesis objectives

2.1 Paper 1: "Review on generation and transmission expansion co-planning models under a market environment"

In the first paper, we present a review on the state of the art of different existing models for the joint optimization of generation and transmission expansion planning.

First, we describe the *co-optimization problem*, which refers to the power system planning by a vertically integrated centralised utility that simultaneously take generation and operation decisions on a perfectly competitive framework. This framework, which results in a single optimization problem, has been standard in different systems in the European context and the U.S. to conduct their policy analysis and recommendations and will serve as a benchmark for our study. This review found that, when simplifying planning models, considering lumpy transmission investments might be more important than representing a complex network. Additionally, given that the economies of scale in generation investment are much lower than in transmission

investment, considering continuous generation investments would be enough to obtain good planning results.

Second, we present the *co-planning problem*, which refers to power system planning under a decentralised market environment that considers imperfect competition and sequential decision making (e.g., transmission investment decisions vs generation investment decisions). We classified the existing models according to their equilibrium structure, regulatory approach, solution techniques, and the most recent developments (uncertainty and storage). We found that the most studied (and the one that lead to the highest welfare) framework, the proactive one, is still not implemented in most of power system's regulations worldwide. This framework, that considers sequential investments between generation and transmission, can result in distinctive investment decisions (compared to a centralised cost-minimizing planning) even by considering perfect competition in the market. We additionally found that when considering imperfect competition in the market, some counterintuitive results can arise, i.e. allowing trade between areas (by building more lines) can decrease total welfare. This literature review served us to define the appropriate equilibrium model to represent the long-term analysis under strategic investment decisions that helps us to give insights on how to evaluate and determine the implication of sub-optimal market structures. From this review, we propose a planning proactive approach, which theoretically is the one that renders the highest welfare. Even though this approach is still not spread around countries, it is starting to be mentioned and regulated in countries' legislation, For example, the US government approved a regulation that includes the concept of anticipative (proactive) transmission planning (FERC, 2011). Similarly, the Chilean government approved a regulation that enforces the consideration of coordination between transmission and generation planning (Ministerio de Energía Chile, 2016). In this review, we found an important gap in the joint representation of batteries and hydropower (and their potential strategic behaviour), which is of major importance, as they will serve to guarantee energy supply in low-carbon systems. Considering the conclusions of this paper, we propose a benchmark and a proactive planning model that fulfils such modelling gaps

In summary, in this paper, we made a state-of-the-art review where we stated distinctive modelling and policy research gaps on generation and transmission expansion planning models. Then, based on that review we define the structure of the benchmark and equilibrium models that are implemented to tackle objectives O1 and O2.

2.2 Paper 2: "Proactive transmission expansion planning with storage considerations"

In the second paper, "Proactive transmission expansion planning with storage considerations", we formulate the *co-planning problem* under a proactive approach in which a centralised TSO takes investment decisions first (by anticipating GENCOs behaviour), and then GENCOs react by taking investment and operation decisions.

First, we present the formulation of this bi-level proactive model in which we consider either a perfect or imperfect competition (Cournot oligopoly) via conjectural variations. To solve the equilibrium model, we convert it into an optimization problem using the KKT conditions to move from a set of optimization problems to a group of equations, which are then linearised using the

methodology proposed by (Fortuny-Amat & McCarl, 1981). In particular, 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. For the interested reader we include in the annex (Section V) an intuitive explanation of the modelling approach followed to represent energy storage.

Second, we propose a case study to analyse the policy implications of considering either perfect competition or a Cournot oligopoly in the market. We additionally consider a Greenfield planning and a Brownfield planning. For the particular case study, we found that capacity transmission expansion is higher when there is a perfectly competitive market than when there is a Cournot oligopoly (which follows the classic economic theory). We found, counterintuitively, that planning the transmission expansion under imperfect competition in the market (and having the TSO as a leader) can, sometimes, lead to a higher welfare to society than when having perfect competition. This counter-intuitive result suggests that for sequential games, the absence of perfect competition can be in particular cases, be beneficial to society (even if market power increases), particular conditions on demand elasticity and congestions can make a system planning under imperfect competition lead to a higher total welfare. We also found that under a Greenfield planning approach generators are less prone to exercise market power compared to a Brownfield planning approach where an existing sub-optimal network can help increase market power.

In summary, in this paper, we presented the complete formulation and implementation of the equilibrium model, which fulfils O2, with an adequate representation of RE operation and technology implementation that determines investment strategies from the perspective of strategic generation companies (GENCOs).

2.3 Paper 3: "Transmission and storage expansion planning under imperfect competition: Social Planner vs. Merchant Investor,"

In the third paper, we present the policy methodology to assess the implications of planning the system, from a simplistic point of view of a centralised cost-minimizing planner, compared to a comprehensive, proactive approach that considers possible strategic market feedback from the electricity market. Additionally, and due to the new challenges of the power system, we introduce a merchant transmission investor (that sometimes can be preferred when assessing isolated projects) and compare the planning results with those of the benchmark and proactive approaches.

First, a summary of the formulation of the benchmark and proactive frameworks is presented while the complete formulation of a merchant investor is introduced. Given these three models, we present a methodology to compute the potential welfare loss of planning the system expansion with the simplified benchmark model, instead of planning with the proactive approach that anticipates the market feedback, we name this welfare loss as “regret”. Second, two case studies are presented. A 3-node case, where all the operation and investment results are studied in detail to understand the logic and implication of the diverse policy objectives. And then, a 24-IEEE case is presented where the results are extended and generalised through a sensitivity analysis of different network and demand setups.

Second, we concluded that if transmission planners disregard strategic market feedback, there is a high chance that they will incur a non-negligible welfare loss. We also found that in some cases, a merchant investor (that follows a congestion-rent maximization objective) can lead to the same welfare loss as disregarding strategic market feedback. Most importantly, this sub-optimal planning output also leads to a significant distortion of the optimal generation mix. Extending the findings in Paper 2, the results might suggest that a Greenfield planning with BESS penetration is more sensitive to different policy objectives. In particular, total generation expansion divergence when considering a merchant investor instead of a social planner (with penetration of BESS) is higher under Greenfield planning, than under Brownfield planning, where most of the electrical infrastructure is already in place. Additionally, the system expansion seems to be more sensitive to systems with imperfect competition and BESS penetration.

In summary, in this paper, we tackle O3 by developing a policy approach that allowed us to identify the essential features to consider when designing new market sets to push forward the energy transition.

3 Conclusions

This thesis has presented some findings and regulatory recommendations on market design and infrastructure planning that will be relevant when facing the energy transition of economies worldwide, in particular, in a context of systems with high penetration of renewables and with the need of storage systems (i.e. batteries), this thesis studied the properties of an optimal system planning, which is essential to provide the proper operation and investment signals when there is imperfect competition in the market. Additionally, this thesis provided some insights on the role of merchant transmission investors in the context of isolated projects and potential imperfectly competitive behaviour, compared as well with the traditional cost-minimizing planning. Among the multiple technological and financial issues that might arise in the power system transformation, an important matter is the degree of imperfect competition in electricity markets, mostly when countries are still at early development stages, because at those stages the exercise of market power has a higher influence in transmission development and can therefore lead to highly suboptimal networks. Therefore, by ignoring the inherent decision sequences between transmission and generation planners (which gives advantages to the leader) and the potential exercise of market power (which is the case in most markets), power system planning can lead to erroneous incentives. Such incentives can lead, for instance, generators to locate their units in certain areas where they might be able to benefit from congestions in the networks, instead of locating them in another location where it has a higher contribution to social welfare. These remarks are more relevant in modern power systems with high penetration of renewables that will need the presence of high shares of storage technologies. In particular, BESS are capable of intertemporal arbitrage and therefore in a context of imperfect competition they will be able to exercise a higher degree of market power, not only temporal but also spatial. Thus, this thesis proposes regulatory and policy recommendations to evaluate power system planning from the perspective of a centralised or merchant transmission planner and the implications of ignoring strategic market feedback from generation companies that might invest and operate strategically. We achieve this by developing bi-level cutting-edge models (that include both short- and long-term storage technologies) that might help regulators, policymakers, and researchers to assess power system planning, considering not only a traditional centralised framework but also a decentralised framework (that can be captured by bilevel models, considering competition in the electricity market, but also in the investments) that will impose new challenges to modern economies.

Conclusions and contributions

The generation and transmission expansion planning has been, for decades, a key task in the electricity sector. In particular, a centralised cost-minimizing approach was sufficient to represent

the needs and the underlying functioning of vertically integrated systems. However, with the liberalization of the electricity sector, new dynamics (such as intraday arbitrage by BESS, high share of intermittent technologies and lower building times that might increase the exercise of market power) enter into the equations and create the need for new methodologies and models to represent the market functioning.

In this context, in Chapter 2.1, we presented a comprehensive literature review. We included the current state of the typical co-optimization problems, which are inelastic single optimization problems, and the novel co-planning equilibriums models, which include a bilevel structure that allows us to model sequential and strategic decisions. From this research, we found the following conclusions.

- First, we found that the main areas of improvement for these models are spatial and temporal resolution, resource adequacy and the economics of energy production in long-term planning problems. Contribution: we contributed to the literature by updating and extending the extensive and growing literature on co-optimization problems.

- Second, for co-planning problems, we found that they are a valuable tool to represent the new dynamics of the market; even when considering perfect competition, different results can arise if generation and transmission decisions are taken at different strategic levels. Additionally, considering the access to the market of merchant investors can broaden regulators' view on how to design policies that permit an optimal system planning, by anticipating the investment results when there is imperfect competition and a merchant investor that tries to maximise its revenues (i.e. congestions rents). Contribution: We contributed to the literature by identifying the current and potential applications of co-planning models into the policy analysis for the new challenges of the power systems.

- Finally, some other main potential research areas are i) regulatory studies, broader analysis on how different types of regulatory structures (which imply distinctive equilibrium structures) impact the way power systems are planned, ii) solution techniques, are an active field of development where more efficient methods (for MPEC and EPEC) are needed to solve real size cases, iii) new challenges, the correct representation of renewable uncertainty and storage modelling are still broad fields of research, and iv) information theory, given that perfect information is a strong assumption in planning models, including imperfect information theory in the GEPTEP problems can make these models more useful for real applications. Contribution: We conducted a throughout classification of co-planning equilibrium models in its various dimensions: regulatory and equilibrium structure, solutions techniques and new developments. We additionally provided the main gaps on each of those classifications by identifying potential areas of research.

In Chapter 2.2, we presented the detailed formulation of our proactive model. We included the main operation and investment considerations to represent and solve the generation and transmission expansion problem in a reasonable time. In particular, we included the generation constraints of the dc power flow equations to model the network, and we introduced a representative period approach that allowed us to represent both long- and short-term equations to model storage technologies (hydro and batteries).

- On the one hand, we formulated the proactive approach. Here, the transmission company acts as a leader by taking investment decisions in the grid first, while GENCOs take

investment and operation decisions later (including storage). This study concluded that there is lower welfare when we run a Brownfield planning, where some inefficiencies are already in place, compared to a Greenfield planning where the whole system is designed from scratch. This situation suggests that, for this particular case, GENCOs can exercise a higher degree of market power when there is existing infrastructure (in particular, the market share of each company is similar in the perfect competition and Cournot case for the greenfield planning, while for the brownfield planning market shares are highly concentrated in a single company in the Cournot case).

- On the other hand, we found that, for the particular system and demand elasticity of the case study, Cournot competition led to higher costs of the system but also to higher welfare. This counterintuitive result suggests that imperfect competition can lead to a better-off situation for society depending on the system topology and the different degrees of demand elasticity. This result might not be the general rule. Still, it confirms that imperfect competition in bi-level models, under some circumstances, can be beneficial to society as a whole, which is confirmed with similar results obtained in previous research.

- Contribution: We contributed to the literature by proposing a GEPTEP co-planning model including for the first time both short- and long-term storage equations with an enhanced representative period approach. With this approach we were able to apply conjectural variations both for thermal and storage technologies to study the implication of imperfect competition in the system expansion planning

Finally, in Chapter 2.3, we performed three policy analyses on the implications of different regulatory structures into the generation and transmission expansion planning. First, we compared the planning results of a proactive planner, which anticipates strategic market feedback, to a centralised cost-minimization planner that assumes an overly simplistic and optimistic framework. Second, we compared the policy implications of allowing a merchant transmission investor, which seeks to maximise congestions rents[4], to execute the transmission expansion planning compared to a proactive planner (either when there is perfect or imperfect competition in the market). Third, we study the policy implications of planning the system with and without the consideration of BESS penetration.

- We proposed two case studies (3-node and IEEE 24 node), from these cases (including several sensitivities on demand elastitcy and network congestion) we could conclude the following: i) Disregarding market feedback can lead to a non-negligible welfare loss, both in the storage and non-storage cases; moreover, we found some results that might suggest that disregarding market feedback could be worse when we have BESS in the mix, as it implies disregarding the effects that flexibility of BESS can have on the exercise of market power. In general, according to all cases and sentitivities considered, disregarding market feedback might have a relatively small impact on

[4] We consider those market incomes are derived from the network congestion rents, which are computed as the price difference between two connected nodes times the flow through the corresponding connecting line. Please note that this is not the only way in which we can consider the market incomes for merchant investors. In general, we have physical rights models, financial models, or a mix of both, as well as point-to-point or flow-based approaches. In this paper, we consider a physical point-to-point congestion rent model, which is a theoretically good-enough approach to represent market incomes for merchant transmission investors. However, there exist more accurate approaches as those in (O'Neill et al., 2008) that take into account the AC power flows or those based on the Vickrey-Clarke-Groves auction theory.

overall welfare loss. However, the subsequent effect on the optimal generation mix can be considered significant.

- We found that, for the considered cases, ii) Merchant investors lead to a worse-off situation, with lower welfare and higher prices. Additionally, in some cases, a merchant investor can lead to the same welfare loss as disregarding strategic market feedback. Most importantly, this sub-optimal planning output also leads to a significant distortion of the optimal generation mix. This sub-optimal generation mix can affect the system's adequacy in terms of responsiveness to long term intermittent resource availability.

- Finally, we found that iii) Greenfield planning with BESS penetration is more sensitive to different policy objectives. In particular, total generation expansion divergence when considering a merchant investor instead of a social planner (with penetration of BESS) is higher under Greenfield planning than Brownfield planning. Additionally, the system expansion seems to be more sensitive to systems with imperfect competition and BESS penetration.

- Contribution: In this paper we contributed to the literature by proposing a comprehensive methodology to assess the implications of different policy objectives in the generation and transmission expansion problem. In terms of modelling, we introduced a linearised merchant transmission investor formulation (in addition to the proactive GEPTEP proposed in Chapter 2.3) and then we compared the welfare outputs with those of a social planner. Additionally, we propose a methodology to compute the welfare loss of not considering imperfect competition in the market, which is compared as well to the total welfare achieved by a merchant investor.

Finally, we list the limitations derived from the assumption made in the overall modelling of this thesis:

- Stochasticity can have a high impact in the planning results. From preliminary studies, where we consider stochastich bilevel model (with uncertainty in the lower level), we found that the consideration of uncertainty in renewable resources might have a higher impact in welfare than imperfect competition. However further studies need to be carried out to confirm these observations.
- The no consideration of losses can have an impact in those systems with low congestion and similar variable costs at different nodes. Therefore, for systems with high penetration of renewables, considering losses might become essential to properly represent nodal prices and congestion rents.
- Considering other type of representation for market incomes for merchant investors can lead to different equlibriums (however it must be assured beforehand that a unique equilibrum exists). However, for this paper considering congestions rents (which are also considered for the S.O problem), sets a comparable basis with the welfare maximization approach.

In general, these results provide regulators and companies with new tools to keep in mind the potential consequences of the new technologies and market dynamics from generators, transmission companies and consumer’s point of view.

Future Research

In future research, policy analyses can be extended by including uncertainty in renewable sources, which become more and more important in systems with a high penetration of renewables, because disregarding renewable sources uncertainty can lead to non-robust investments. This issue is fundamental in the equilibrium model, where uncertainty can be represented with stochastic models and with robust multilevel models that can assess the interrelations of long and short-term uncertainties in the capacity expansion planning problem. Moreover, alternative renewable energy policy designs could be included in the transmission planner objective function to test how social welfare can be affected more deeply. Finally, the representation of the transmission network can be improved by introducing a linearised loss approximation or A.C. approach. This improvement can eliminate multiple solutions (in equilibrium models) and provide more accurate dispatch results (including BESS's charge and discharge).

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Abstract: This study presents a review of the state-of-the-art on the coordination of generation and transmission expansion planning. First, the authors present the different investment and operation modelling approaches, with an emphasis on the centralised co-optimisation problem. Second, a comprehensive review of co-planning hierarchical equilibrium models, under a market environment, is carried out. The authors categorise the distinctive market approaches that usually represent the lower level of co-planning problems. They offer an updated and detailed classification of multilevel equilibrium models, based on their hierarchical and regulatory structure versus their equivalent reduced structure. Finally, the authors identify research gaps in the literature of each one of the mentioned model categories.

1 Introduction

Power systems were conventionally structured under a centralised environment, where a cost minimising vertically-integrated utility was in charge of deciding, among other matters, both transmission expansion planning (TEP) and generation expansion planning (GEP). However, due to computational limitations, in the past, TEP and GEP were usually solved as independent problems. A great amount of research has been published on these separate problems, with the focus shifting recently to contemplating bigger networks, the more detailed operation of conventional units, renewable generation, batteries, distributed generation, and their corresponding support schemes. For a complete review of these separate problems, please refer to [1].

With the development of computational capability, the joint consideration of TEP and GEP became possible, allowing the important links between generation dispatch and transmission supply along with their siting and sizing decisions. These models, usually known as GEP and TEP co-optimisation models (GEPTEP co-optimisation models), take into consideration the links between generation and transmission, resulting in a lower system cost compared to a separate GEP/TEP optimisation approach, as shown in [2–5]. This cost minimisation framework is equivalent to maximising the total welfare of the system when three assumptions are made: (i) perfect competition, (ii) simultaneous operating and investment decisions, and (iii) perfect information. However, this co-optimisation framework does not address sequential and strategic decisions that emerge in a decentralised market environment.

The vast majority of power systems today are structured in a liberalised market, in which private companies compete with each other (in generation and retail). Therefore, the investment and operation decisions in this market environment are quite different from those in a centralised environment. In a liberalised market, generation expansion and operation are decided in a competitive way where every generation company (GENCO) makes its own decisions aiming to maximise total profits, while the transmission planning remains centralised.

In this sense, the liberalisation of electricity markets has introduced new dynamics that lead to conflicting interests between the different decision makers in the electric power system. The behaviour of GENCOs can be modelled by means of game theory to represent their strategic interactions as Nash equilibrium. Moreover, if we consider the sequence between investment and operation for these strategic agents, hierarchical models (bi-level) allow us to represent such structures. Bearing this in mind, hierarchical equilibrium models represent an adequate tool to study how different agents in GEPTEP problems behave under a market environment.

Once the context is set, we can move on from the term 'co-optimisation' to the more accurate 'co-planning'. We introduce this term, given that these models do not address, in essence, a single optimisation problem. Thus, co-planning models help us to understand how transmission companies (TRANSCOs) and GENCOs take strategic and sequential decisions. For example, consider the case where transmission expansion decisions are made first, and subsequently, under a market framework, GENCOs make their expansion decisions. In this sense, equilibrium models, in particular, bi-level or multi-level problems help us model this kind of interaction.

It is important to note that strategic behaviour does not only occur in operation but also in investment decisions. This is particularly true nowadays because of the shorter construction span of generation units (mainly for renewables technologies) and longer times for transmission lines (because of stricter environmental restrictions or more demanding communities) allow GENCOs to site their units strategically in such a way that they induce congestions in the network, leading to higher operational incomes for GENCOs.

This review aims to present an overview of the current state of GEPTEP models: in Section 2, the classical network and generation modelling are presented. We update the references presented in Krishnan *et al*. [3] for co-optimisation models and we extend it to the co-planning models. In Section 3, the properties of co-planning models and their solutions are analysed. As a novelty, we classify hierarchical GEPTEP papers based on their general hierarchical structures and sequential decisions.

Therefore, we contribute to the relevant literature by classifying both the hierarchical structure and the solution techniques of the co-planning models, offering a direct comparative of co-planning models based on consistent parameters. Additionally, we describe and classify the most commonly used techniques to solve equilibrium models, and we consider the different investment and operation modelling options and their impact on both the equilibrium structure and the type of mathematical problem. Lastly, in Section 4, we conclude.

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References		[18]	[19]	[20]	[21]	[22]	[23]	[24]	[25]
Year		2015	2018	2014	2017	2013	2018	2017	2017
network represents model	pipe line								X
	DC	X	X	X	X	X	X		
	AC							X	

introduces the value of money over time in the whole optimisation horizon.

Finally, it is important to note that the mathematical-based algorithms usually consider a single target year because they are not suitable for large-scale problems. Consequently, most of the work done for multi-year programming has been tackled with some alternative meta-heuristics algorithms [49]. However, recent advances in computational speed, by properly considering the most relevant assumptions, have allowed tackling multistage programming as seen in [21], making it possible to determine not only the optimal siting but also the optimal time of construction of the investments. Additionally, the advancements in algorithms to represent uncertainty, that also considers large-scale problems (see Section 3.4.2), has also permitted to tackle the multistage programming [46].

2.4 Size reduction techniques

Long-term models have to deal with the trade-off between the representation of short-term operation constraints and the representation of long-term investment decisions. This implies that hourly operating constraints cannot be retained for several years in a large system because the model becomes computationally intractable. This concern has increased because of the high penetration of renewable technologies that make the impact of ramping constraints, and the capability of storage technologies to balance them, more relevant.

Consequently, current research is focused on reducing either the network size or the time steps representation. The actual transmission network can be reduced so that an equivalent resulting network renders the same or approximate solution. Some of these techniques [59–62] have been applied only for TEP problems. On the other hand, time-steps can be reduced by, for example, using load levels or representative days. As seen in Table 1, most of the models used a traditional load level approach and only a few of them used a representative period approach.

Table 2 Classification of GEPTEP co-planning models

Authors	[26]/[27]	[28]/[29]	[30]	[31]	[32]/[33]	[34]	[35]/[36]/[37]
publication year	2006/2007	2013/2018	2009	2011/2012	2007/2012	2010	2013/14/17
type	optimistic	optimistic	optimistic	optimistic	optimistic	optimistic	optimistic/ pessimistic
network investment	fix investment	binary new lines	binary new lines	binary new lines	binary new lines	binary new lines	CONT/binary new lines
TSO objective function	max social welfare	max SW/max PR–lc (FB)	max PR – IC with FB	max welfare-IC	max profits/min CP-IC	several planning criteria	min total cost/min OC min–max
generation investment	CONT.	CONT.	CONT.	CONT.	binary new generation (NG)	binary NG	CONT/binary NG
GENCOs objective	max profit	max profit	max PR-IC	max profit	max PR & CapPay	max PR-IC	max profit
ISO objective	max social welfare/RD	max social welfare	min CP	max SW	min P. mis. min OC	max SW	min cost operation/
dynamicity	static	static	static	static	static	static	static
regulatory framework	proactive versus reactive	proactive	other see Table 5	other	other (GEPTEP in the upper level and MO in the lower level)	proactive	proactive
hierarchical structure	MLMF	one leader multiple followers (OLMF)	one level	OLMF	multi leader one follower (MLOF)/ MLMF	MLMF	MLMF
operation competition	strategic	perfect	strategic	strategic	strategic/perfect	strategic	perfect
uncertainty	no	no	no	no	yes	no	no/deterministic (DET)/yes
demand elasticity	elastic	inelastic	inelastic	elastic	elastic/inelastic	inelastic	inelastic
time represent.	1 h	load level	1 h	1 h	load level	load level	blocks
end effect	annual	annual	annual	annual	net present value (NPV)/annual	NPV	annual
storage represent.	no	no/short-term	no	no	no	no	no
test cases (when several cases are tested only the biggest one has been referenced)	Chilean 32 /Cornell 30	IEEE-21 Garver-6	IEEE 14 bus	6-bus	6-bus/IEEE-118	5- bus	4-bus/Chilean 34/24 Node
solution technique	sequential quadratic programing- linear complementarity problem (first level)	MIP	quadratically constrained program	MIP (authors compare NLP, mixed integer quadratic program (MIQP) and MIP approaches)	iterative (holistic simulation by using benders and the Lagrange relaxation)/MIP	iterative agent based	MIP (generation strategies are enumerated and finally a MIP is solved)/CG (CG and disjunctive Cutting plane)

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Authors	[38]	[39]/[40]	[41]	[42]	[43]/[44]	$[32]_1$, $[34]_2$, $[45]_1$, $[46]_2$
publication year	2014	2014/2017	2017	2018	2015/2019	18/17/19/18
type	optimistic	pessimistic	pessimistic	optimistic	optimistic	robust
network investment	binary new lines	binary new lines	binary exp./CONT.	binary upgrades	cont./binary new lines.	binary new lines
TSO objective function	min weighted sum CC-gencos profit (GP)	min IC–SW	min LIC + GIC + OC	min LIC + Exp. OC	min IC + OC	min IC + OC
generation investment	binary NG	CONT	binary expansion	CONT	CONT	CONT
GENCOs objective	max profit	max profit	max exp PR-IC	max exp PR-IC	max profit	—
ISO objective	min accep. bids	max social welfare	min OC	max social welfare	max congestion rent (CR)	min OC
dynamicity	multi-period	static	static	static	static	$stat._1/dyn_2$
regulatory framework	proactive	proactive	proactive–reactive	reactive	proactive	other see Table 5
hierarchical structure	MLMF	MLMF	OLMF/MLOF	MLMF	OLMF	OLMF
operation competition	perfect	strategic	perfect	perfect	perfect/strategic	perfect
uncertainty	no	no	yes	no	no	yes
demand elasticity	inelastic	elastic	inelastic	inelastic	elastic	inelastic
time represent.	1 h	1 h/blocks	blocks	represen. periods	1 h/ERP	represen. periods
end effect	NPV	annual	annual	annual	annual	annual
storage represent.	no	no	no	short term	short/short & long-term	no
test cases (when several cases are tested only the biggest one has been referenced)	Garver-6	IEEE-118/IEEE-14	IEEE-118	WEEC-240	4-bus	118/Chile 20/118/118
solution technique	*K*th best algorithm	diagonalization (DG) and complementarity reformulation (CF)/mixed integer linear programming (MILP)	MBA/MILP	MIP/iterative CG	MIP	CG_2

SW, social welfare; CC, costumer cost; CP, consumer payment; IC, investment cost; OC, operation cost, ERP, enhanced representative periods; CONT, continuous; LIC, line investment cost; GIC, generation investment cost.

In general, detailed clustering approaches for time reduction [63–66] are proposed for GEP problems when intraday constraints are needed to be modelled, as in the case of battery operation. However, only some of these techniques have been applied to GEPTEP problems. For instance, Bustos *et al.* [23] applied a load level approach with a square-mean-error clustering technique in a GEPTEP problem with batteries deployment. Additionally, they characterise wind and solar availability profiles of each hour before clustering load levels, but they disregard transitions between clusters. Some of these techniques have been applied to GEPTEP co-planning problems, as will be discussed in 3.4.

2.5 Most recent developments

The major recent developments in GEPTEP have been the introduction of renewables generation, which brings along a high uncertainty in renewables resources, and the utilisation of storage technologies that help manage the intermittency introduced by renewables.

2.5.1 Uncertainty representation: There are multiple sources of uncertainty for GEPTEP problems; some of them are long-term uncertainties such as climate variables (i.e. hydro seasons), fuel availability, and demand growth; some are short terms, such as daily weather for renewables, units availability, daily demand, and transmission capacity factor. The representation of uncertainty was initially approached by probabilistic methods, in which the availability of either generation units or lines is simulated to take into account reliability measures [14, 20]. Later, stochastic programming has been considered in a few cases [17, 21] applied to the traditional co-optimisation model. Finally, other techniques such as robust optimisation have appeared, mainly applied to co-planning models in a market environment context, as will be discussed in Section 3.4.2.

2.5.2 Storage modelling: Co-optimisation of transmission and storage investments can be found most notably in [18, 21], both studies achieve a lower cost system compared to a separate optimisation. Energy storage systems (ESS) sizing and siting optimisation are also presented in [67, 68]. Wogrin and Gayme [67] demonstrate that the conditions of siting are dependent on the type of ESS technology; Fernández-Blanco *et al.* [68] conclude that a minimum profit constraint should be included in order to guarantee recovery of investment.

Additionally, Hu *et al.* [4] show that investment in ESS reduces transmission investment costs. In [69], the authors consider ESS and a DC transmission loss approximation, the conclusion is that ESS reduces transmission costs and add flexibility to the system. The general inference of the previous studies is that ESS is a substitute for transmission, however, Bustos *et al.* [23] show that ESS can also be complementary to transmission, depending on the system characteristics and the level of distribution of the ESS deployment.

2.6 Modelling approaches gaps

Cole *et al.* [8] research the challenges for renewables generation modelling in policy analysis models and compare results for a US study case. They conclude that active areas for modelling enhancement are (i) spatial and temporal resolution, (ii) resource adequacy, and (iii) economics of energy production. Additionally, lower times of constructions for a renewable generation (wind,

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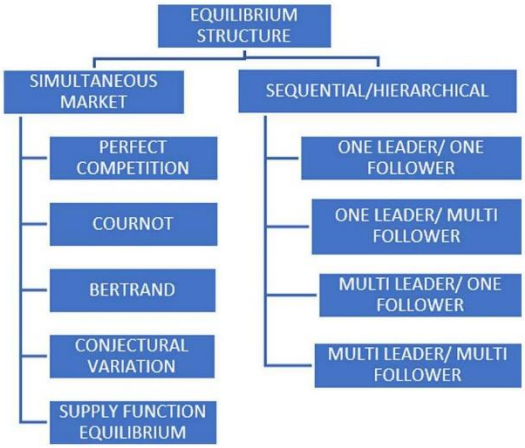

Fig. 1 *General mathematical structure of equilibrium models*

solar), and longer construction time for transmission allow GENCOs to exercise more market power in response to transmission siting, making the analysis of strategic decisions more relevant. Finally, considering strategic reactive power in the co-planning problem could help reduce load shedding and overall cost of the system, through joint allocation of transmission lines, conventional units, and reactive power sources [17].

3 Co-planning equilibrium models

In this section, we present a literature review on equilibrium co-planning GEPTEP models (as opposed to co-optimisation models) with a particular focus on multi-level models. We will consider four different categories in the analysis of co-planning GEPTEP models: equilibrium structure, regulatory framework, solution techniques, and the most recent development on the modelling of storage and uncertainty in a market environment. We will provide a detailed literature review and a classification of the existing equilibrium GEPTEP models, as well as the individual discussion on each category.

In Section 3.1, we classify the different GEPTEP co-planning models depending on their equilibrium structure. In order to do so, we first introduce market-only (no investment) equilibrium models, as they usually constitute the lower level of multi-level co-planning models. We then present the possible different structures of equilibrium models and we classify co-planning models accordingly.

In Section 3.2, we examine the possible regulatory frameworks where co-planning GEPTEP models are applied, and the corresponding hierarchy of decisions and the degree of competition considered. Section 3.3 explores the most common solutions techniques for hierarchical equilibrium models and classifies the literature in the corresponding categories. Finally, Section 3.4 contains a review of storage and uncertainty approaches under a co-planning market framework. Table 2 summarises the properties of GEPTEP co-planning models explored in the whole Section 3.

3.1 Equilibrium structure

When discussing the equilibrium structure of GEPTEP models, several different cases have to be considered, as depicted in Fig. 1.

The first distinction is whether the nature of the game is simultaneous or sequential. Simultaneous games are equilibrium structures where all decision variables are assumed to be taken simultaneously, i.e. TEP investment, GEP investment, and market operating decisions happen all at once. In a sequential or hierarchical structure, one set of decisions is taken before the other in a Stackelberg manner. Section 3.1.1 introduces simultaneous equilibrium models, both market and co-planning. In Section 3.1.2, we continue with sequential equilibrium markets and conclude with the characterisation of sequential co-planning models.

3.1.1 Simultaneous one-level structure: We present simultaneous market models, to then cite some simultaneous co-planning models, despite the latter being scarce in the literature (given that co-planning models are usually more interesting when studying the sequence between investment and operation decisions).

Simultaneous market models: There exists a wide range of research on simultaneous equilibrium models that simulate the electricity market functioning, mainly to represent oligopolistic behaviour among decentralised GENCOs. In this sense, the following modelling approaches are usually studied: (a) perfect competition: no market power, (b) Cournot: firms decide on quantity, (c) Bertrand: firms decide on price, (d) conjectural variations: a generalisation that over a 'conjecture', can result in models (a) & (b), and (e) supply function equilibrium (SFE): firms decide a price-quantity bid. A description of simultaneous equilibrium models applied to electricity markets when the network is disregarded is shown in [70]. Additionally, a review of oligopolistic network-constrained models (ONCMs) is presented in [71]. The seminal paper on ONCMs by Hashimoto [72] introduces the network equilibrium model to study systematically the oligopolistic behaviour of producers in a simplified transportation network. Under this framework, we identify two decision makers: GENCOs and ISO (or TSO). It is important to distinguish the two main features that affect the way prices are created in ONCMs (please refer to Table 3 for the summary)

(a) GENCOs reaction to transmission prices. As shown in [73], even if generation operation is competitive, GENCOs can exercise market power if transmission rights are passive. As an alternative, in [73], a parallel market that is proposed for transmission rights that affect generators' bids and leads to optimal pricing. Subsequently, in [74, 75], the authors consider two different ways for modelling transmission prices, stamp (uniform), and marginal prices. This is obtained by considering that GENCOs react *a la Cournot* to transmission prices. Authors claim that multiple equilibria can arise under stamp pricing; while uniqueness can only be guaranteed for marginal.

(b) Nodal price difference: a concern with previous models [73–75] is that differences in nodal prices might not necessarily be explained by GENCOs' marginal costs. Hobbs [76] proposes adding an arbitrager to the network. With this in mind, Hobbs [76] proposes solving the bilateral market with a quadratic optimisation problem (that copes with large-scale systems). Under this framework, GENCOs compete *a la Cournot*; while they react to transmission prices *a la Bertrand* (GENCOs cannot affect transmission prices). Hobbs [76] also shows that a bilateral market with an arbitrager is equivalent to a POOLCO market (where players react *a la Cournot* to transmission prices).

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Table 3 ONCM models characteristics

	TSO/ISO* objective function	GENCO objective function	Reaction to prices	Arbitrage	Structure
[73]	maximise: social welfare	maximise: profits – TP	Cournot	no	SIM
[74]	i) min: investment cost	maximise: profits – TP	Cournot	no	SIM
	ii) fixed rule				
[75]	fixed rule	maximise: profits	Bertrand	no	SIM
[76]	maximise: congestion rents	maximise: profits – TP- ABP	Bertrand	both	SIM
[77]	maximise: social welfare	i) max: profit + nodal premium	i) Bertrand	no	i) SIM
		ii) anticipate	ii) Stackelberg		ii) SEQ
[78]	maximise congestion rents + ABP	maximise: profits – TP- ABP	i) Cournot	yes	i) SIM
			ii) Stackelberg		ii) SEQ
[79]	maximise: social welfare	maximise: profits – TP	Stackelberg	yes	SEQ
[80]	maximise: utility	maximise: benefits	Stackelberg	no	SEQ
[81]	maximise congestion rents + ABP	maximise: profits	i) Bertrand	yes	i) SIM
			ii) Stackelberg		ii) SEQ

SIM, simultaneous; SEQ, sequential; TP, transmission price; ABP, arbitraged payments (nodal price × traded quantities).

Table 4 Classification of hierarchical multilevel models

	Leaders	Followers
OLOF	one	one
OLMF	one	multiple
MLOF	multiple	one
MLMF	multiple	multiple

Simultaneous co-planning models: As mentioned before, our search only found two papers that deal with simultaneous co-planning models. On the one hand, Wei and Smeers [74] model both transmission and GEP. However, computation limitations at the time of publication prevent the study of a real size model. Additionally, in [30], the authors formulate an equilibrium model to study the strategic interactions between TRANSCOs and GENCOs; then they transform the resulting mixed complementarity problem (MCP) to a quadratic programming problem, allowing them to solve big size problems. While a simultaneous decision-making structure leads to simpler models, it is also a simplification of reality that can potentially lead to a distortion of optimal planning results.

3.1.2 Hierarchical multi-level structure: Contrary to simultaneous games, the sequential games model a decision-making hierarchy *a la Stackelberg* [82].

Von Stackelberg [82] simulates a market with a leading firm and multiple followers. This game is defined as an equilibrium, where the decisions of the leader are made considering the best reaction of the followers that, simultaneously, make their decisions knowing how the leader would react anticipating their own decisions. In this sense, bi-level programming generalises the Stackelberg model by extending the number of players (and the type of decision) in the game. Table 4 classifies these models following [83].

It is important to note that the different levels in a multi-level framework can be either represented by different actors (e.g. TRANSCO, system operator or GENCOs) or by different types of decisions (e.g. investment and operation). As mentioned in Section 3.1.1, the market is generally considered as a simultaneous game, where GENCOs and system operator decisions are taken. Nevertheless, other models consider a sequence between the decisions of GENCOs and the clearing process made by the system operator. These models are called 'hierarchical market models', and some of their properties will be discussed because they are relevant for the subsequent review of hierarchical GEPTEP models.

Hierarchical market models: In Table 3, the main characteristics of simultaneous ONCMs (see in 3.1.1) and hierarchical ONCMs (as an alternative to improve transmission pricing) are presented.

In this respect, Metzler [78] extends the work on simultaneous ONCM done in [76]. They propose a sequential Stackelberg model where GENCOs anticipate TSO decisions (leader). The main contribution of [78] is to demonstrate that their proposal is a generalisation of [76]. Additionally, Neuhoff *et al.* [84] make a comparison of three large-scale hierarchical market models. Neuhoff *et al.* [84] make a comparison of the model comprehensive market power in electricity transmission and energy simulator [85], Cambridges I, II [79], and the Madrid model [80].

Neuhoff *et al.* [84] find that, when the perfect competition is considered, production and pricing results are the same for all models. However, when the oligopolistic competition is considered, pricing results might highly differ; prices could be twice as much in one case compared to others. Therefore, whenever a GEPTEP model is analysed, a strong emphasis must be made on how the market is represented, given that the resulting prices can highly affect investment decisions.

Hierarchical GEPTEP models: In this sub-section and the following sections (Sections 3.1.2, 3.2, 3.3, and 3.4), we characterise co-planning equilibrium models. Table 2 summarises this information.

Bi-level models can represent the sequence between investment and operation decisions in either GEP or TEP problems separately. For instance, Garcés *et al.* [57] consider a bi-level TEP by modelling market competition in the lower level and transmission expansion in the upper level. Some other authors develop a bi-level GEP by considering either perfect or imperfect competition in the lower level [86–89]. In order to properly classify and understand the existing hierarchical structure of GEPTEP problems, the difference between decisions and decision-makers must be pointed out.

Decision-makers can be typically classified as GENCOs, TRANSCO(s), and market operators. On the other hand, decisions can be classified as GEP, TEP, and market operation (MO). MO could also be split into a market clearing (MC) and GENCOs operation (GO). In reality, there is an inherent sequence in GEPTEP decision making: the investment stage before the market stage. Now, as we have pointed out previously in Table 3, there even exist different sequential stages within the market stage. Conceptually, a complete GEPTEP model consists of multiple concatenated hierarchical stages; however, when decisions are assumed to be simultaneous, they are reduced mathematically to one single stage.

In the remainder of this section, and summarised in Table 5, we characterise GEPTEP co-planning models according to their conceptual sequence and their corresponding mathematical sequence.

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Table 5 GEPTEP model classification depending on hierarchical structure (mathematical levels 1–4 versus GEPTEP options I–VIII)

	I	II	III	IV	V	VI	VII	VIII
1	GEP TEP MO	GEP	TEP	GEP TEP	GEP	GEP	TEP	TEP
2	—	TEP MO	GEP MO	MO	TEP	MO	GEP	GEP
3	—	—	—	—	MO	TEP	MO	MC
4	—	—	—	—	—	—	—	GO
	[30] [74]	—	[28, 29] [43] [44] [92]	[32] [31] [33] [93]	[41] [42]	[90]	[38, 91] [26, 41] [35, 37] [36, 39] [27, 40]	[34]

In Table 5, we classify the GEPTEP models considering the investment and operation decision hierarchy. To that purpose, Table 5, lists eight (I–VIII) different options, which are shown in the column space. The row space of Table 5 represents the separate mathematical levels of each model. Please note that simultaneous decisions are represented in Table 5 when decisions appear together on a single level. The simplest GEPTEP option, *option I*, is a single-level equilibrium model, which considers GEP, TEP and MO decisions simultaneously. Options II, III, and IV represent bi-level models, in which mathematically speaking there are only two levels.

This means that conceptually speaking two of the three decision levels (GEP, TEP, and MO) are considered to be taken simultaneously. Options V, VI, and VII represent three-level co-planning models with the following structure: some investments are made in the upper level (GEP/TEP) given some other investments in the middle level (TEP/GEP), subject to MO in the lower level. Finally, model VIII is a four-level model with the same structure as the previous three-level models; but also considers the market model is itself hierarchical. Additionally, some techniques can be applied to reduce the initial three-level model to a two-level structure as shown in [26, 33].

Anyhow, reduction techniques are applied only for solving purposes, and therefore the underlying hierarchical structure remains an MLMF, which is much more complex than an OLMF structure (when no anticipation of the market and only one leader is considered). This fact would imply to have, instead of a mathematical programme with equilibrium constraints (MPEC), an equilibrium programme with equilibrium constraints (EPEC), whose solution technique is more complex (see Section 3.3).

3.1.3 Equilibrium structure gaps: In terms of the commented structures of GEPTEP equilibrium models, we can identify some issues for potential further research. For instance, in Table 3, we have identified a potential model II that has not been proposed in the literature yet. This model could represent an electricity market with generation investment in the upper level and merchant transmission investments and operation at the lower level. Additionally, most of the research has focused on proactive models (see Table 5) type VII, but a large field of research on reactive model types V and VI still remain almost unexplored. Finally, the most realistic framework would be similar to structure VIII (four levels), where there is a sequence between TEP and GEP, while investment decisions anticipate the market outcome and, at the same time, MC anticipates generation operation (as in hierarchical market models). However, this framework is intractable from an equilibrium point of view, and therefore iterative algorithms can help to simulate the real operation of the market.

3.2 Regulatory framework

From a regulatory point of view, GEPTEP co-planning models can be classified depending on the decision maker considered to be the leader (which implies which investment decisions are assumed to be taken first). Depending on whether GEP or TEP is considered to be first, the regulatory framework can be proactive or reactive. Moreover, co-planning models can also be classified according to the level of competition in the market: markets with an oligopolistic structure versus those closer to perfect competition, both will be discussed below.

3.2.1 Proactive versus reactive planning approaches: A key issue in generation and TEP is the choice of which investment decision is considered to be taken first. Does the transmission planner take its decisions after the generation has been sited or do the GENCOs plan their investments after transmission assets have been decided? What comes first, the chicken or the egg?

These choices are proactive and reactive transmission planning approaches. Sauma and Oren [27] propose a proactive planning approach as a framework in which the network planner has the ability to influence generation investment and spot market behaviour. In terms of the hierarchy, it means that TRANSCO is the leader and the GENCOs that anticipate market outputs are the followers.

Respectively, under a reactive planning approach, the network planner assumes that generation capacities are given, and then makes an optimisation based only on the spot market equilibrium. Reactive planning is thus represented by a model with multi-leaders GENCOs and one or several TRANSCOs as followers. Sauma and Oren [27] consider an oligopoly structure and demonstrate theoretically how proactive planning leads to greater social welfare in comparison to reactive planning.

Some alternative approaches are available like presented in [31] (please see Table 5). Here, a two-level model is defined, where the upper level represents the investment decisions (both GEP and TEP), while the lower level represents the MO. Jin and Ryan [31] additionally consider fuel supply as another investment variable. In practice, as mentioned in [25] most of the TRANSCO companies in the world follow a reactive approach, and, to the best of our knowledge, no institution has applied a strictly proactive approach as the one proposed in [27]. However, as mentioned in [37] there are some other approaches that are close to proactive planning. For example, the US government approved a regulation that includes the concept of anticipative (proactive) transmission planning to obtain a higher social welfare [94]. In Chile, a regulation that enforces the consideration of coordination between transmission and generation has also been approved [95]. Additionally, in the current European context, ENTSOE plays the role of a centralised agent that proposes future planning pathways, coordinated regionally, and then GENCOs can react to its decisions. Thus, under this regulatory context, a proactive planning approach would make more sense.

Proactive planning approach: Most of the literature in co-planning equilibrium models for GEPTEP has used a proactive planning approach. Proactive planning research can be summarised as follows. On the one hand, Sauma and Oren [26] extend the work done in [27]; they analyse different objective functions and consider a spot market where the distinctive ownership structures are reflected (one GENCO can own several units), as proposed in [77]. Pozo *et al.* [35] extend the theoretical work done in [26, 27]

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where the complete multi-level model was not solved and only a set of different fixed transmission investment plans were evaluated. The work done in [35] proposes the first complete model; however, they relax the Cournot assumption and consider only perfect competition in the spot market.

On the other hand, Pozo *et al*. [36] also define three levels and assume perfect competition in the market in the lower level, strategic generation expansion in the middle level and transmission expansion in the upper level. Compared to [35, 36] adds uncertainty in the demand and applies the model to a real-size case study. The same authors in [36] extend their work in [37] by proposing a pessimistic and optimistic network planner (the pessimistic case is used to eliminate multiple equilibria by considering the worst generation expansion case) to describe all possible outcomes of the EPEC in the lower level. The authors conclude that in practice, if multiple generation expansion exists in the equilibrium, proactive planning does not always yield the best welfare results, and it can even reduce social welfare.

Additionally, Jin and Ryan [39] extend this approach and propose a model with Cournot strategic decisions in the market. Finally, Motamedi *et al*. [34] relax the Cournot assumption (in reaction to transmission prices) and propose a two-level approach in the market outcome by considering the interaction between ISO MC problem and GENCOs optimal bidding strategies (please see Section 3.1.2 and Table 5), resulting in a four-level model. This model is solved by means of an agent-based methodology.

Apart from the three-level proactive approach, there are two-level approaches where transmission investment decisions are taken first and then generation investment and operation decisions are taken simultaneously. On the one hand, the work in [28] models the lower level based on the work of [76]. Jenabi *et al*. [28] consider perfect competition in the lower level and define different objective functions in the upper level that are compared with a vertically integrated one-level approach. Additionally, they consider a network fee so the TRANSCO can recover investments in the case of a flow-based fee regulation, typically used in the US. Later, Weibelzahl and Märtz [29] extend the work in [28], choosing a pessimistic TRANSCO and demonstrating some subsequent uniqueness properties, battery expansion is also considered in their framework.

On the other hand, Maurovich-Horvat *et al*. [43] consider a stochastic bi-level model with merchant (for details on modelling of merchant TRANSCOs refer to [96, 97]) investors of transmission in the upper level and wind expansion and MO in the lower level, considering Cournot competition. Finally, the authors of [44, 92] apply the same structure, but consider storage expansion and Cournot competition in the lower levels. Additionally, Gonzalez-Romero *et al*. [92] compare the bi-level model with the traditional inelastic cost minimisation approach. Both works [43, 44] find counterintuitive results when considering Cournot competition in the lower level compared to a perfect competition case.

Reactive planning approach: As mentioned above, the reactive planning approach was first proposed in [26], where some theoretical properties were shown and some other practical results were presented for fixed transmission plans. Unfortunately, subsequent research is limited. In general, under this approach, several GENCOs are considered as the leaders and a single TRANSCO as a follower. However, it could also be the case that only one GENCO is the leader and the rest GENCOs and TRANSCO(s) are followers, this would represent an OLMF structure, which, as mentioned above, is simpler to solve.

There are only three subsequent studies on reactive planning. In [41], the authors propose a new comparison between proactive and reactive approaches. In contrast to the work done by Pozo *et al*. [36], Tohidi *et al*. [41] do not consider anticipation of market outcomes by GENCOs and propose the elimination of the multiple Nash equilibria by considering a pessimistic or optimistic TRANSCO. Additionally, Dvorkin *et al*. [42] propose a real size reactive planning approach in which merchant storage is decided in the upper level, while transmission investment and MO are decided in the middle and lower level, respectively. The authors conclude that the co-planning of storage and transmission lead to greater cost savings than an independent storage planning. Akbari *et al*. [90] propose a four-level with merchant TRANSCOs.

Finally, in terms of transmission modelling, it is important to note that for all proactive planning models, capacity expansion of new lines is represented by binary variables, while, in reactive planning, line expansions are represented by continuous variables to keep the convexity of the lower level, as shown in [41]. However, in [42], transmission expansions are represented by binary variables by applying the dual formulation of the lower level and using the strong duality condition as it will be discussed in Section 3.3

3.2.2 Perfectly competitive versus oligopolistic GEPTEP approaches: In the usual proactive planning approach, a centralised TEP and several GENCOs are considered. Thus, given the three-level structure of GEPTEP problems (see Section 3.1.2); there could be strategic decisions either on GO decisions or on GENCOs investment decisions. As mentioned in Section 3.1.1, the competition between generators in the spot market, and their reaction to transmission prices, can be modelled as either Cournot, Bertrand or SFE. We will discuss the different approaches found in the literature for GEPTEP problems.

Competitive market: Most of the GEPTEP hierarchical models consider perfect competition in the spot market (please see Table 2). This simplifies the solution techniques, and more importantly, guarantees that under certain conditions, the uniqueness of the solution is achieved.

If perfect competition (both in GENCOs investment and market functioning) and cost minimisation objective is considered in both levels, there would not be a difference between a proactive bi-level decentralised GEPTEP problem and a centralised vertically integrated co-optimisation problem, as shown in [98]. In other words, if the objective function of both levels is aligned and a perfectly competitive market is considered, both approaches will render the same solution.

Oligopolistic market: As mentioned above, there could be strategic behaviour either in the investment or in the generation operation decisions. If only strategic investment decisions are considered and no anticipation of the competitive spot market is assumed (simultaneous generation and perfectly competitive MO), the problem will have an MPEC structure. However, even in this case, multiple Nash equilibria can arise. As mentioned in Section 3.1.2 no anticipation of the spot market is assumed in [15, 28, 41]. In [29, 41], multiple equilibria are eliminated considering a pessimistic TRANSCO approach.

If the only anticipation of the spot market is considered, there might still exist multiple Nash equilibria (as pointed out in [36]) given that an EPEC problem would be tackled. As mentioned in Section 3.2.1, in the context of proactive planning some models consider strategic decisions in both investment and operation levels, as shown in [34, 39] (Cournot or SFE). However, they represent a MLMF structure, whose solution method does not guarantee a globally optimum solution.

3.2.3 Regulatory framework gaps: In spite of the fact that proactive planning has been proven to lead to the most efficient investment and operation results (and most of the research has focused on its analysis), in practice, few jurisdictions have strictly applied this approach. Therefore, it is important to compare different regulatory contexts to be able to propose additional formulations of the GEPTEP problem for understanding the operation and investment strategies in an imperfect market structure. Additionally, the lower construction times for generation and the higher construction times for transmission lines allow GENCOs to exercise strategic investment and operation decisions more easily. This scenario leaves an open field for future research on novel regulatory structures to model the entrance of new merchant GENCOs in the market.

3.3 Solution techniques

In this section, we present the techniques used to solve hierarchical GEPTEP co-planning problems. Depending on the initial

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$$Max\ F(x,y)$$
$$Subject\ to:$$

$$\begin{array}{lll} Max\ f(x_1,y) & Max\ f(x_2,y) & \dots\ Max\ f(x_n,y) \\ subject\ to & subject\ to & \dots\ subject\ to \end{array}$$

$$\begin{array}{lll} g_1(x_1,y) \le 0 & g_2(x_2,y) \le 0 & \dots g_n(x_n,y) \le 0 \\ x_1,y \ge 0 & x_2,y \ge 0 & \dots\quad x_n,y \ge 0 \end{array}$$

Fig. 2 *Bi-level problem with an OLMF structure*

$$Max\ y\ F(x,y)$$
$$Subject\ to:$$

Dual
$$\partial L/\partial x_1 = 0 \quad \partial L/\partial x_2 = 0 \quad \dots \quad \partial L/\partial x_n = 0$$

CC
$$\lambda_1 g_1(x_1,y) = 0 \quad \lambda_2 g_2(x_2,y) = 0 \dots \lambda_n g_n(x_2,y) = 0$$

Primal
$$\begin{array}{llll} g_1(x_1,y) \le 0 & g_2(x_2,y) \le 0 & \dots & g_n(x_n,y) \le 0 \\ x_1,y \ge 0 & x_2,y \ge 0 & \dots & x_n,y \ge 0 \end{array}$$

Fig. 3 *OLMF problem with lower level KKT conditions*

hierarchical structure (please see Section 3.1.2), the techniques might be different. Therefore, in order to solve problems with a single leader, i.e. an one leader one follower (OLOF) or OLMF structure, the solution techniques for the arising mathematical programmes with equilibrium constraints (MPECs) described in Section 3.3.1 are to be used. Alternatively, if there are multiple leaders in the upper level, i.e. an MLOF or MLMF structure, the techniques explained in Section 3.3.2 to solve EPEC are to be used.

3.3.1 Mathematical programmes with equilibrium constraints: When a bi-level problem is defined as an OLMF game (as defined in Section 3.1.2), its mathematical structure is seen as an MPEC or as a simple bi-level programming problem. As seen in Fig. 2, the OLMF is a type of mathematical structure in which a single optimisation problem (upper level) is constrained by several simultaneous optimisation problems (lower level) that represent an equilibrium. In Fig. 2, x and y represent lower and upper level decision variables, respectively.

As explained in Section 3.1.2, in some cases, this lower-level equilibrium can be converted into a single optimisation problem. Nevertheless, even if this is possible, the resulting complete problem cannot be solved directly by classical optimisation techniques, because an optimisation problem is constrained by another optimisation problem.

Therefore, in order to solve a bi-level problem with an OLMF structure, we can follow the next steps. First, the set of lower-level optimisation problems can be converted into a set of non-linear and non-convex constraints by applying the Karush–Kuhn–Tucker (KKT) (if the optimisation problem is convex) conditions. As seen in Fig. 3, the resulting optimisation problem is constrained by the primal feasibility constraints, the dual feasibility constraints and the complementarity conditions (CC).

The resulting set of constraints is non-linear and non-convex, given the CC of the problem. This lower level has the structure of a MCP, and therefore the whole problem has the structure of an MPEC. Please note that bi-level (OLMF) problems are particular cases of MPECs.

Now we list the most used techniques to solve this kind of problem. As mentioned in [99], these techniques can be divided into dedicated (efficient algorithms that ensure global optimality but require significant additional coding) and non-dedicated algorithms. We explain here the non-dedicated algorithms (that can be implemented directly using commercial software): NLP/MPEC, regularisation, penalisation, MIP KKT-DUAL.

NLP/MPEC: The only non-convexity in Fig. 3 is the one introduced by the CC. Therefore, this problem can be solved directly using an ordinary NLP solver. However, given that this is a specific NLP structure embedded in an MPEC, specific solvers, such as PATH, that tackle directly this problem more efficiently can be used. Unfortunately, both non-linear and MPEC solvers cannot guarantee a globally optimal solution to the MPEC, given that all feasible points are non-regular [99], and consequently, solution methods can easily get stuck in a local optimum or not even find a feasible solution.

Regularisation: This method [99] relaxes the complementarity condition of the MPEC problem. Instead, the set of equations for $g_n(x_n, y) \le t$ are solved. Then the NLP problem for small values of t is iteratively solved. The solution of each iteration will be the initial point of the following iteration; this process is faster but only provides a local optimum point solution for the MPEC.

Penalisation: The penalisation approach [99] is similar to regularisation. Conversely, in this case, the CCs are penalised in the objective function by a parameter that is reduced along with the iterations until a sufficiently small value of the parameter is reached. As before, the solution of each iteration will be the initial point of the following iteration.

MIP KKT-DUAL: As an alternative, the non-linear problem described in Fig. 3 can be converted into a MILP (when the upper level objective function is linear) by linearising the CC. This linearisation can be achieved by applying the methodology proposed by Fortuny-Amat and McCarl [100] or by the discretisation method proposed in [101]. In the first case, a disjunctive formulation is applied to transform complementarity constraints into binary constraints. This is done by splitting the original constraint into two disjunctive constraints limited by a large enough parameter. This is usually known as the Big M constraints.

This method is, by far, the most used method to solve bi-level problems. However, most of the papers that use it do not explicitly mention a method to determine the Big-M values. In fact, as mentioned in [102] if these values are small, suboptimal solutions can appear, and conversely, too large Big-Ms can lead to numerical issues (when different variable magnitudes are reflected in dual variables), such as unstable solutions or large execution times. In [99], a method is proposed to define Big M values by mixing the regularisation and KKT-MIP previously commented methods. The authors show that this method is more efficient computationally speaking and it reaches the optimal solution in more cases compared to other methods. This method is proposed for linear bi-level problems, but it seems to be also efficient for convex problems in general.

Additionally, instead of applying the whole set of KKT conditions, the CCs can be replaced by the strong-duality conditions (where the objective function of the dual problem equals the objective function of the primal problem), which together with its primal and dual feasibility conditions, leads to an equivalent primal–dual formulation.

In [103], a comparison of the KKT and the primal–dual formulation is presented and applied to a vulnerability analysis of the power system. The authors find that the primal–dual approach is more efficient because the size of the problem is highly reduced. This is the result of the lower number of Big Ms (alternatively index constraints or SOS1 variables can be used to programme disjunctive constraints [104]) needed to linearise the strong duality conditions compared to those needed to linearise the CCs (it depends on the ratio #variables /#constraints).

3.3.2 Equilibrium problem with equilibrium constraints (EPEC): In case of structures with multiple leaders and one

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follower or multiple followers, it will be more difficult to solve the resulting problem, given that the resulting formulation consists of several optimisation problems (equilibrium) subject to several optimisation problems (equilibrium). This problem can be seen as a collection of several MPECs. As shown in [83], in order to solve this problem, the following techniques are available: (a) *diagonalisation algorithms*, the MPEC of every agent is solved sequentially one after the other. (b) *Simultaneous solution method*, all problems are solved simultaneously by defining the strong stationary condition. (c) *System of inequalities with equilibrium constraints* used when the problem has finite strategies.

Unfortunately, the solution of multilevel equilibrium problems can only be guaranteed for the case of OLMF models (MPECs). For MLOF and MLMF (EPEC) problems, there is no guarantee of the existence of the equilibrium. As mentioned in [83], there is still a lack of understanding of the existence of EPEC solutions, thus, only simulation models and approximation algorithms are applied. Additionally, we can have hybrid methods as the *one level reformulation of bi-level games*. In this case, the lower level is reformulated by its equivalent KKT conditions and then it is inserted into every optimisation problem in the upper level. Then the KKT conditions of the whole problem are formulated and solved again. However, the resulting solution might not be an optimum. Ex-post validation should be carried out to verify its optimality. An example of this approach can be found in [40].

Albeit the difficulty of solving these mathematical structures, in the literature, there are several models that tackle more than two levels, by trying to reduce the multi-level problems into a two or one level equivalent problem.

For instance, Motamedi *et al.* [34] propose a coordination framework to take into account the reaction from GENCOs by adopting generation expansion decisions within a four-level problem. They solve the coordination problem iteratively using agent-based modelling and a search-based optimisation technique. In [105], they further extend the model and develop an iterative process by simulating the interaction between TRANSCOs and the ISO and they propose a multi-leader–multi-follower agent-based model. They consider both several TRANSCOs and GENCOs. Additionally, we can find an EPEC problem when only one TRANSCO is considered in the upper level and multiple investing GENCOs in the middle level to anticipate the market outcome of the lower level. In this case, the middle and lower level results in a MLMF structure and thus an EPEC formulation is solved as presented in [36].

Finally, it is important to note that, in most co-planning models, generation expansion is modelled as a continuous variable, as shown in [25, 30, 35, 91]. This assumption responds to the need to obtain convexity conditions in the lower levels and implies that (in most cases) only repowering of existing units is represented.

Alternatively, other authors represent the expansion decisions with integer variables, as [13, 33, 38], but in these cases, only the GEP model is solved for new wind generators. Finally, to the best of our knowledge, only [37, 41] consider binary variables in both investment levels of the GEPTEP problem, which yields non-convex sub-problems that can only be solved by using complex algorithms such as column generation (CG) or the Moore–Bard Algorithm (MBA). Authors in [37] propose a CG and cutting plane algorithm to solve a three-level proactive problem. The CG algorithm is close to the usual diagonalisation technique, but it considers a master problem that creates a meaningful solution to the sub problem that is solved by a diagonalisation-like procedure. This algorithm guarantees a global solution and efficient computation times.

3.3.3 Solution technique gaps: In the case of MPEC problems, there is still an active field of research for finding efficient methods to solve these optimisation problems. As mentioned before in [102], Big M is the most common technique to solve the one-level reformulation of bi-level programs. However, small values of Big Ms can lead to suboptimal solutions and large constants can lead to numerical issues (if different orders of magnitude are present in the dual variables of the lower level). Additionally, some authors have tackled the consideration of binary variables in the lower level but all the solutions imply the implementation of complex dedicated algorithms [37, 41, 42]. Finally, even though some progress has been done in the resolution of EPECs [37] there is even more space for research in this area, given that its application to real size cases is still an immature area of knowledge.

3.4 Most recent developments

In this section, we introduce the most recent research on co-planning equilibrium models. This research focuses on modelling the detailed operation of storage technologies and on representing renewable uncertainty using novel hierarchical structures.

3.4.1 Representation of storage in GEPTEP co-planning models: Only [41] is the only study that considers long-term hydro storage in equilibrium models, but a simplified version that does not consider reservoir management. To the authors' knowledge, two reviewed papers have addressed short-term storage modelling in GEPTEP co-planning models.

On the one hand, Weibelzahl and Märtz [29] consider storage expansion and perfect competition in the spot market simultaneously formulated at the lower level. Weibelzahl and Märtz [29] show that adequate storage investment can reduce the line investment cost of the TSO. They also show that investment in a zonal market can be suboptimal compared to a nodal market.

On the other hand, in [42] investment in merchant storage resources is considered in the upper level. The authors use a representative period approach to simulate the time steps in which the period of study is divided. The authors demonstrate that merchant storage is economically feasible under the case study considered.

More recently, authors in [44] propose a co-planning model that includes Cournot competition in the market and the representation of short-term (batteries) and long-term (hydro) storage resources with a representative-period formulation that includes a transition matrix and cluster indices as proposed in [63]. Additionally, authors in [44] find counterintuitive results when a proactive approach is considered with a Cournot competition in the market.

3.4.2 Representation of uncertainty in investment and operating decisions: Given the complexity of GEPTEP hierarchical models, most of the papers reviewed do not consider the modelling of uncertainty (as seen in Table 2) in their formulations. Accordingly, given that the correct implementation of renewables depends mainly on the introduction of the uncertain availability of the resources, renewables are usually not included in detail in these models (additionally, determining support schemes is an important field of research that has not been fully assessed by GEPTEP models but has been assessed separately in bi-level GEP and network constrained GEP [106, 107].) are usually not included in detail in these models.

As mentioned in Section 2.5, probabilistic and stochastic approaches were the most common way to represent uncertainty For instance, Baringo and Conejo [33] considers a stochastic approach with scenarios for wind levels and demand. However, it considers traditional load blocks and therefore it is not suitable for adequately simulating storage operation. Baringo and Conejo [33] study how different wind subsidies schemes affect the total welfare of the system. They conclude that transmission investments highly condition the investment in wind. They consider different hydro seasons, limiting the maximum energy produced at each season, and consider a Weibull distribution to introduce stochasticity in wind speed that limits the maximum generation capacity of each winding unit. They also consider a load block approach.

Recent developments in uncertainty representations have introduced other techniques such as robust optimisation, mainly by the application of adaptive robust optimisation, which has proved to be computationally efficient and to represent properly the long-term uncertainties [46].

In this sense, the most recent work on robust GEPTEP considers a min–max–min approach in which simultaneous GEP and TEP decision is taken in the upper level, uncertainty realisation in the middle level and operation in the lower level [45, 46]. In

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particular, Baringo and Baringo [93] consider stochastic programming and robust optimisation to deal with both long- and short-term uncertainties. Finally, some other authors additionally consider a certain type of reliability criteria [108, 109]. Please note that the computation efficiency of the algorithms used to solve robust problems has permitted to consider multistage dynamic planning approaches, which had been previously of limited application [45, 46].

A different approach for representing uncertainty is presented in [37]. The authors introduce uncertainty in generation investment, by using similar techniques to those used in robust optimisation. Therefore, Pozo *et al.* [37] take into account the possible multiple generation investment equilibria resulting from a hierarchical model (see Section 9). Therefore, instead of considering the parameters as the uncertainty set, the authors consider the multiple investment equilibria (resulting from the middle level) as their uncertainty set.

It is important to highlight the recent prolific research in robust optimisation. The theoretical background to solve robust optimisation problems is close to the dual theory and the techniques used to solve hierarchical models. However, in hierarchical models, the levels considered represent either different agents or decisions. Conversely, in robust optimisation, the levels considered typically represent different instances of uncertainty realisation. For instance, in [93], both the GEP and TEP expansion decisions are made in the second level where the worst operational case is simulated and in the third level corrective measures are taken to minimise operational costs. This robust optimisation framework can be an important field of research that, together with stochastic programming, is able to couple long and short-term uncertainties in capacity expansion planning.

3.4.3 Gaps in storage and uncertainty modelling approaches: Renewable uncertainty and storage operation are still wide fields of research in co-planning equilibrium models. Given the properties of equilibrium models, there is an interesting field of research to study and compare extreme competition cases, where the uncertainty can come not only from the fuel and sources availability but also on the multiple equilibria that can arise from imperfect competition. Additionally, detailed time representation and novel solution techniques can permit us to model more complex markets.

4 Concluding remarks

In this study, we addressed the GEPTEP problem. First, we considered the GEPTEP co-optimisation problem in a centralised environment in which a vertically integrated utility takes investment and operation decisions. Then, we focused on the GEPTEP co-planning problem in a market environment, where strategic behaviour and sequential decisions of decentralised agents was studied.

The main findings of this literature review are two-fold:

(i) Given the usual tractability trade-off in planning problems, it is difficult to determine the best modelling options to represent GEPTEP problems, however, we found that: (a) in general, considering lumpy transmission investments might be more important than representing a detailed network. (b) In contrast, given that the economies of scale in generation investment are much lower than in transmission investment, lumpy generation investment can be sometimes disregarded. (c) Finally, as shown by Xu and Hobbs [110], a thorough uncertainty representation can be more important than representing generation operating constraints in a detailed manner.

(ii) For the case of GEPTEP co-planning problems in a market environment, we found that it is a very useful framework to model more realistic market structures. In general, the most studied proactive approach, which renders higher welfare, is still not spread around countries. We found that even if there is perfect competition in the operation, considering the strategic sequential investment decisions between transmission and generation can highly change the planning results. Additionally, the consideration of merchant investors helps to give insights on how to define optimal support schemes. Finally, some counterintuitive results arise when considering imperfect competition in the MO, i.e. under Cournot competition, allowing trade between areas (by building more lines) can decrease total welfare [26, 43, 44].

We found the following gaps in the literature:

(i) Modelling approaches: there is an active field of research on spatial and temporal resolution, resource adequacy and economics of energy production. (ii) Equilibrium structure: most of the equilibrium structures studied considers a two-, three- or even four-level traditional proactive approach, however, some proactive structures and most reactive structures remain unexplored. (iii) Regulatory structure: in spite of the fact that proactive planning has been proven to lead to the most efficient investment and operation results, in practice, few jurisdictions have strictly applied this approach. Therefore, it is important to compare different regulatory contexts in order to understand the optimal operation and investment strategies in imperfect markets. (iv) Solution technique: in the case of MPEC problems, there is still an active field of research for finding efficient and standard methods to solve these equilibrium problems. Additionally, even though some progress has been achieved in the resolution of EPECs, there is even more space for research in this area, given that its application to real-size cases is still an immature area of knowledge. (v) Most recent developments: renewable uncertainty and storage operation are still wide fields of research in co-planning equilibrium models. On the one hand, more studies on the complementarity between transmission and storage investment are necessary, as well as the joint consideration of both short-term and long-term storage. On the other hand, given the properties of equilibrium models, there is an interesting field of research to study and compare extreme competition cases, where the uncertainty can come not only from the fuel prices and the availability of generating units but also from the multiple equilibria that can arise from imperfect competition. Finally, given that perfect information is a strong assumption, including imperfect information theory in the GEPTEP problems, can make these models more useful for real applications.

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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.

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

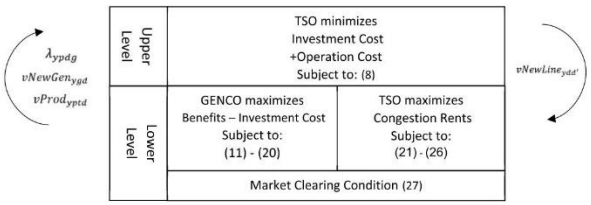

Fig. 1. Model hierarchy.

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

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

$$vNewLine_{y-1,dd'} \leq vNewLine_{ydd'} \;\; \forall \; (d, d') \in LC \;\; \forall \; y \tag{8}$$

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.

$$\underset{LL}{arg\ \text{Maximize}} OI - OC - GI \tag{9}$$

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

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

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).

$$0 \leq vProd_{ypgd} \leq pMaxProd_g: \; \bar{\rho}_{ypgd}, \underline{\rho}_{ypgd} \;\; \forall \; g \in GED, \forall \; ypd \tag{11}$$

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

$$0 \leq \; vProd_{ypgd} \leq pMaxProd_g \times vNewGen_{ygd} \quad : \bar{\omega}_{ypgd}, \underline{\omega}_{ypgd} \qquad \forall \; g \in GCD, \forall \; ypd \tag{12}$$

$$0 \leq \frac{vCon_{yphd}}{pEfficiency_h} \leq pMaxCons_h \quad : \bar{\kappa}_{yphd}, \underline{\kappa}_{yphd} \qquad \forall \; h \in GED, \;\; \forall \; ypd \tag{13}$$

$$0 \leq \frac{vCon_{yphd}}{pEfficiency_h} \leq pMaxCons_h \times vNewGen_{yhd} \quad : \bar{\eta}_{yphd}, \underline{\eta}_{yphd} \qquad \forall \; h \in GCD, \;\; \forall \; ypd \tag{14}$$

$$-vNewGen_{y-1,gd} + vNewGen_{ygd} \geq 0 \qquad : \underline{\beta}_{ygd} \qquad \forall \; ygd \tag{15}$$

$$0 \geq -vNewGen_{ygd}; \; 0 \leq MaxGen_g - vNewGen_{ygd} \quad : \bar{\sigma}_{ygd}, \underline{\sigma}_{ygd} \qquad \forall \; ygd \tag{16}$$

$$pMinLevel_h \leq vLevel_{yphd} \leq pMaxLevel_h \qquad : \bar{\mu}_{yphd}, \underline{\mu}_{yphd} \qquad \forall \; yphd \tag{17}$$

$$0 \;\; \leq \;\; vSpill_{yphd} : \underline{\mu}'_{yphd} \qquad \forall \; yphd \tag{18}$$

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

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

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. [6]. 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

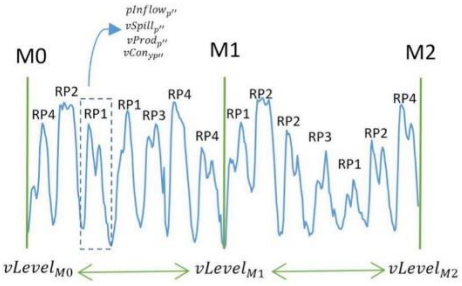

Fig. 2. Interday energy balance.

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

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

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

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

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

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

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

2.2.2.3. Market clearing.

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

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).):

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

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

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

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

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* $Pt = Ps \cup Pa$

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

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

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

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

[2] Linearized conditions can be found in ANNEX.

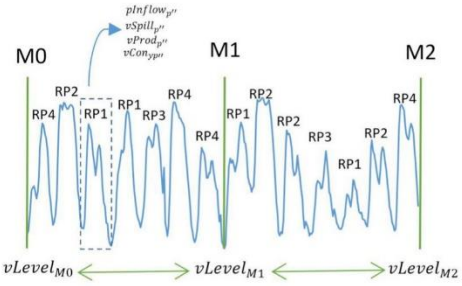

Fig. 2. Interday energy balance.

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s.t

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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).):

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

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

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

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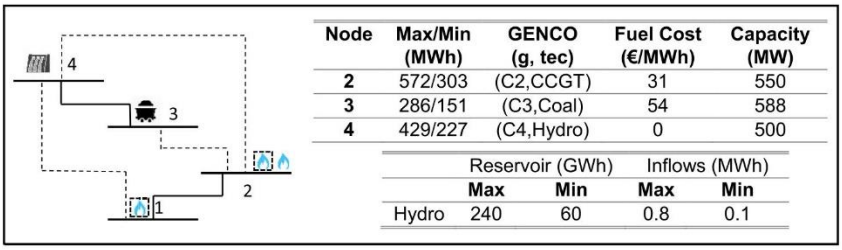
$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p},d} pW_{rp} * \left(-FuelCost_{tp} + vProd_{yptd} * \frac{\partial\lambda_{ypd\in(GAD)}}{\partial vProd_{yptd_g}}\right)\right) + \lambda_{ypd\in(GAD)} - \bar{\rho}_{ypgd\in(GED)} + \underline{\rho}_{ypgd\in(GED)} - \bar{\omega}_{ypgd\in(GCD)} + \underline{\omega}_{ypgd\in(GED)}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

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

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

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

[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.

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

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. [31] 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 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.

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

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.

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

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

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.

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

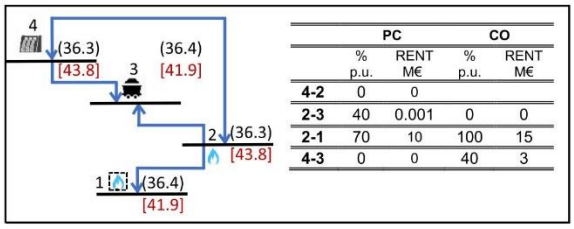


Fig. 4. Flows direction and congestion BrownField.

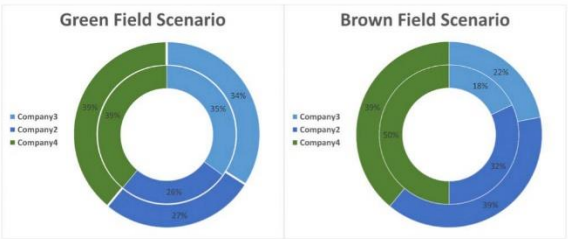


Fig. 5. Market share.

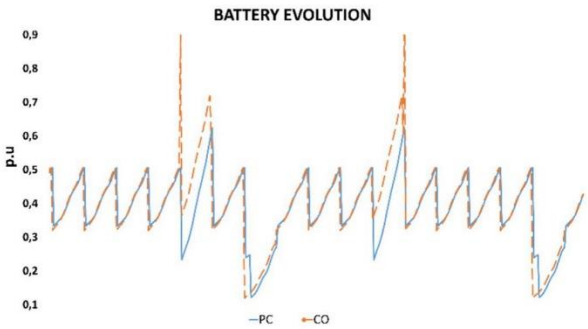


Fig. 6. Battery usage.

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 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.

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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 $p' \in \Gamma_{rp,p}$
$w(g) \in W$	Wind generation

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

$$\underline{\tau}_{ypdd'} \leq \underline{M\tau} * \left(1 - \underline{Y\tau}_{ypdd'}\right)$$

$$\forall\ (d, d')\ \in LC, \forall\ yp \tag{48}$$

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

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

$$\forall\ gd \in GCD,\quad \forall\ yp \tag{49}$$

$$vNewGen_{ygd} \leq \underline{M\sigma} * \underline{Y\sigma}_{ygd}$$

$$\bar{\sigma}_{ygd} \leq \underline{M\sigma} * (1 - \underline{Y\sigma}_{ygd})$$

$$MaxGen_g - vNewGen_{ygd} \leq \underline{M\sigma} * \underline{Y\sigma}_{ygd}$$

$$\bar{\sigma}_{ygd} \leq \overline{M\sigma} * (1 - \overline{Y\sigma}_{ygd})$$

$$\forall\ gd \in GCD,\quad \forall\ yp \tag{50}$$

$$pMinLevel_h - vLevel_{yphd} \leq \underline{M\mu} * \underline{Y\mu}_{yphd}$$

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

$$vLevel_{yphd} - pMaxLevel_h \leq \overline{M\mu} * \overline{Y\mu}_{yphd}$$

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

$$\forall\ gd \in GCD,\quad \forall\ yp \tag{51}$$

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Paper III

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Transmission and storage expansion planning under imperfect market competition: Social planner versus merchant investor

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ABSTRACT

The growing penetration of renewable technologies and the increasing need for energy storage technologies constitute a new challenge for electricity market design. In this context, decentralized generation companies decide their investments by maximizing their own profit, while centralized TSOs decide network expansion by aiming to maximize the overall social welfare. This already challenging environment is further complicated by the intermittency of renewable production and the short- and long-term dynamics of storage technologies, which may enable generation companies to exercise new forms of market power. However, traditional (and widely utilized) cost minimization planning models do not account for these types of strategic interactions, nor for the introduction of new transmission merchant investors needed to achieve the full integration of isolated renewables in the system. In this paper, we study the policy implications of planning the system, either by a merchant investor or by a traditional cost-minimization planner, instead of a social planner through a proactive framework that accounts for distinctive degrees of competition. Therefore, we present a bi-level proactive transmission framework, in which a centralized TSO takes network investment decisions by anticipating the reaction of decentralized generation companies, as well as a merchant investor that maximizes congestion rents. Finally, we carry out a comprehensive analysis of a 3-node greenfield case, and we extract more general insights from a brownfield IEEE 24-node case. We found that, compared to a social planner, both the traditional cost-minimization planner and the merchant investor would lead to a relatively small diminishing of social welfare. Nonetheless, the resulting generation mix of the system can drastically change.

1. Introduction

In modern electricity markets, centralized and regulated transmission system operators (TSOs) decide network expansion by aiming to minimize total costs (or maximize welfare), while decentralized generation companies (GENCOs) decide their generation investment by maximizing their own profit. This market structure creates contradictory incentives (intensified by the intermittency of renewables and the penetration of Battery Energy Storage Systems (BESS)) between these two market participants and can lead to different outputs depending on who is considered as the leader in the market. Additionally, in this liberalized environment, there are growing opportunities for merchant transmission investors to enter the market, as exemplified by international tie lines or connections to isolated projects (off-shore wind farms). In order to present the state of the art, we first introduce the existing regulatory approaches for transmission and generation expansion planning. Then, we present the relevant literature, and finally, we state our research questions and objectives.

1.1. Regulatory approaches

Originally, power systems were planned by vertically integrated utilities (that own the transmission and generation assets, see Fig. 1) with a cost-minimization objective, in which Generation Expansion Planning (GEP), Transmission Expansion Planning (TEP), and operation decisions were simultaneously taken under the assumptions of inelastic demand and perfect information, and in the absence of competition.

However, such a planning framework is highly questionable in modern markets. The generation business has been liberalized by allowing GENCOs to invest and operate freely, while transmission

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Fig. 1. Cost-minimizing centralized approach.

investment decisions are still regulated and operated by a centralized transmission company (TRANSCO). As seen in Figs. 2 and 3, this liberalized framework can be modeled considering two main regulatory approaches:

In the proactive approach, we consider that the TSO[1] is the leader in the market that takes its transmission investment decisions (TEP) by anticipating the generation investment (GEP) and operation decisions of GENCOs. In the reactive approach, the TSO is the follower that reacts to GENCOs decisions. Please note that the previously presented cost-minimizing approach is equivalent to a proactive approach with inelastic demand and perfect competition.

Despite the theoretical optimality of the proactive approach (Sauma and Oren, 2007),(Sauma and Oren, 2009), most of the TSOs in the world follow a reactive approach (Spyrou et al., 2017). However, some countries (Pozo et al., 2017a) are applying regulations similar to the proactive approach (as originally proposed by (Sauma and Oren, 2006)). For example, the US government approved a regulation that includes the concept of anticipative (proactive) transmission planning (FERC, 2011). Similarly, the Chilean government approved a regulation that enforces the consideration of coordination between transmission and generation planning (Ministerio de Energia de Chile, 2016). Lastly, in the current European context, ENTSOE plays the role of a centralized and regional coordinator that proposes future planning pathways [7], by anticipating how generation companies can react on a national scope.

As a consequence of the mentioned advantages, we decide to implement a proactive planning approach. It is important to note that, under this framework, GENCOs could behave strategically in both generation expansion and operation. From now on, we will call this behavior the *'strategic market feedback'*. Additionally, as a consequence of the complex deployment of energy systems, sometimes merchant transmission investors are essential to deploy certain types of projects (international tie-lines or interconnections for off-shore wind farms). Therefore, apart from considering a centralized TSO, we study the case of a transmission investor that takes its investment decision by trying to maximize its incomes, known as congestion rents.

Finally, we will focus on the potential strategic behavior of GENCOs, since they are particularly relevant nowadays given several features: i) construction times for transmission lines are consistently higher compared to construction times for generating units ii) high penetration of intermittent renewable technologies with decreasing capital costs iii) introduction of Battery Energy Storage Systems (BESS).

Although energy storage existed already in the form of pumped hydro, BESS (whose global deployment in 2018 has doubled that of

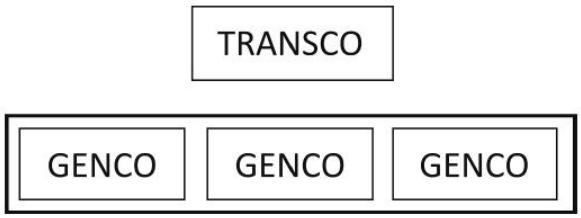

Fig. 2. Proactive approach.

[1] We consider that the TRANSCO is in fact a regulated TSO.

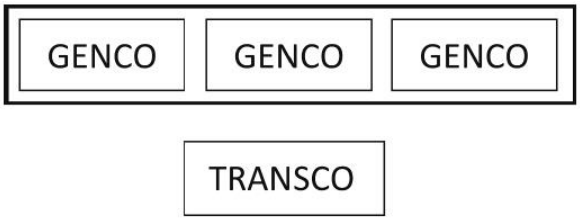

Fig. 3. Reactive approach.

2017 (IEA, 2020)) present additional features: i) they help stabilize market prices (Weibelzahl and Märtz, 2018); ii) they can be sited anywhere in the network and can react more rapidly to the operational needs; iii) they are natural arbitragers of the market; and, iv) they can either be supplementary (replace the network) or complementary (reinforce transmission services) to the network (Xu et al., 2018), (Bustos et al., 2018; Neetzow et al., 2018), (Steinke et al., 2013).

1.2. Literature review

Recently, there has been continuous research on power systems on what we call 'co-planning equilibrium models for generation and transmission expansion planning' (GEPTEP) (Carpio and Pereira, 2007; Chao and Wilson, 2020; Jenabi et al., 2013; Jin et al., 2014; Pozo et al., 2017a, Pozo et al., 2013b; Weibelzahl and Märtz, 2018). These models refer to the joint GEPTEP, considering a decentralized market framework. In contrast to the GEPTEP co-optimization problem (centralized cost-minimizing approach), co-planning problems embrace a more general market structure that considers both sequential (e.g.; first TEP and then GEP) and strategic decisions (e.g.; Cournot competition). This type of structure leads to a hierarchical optimization problem that is complex to solve. For a detailed review of co-planning equilibrium problems please refer to (I-C Gonzalez-Romero et al., 2019).

Typically, GEPTEP co-planning models include three types of market agents, namely: GENCOs, the TSO, and the Market Operator (MO). Accordingly, a three-level hierarchical structure is usually considered (Pozo et al., 2013a) (Taheri et al., 2017); some GEP (or TEP) investment decisions are decided in the upper level, given some other TEP (or GEP) investment decisions in the middle level,[2] and subject to the spot market (where GENCOs and the MO interact)[3] in the lower level. This three-level equilibrium structure implies solving a complex Equilibrium Problem with Equilibrium Constraints (EPEC) whose solution techniques are an active field of research (Pozo et al., 2017b). As an alternative, instead of a three-level structure, we can consider a bi-level equilibrium that implies solving a Mathematical Problem with Equilibrium Constraints (MPEC). Following the proactive approach, we consider the TSO in the upper level (which is in charge of deciding TEP), and simultaneously GENCOs (GEP and operation) and MO in the lower level, as the structure depicted in Fig. 2. In this paper, and following the approach of (I-C. Gonzalez-Romero et al., 2019a) and (I-C. Gonzalez-Romero et al., 2019b), we consider imperfect competition in the lower level (contrary to most works that consider perfect competition), with a conjectured price response framework (based on (Wogrin et al., 2011b) which presents the single-level equivalent of a bi-level model using conjectural variations). For more details see Section 2.3.2.

Most of the articles discussed above assume that a regulated transmission planner is in charge of network expansion. However, merchant investors are sometimes essential to carry out certain types of projects, namely, international tie-lines or interconnections for off-shore wind

[2] Depending on whether a proactive or reactive approach is considered

[3] Some models even consider a sequence between the market clearing and the operation

farms. Previous articles (Jenabi et al., 2013; Maurovich-Horvat et al., 2015; Weibelzahl and Märtz, 2018) have addressed this topic in the literature; authors in (Jenabi et al., 2013) compare a merchant investor with a social planner by considering perfect competition in the lower level. A potential new line of research would place a direct competition between a social planner and a merchant investor at the upper level, with generators competing at the lower level. This approach would however result in an EPEC problem with a more complex solution. Additionally, authors in (Weibelzahl and Märtz, 2018) extend the work of (Jenabi et al., 2013), by modeling BESS in a zonal pricing scheme under a perfect competition environment. In contrast, authors in (Maurovich-Horvat et al., 2015) model a transmission merchant investor subject to wind expansion and Cournot competition, disregarding storage operation and considering only a 3-node case.

As mentioned in the previous section, BESS are becoming more and more important as they bring several advantages to the network. To our knowledge, only (Dvorkin et al., 2017) and (Weibelzahl and Märtz, 2018) have considered comprehensive storage co-planning models. On the one hand, authors in (Dvorkin et al., 2017) develop a tri-level reactive model, with a merchant storage investor in the upper level, while transmission expansion and market operation are modeled in the middle and lower level respectively. On the other hand, authors in (Weibelzahl and Märtz, 2018) model battery expansion in the lower level and choose a pessimistic TSO (with certain uniqueness properties) in the upper level. However, both (Dvorkin et al., 2017) and (Weibelzahl and Märtz, 2018) assume perfect competition in the market and disregard hydro storage. Additionally, authors in (Maurovich-Horvat et al., 2015) consider a stochastic bi-level model with a merchant transmission investor in the upper level and both wind expansion and strategic operation in the lower level.

In this type of planning model, there is a common trade-off between a detailed representation of technical operating constraints and the tractability of the model. In particular, it is difficult to jointly consider storage facilities that operate in different time horizons because the choice of time representation (i.e., load levels vs representative hours) would naturally facilitate the representation of one storage facility over the other (i.e., pump-hydro vs batteries). Consequently, authors in (I-C. Gonzalez-Romero et al., 2019a) and (I-C. Gonzalez-Romero et al., 2019b), apply a similar structure to the one proposed by (Maurovich-Horvat et al., 2015), considering Cournot competition in the lower level; however, authors additionally model both short- and long-term storage by applying the enhanced representative periods' approach proposed by (Tejada-Arango et al., 2018). In the present paper, we extend our work in (I-C. Gonzalez-Romero et al., 2019a) in several forms: i) we incorporate different GENCOs ownership structures in the lower level ii) we develop a comprehensive policy analysis by considering distinctive network setups iii) we introduce a linearized merchant investor formulation and compare it to a social planner as presented below.

In summary, we propose a novel proactive model that considers both social and merchant transmission planners that anticipate the strategic behavior of GENCOs that, in turn, own a diversified portfolio[4] including renewable and long and short-term storage technologies.

1.3. Policy question and contributions

Despite the fact that most of the electricity markets in the world are liberalized, transmission planners do not consider the potential strategic behavior in the market and they continue developing TEP under a traditional cost-minimizing approach (assuming the results of a centralized GEP expansion). Thus, we raise our *first* set of questions i) How much the ideal generation capacity investment, assumed by an optimistic TSO in a cost-minimizing approach, differs from reality (as a result of the strategic market interactions between GENCOs)? What is the cost of sub-optimal transmission expansion planning due to overly optimistic generation capacity expansion assumptions? We propose a methodology that allows us to compute the welfare loss of considering a simple and overly optimistic cost minimization approach, instead of a more complex approach where a TSO foresees strategic market outcomes (Cournot competition).

After setting this methodology, we examine our *second* set of questions ii) which are the investment and operation implications of considering a merchant transmission investor instead of a centralized one? As mentioned before, there is a growing interest in regulating merchant investors for certain types of projects (international tie-lines or connections to off-shore wind farms). In this regard, we ask ourselves: is it always desirable to count on a centralized TSO to plan the system? Or is it beneficial (under any circumstances) to rely on a merchant transmission investor to undertake the system planning? Finally, we investigate how storage integration in the system affects the answer to the previous questions.

The *third* set of questions revolves around storage systems iii) Do storage systems complement or substitute the grid investments? Does the substitution or complementarity of storage vary depending on the degree of competition in the market?

To wrap up, our contributions are threefold: a) we carry out a comprehensive policy analysis in which we study the implications of disregarding market feedback in transmission expansion planning under different systems set-ups; b) we consider a merchant transmission investor who recovers its investment by maximizing congestion rents, and we compare the investment and welfare results with those of a social planner; c) we are the first to comprehensively consider strategic investment in both batteries (short-term storage) and pumped-hydro (medium-term storage) in bi-level models.

2. Mathematical formulation

In this section, we present the main structure of the corresponding models, we include the main constraints and main decision variables. Given that the main formulation was already presented in (I-C. Gonzalez-Romero et al., 2019a), we omit the detailed formulation in this section, but the interested reader can refer to the Appendix. In Section 2.2 we present the cost-minimization problem from the perspective of a vertically integrated utility. In Section 2.3 we present the bi-level model that correctly represents the liberalized market (and is used to answer our first set of research questions). In this section, we also introduce the formulation to consider both short-term and long-term storage, which helps us answer our third set of research questions about complementarity or substitution between storage systems and the grid. Then, in Section 2.4, we present the methodology that allows us to answer our first set of research questions concerning the implications of disregarding market feedback on generation expansion and total welfare. Finally, in Section 2.5 we introduce the formulation to represent a merchant investor, this formulation will allow us to answer our second set of research questions on the benefits and drawbacks of planning the system under a merchant transmission planner.

An additional contribution of this paper is the novel formulation of merchant transmission investor stated in Section 2.5.

2.1. Notation

Sets / Indices

$y \in Y$	year
$p \in P$	periods (hours in the year)
$rp \in RP$	representative periods

(continued on next page)

[4] We consider only one GENCO per node, and therefore, spatial arbitrage cannot be exercised. In this paper, we focus on temporal arbitrage, and, on how different degrees of competition in the market can lead to higher congestions in the lines.

(*continued*)

$\Gamma_{rp,\,p}$	set of correspondence between rp and p
$d,\,d' \in D$	nodes
$g \in G$	generator unit g
$LA(d,d')$	set of all possible lines from node d to d'
$LE(d,d')$	set of existing lines from node d to d'
$k \in K$	discretization steps

Parameters

$pMaxFlows_{dd'}$	Maximum flow in line dd'	MW
$pReactance_{dd'}$	Reactance of line dd'	[p.u.]
$pFCost_t$	Fuel cost of technology t	€/MWh
$pInvC_{dd'}$	Annualized investment cost of line dd'	€
$pDemand_{ypd}$	Demand intercept at year y period p at node d	MW
$pDSlope$	Demand slope	$MW^2/€$
pW_{rp}	Weight of each representative day	[p.u.]
pSB	Base power	MW
θ_g	Conjectural variation of GENCO g	$€/MW^2$
$\bar{\lambda}$	Price upper bound	€/MW
$\Delta Flows_{ypdd'}$	Flow step magnitude year y at period p from node d to d'	MW

Variables

$vProd_{ypgd}$	Production at year y at period p of generator g at node d	MW
$vNewLine_{ydd'}$	Investment status at year y of line from node d to d'	{0,1}/ MW
$vFlows_{ypdd'}$	Flows at year y at period p from node d to d'	MW
$vBinFlow_{ypdd'k}$	Binary variable for flow at year y period p from node d to d' and step k	{0,1}/ MW
$vF\lambda_{ypdd'k}$	Flow times price at year y period p from node d to d' and step k	MW
$vDemand_{ypd}$	Demand at year y period p at d	MW
λ_{ypd}	Prices at year y period p node d	€/MW

2.2. Benchmark: cost minimization model (CMM)

Traditionally, capacity expansion has been planned from the point of view of a centralized vertically integrated utility. In such a framework, depicted in Fig. 4, the central planner decides *simultaneously* transmission and generation capacity expansion as well as the market operation by minimizing the total system cost. Additionally, the central planner assumes perfect competition and perfect information.

It is important to note that there is always a trade-off between how fine time granularity is considered and how detailed market operation is modeled. This disjunctive is especially important for the simultaneous representation of hydro and battery storage. In fact, most models consider either load blocks (systems states) or representative periods. However, each of these options is more suitable for either of the storage technologies. In order to overcome this issue, we consider an enhanced representative periods framework proposed by (Tejada-Arango et al., 2018), which considers a representative-periods approach together with a transition matrix that shows how each representative period is connected to each other. From this framework, it is not only possible to model the battery storage (by representing the detailed hourly operation inside each representative day), but also the hydro operation with its interday charging cycles, by taking advantage of the links between representative periods (given that we know which of representative days correspond to every week or month of the year). In this sense, a time window (more than a day, i.e. week or month) is chosen to verify the hydro storage balance (as the sum of inflows and outflows of all the representative days belonging to that week or month) and to follow the yearly evolution of the reservoir. Apart from this consideration, this model includes basic operating constraints.

The main constraints considered are:

i) Maximum and minimum power outputs for existing and new conventional generators, new investments are considered as continuous variables.
ii) Maximum and minimum power outputs for existing and new wind generators, considering them as non-dispatchable technologies.
iii) Maximum and minimum power outputs and consumption inputs for storage units. Considering both inter-day constraints for short-term technologies (BESS) and intra-day constraints for long-term storage technologies (hydro).
iv) Power flow constraints considering a linearized DC power flow for existing and new lines. We consider binary variables for network expansion.
v) Market clearing condition.

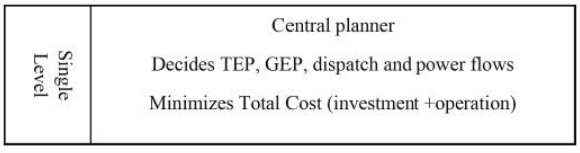

Fig. 4. Cost minimization structure.

2.3. Bi-level problem: proactive model (PM)

We consider a proactive approach in which the TSO plans the system, as the leader in the market, by anticipating both GEP and operation decisions.

2.3.1. Bi-level structure

Let us explain the main differences between the CMM (Section 2.2) and the PM frameworks.

First, in the lower level, we consider three types of players (each one with its own optimization problem), namely, GENCOs, the system operator (SO), and Consumers. The collection of these players' constraints is the same as that of the CMM framework. Second, the *market clearing condition* couples every player's optimization problem, by ensuring that total supply is equal to the demand at each node. This constraint is the only one that differs from the CMM, given that in CMM the demand is a parameter (inelastic) while in the PM framework it is considered to be variable (elastic demand) see 2.3.2.

Mathematically speaking, Fig. 5 shows a structure in which an optimization problem (upper level) is constrained by several optimization problems (lower level). Please note that such a structure cannot be solved directly as an optimization problem, therefore, we need to transform it into a single-level problem. First, we convert the set of optimization problems at the lower level into a set of constraints, by considering the equivalent KKT conditions. These conditions, which include some non-linear complementarity conditions, can be linearized by applying the well-known disjunctive constraints (Fortuny-Amat and McCarl, 1981) with tight and meaningful big-Ms (Pineda et al., 2018). To sum up, this process leads to a single-level MIP problem where the upper-level optimization problem is subject to a set of linearized equilibrium constraints. For specific details, please refer to Appendix.

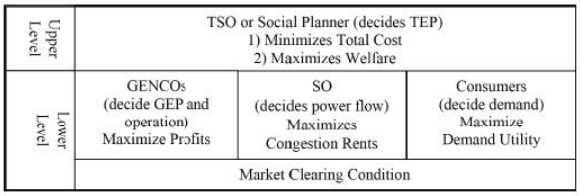

Fig. 5. Bi-level model structure.

2.3.2. Market responsive framework

Following the work of (Wogrin et al., 2011a), we consider an affine relation between price 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).

$$vDemand_d = pDemand_d - pDslope_d * \lambda \forall d \quad (1)$$

We furthermore define a conjectural variation $\theta_g = \partial\lambda/\partial vProd_g$ 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 production $vProd_g$. 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 a Cournot oligopoly (CO). Any intermediate value of the conjecture allows us to model different degrees of competitive behavior.

2.4. Regret computation: CMM vs PM

In order to compare the benchmark model and the bi-level problem, we compute what we refer to as *regret*. The regret represents the additional cost (or missing welfare) resulting from planning the system in a centralized traditional manner (CMM), where all decisions are considered to be simultaneous and perfectly competitive, compared to planning the system in a more realistic decentralized manner (PM) where TEP decisions are assumed to be taken before GEP decisions and considering market feedback given by GENCOs strategic behavior. Given that the CMM model is inelastic, while the PM is elastic, a specific methodology is needed to make these models comparable. This methodology is depicted in Fig. 6.

Steps for Regret Computation

i. We solve the *PM model* (considering Cournot competition in the lower level).
ii. For the exact same system demand obtained by the PM, we solve the inelastic CMM, which obtains some TEP and GEP investments (that might differ from the ones obtained by the PM). We refer to this model as the *Naïve CMM*; it is "naïve" because it does not reflect the strategic behavior of GENCOs. Therefore, the TEP and GEP obtained by the Naïve CMM might be erroneous given that they assume perfect competition, which is not always the case.
iii. We fix the TEP solution obtained by the naïve CMM, the one that would actually take place in a centralized planning system, and see which would be the reaction of the actual strategic GENCOs. To this purpose, after fixing the TEP solution we re-run the PM model (which is equivalent to just solving the equilibrium problem described by the lower level of PM). This allows us to assess to what extent the "wrong" TEP decision, obtained by the naïve CMM, is going to distort the resulting market equilibrium and GEP decisions made in imperfect markets. The solution of this third model allows us to compute the *Actual CMM* because it accounts for decision errors made by a cost-minimization approach.
iv. Therefore, the regret of using a CMM approach is computed as the total cost (or welfare) of the Actual CMM minus the total cost (or welfare) of the PM.

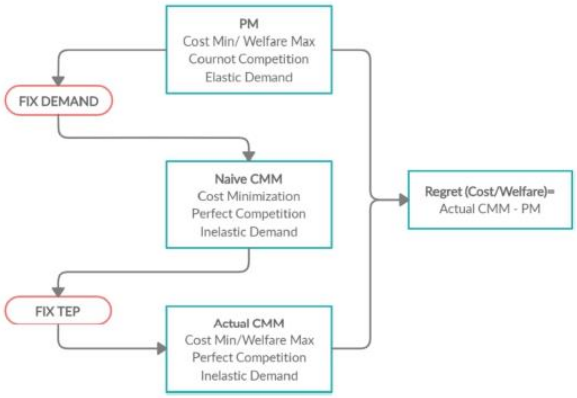

Fig. 6. Regret computation methodology.

2.5. Bi-level problem: merchant transmission system investor

In addition to the social planner considered in Fig. 5, we also consider a merchant transmission investor (contrary to a typically centralized regulated entity) that recovers its investment directly from the market operation. Such a model structure is depicted in Fig. 7.

We consider that those market incomes are derived from the network congestion rents, which are computed as the price difference between two connected nodes times the flow through the corresponding connecting line. Please note that this is not the only way in which we can consider the market incomes for merchant investors. In general, we have physical rights models, financial models, or a mix of both, as well as point-to-point or flow-based approaches. In this paper, we consider a physical point-to-point congestion rent model, which is a theoretically good-enough approach to represent market incomes for merchant transmission investors. However, there exist more accurate approaches as those in (O'Neill et al., 2008) that take into account the AC power flows or those based on the Vickrey-Clarke-Groves auction theory.

$$\arg \underset{vNewLine_{ydd'}}{Maximize} \sum_{y,p,d} pW_{rp} * vFlows_{ypdd' \in LA} * \left(\lambda_{ypd'} - \lambda_{ypd}\right) - \sum_{ydd' \in LC} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \quad (2)$$

Subject to : Lower Level Problem

Please note that the lower problem is the same as the one of the social planner, which, as mentioned in 2.3, consists of the same constraints enumerated in 2.2 with the addition of considering elastic demand. We consider that the only costs for the merchant investor are the investment costs. Let (2) represent the merchant investor's objective function. The first term of this objective function represents the congestion rents ($vFlows_{ypdd'} * \lambda_{ypd} - vFlows_{ypdd'} * \lambda_{ypd'}$) and corresponds to a non-linear, non-convex term, which can cause numerical difficulties when solving the problem. Therefore, we have decided to linearize this term in order to solve the resulting MPEC as a MILP just as the PM model in Section 2.3.1. Similar linearization techniques have been applied in bi-level models in (Pereira et al., 2005; Weibelzahl and Märtz, 2018).

For illustration purposes, we demonstrate how to linearize $vFlows_{ypdd'} * \lambda_{ypd'}$. We start by discretizing the variable *vFlows*, by applying a binary expansion like the one proposed in (Pereira et al., 2005). Eq. (3) reconstructs *vFlows* by starting from the lower bound and adding some slices until the upper bound of *vFlows* is achieved.

$$vFlows_{ypdd'} = -pMaxFlows_{dd'} + \Delta Flows_{ypdd'} * \sum_k 2^k * vBinFlow_{ypdd'k} \quad (3)$$

Fig. 7. Bi-level merchant transmission investor.

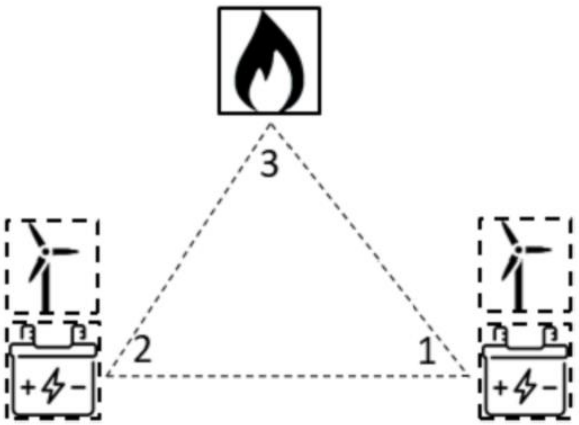

Fig. 8. 3-Node system characteristics.

Table I
3-Node system line characteristics.

From Node	To Node	Reactance [p.u]	Life Time (years)	Total CAPEX (M€)	Annual CAPEX (M€)	Capacity (MW)
1	2	0,06	40	2	0,125	20
2	3	0,05	40	2	0,125	20
1	3	0,03	40	2	0,125	20

Where $vBinFlow_{ypdd'k}$ is a binary variable and $\Delta Flows_{ypdd'}$ is the step magnitude in which we divide the variable $vFlows_{ypdd'}$, which is given by (4).

$$\Delta Flows_{ypdd'} = \left| -pMaxFlows_{ypdd'} - pMaxFlows_{ypdd'} \right| / 2^K \tag{4}$$

Let us define the binary expansion of $vFlows_{ypdd'} * \lambda_{ypd'}$ in eq. (5).

$$vFlows_{ypdd'} * \lambda_{ypd'} = -pMaxFlows_{dd'} * \lambda_{ypd'} + \Delta Flows_{ypdd'} * \sum_k 2^k * vBinFlow_{ypdd'k} * \lambda_{ypd'}. \tag{5}$$

Given that the nonlinear term $vBinFlow_{ypdd'k} * \lambda_{ypd' \in (GAD)}$ is the product of a binary variable and a continuous variable, we can linearize it by renaming the product $vF\lambda_{ypdd'k} = vBinFlow_{ypdd'k} * \lambda_{ypd'}$ and adding the two following equivalent equations:

$$0 \le \lambda_{ypd' \in (GAD)} - vF\lambda_{ypdd'k} \le \overline{\lambda} * \left(1 - vBinFlow_{ypdd'k}\right) \tag{6}$$

$$0 \le vF\lambda_{ypdd'k} \le \overline{\lambda} * \left(vBinFlow_{ypdd'k}\right) \tag{7}$$

Please note that we assume that prices are non-negative and therefore λ is zero.

Thus, we re-formulate the complete problem as follows:

$$\underset{vF\lambda_{ypdd'k}}{argMaximize} \sum_{y,p,d,k} pW_{rp} * \left(vF\lambda_{ypdd'k} - vF\lambda_{ypd'dk}\right) - \sum_{ydd' \in LC} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \tag{8}$$

Subject to : *Equations* (3) – (7) *and Lower Level Problem*

It is important to note that – as with every linearization technique – the result depends on the steps considered for the discretization. Therefore, the bigger k, the smaller is the step size, and hence, the closer the solution would be to the global optimum.

$$\underset{vNewLine_{ydd'}}{arg\ Maximize} \sum_{y,p,d} pW_{rp} * vFlows_{ypdd' \in LA} * \left(\lambda_{ypd'} - \lambda_{ypd}\right) - \sum_{ydd' \in LC} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right)$$

3. Case study

In order to test the properties of the proposed model we consider two case studies, i) an illustrative 3-node greenfield case, where we study in detail the investment and operation results and ii) a modified 24-IEEE brownfield test case where we run a sensitivity analysis to generalize some policy implications.

3.1. Illustrative 3-node case

We describe the greenfield test system in Section 3.1.1, then we study the policy implications of allowing a merchant investor to plan the system acknowledging the imperfect competition in the market. For that purpose, we first study a system without storage technologies in Section 3.1.2, and then we compare it with a system that includes BESS penetration in Section 3.1.3.

3.1.1. System description

We start out by considering a simple three-node example with: one existing conventional generator (CCGT) located at Node_3; candidate wind generators located at Node_1 and Node_2; and, candidate Battery Energy Storage System (BESS) located at Node_1 and Node_2. We consider that the generation units at each node belong to a different GENCO. Additionally, we study a greenfield approach with no existing transmission infrastructure.

In Fig. 8, dotted lines represent candidate elements, either generation units or transmission lines, while continuous lines represent existing elements. We consider a single representative day for a single target year in the future.

Table I shows the technical characteristics of the transmission lines. We consider three candidate lines of 20 MW and 100 km with a total capital cost of 1000€/MW·km and a 5,5% discount rate which leads to the annual cost presented in Table I. Additionally, Table II shows the capital cost (WindEurope, 2017) and variable cost of GENCOs as well as their location and technical characteristics. Please note that the BESS has a 4-h charge/discharge duration which implies a typical storage capacity of 40 MWh. In order to compute annual capital costs for GENCOs, we consider a 7% discount rate (CNMC [WWW Document], 2018).

Fig. 9 shows the hourly demand intercept at the 3 different nodes; additionally, for Node_2 and Node_3 we consider a constant demand slope (β) of 1,6 €/MWh^2 and for Node_1 a slope of 2.5 €/MWh^2. These values are aligned with what is usually found in the literature (Maurovich-Horvat et al., 2015; Sauma and Oren, 2006).

The corresponding conjectural variations, defined in 2.3.2, appear in Table III.

Table II
3-Node system GENCOs characteristics.

	Node	Status	Life time (years)	Total CAPEX k€/MW	Annual CAPEX k€/MW	Variable cost €/MWh	Maximum capacity MW
CCGT	3	Existing			–	50	55
Wind	1/2	Candidate	25	1000	85,80	0	26*
BESS	2/2	Candidate	15	500	54,89	0	10*

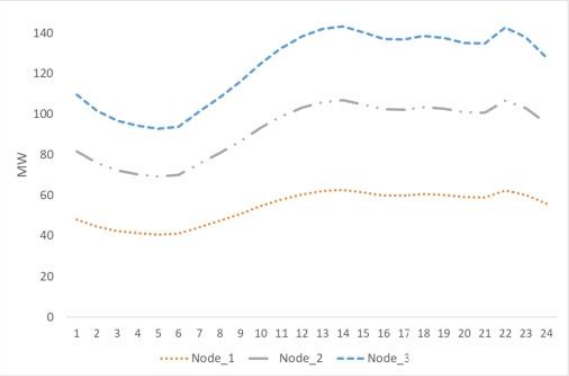

Fig. 9. Hourly demand intercept.

Table III
Conjectural variations for each degree of competition.

PC	CO
0	$1/\beta$

3.1.2. System planning without the consideration of storage systems

In this section, we firstly consider a system with an existing CCGT generator where no batteries are considered as candidates and only wind generators are considered for generation expansion (see Fig. 10). Then, in order to help answer our second set of research questions, we conduct a policy analysis in Section 3.1.2.1 to compare the planning results from the point of view social planner with those of a merchant investor, and finally, in Section 3.1.2.2, we analyze the planning results of a social planner that disregards the market feedback, which would allow us to answer our first set of research questions.

3.1.2.1. Merchant transmission investor vs social planner in no-storage case. In order to address our second set of research questions, we analyze the economic results of a merchant transmission investor compared to a social planner. As formulated in Section 2.5, we consider a merchant investor at the upper level that aims at maximizing its own profit. This type of regulation is not usually applied to a complete system but to specific projects. For instance, merchant investment is applied for interconnections in Europe (ACER, 2018) and has been expanding in the US, in fact in 2018 the FERC extended the authorization for off-shore wind farms connections by allowing this type of investments, only if the merchant transmission company assumes all market risk (FERC, 2018).

- *Perfect Competition*

As we can see from Table IV, for the *perfect competition case*, even when both the social planner and the merchant investor invest in two transmission lines, they decide on different network connections. The social planner connects both wind nodes with the CCGT node, while the merchant investor decides to have the wind generator located at Node_2 isolated, this would result in higher prices on average and higher price differences. Additionally, the total generation investment is decreased in the merchant investor case, in particular, the investment in Node_1 (directly connected to the most expensive Node_3) increases, while the investment Node_2 decreases (as not all energy can be evacuated).

These final investment decisions lead to some nodal price divergence. In the social planner case, the excess of wind from Node_1 and Node_2 goes directly to Node_3 through independent lines, which implies low congestion in the lines and therefore overall lower prices, as shown in Fig. 11. In the merchant investor case, less wind energy can evacuate Node_2 to finally get to Node_3, as a consequence of transmission congestions, which results in higher prices in Node_3, as well as higher price differentials, as shown in Fig. 12.

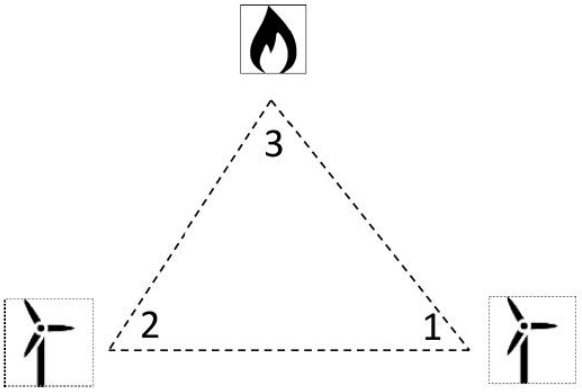

Fig. 10. No storage 3-node system characteristics.

Table IV
Economic results social planner vs a merchant transmission investor.

		Perfect Competition (PC)		Cournot Oligopoly (CO)	
		Social Planner Max Welfare	Merchant I. Max Rent	Social Planner Max Welfare	Merchant I. Max Rent
TEP	**Lines**	2–3/1–3	1–2/1–3	1–3	0
	MW	40	40	20	0
WIND_1		350,2	418,3	151,0	110,1
WIND_2		480,1	324,1	192,3	192,3
GEP	**MW**	830,3	742,4	343,3	302,3
Demand	**TWh**	9,36	8,82	5,38	5,23
Total cost	**M€**	92,83	85,58	49,03	46,70
Relative cost	**M€/ TWh**	9,92	9,70	9,11	8,93
Cong. rent	**M€**	1,29	3,18	−0,13	0,00
Total SW	**M€**	89,02	88,05	75,53	74,12

- *Cournot case*

As seen in Table IV, for the *Cournot Case* the social planner only invests in one line while the merchant investor does not invest in any line, these results align with those found in (Maurovich-Horvat et al., 2015). The total generation capacity is lower, decreasing only the capacity at Node_1 that is no longer connected to Node_3. This shows that in the Cournot case, it is better not to build any transmission lines, as the congestion rents will not be sufficient to recover the investment cost of such lines. As seen in Fig. 13, in the social planner caseprices at Node_3 and Node_1 are the same in all periods, a consequence of not having congestions in the transmission line 1_3. Please also note that the thermal generation at Node_3 is not fully utilized compared to the PC case, the Cournot equilibrium leads to some withdrawn capacity that increases prices in order to maximize GENCOs profits.

Fig. 14 shows that, in the merchant investor case, prices at Node_3, Node_2, and Node_1 are always different, a consequence of not having any lines in the system. In this case, we get that prices in Node_3 are the highest in the system while those at Node_1 are the lowest. This scenario obtains the most inefficient results because exchanges between nodes are not possible.

In summary, in this subsection, we found that both in the PC and CO cases, the investments of a merchant investor lead to a worse-off situation with lower welfare and higher prices. In particular, in the CO case,

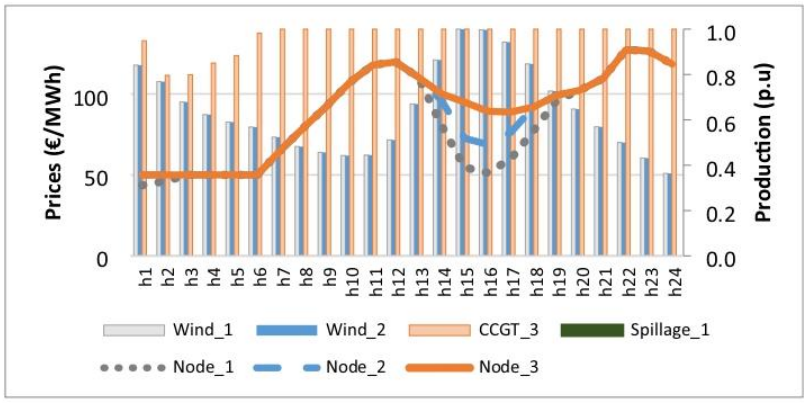

Fig. 11. Resulting prices & dispatch: social planner – PC no storage.

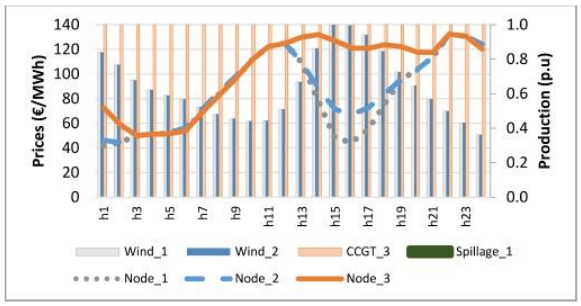

Fig. 12. Resulting prices & dispatch: merchant investor – PC no storage. The bars represent the dispatch of the generators (right axis) and the represent lines de nodal prices (left axis)

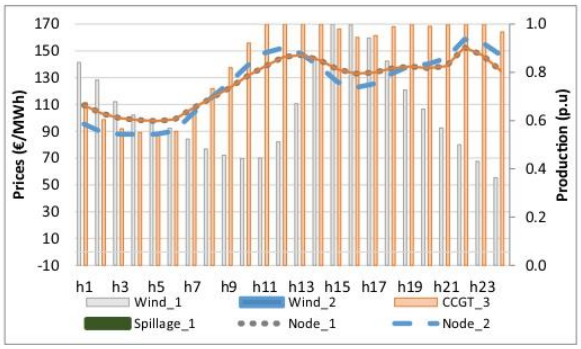

Fig. 13. Resulting prices & dispatch: social planner -CO no storage.

the welfare loss is higher than in the PC case.

3.1.2.2. Regret vs generation mix in no-storage case. In this section, we address the concerns raised in our first set of research questions. We compute the regret, as introduced in 2.4, resulting from a centralized social planner that ignores the market feedback compared to a proactive social planner that anticipates the strategic market feedback i.e., Cournot competition in the lower level. Therefore, we compare the results of the CO model, now called PM_CO, with the Actual CMM.

As we can see from Table V and previous sections, PM_CO invests in lines 1➔3, which leads to a total welfare of 75,53 M€. Given this exact

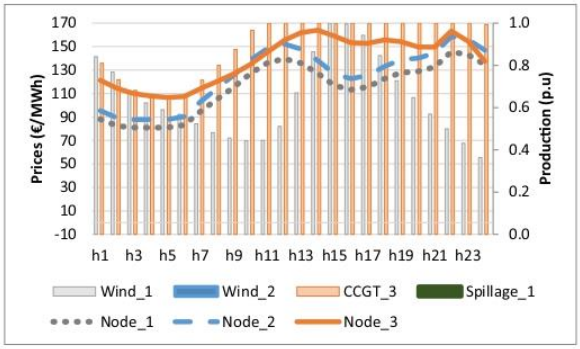

Fig. 14. Resulting prices & dispatch: merchant investor -CO no storage. The bars represent the dispatch of the generators (right axis) and the represent lines de nodal prices (left axis).

Table V
Economic results for the PM planning with distinctive market structures.

	Units	PM CO	Actual CMM	Absolute Difference	Relative Difference (%)
	Lines	1–3	1–2/2–3		
Total TEP	MW	20	40	20	100,00
Wind_1	MW	151,02	147,08	−3,94	−2,61
Wind_2	MW	192,26	202,92	10,66	5,54
Total GEP	MW	343,28	350,00	6,72	1,96
Total SW	M€	75,53	75,45	−0,08	**−0,10**

same demand, we can conceive a Naïve CM planner that designs the system disregarding the strategic market feedback. In such a case the centralized planner based on the Naïve CMM would build lines 1➔2 and 2➔3 with the expectation that GENCOs would build and operate the most competitive generation capacity.

However, markets are not perfect and usually we can find an oligopoly in the production, therefore, we evaluate the actual results of the strategic market given the TEP decided by the Naïve CMM. We call this result the Actual CMM which leads to a total welfare of 75,45 M€ which is 0,08 M€ lower compared to the PM_CO. At a first glance, the regret (or relative welfare difference) of planning the system in a proactive manner rather than a traditional cost minimization might seem negligible. However, this small difference comes along with a structurally different power system. In the Actual CMM case, two lines are invested compared to the only one line invested in the PM case.

Additionally, the Wind_1 capacity invested decreases by 2.6%, and the Wind_2 capacity invested increases by 5.5%, leading to a different generation mix. Remarkably, there is indeed an over-investment in the Actual CMM compared to the PM case. This is the result of the different elasticities in the nodes and the extra capacity that can be commissioned to take advantage of the additional transmission capacity.

Please note that, in this case, disregarding market feedback leads to a slightly lower welfare loss compared to the welfare loss obtained when a merchant investor plans the investments instead of a social planner (see 3.1.2.1).

3.1.3. System planning considering storage systems

As shown in Fig. 15, we now consider a system where BESS, as well as Wind turbines, are candidate technologies for generation expansion. This case would allow us to answer our third set of research questions. Similarly to the previous section, we conduct a policy analysis in Section 3.1.3.1 to compare the planning results from the point of view social planner with those of a merchant investor when considering BESS and, in Section 3.1.3.2, we analyze the planning results of a social planner that disregards the market feedback when considering BESS. Finally, in order to answer our third set of research questions, we assess how introducing BESS in the generation technology mix changes the results from Section 3.1.2.

3.1.3.1. Merchant transmission investor vs social planner in storage case.

In this section, we again compare the planning results of a social planner and a merchant investor. However, in order to address our third set of research questions, we add the possibility to invest in BESS and we compare the results to the case without storage.

By comparing tables Tables IV and VI, we observe that the TEP investments in the storage and no-storage case are identical. However, having the option of investing in BESS technologies has a positive impact on social welfare, which increases from 89.2 to 92.85 M€ in the perfectly competitive case. Given the new candidate batteries and the transmission decisions of the social planner, decentralized GENCOs decide to invest more wind capacity in each node, along with some BESS capacity. (See Tables VII and VIII.)

Please note that, as shown in Fig. 16, the nodal prices are flattened compared to the no-storage case described in Section 3.1.2.1. Additionally, Fig. 17 registers the battery usage (which is similar for BESS_1 and BESS_2). As we can see, the battery charging coincides with low nodal prices and the battery discharge coincides with high nodal prices.

As shown in Fig. 16 for the social planner case, the effect of batteries on price creation is the reduction of volatility. These flat prices go against the congestion rent maximization objective, and therefore, for the merchant investor case no batteries are built (as seen in Table VI),

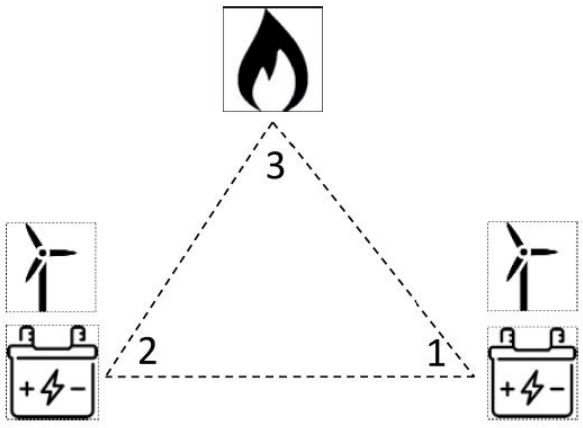

Fig. 15. Storage 3-node system characteristics.

Table VI
Economic results social planner vs a merchant transmission investor.

		Perfect Competition (PC)		Cournot Oligopoly (CO)	
		Social Planner Max Welfare	Merchant I. Max Rent	Social Planner Max Welfare	Merchant I. Max Rent
TEP	**Lines**	2–3/1–3	1–2/1–3	1–3	/
	MW	40	40	20	0
WIND_1		374,3	418,3	150,5	111,3
WIND_2		505,8	324,1	194,4	194,4
BESS_1		27,0	0,0	10,8	9,9
BESS_2		46,1	0,0	17,5	17,5
GEP	**MW**	880,0	742,4	344,9	305,7
Demand	**TWh**	9,78	8,82	5,41	5,25
Total cost	**M€**	98,85	85,58	49,65	47,28
Relative cost	**M€/ TWh**	10,11	9,70	9,18	9,01
Cong. rent	**M€**	1,29	3,18	−1,25	0,00
Total SW	**M€**	92,85	87,73	76,58	75,12

Table VII
Economic results for the PM planning with distinctive market structures.

	Units	PM CO	Actual CMM	Absolute Difference	Relative Difference (%)
	Lines	1–3	1–2/2–3		
Total TEP	MW	20	40	20	100,00
Wind_2	MW	150,49	146,90	−3,6	−2,39
Wind_1	MW	194,42	202,64	8,2	4,22
BESS1		12,29	11,86	−0,4	−3,52
BESS2		7,58	7,59	0,0	0,07
Total GEP	MW	364,79	368,98	4,2	1,15
Total SW	M€	76,57	76,43	−0,1	**−0,18**

Table VIII
GENCOs conjectures.

GENCO_21	GENCO_23	GENCO_5	GENCO_7
1/ 3β	1/ 2β	1/ 2β	1/ 3β

which leads to the exact same investment plan as in Section 3.1.2.1.

In the Cournot case, we found similar transmission investments as in the no-storage case. However, for the generation, we find some BESS capacity investment both by the social planner and the merchant investor.

Fig. 18 shows that, for the Cournot case case, prices also tend to be flattened compared to the case without storage, however, the effect is significantly lower than that of the PC, as less BESS capacity is invested. However, as we can see from Fig. 19 (the battery usage is similar for both BESS_1 and BESS_2), the battery still follows an economic rationale, charging at low prices and discharging at high prices.

Finally, as shown in Fig. 20, for the merchant investor case, the price differentials are the highest, as no transmission lines are commissioned. However, the price variation is slightly lower than in the case with no storage.

Fig. 21 shows that the battery utilization in the Cournot case is similar to the social planner case, but, given that the total BESS capacity is slightly lower, the impact on price flattening is slightly lower as well.

As we can see in this section, the TEP decisions from the non-storage vs storage case are the same. However, the GEP decisions are different. In general, in the storage case, more generation capacity is installed as a whole, and higher welfare is achieved. However, the welfare loss is also higher, in particular in the PC case where the arbitrage in Batteries has a higher impact on social welfare.

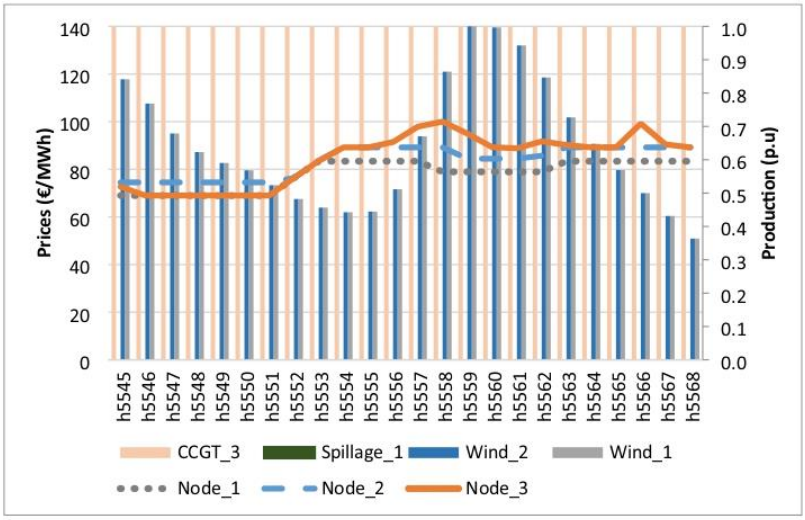

Fig. 16. Resulting prices & dispatch: social planner – PC storage.
The bars represent the dispatch of the generators (right axis) and the represent lines de nodal prices (left axis).

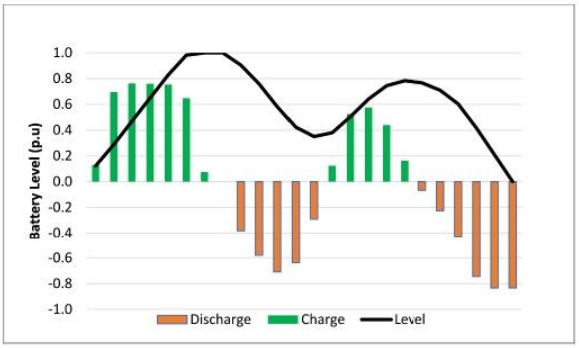

Fig. 17. Battery usage: social planner – PC storage.

3.1.3.2. Regret vs generation mix in storage case. In order to assess our third set of research questions, we compare this section with section 3.1.2.2. Table VII shows that, in the storage case, we have similar results as in the No-storage case. Even though the total regret in the case with storage is double that in the case without storage, it is still relatively small, only 0.18%, while the generation mix differences are still around 1%. The results might indicate that disregarding market feedback when planning TEP could be worse when BESS is in the mix, as it implies disregarding the effects that flexibility of BESS can have on the market power.

3.1.4. Main takeaways

The previous sections allowed us to answer the third set of research questions. The main takeaways of our study can be summarized as follows:

- When comparing a social planner with a merchant investor, we find that the TEP decisions from the non-storage vs storage cases are the same; however, the GEP decisions are different. In general, in the storage case, more generation capacity is installed as a whole and higher welfare is achieved. Both in the PC and CO cases, the investments of a merchant investor lead to a worse-off situation with lower welfare and higher prices. In particular, in the no-storage case under CO, the welfare loss is higher than in the PC case, while in the storage case the welfare loss is higher in the PC case, where the arbitrage by Batteries has a higher impact on the social welfare.
- Disregarding market feedback can lead to a non-negligible welfare loss, both in the storage and non-storage cases; however, we found some results that might suggest that disregarding market feedback could be worse when we have BESS in the mix, as it implies disregarding the effects that flexibility of BESS can have on the exercise of market power.

3.2. IEEE-24 bus test case

In this section, we consider an IEEE-24 modified system (brownfield) to further test this model and assess whether initial policy insights from the 3-node greenfield case are still true in larger power systems. First, in Section 3.2.2, we want to assess whether, as for the 3-node case, a merchant investor leads to a worse-off situation in both the CO and PC cases with and without storage. This would allow us to extend our insights to the second and third set of research questions. Second, In Section 3.2.3, we want to confirm if disregarding market feedback leads to a non-negligible welfare loss, as found in the 3-node case. However, in this Section, we only consider the storage case, given that no regret was found in the non-storage case. This analysis broadens our answers to the first set of research questions.

3.2.1. System description

This IEEE-24 modified system as the one considered in (Xu et al., 2018), that more or less reflects the conditions of the WECC systems in the United States.

As shown in Fig. 22, this system is made up of 24 buses, 33 existing lines, and 12 existing conventional generators. Continuous lines represent existing elements and dotted lines represent candidate elements. We consider 3 candidate conventional generators at nodes 3, 10, and 19, as well as 6 wind candidate generators at buses 3, 5, 7, 16, 21, 23. As a result of different run cases, we modified the system so that some border nodes from south to north (Node_9, Node_3, Node_24) have higher demand, leading to higher congestions, so we can easily analyze the consequences of different TEP alternatives.

Additionally, we consider 4 candidate BESS at nodes 1, 3, 15, and 1 hydro candidate at node 19. We consider 4 representative days (h3697-h3720, h8425-8848, h5305-h5328 and h1897-h1920). As seen in

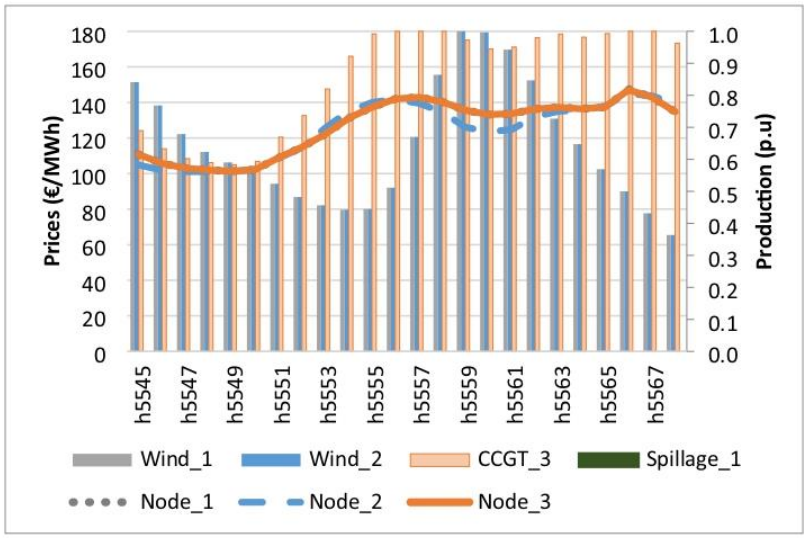

Fig. 18. Resulting prices & dispatch: social planner – CO storage.
The bars represent the dispatch of the generators (right axis) and the represent lines de nodal prices (left axis).

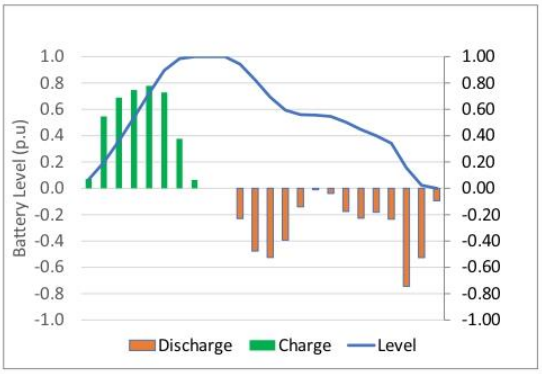

Fig. 19. Battery usage: social planner – CO storage.

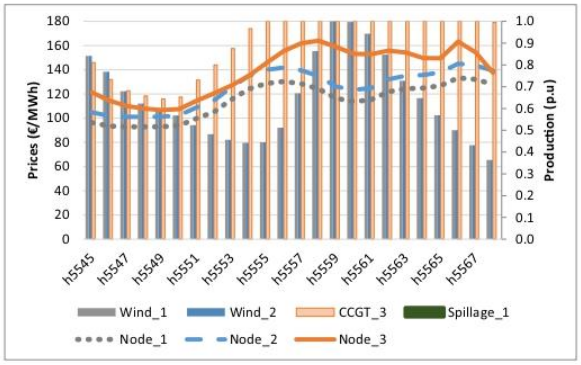

Fig. 20. Resulting prices & dispatch: merchant investor – CO storage.
The bars represent the dispatch of the generators (right axis) and the lines represent de nodal prices (left axis).

Fig. 23, we consider different real profiles for the wind candidate

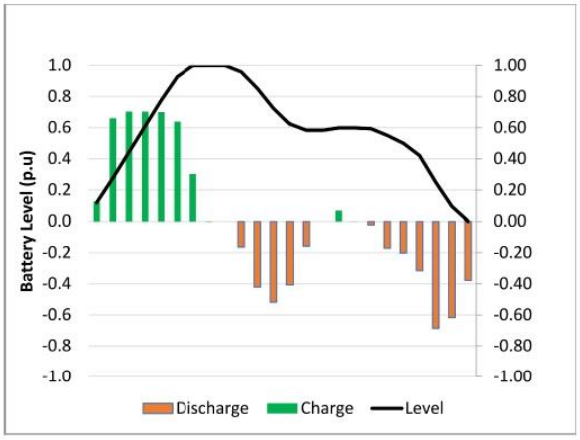

Fig. 21. Battery usage: merchant investor – CO storage.

generators (as those existing in the WECC system) located in the south (nodes 3, 5, 7) and those located in the north (nodes 16, 21, 23). Additionally, we consider a yearly hydro inflow shown in Fig. 24, and a 168 h window (as defined in 2.2) for the inter-day storage constraints. We consider similar capital costs as in the 3-node case, but we variate the wind capital cost to reflect different geographical conditions. We variate from up to 40% of the capital cost for different nodes and consider a cost of 1300 k€/MW for conventional generators assuming a lifetime of 30 years and a 7% discount rate (equivalent to 104 M€/MW annually). Finally, we consider a transmission capacity of 30 MW for each of the transmission lines (existing and candidates) of the system and a demand slope of 0,55 €/MWh^2. In order to have a more realistic representation of imperfect competition (instead of the most extreme Cournot case), we consider some GENCOs with intermediate market power, as that given by the conjectural variation (see Table VIII).

3.2.2. Merchant transmission investor vs social planner – storage vs non-storage

As mentioned in the introduction, in this subsection we extend our

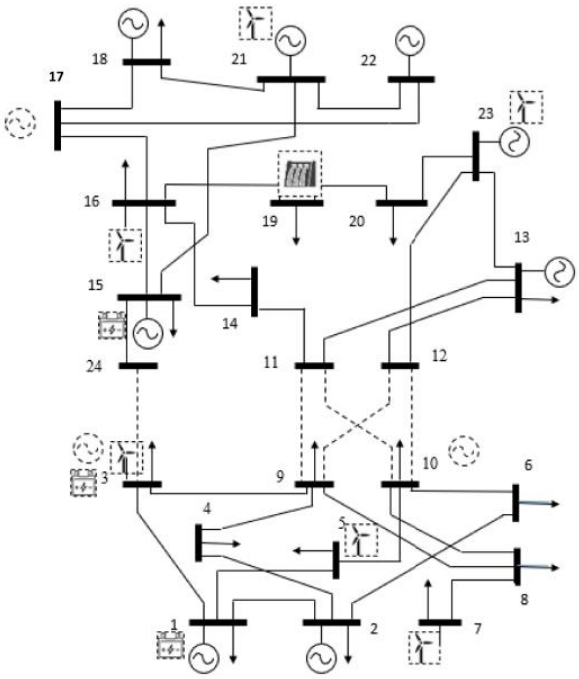

Fig. 22. IEEE-24 test case.

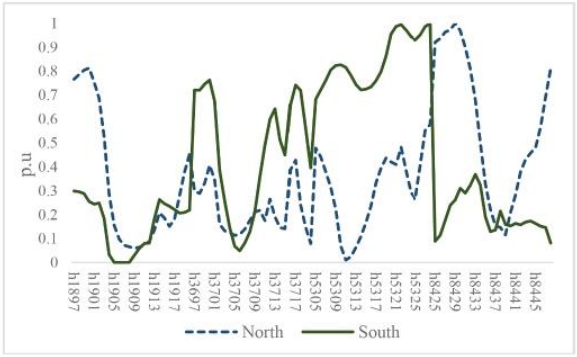

Fig. 23. Wind profiles.

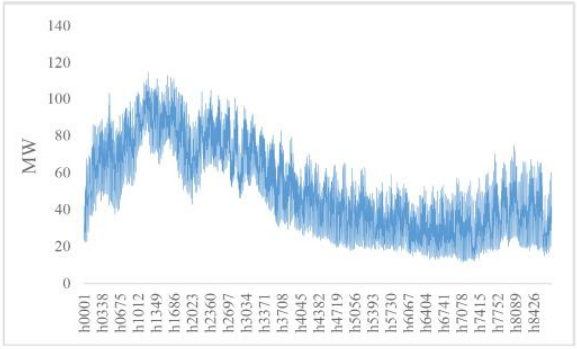

Fig. 24. Yearly hydro inflows.

insights on the second and third set of research questions. Tables IX and X show the economic results of planning the system for the Non-Storage and Storage cases respectively, by considering distinctive objective functions for the social planner (maximizing welfare) and the merchant investor (maximizing congestion rents). We compare the economic efficiency of such regulatory schemes by comparing the total welfare and relative cost in each case.

For the Non-storage case the welfare maximization and the congestion rent maximization objectives lead to the same result, installing only one line to connect the north and south regions of the system. This is true for both the PC and CO competition schemes, where the planner decides to invest in line 10–12. Unsurprisingly, the higher demand supplied in the PC case, which benefits both the consumers and GENCOs, leads to a higher welfare and a lower relative cost per MWh. However, for the case of congestions rent, we see that in the CO case the rents are higher than in the PC case, even if the total demand is considerably higher. This is a consequence of the elasticity of the demand that, in turn, implies a high level of market power that allows GENCOs to benefit from higher transmission congestions. For the Storage case we obtain slightly different results; in the PC, we see that the planner invests only in one line, just like in the No Storage case. However, for the CO, we find that there is a difference between the social planner and the merchant investor. A social planner would invest in the transmission lines 10_12 and 9_12, decreasing the capacity of GENCOs to exercise their market power (which is higher for storage units as they rely merely on price arbitrage) in order to maximize the social welfare; the merchant investor would find it more profitable to keep investing in a single line as it would maximize its congestion rents.

Fig. 25 shows that investments in the CO case are always lower than the investment in the PC case. Please note that storage generation is almost non-profitable in the Cournot case, which is similar to the results in the 3-node greenfield case. As mentioned before, these results are case-dependent. However, we identified a trend in CO cases to underinvest compared to the PC case, especially in BESS and wind, while conventional generation and hydro investments tend to remain closer to the PC case. This could be explained, similarly to Section 3.1, because of the greater market power that BESS and wind can exercise when belonging to the same GENCO. Please also note that in the storage case the wind investments are even higher than in the non-storage, and the conventional investments are lower. This happens because renewable technologies are complementary with the BESS, and therefore it is profitable to replace additional conventional capacity with renewable capacity to profit from their arbitrage services.

In this Subsection (3.2.2) we found that, similar to the 3-node case, the welfare loss when a merchant investor plans the system (compared to a social planner) is higher when we consider BESS in the system than when we do not. However, in the 24-Node case, where we consider a more meshed network, there is no welfare loss in the no-storage case,

Table IX
Economic results 24-node case – no storage.

		Perfect Competition (PC)		Cournot Oligopoly (CO)	
		S. Planner Max Welfare	Merchant I. Max Rent	S. Planner Max Welfare	Merchant I. Max Rent
TEP	**MW**	30	30	30	30
	Lines	10_12	10_12	10_12	10_12
GEP	**MW**	3396	3396	1652	1652
Demand	**TWh**	337,35	337,35	198,96	198,96
Total cost	**M€**	786,26	786,26	481,52	481,52
Relative cost	**M€/TWh**	2,33	2,33	2,42	2,42
Cong. rent	**M€**	87,41	87,41	94,61	94,61
Total SW	**M€**	1461,64	1461,64	1179,09	1179,09

Table X
Economic results 24-node case –storage.

		Perfect Competition (PC)		Cournot Oligopoly (CO)	
		S. Planner Max Welfare	Merchant I. Max Rent	S. Planner Max Welfare	Merchant I. Max Rent
TEP	**MW**	30	30	60	30
	Lines	10_12	10_12	10_12, 9_12	10_12
GEP	**MW**	4053	4053	1737	1719
Demand	**TWh**	339,500	339,500	203,035	198,791
Total cost	**M€**	811,618	811,618	487,615	484,256
Relative cost	**M€/ TWh**	2391	2391	2402	2436
Cong. rent	**M€**	85,382	85,382	87,549	92,678
Total SW	**M€**	1513,865	1513,865	1191,252	1190,615

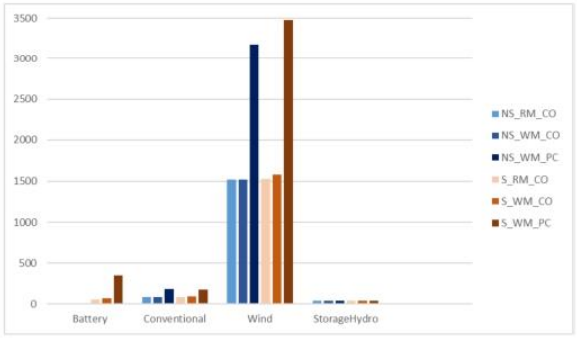

Fig. 25. Generation investment (MW) in conventional technologies, wind, BESS and hydro.
*NS prefix = No-Storage, S prefix = Storage.

neither the CO nor the PC case. On the other hand, in the storage case, we find no welfare loss in the PC case and a non-negligible difference in the CO case.

Therefore, in this 24-node case that mimics the conditions of the WECC system, it seems that the investment results of a merchant investor and social planner might be the same if there is actually perfect competition in the market. This finding is contrary to what we found in the 3-node case, where a merchant investor led to a suboptimal solution even in the perfect competition case. However, and similarly to the 3-node case, if we assume some degree of imperfect competition, and consider a high penetration of batteries we may come across different results, as the investment plans of a merchant investor might lead to suboptimal results. Therefore, these results might suggest that a greenfield approach (exemplified in the 3-node case), is more sensitive to different policy objectives than a brownfield approach (exemplified by the 24-node case), where most of the electrical infrastructure is already in place.

3.2.3. *Welfare loss and generation mix distortion storage case*

This section extends our conclusions on the first set of research questions. Similar to the 3-node case, in this section, we compute the regret, as defined in 2.4, of disregarding market feedback in transmission expansion planning. The regret is computed as the welfare difference (relative to PM_CO) between the PM_CO case and the Actual CMM. We found that in the Non-storage case there is no regret, so we will focus on the results of the storage case. Additionally, we also investigate how the generation mix changes under the different planning paradigms, and we compute the total GEP change by taking the difference between the GEP invested in the PM_CO and the Actual CMM relative to the existing generation capacity (4,32 GW).

Table XI shows the welfare and investment differences between the Actual CMM and the PM_CO. In this case, the Actual CMM invests only in line 10➔12, which leads to 3.76% GEP underinvestment compared to the PM_CO case and a welfare regret of 0,05%. For this specific case, the welfare regret is almost negligible, while the GEP underinvestment is significant, mainly for the BESS units. These results are consistent with the findings in the 3-node case, and they suggest (similarly to the previous section) that in a brownfield approach (24-node case) the regret is lower than in the 3-node greenfield approach. In order to understand how these results vary among different system characteristics of the 24-node case, we run a sensitivity analysis of the regret computation and the generation mix change. We examine different levels of the demand slope, from 0,45 €/MWh2 to 1.67 €/MWh2, and we consider different constrained systems by varying the capacity of all transmission lines from 25 MW to 60 MW.

Given that the elasticity variation across the different cases can have a high impact on the total welfare, we decide to compute the regret in terms of the total cost, as the total cost difference (relative to PM_CO) between the PM_CO case and the Actual CMM.

As we can see in Fig. 26, there is a non-linear relationship between regret and demand slope, as well as between regret and system congestion. Even though the percentage numbers of the regret seem relatively small (below 1.05% in the cases studied here), in absolute terms, the regret still ranges in the order of millions of euros. Fig. 26 shows that, for non-elastic markets (in this case lower than 0.45), there is not welfare regret when ignoring market feedback. On the other hand, for more elastic demand scenarios the regret would increase by having fewer congestions in the system, up to a point where it would decrease again. For this particular system, the maximum regret is reached when there is a demand slope of 0.63 and the capacity of the lines is 40 MW. Therefore, disregarding strategic market feedback in a relatively high-congested system can be considered a non-negligible planning regret. This is the natural result of a congested system, more prone to present inefficiencies if no proper expansion is undergone (which is consistent with the non-negligible regret found in the 3-node case). There is no clear evidence on how elasticity affects the regret of disregarding market feedback, but from Fig. 26 we can see that low-congested systems are more sensitive to demand elasticity than highly-congested systems.

The relatively small welfare regret, shown in Fig. 26, can be somehow misleading if we do not investigate how the generation mix changes. Fig. 27 shows how the generation mix changes depending on how constrained or elastic the demand in the system is. Fig. 27 shows the existence of a distortion of the capacity mix, ranging from 1% to 4%. As we can see, lower demand slopes and less constrained systems lead to higher GEP difference. It is worth noting that for every level of elasticity and transmission capacity there is a breaking point that goes from maximum to zero GEP difference. In this case, the scenario with the highest GEP difference corresponds to the (0.63,60) which is different from the maximum regret point (0.63,40). Therefore, from the previous two analyses, we can conclude that TEP decisions made by a cost-minimizing TSO that disregards strategic market feedback will generate a relatively small welfare loss that tends to increase for elastic

Table XI
Proactive vs cost minimization: welfare and investment results.

	Units	PM CO	Actual CMM	Difference (MW)	Difference (%)
	Lines	10–12,9–12	10–12		
Total TEP	MW	60	30	−30	−50,00%
BESS	MW	68,97	57,65	−11,32	−16,41%
	MWh	275,88	230,60	−45,28	−16,41%
Wind	MW	1584,44	1532,52	−51,92	−3,28%
Thermal	MW	91,9	89,55	−2,35	−2,56%
Total GEP	MW	1745,31	1679,72	−65,59	−3,76%
Total SW	M€	1191,252	1190,615	−0,637	−0,05%

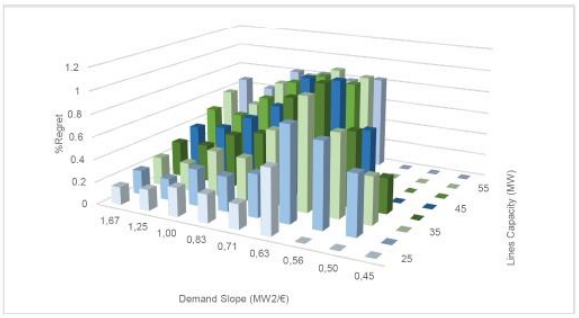

Fig. 26. Regret computation sensitivity.

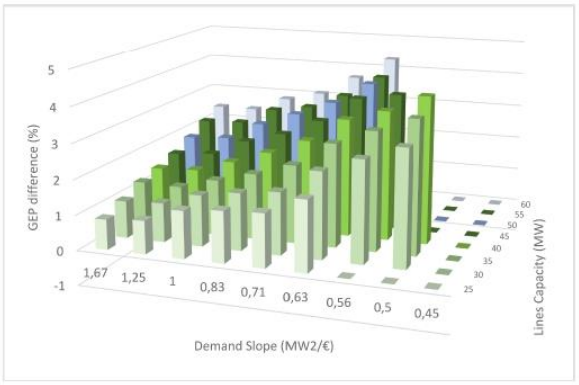

Fig. 27. Generation mix sensitivity.

systems with mid-constrained systems. In this specific case, the decisions of the cost-minimizing TSO will result in a significant GEP over-investment when there is low system congestion and a mid-elasticity level.

From our sensitivity case we show, in Fig. 28, the case with 60 MW capacity on transmission lines and a slope of 0.63 $MW^2/€$. In this case, we can see a significant variation in the generation mix, which can affect the robustness of the system. In fact, in the Actual CMM, 71 MW of additional capacity is invested in wind generation, but only 11 MW (44 MWh) of storage and 4 MW of conventional generation (given a higher demand). This structure would react significantly differently to variations in the wind availability that could lead to a high level of stress in the system, implying lower robustness.

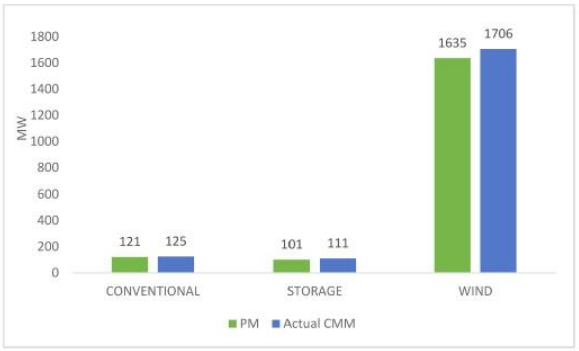

Fig. 28. Generation mix distortion.

3.2.4. Main takeaways

In summary, for this case study, we can conclude that disregarding market feedback might have a relatively small impact in terms of overall welfare loss (which we referred to as regret); however, the subsequent impact on the optimal generation mix can be considered non-negligible. In this case study, we have observed relative generation mix distortions of up to 4.3%. The distortion of the optimal generation capacity mix can, in turn, have important results on the robustness of the system, but this analysis is out of the scope of this paper.

4. Conclusions and policy implications

In this paper, we proposed a model that represents generation and transmission expansion planning from the perspective of a proactive social planner. This social planner designs the system considering the feedback from either a perfectly competitive market or a Cournot oligopoly. Additionally, we considered also the formulation of a merchant investor that aims to maximize its congestion rents. As a novelty, we included investment and operation of long- (hydro) and short- (BESS) term storage systems.

This model allows us to answer questions on a wide range of policy issues: in our first set of research questions, we raised some doubts about how much the ideal generation capacity investment, assumed by an optimistic TSO in a cost-minimizing approach, differs from reality (because of strategic interactions between GENCOs), as well as what portion of the cost of sub-optimal transmission expansion planning is due to overly optimistic generation capacity expansion assumptions. To tackle these questions, we proposed a measure to evaluate the welfare loss of planning the system under the overly-simplistic view of a cost-minimizing, vertically-integrated utility instead of a more realistic proactive framework that recognizes the possible strategic feedback (coming from GENCOs operation and investment decisions). We concluded that, if transmission planners disregard strategic market feedback, there is a high chance that they will incur a non-negligible welfare loss. Progressing into our second set of research questions, we asked ourselves whether it is always desirable to count on a centralized TSO or if it can be beneficial to rely on a merchant transmission investor to undertake the system planning. We found that in some cases, a merchant investor (that follows a congestion-rent maximization) can lead to the same welfare loss as disregarding strategic market feedback. Most importantly, this sub-optimal planning output also leads to a significant distortion of the optimal generation mix. This distortion can result in an over/under-investment, depending on the system characteristics. Additionally, this sub-optimal generation mix can affect the robustness of the system, in terms of the responsiveness to intermittent resource availability.

Our third set of questions addressed the effect of storage systems on system planning, and whether it varies with imperfect competition or not. To answer these questions, we evaluated the policy implications of planning the system under different objectives: those of a social planner (maximizing welfare) and those of a merchant investor (maximizing congestion rents). We tested such planning objectives while considering either Cournot or perfect competition in the market. We concluded that the sub-optimal outputs from merchant investor planning (that maximizes congestion rents) are case-dependent. In particular, the results might suggest that a greenfield approach with BESS penetration is more sensitive to different policy objectives than a brownfield approach, where most of the electrical infrastructure is already in place. Additionally, the system expansion seems to be more sensitive to systems where there is imperfect competition and penetration of BESS.

In future research, we plan to explore those implications by extending the model and including uncertainty in renewable sources. Moreover, alternative RES policy designs could be included in the transmission planner objective function to test more deeply how social welfare can be affected.

Data availability

Dataset related to this article can be found in https://stexem.iit.comillas.edu/en/data/. This webpage hosts all the information related to funding project of this article.

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.eneco.2021.105591.

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APPENDIX

NOTATION

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 units
$t(g) \in T$	Thermal units
$w(g) \in W$	Wind generation
$h(g) \in H$	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' $\in \Gamma_{rp,p}$
$k \in K$	discretization steps

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	€
$pInvC_g$	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]
$pInfl_{yphsd}$	Energy inflows for year *y* period *p* storage *hs* at node d	MWh
$pMaxLevel_h$	Max reservoir level of storage unit *h*	MW
$pMinLevel_h$	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
TC	Total Costs	€
LI	Line Investment Costs	€
GI	Generation Investment Costs	€
OC	Operation Cost	€
UD	Utility of the Demand	€
$\Delta Flows_{ypdd'}$	Flow step magnitude in year y at period p from node *d* to *d'*	MW

Variables

$vProd_{ypgd}$	Production at year y period p of generator g at node d	MW
$vWind_{ywgd}$	Wind production at year y period p of wind generator w at node d	MW
$vNewGen_{ygd}$	Investment status at year y of generation unit g at node d	MW
$vNewLine_{ydd'}$	Investment status at year y of line connecting node d to d'	{0,1}/MW
$vFlow_{ypdd'}$	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
$vConw_{yphd}$	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 period p node d	€/MW
$vBinFlow_{ypdd'k}$	Binary variable for flow in year y period p from node d to d' and step k	{0,1}/MW
$vF\lambda_{ypdd'k}$	Flow times price at year y period p from node d to d' and step k	MW
$vDemand_{ypd}$	Demand at year y period p at d	MW

In this Appendix, we present the formulation of the three expansion problems described and evaluated in the main text. We describe the formulation considering as a backbone the Bilevel Proactive Model (PM), as it includes most of the formulation of the rest of the problems. On the one hand, the Cost Minimization Model (CMM) is a special case of the PM and the Merchant Transmission System Investor (MI) has essentially the same structure of PM but with a different objective function. Therefore in sections I, II, III, we present the main structure of each problem and in section IV, we present the detailed formulation of each one of the blocks that constitute the bi-level proactive model.

I. Benchmark: Cost Minimization Model (CMM)

Traditionally, capacity expansion has been planned from the point of view of a centralized vertically integrated utility. In such a framework, the central planner decides *simultaneously* transmission and generation capacity expansion as well as the market operation by *minimizing* the total system cost.

$$\underset{DV}{\text{Minimize}}\ (OC + LI + GI) \qquad \text{(I.1)}$$

$$DV: \{vNewGen_{ygd}, vNewLineydd', vProd_{ypgd}, vWind_{ypwd}, vCon_{yphd}, vSpill_{yphd}, vLevel_{yphd}\ \}$$

Additionally, the central planner assumes perfect competition, inelastic demand, and perfect information. Therefore the formulation of the central planner would be given by the following equations:

Objective Function (I.1), (A.4)(A.2) - (A.6)
Subject to:

Operation Equations	(B.6)-(B.18)
Energy Balance Equation	(I.2)

Energy balance equation considering inelastic demand:

$$\sum_{g \epsilon GAD} vProd_{ypgd} + \sum_{g \epsilon GAD} vWind_{ypwd} + \sum_{d' \epsilon LA} vFlows_{ypdd'} - \sum_{d' \epsilon LA} vFlows_{ypd'd} : + \sum_{h \epsilon GAD} \frac{vCon_{yphd}}{pEfficiency_h} = pDemand_{ypd} \quad : \lambda_{ypd} \ \forall y, p, d \tag{I.2}$$

II. Bi-level Proactive Model (PM)

In this section, we present the proactive GEPTEP co-planning problem by means of a bi-level equilibrium model. 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 with its equivalent KKT conditions, and then by linearizing the resulting non-linearities.

We present the proactive framework in which a social planner TSO - which can be understood as an entity where both TSO and regulator are considered together - (from now on TSO) proposes investments and GENCOs react to its decisions. Figure 5 in Section 2 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 and consumers decide the level of energy they demand.

The complete problem is therefore composed of the following equations

Objective Function	(A.1)-(A.6)
Subject to:	
Primal feasibility conditions	(B.3)-(B.26)
Dual feasibility conditions	(C.4)-(C.9)
Linearized complementary slackness conditions	(D.1)-(D.15)

III. Bi-level Problem: Merchant Transmission System Investor

Finally, we consider a merchant transmission investor (contrary to a typically centralized regulated entity) that recovers its investment directly from the market operation. We consider that those market incomes are derived from the network congestion rents, which are computed as the price difference between two connected nodes times the flow through the corresponding connecting line.

$$arg \underset{vNewLine_{ydd'}}{\text{Maximize}} \sum_{y,p,d} pW_{rp} * vFlows_{ypdd' \in LA} * (\lambda_{ypd'} - \lambda_{ypd}) \quad \text{(III.1)}$$
$$- \sum_{ydd' \in LC} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right)$$

The complete formulation of this problem is similar to the PM model adding the constraints for linearization of the congestions rents.

Objective Function	(III.1)
Subject to:	
Primal feasibility conditions	(B.3)-(B.26)
Dual feasibility conditions	(C.4)-(C.9)
Linearized complementary slackness conditions	(D.1)-(D.15)
Linearized congestion rents	(F.1)-(F.6)

IV. Formulation Blocks

In this section, we develop each one of the formulation blocks that set up the generation and transmission expansion planning problems presented in sections I, II, and III.

A. Upper Level: TEP

The social planner TSO aims at maximizing the total expected welfare, computed as the Utility of the Demand (UD) minus total costs. Total Costs (TC) are composed of Line Investment Costs (LI), Generation Investment Costs (GI), and Operation Costs (OC). Therefore, the actual objective function would be given by (A.1). Note that we do not allow for de-investment as imposed by equations (A.4) and (A.5). Equation (A.2) represents the utility of demand resulting from the area under the demand curve.

$$\underset{vNewLineydd'}{\text{Maximize}} \; UD - (OC + LI + GI) \quad \textit{(A.1)}$$

Subject to (A.2) - (A.6), and Lower Level equilibrium

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

$$OC: = \sum_{y,(p,rp) \in \Gamma_{rp,p,t,d}} pW_{rp} * pFCost_t * vProd_{yptd} \quad \textit{(A.3)}$$

$$LI := \sum_{ydd'} (Y - y + 1) * pInvL_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \quad (A.4)$$

$$GI: = \sum_{gyd} (Y - y + 1) * pInvC_g \ * \left(vNewGen_{ygd} - vNewGen_{y-1,gd}\right) \quad (A.5)$$

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

B. 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 maximize congestions rents (deciding power flows and voltage angles). The consumers, GENCOs and SO's optimization problems are linked by the market-clearing condition (B.26). This market structure (see the market-responsive framework in Section 2.3.2 implies that GENCOs do not anticipate market outcomes in their expansion decisions. 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 [37]. 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 [38]. Additionally, we assume that there is only one GENCO per node, but we might have several generation units per GENCO.

Moreover, in the formulation of the market model we use enhanced representative days [28] 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 [28] and upon which we comment briefly later on. From now on, each equation is defined for $p \in \Gamma_{rp,p}$.(except (B.18)). Please note that $\Gamma_{rp,p}$ indicates which hours, from the whole year, belong to each representative day.

a) Consumer: Demand Utility maximization

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

$$Max_{vDemand_{ypd}} UD \quad (B.1)$$

Subject to (A.2) and (B.2)

$$vDemand_{y,p,d} \geq 0 \qquad : \iota_{y,p,d} \quad \forall ypd \quad (B.2)$$

b) GENCO: Profit Maximization Problem

$$arg \ \underset{GV}{\text{Maximize}} \ Profit = OI - OC - GI \quad (B.3)$$

Subject to (A.3), (A.5), (B.4)-(B.18).

$$GV: \{vNewGen_{ygd}, vProd_{ypgd}, vWind_{ypwd}, vCon_{yphd}, vSpill_{yphd}, vLevel_{yphd} \ \} \quad (B.4)$$

$$OI: = \sum_{y,p,rp,g,d} pW_{rp} * (\lambda_{ywpd}) * (vProd_{ypgd \in GAD} - vCon_{yphd \in GAD}) \quad (B.5)$$

$$0 \le vProd_{ypgd} \le pMaxProd_g \quad : \bar{\rho}_{ypgd},\ \underline{\rho}_{ypgd} \quad \forall yp, \forall gd \in GED \quad \text{(B.6)}$$

$$0 \le\ vProd_{ypgd} \le pMaxProd_g * vNewGen_{ywd} \quad : \bar{\omega}_{ypgd},\ \underline{\omega}_{ypgd} \quad \forall yp, \forall gd \in GCD \quad \text{(B.7)}$$

$$0 \le vWind_{ypwd} \le pMaxWind_{pwd} \quad : \overline{\rho w}_{ypwd}, \underline{\rho w}_{ypwd} \quad \forall yp, \forall wd \in GED \quad \text{(B.8)}$$

$$0 \le vWind_{ypwd} \le pMaxWind_{pwd} * vNewGen_{ywd} \quad : \overline{\omega w}_{ypwd}, \underline{\omega w}_{ypwd} \quad \forall yp, \forall wd \in GCD \quad \text{(B.9)}$$

$$pMinLevel_h \le vLevel_{yphd} \le pMaxLevel_h \quad : \overline{\mu e}_{yphd}, \underline{\mu e}_{yphd} \quad \forall yp, \forall hd \in GED \quad \text{(B.10)}$$

$$0 \le vLevel_{yphd} \le pMaxLevel_h * vNewGen_{yhd} \quad : \overline{\mu c}_{yphd}, \underline{\mu c}_{yphd} \quad \forall yp, \forall hd \in GCD \quad \text{(B.11)}$$

$$0 \le \frac{vCon_{yphd}}{pEfficiency_h} \le pMaxCons_h \quad : \overline{\kappa e}_{yphd}, \underline{\kappa e}_{yphd} \quad \forall yp, \forall hd \in GED \quad \text{(B.12)}$$

$$0 \le \frac{vCon_{yphd}}{pEfficiency_h} \le pMaxLevel_h * ETD * vNewGen_{yhd} \quad : \overline{\kappa c}_{yphd}, \underline{\kappa c}_{yphd} \quad \forall yp, \forall hd \in GCD \quad \text{(B.13)}$$

$$-vNewGen_{y-1,gd} + vNewGen_{ygd} \ge 0 \quad : \underline{\beta G}_{ygd} \quad \forall y, \forall gd \in GCD \quad \text{(B.14)}$$

$$0 \ge -vNewGen_{ygd}; 0 \le MaxGen_g - vNewGen_{ygd} \quad : \bar{o}_{ygd}, \underline{o}_{ygd} \quad \forall y, \forall gd \in GCD \quad \text{(B.15)}$$

$$0 \le vSpill_{yphd} \quad : \varepsilon_{yphd} \quad \forall yp, \forall hd \in GAD \quad \text{(B.16)}$$

$$vLevel_{yph_fd} = vLevel_{y,p-1,hf,d} + pIniLevel_{y=1,p=1,hf,d} - vProd_{yph_fd} + vCon_{yph_fd} \quad : \psi_{yphd} \quad \forall h_f d \in GAD, \forall yp, p < pf \quad \text{(B.17)}$$

$$vLevel_{ywphsd} = vLevel_{y,w,p-M,hs,d} + pIniLevel_{y=1,p=1,hs,d} + \sum_{p'}^{p} \sum_{p''} \left(pInfl_{ywp''hsd} - vSpill_{ywp''hsd} - vProd_{ywp''hsd} + vCon_{ywp''hsd}\right) \quad : \psi'_{yphd} \quad \forall hs, d \in GAD, \forall yp, p < pf \quad \text{(B.18)}$$

$$with\ p` = p - M + 1\ and\ p \in Ps, p'' \in H(p', p'')\ \ Ps = \left\{ps \middle| \frac{ps}{M} \in Z^+\right\}$$

Equation (B.5) represents operational incomes of GENCOs, equations (B.6), (B.8), (B.10), and (B.12) represent upper and lower bounds of the existing elements of the system. While equations (B.7), (B.9), (B.11), and (B.13) represent the lower and upper bounds of the candidate generation investments in the system. Equation (B.14) avoids de-investments and (B.15) defines the non-negativity of new generation and maximum investment where applicable. Finally, equations (B.17) and (B.18) represent the storage balance conditions as proposed in [28].

On the one hand, equation (B.18) 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 the 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 (B.17) is considered to represent short-term storage when the 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 [28], 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 B.1. 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).

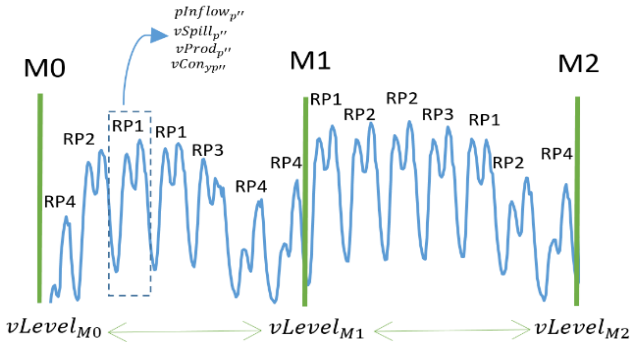

Figure B.1: Intraday Energy Balance

c) System Operator (SO)

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

$$arg \underset{vFlows_{ypdd'}, vTheta_{ypd}}{\text{Maximize}} \; CongestionRents = \sum_{y,p,d} (\lambda_{ypd} - \lambda_{ypd'}) * vFlows_{ypd'd} \tag{B.19}$$

Subject to (B.20)-(B.25), where

$$pMaxFlow_{dd'} \geq vFlow_{ypdd'} \geq -pMaxFlow_{dd'} \quad : \bar{\phi}_{ypdd'}, \underline{\phi}_{ypdd'} \forall yp, \forall (d,d') \in LE \tag{B.20}$$

$$vFlow_{ypdd'} = pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} \quad : \phi_{ypdd'} \quad \forall yp, \forall (d,d') \in LE \tag{B.21}$$

$$vFlow_{ypdd'} \geq -pMaxFlow_{dd'} * vNewLine_{ywdd'} \quad : \underline{\zeta}_{ypdd'} \quad \forall yp, \forall (d,d') \in LC \tag{B.22}$$

$$-vFlow_{ypdd'} \geq -(pMaxFlow_{dd'} * vNewLine_{ydd'}) \quad : \bar{\zeta}_{ypdd'} \quad \forall yp, \forall (d,d') \in LC \tag{B.23}$$

$$-vFlow_{ypdd'} \geq -pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} - pMaxFlow_{dd'}(1 - vNewLine_{ydd'}) \quad : \bar{\tau}_{ypdd'} \quad \forall yp, \forall (d,d') \in LC \tag{B.24}$$

$$vFlow_{ypdd'} \geq \left(pSB * \frac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} - pMaxFlow_{dd'}(1 - vNewLine_{ydd'}) \right) \quad : \underline{\tau}_{ypdd'} \quad \forall yp, \forall (d,d') \in LC \tag{B.25}$$

Equations *(B.21)* and *(B.22)* represent the DC formulation of the network for existing lines, while equations *(B.23)* - *(B.25)* represent the DC power flow formulations for new lines.

d) Market Clearing (MC)

$$\sum_{g\epsilon GAD} vProd_{ypgd} + \sum_{g\epsilon GAD} vWind_{ypwd} + \sum_{d'\epsilon LA} vFlows_{ypdd'} - \sum_{d'\epsilon LA} vFlows_{ypd'd} : + \sum_{h\epsilon GAD} \frac{vCon_{yphd}}{pEfficiency_h} = vDemand_{ypd} \quad (B.26)$$
$$: \lambda_{ypd}\ \forall y, p, d$$

The simultaneous consideration of the GENCOs, Consumers, SO, and the market-clearing condition represent the wholesale market for the case of perfect and imperfect competition (depending on the conjectural variation described in 2.3.2).

C. Lower Level: KKT Conditions

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

- Primal feasibility conditions. GENCOs: (B.4)-(B.18) SO: (B.19) - (B.25) MC:(B.26)
- Dual feasibility conditions. GENCOs/MC: (C.4)-(C.9) SO: (C.1) - (C.3)
- Complementary slackness conditions

Dual feasibility conditions: (Each equation is defined for $p \in \Gamma_{rp,p}$, except for equations (C.1) to (C.9).

$$\lambda_{ypd'} - \lambda_{ypd} + \underline{\phi}_{ypdd'\epsilon LE(d,d')} - \bar{\phi}_{ypdd'\epsilon LE(d,d')} + \phi_{ypdd'\epsilon LE(d,d')} + \underline{\zeta}_{ypdd'\epsilon LC(d,d')} - \bar{\zeta}_{ypdd'\epsilon LC(d,d')} + \bar{\tau}_{ypdd'\epsilon LC(d,d')} - \underline{\tau}_{ypdd'\epsilon LC(d,d')} = 0 \quad (C.1)$$
$$: vFlows_{ypdd'} \quad \forall ypdd'\ LA$$

$$\sum_{d\in LE(d,d')} \frac{pSB}{pReactance_{dd'}} * \phi_{ypdd'} - \sum_{d'\in LE(d,d')} \frac{pSB}{pReactance_{d'd}} * \phi_{ypd'd} + \sum_{d\in LC(d,d')} \frac{pSB}{pReactance_{dd'}} * \bar{\tau}_{ypdd'} - \sum_{d'\in LC(d,d')} \frac{pSB}{pReactance_{dd'}} * \underline{\tau}_{ypd'd} - \sum_{d'\in LC(d',d)} \frac{pSB}{pReactance_{d'd}} * \bar{\tau}_{ypd'd} + \sum_{d\in LC(d,d')} \frac{pSB}{pReactance_{d'd}} * \underline{\tau}_{ypdd'} = 0 \quad (C.2)$$
$$: vTheta_{ypd}, \quad \forall ypd$$

$$\sum_{gyd} (Y - y + 1) * pInvC_g + \sum_{gyd} (Y - y) * pInvC_g + pMaxProd_g * \bar{\omega}_{ypgd} + pMaxWind_{pgd} * \overline{\omega W}_{ypgd} + pMaxLevel_h * \bar{\mu c}_{ywphd} + pMaxLevel_h * ETD * \bar{\kappa c}_{yphd} + \underline{\beta G}_{ygd} - \underline{\beta G}_{y+1,gd} - \bar{o}_{ygd} + \underline{o}_{ygd} = 0 \quad (C.3)$$
$$: vNewGen_{ygd} \quad \forall ygd \in GCD$$

$$-vDemand_{ypd} + pDemand_d - pDSlope * vProd_{ypgd} + \iota_{y,p,d} = 0 \quad (C.4)$$
$$: vDemand_{ypd} \quad \forall ygd \in GAD$$

$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p},} pW_{rp} * (-FuelCost_t + vProd_{ypgd} * \frac{\partial \lambda_{ypd\epsilon(GAD)}}{\partial vProd_{ypgd}}) \right) + \lambda_{ypd\epsilon(GAD)} - \bar{\rho}_{ypgd\epsilon(GED)} + \underline{\rho}_{ypgd\epsilon(GED)} - \bar{\omega}_{ypgd\epsilon(GCD)} + \underline{\omega}_{ypgd\epsilon(GED)} + \sum_{p''}^{p'} (\psi_{yph}) = 0 \quad (C.5)$$
$$: vProd_{ypgd} \quad \forall y, g, d \in (GED)\ \forall p' \in H(p', p) \,/\, \ p \in Pa,\ p' \in Ps$$

$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p}} pW_{rp} * \left(vWind_{ypwd} * \frac{\partial\lambda_{ypd\in(GAD)}}{\partial vWind_{ypwd}}\right)\right) + \lambda_{ypd\in(GAD)} - \overline{\rho w}_{ypwd\in(GED)} + \underline{\rho w}_{ypwd\in(GED)} - \overline{\omega w}_{ypwd\in(GCD)} + \underline{\omega w}_{ypwd\in(GED)} + \sum_{p''}^{p'}(\psi_{yph}) = 0 \quad (C.6)$$
$$: vWind_{ypwd} \quad \forall y, g, d \in (GED)\ \forall p' \in H(p', p) \,/\, p \in Pa,\ p' \in Ps$$

$$\left(\sum_{y,(p,rp)\in\Gamma_{rp,p,}} pW_{rp} * (-FuelCost_t + (vProd_{yphd} - vCon_{yphd}) * \frac{\partial\lambda_{ypd\in(GAD)}}{\partial vProd_{ypgd}})\right) + \bar{\kappa}_{yphd} \quad (C.7)$$
$$- \underline{\kappa}_{ygphd} + \psi_{yph_fd} + \sum_{p''}^{p'}\left(\psi'_{yphd}\right) = 0$$
$$: vCon_{yphd} \quad \forall p' \in H(p', p), p \in Pa,\ p' \in Ps, \forall y, hd \in (GED)$$

$$-\overline{\mu}_{yphd} + \underline{\mu}_{yphd} + \sum_{p''}^{p'} \psi_{ywphd} = 0$$
$$: vSpill_{yphd} \quad \forall p' \in H(p', p)\ \ p \in Pa,\ p' \in Ps, \forall y, hd \in (GED) \quad (C.8)$$

$$-\overline{\mu e}_{yphd} + \underline{\mu e}_{yphd} - \overline{\mu c}_{yphd} + \underline{\mu c}_{yphd} + \psi_{yp\in Pa,h_fd} + \psi_{y,p+1\in Pa,h_fd} + \psi'_{yp\in Ps,hd} \quad (C.9)$$
$$- \psi'_{y,p+M|p\in Ps,hd} = 0$$
$$: vLevel_{yphd} \qquad \forall p \in Pt, \forall yhd \in GED$$

For equations *(C.9)* we define $Pa = \{p|p \in \Gamma_{rp,p}\}, Ps = \left\{ps|\frac{ps}{M} \in Z^+\right\},\ and\ Pt = Ps \cup Pa$

D. Linearized Complementarity conditions.

Each set of equations corresponds to the linearization of a complementarity condition. Please note that equality constraints do not need a complementarity condition. We denote $\overline{Mdual}, \underline{Mdual}$ as the 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. Additionally, we implement a regularization method to compute Big Ms as proposed in [30].

$$\begin{gathered} vProd_{ypgd} \le \underline{M\rho} * \underline{Y\rho}_{ypgd} \\ \underline{\rho}_{ypgd} \le \underline{M\rho} * \left(1 - \underline{Y\rho}_{ypgd}\right) \\ vProd_{ypgd} - pMaxProd_g \le \overline{M\rho} * \overline{Y\rho}_{ypgd} \\ 0 \le \bar{\rho}_{ypgd} \le \overline{M\rho} * \overline{Y\rho}_{ypgd} \end{gathered} \quad \begin{gathered} \forall gd \in GED, \\ \forall yp \end{gathered} \quad (D.1)$$

$$\begin{gathered} Wind_{ypwd} \le \underline{M\rho w} * \underline{Y\rho w}_{ypwd} \\ \underline{\rho w}_{ypwd} \le \underline{M\rho w} * \left(1 - \underline{Y\rho w}_{ypgd}\right) \\ \overline{\rho w}_{ypgd} \le \overline{M\rho w} * \overline{Y\rho w}_{ypwd} \\ Wind_{ypwd} - pMaxWind_{wp} \le \overline{M\rho w} * \overline{Y\rho}_{ypwd} \end{gathered} \quad \begin{gathered} \forall wd \in GED, \\ \forall yp \end{gathered} \quad (D.2)$$

$$\begin{gathered} 0 \le vProd_{ypgd} \le \underline{M\omega} * \underline{Y\omega}_{ypgd} \\ 0 \le \underline{\omega}_{ypgd} \le \underline{M\omega} * (1 - \underline{Y\omega}_{ypgd}) \\ vProd_{ypgd} - pMaxProd_g * vNewGen_{ygd} \le \overline{M\omega} * \overline{Y\omega}_{ypgd} \\ \bar{\omega}_{ypgd} \le \overline{M\omega} * \overline{Y\omega}_{ypgd} \end{gathered} \quad \begin{gathered} \forall gd \in GCD, \\ \forall yp \end{gathered} \quad (D.3)$$

$$vWind_{ypwd} - pMaxWind_{pwd} * vNewGen_{ywd} \leq \underline{M\omega w} * \underline{Y\omega w}_{ypwd}$$
$$\underline{\omega w}_{ypwd} \leq \underline{M\rho w} * \left(1 - \underline{Y\omega w}_{ypwd}\right)$$
$$\overline{\rho w}_{ypgd} \leq \overline{M\rho w} * \overline{Y\rho w}_{ypgd}$$
$$Wind_{ypwd} - pMaxWind_{wp} \leq \overline{M\rho w} * \overline{Y\rho}_{ypwd}$$
$\forall wd \in GCD$ $\forall$yp (D.4)

$$pMinLevel_h - vLevel_{yphd} \leq \underline{M\mu e} * \underline{Y\mu e}_{yphd}$$
$$\underline{\mu e}_{yph} \leq \underline{M\mu e} * (1 - \underline{Y\mu e}_{yphd})$$
$$vLevel_{yphd} - pMaxLevel_h \leq \overline{M\mu e} * \overline{Y\mu}_{yphd}$$
$$\overline{\mu e}_{yph} \leq \overline{M\mu} * (1 - \overline{Y\mu}_{yphd})$$
$\forall gd \in GED,$ $\forall yp$ (D.5)

$$pMinLevel_h \leq \underline{M\mu c} * \underline{Y\mu c}_{yphd}$$
$$\underline{\mu c}_{yph} \leq \underline{M\mu c} * (1 - \underline{Y\mu c}_{yphd})$$
$$vLevel_{yphd} - pMaxProd_h * ETD * vNewGen_{yhd} \leq \overline{M\mu c} * \overline{Y\mu}_{yphd}$$
$$\overline{\mu c}_{yph} \leq \overline{M}c * (1 - \overline{Y\mu}_{yphd})$$
$\forall gd \in GCD,$ $\forall yp$ (D.6)

$$\frac{vCon_{yphd}}{pEfficiency_h} \leq \underline{M\kappa e} * \underline{Y\kappa e}_{ypgd}$$
$$\underline{\kappa e}_{yhpd} \leq \underline{M\kappa e} * (1 - \underline{Y\kappa e}_{ypgd})$$
$$\frac{vCon_{yphd}}{pEfficiency_h} - pMaxCons_h \leq \overline{M\kappa e} * \overline{Y\kappa e}_{ypgd}$$
$$\bar{\kappa}_{yhpd} \leq \overline{M\kappa} * (1 - \overline{Y\kappa}_{ypgd})$$
$\forall hd \in GED,$ $\forall yp$ (D.7)

$$\frac{vCon_{yphd}}{pEfficiency_h} \leq \underline{M\kappa c} * \underline{Y\kappa c}_{ypgd}$$
$$\underline{\kappa c}_{yhpd} \leq \underline{M\kappa c} * (1 - \underline{Y\kappa c}_{ypgd})$$
$$\frac{vCon_{yphd}}{pEfficiency_h} - pMaxLevel_h * ETD * vNewGen_{yhd} \leq \overline{M\kappa c} * \overline{Y\kappa c}_{ypgd}$$
$$\bar{\kappa}_{yhpd} \leq \overline{M\kappa c} * (1 - \overline{Y\kappa c}_{ypgd})$$
$\forall gd \in GCD,$ $\forall yp$ (D.8)

$$-vNewGen_{y-1,gd} - vNewGen_{ygd} \leq \underline{M\beta G} * \underline{Y\beta G}_{ygd}$$
$$\underline{\beta G}_{ygd} \leq \underline{M\beta G} * (1 - \underline{Y\beta G}_{ygd})$$
$\forall gd \in GCD,$ $\forall yp$ (D.9)

$$vNewGen_{ygd} \leq \underline{Mo} * \underline{Yo}_{ygd}$$
$$\bar{o}_{ygd} \leq \underline{Mo} * (1 - \underline{Yo}_{ygd})$$
$$MaxGen_g - vNewGen_{ygd} \leq \underline{Mo} * \underline{Yo}_{ygd}$$
$$\bar{o}_{ygd} \leq \overline{Mo} * (1 - \overline{Yo}_{ygd})$$
$\forall gd \in GCD,$ $\forall yp$ (D.10)

$$-vFlows_{ypdd'} + pMaxFlows_{dd'} \leq \underline{M\phi} * \underline{Y\phi}_{ypdd'}$$
$$\underline{\phi}_{ypdd'} \leq \underline{M\phi} * (1 - \underline{Y\phi}_{ypdd'})$$
$$-vFlows_{ypdd'} - pMaxFlows_{dd'} \leq \overline{M\phi} * \overline{Y\phi}_{ypdd'}$$
$$-vFlows_{ypdd'} - pMaxFlows_{dd'} \leq \overline{M\phi} * (1 - \overline{Y\phi}_{ypdd'})$$
$\forall (d, d') \in LE,$ $\forall yp$ (D.11)

$$vFlows_{ypdd'} + pMaxFlows_{dd'} * vNewLine_{ydd'} \leq \underline{M\zeta} * \underline{Y\zeta}_{ypdd'}$$
$$\underline{\zeta}_{ypdd'} \leq \underline{M\zeta} * (1 - \underline{Y\zeta}_{ypdd'})$$
$\forall (d, d') \in LC,$ $\forall yp$ (D.12)

$$-vFlows_{ypdd'} + \left(pMaxFlows_{dd'} * vNewLine_{ydd'} \right) \leq \overline{M\zeta} * \overline{Y\zeta}_{ypdd'}$$
$$\bar{\zeta}_{ypdd'} \leq \overline{M\zeta} * (1 - \overline{Y\zeta}_{ypdd'})$$
$\forall (d, d') \in LC,$ $\forall yp$ (D.13)

$$-vFlows_{ypdd'} + \begin{pmatrix} pSB * \dfrac{vTheta_{ypd} - vThetha_{ypd'}}{pReactance_{dd'}} \\ +pMaxFlows_{dd'}(-1 + vNewLine_{ydd'}) \end{pmatrix} \leq \overline{M\tau} * \overline{Y\tau}_{ypdd'}$$
$$\bar{\tau}_{ypdd'} \leq \overline{M\tau} * (1 - \overline{Y\tau}_{ypdd'})$$
$\forall (d, d') \in LC,$ $\forall yp$ (D.14)

$$vFlows_{ypdd'} + \begin{pmatrix} -pSB * \dfrac{vTheta_{ypdd'} - vThetha_{ypdd'}}{pReactance_{dd'}} \\ -pMaxFlows_{dd'}(1 - vNewLine_{ydd'}) \end{pmatrix} \quad \forall (d, d') \in LC, \quad \text{(D.15)}$$
$$\leq \underline{M\tau} * \underline{Y\tau}_{ypdd'} \quad \forall yp$$
$$\underline{\tau}_{ypdd'} \leq \underline{M\tau} * (1 - \underline{Y\tau}_{ypdd'})$$

E. Equivalent one-level MIP

After taking the KKT conditions of the lower level and linearizing the complementarity conditions we end up with a MIP problem that can be solved by commercial software. This complete problem is therefore composed of the following equations

Objective Function	(A.1)
Subject to:	
Primal feasibility conditions	(B.3)-(B.26)
Dual feasibility conditions	(C.4)-(C.9)
Linearized complementary slackness conditions	(D.1)-(D.15)

F. Linearization for congestions rents

Finally, for illustration purposes, we demonstrate how to linearize the $vFlows_{ypdd'} * \lambda_{ypd'}$ term for the Bi-level Problem: Merchant Transmission System Investor. We start by discretizing the variable $vFlows$, by applying a binary expansion like the one proposed in (Pereira et al., 2005). Equation (F.1) reconstructs $vFlows$ by starting from the lower bound and adding some slices until the upper bound of $vFlows$ is achieved.

$$vFlows_{ypdd'} = -pMaxFlows_{dd'} + \Delta Flows_{ypdd'} * \sum_{k} 2^k * vBinFlow_{ypdd'k} \quad \text{(F.1)}$$

Where $vBinFlow_{ypdd'k}$ is a binary variable and $\Delta Flows_{ypdd'}$ is the step magnitude in which we divide the variable $vFlows_{ypdd'}$, which is given by (F.2)

$$\Delta Flows_{ypdd'} = \left| -pMaxFlows_{ypdd'} - pMaxFlows_{ypdd'} \right| / 2^K \quad \text{(F.2)}$$

Let us define the binary expansion of $vFlows_{ypdd'} * \lambda_{ypd'}$ in equation (F.3).

$$vFlows_{ypdd'} * \lambda_{ypd'} = -pMaxFlows_{dd'} * \lambda_{ypd'} + \Delta Flows_{ypdd'} * \sum_{k} 2^k * vBinFlow_{ypdd'k} * \lambda_{ypd'}. \quad \text{(F.3)}$$

Given that the nonlinear term $vBinFlow_{ypdd'k} * \lambda_{ypd' \in (GAD)}$ is the product of a binary variable and a continuous variable, we can linearize it by renaming the product $vF\lambda_{ypdd'k} = vBinFlow_{ypdd'k} * \lambda_{ypd'}$ and adding the two following equivalent equations:

$$0 \leq \lambda_{ypd' \in (GAD)} - vF\lambda_{ypdd'k} \leq \overline{\lambda} * (1 - vBinFlow_{ypdd'k}) \quad \text{(F.4)}$$

$$0 \leq vF\lambda_{ypdd'k} \leq \overline{\lambda} * (vBinFlow_{ypdd'k}) \quad \text{(F.5)}$$

Please note that we assume that prices are non-negative and therefore $\underline{\lambda}$ is zero.

Thus, we re-formulate the complete problem as follows:

$$\arg\underset{vF\lambda_{ypdd'k}}{\text{Maximize}} \sum_{y,p,d,k} pW_{rp} * (vF\lambda_{ypdd'k} - vF\lambda_{ypd'dk}) - \sum_{ydd' \in LC} (Y - y + 1) * pInvC_{dd'} * \left(vNewLine_{ydd'} - vNewLine_{y-1,dd'}\right) \quad \text{(F.6)}$$

$$Subject\ to: Equations\ (\text{F.1}) - (\text{F.5})\ and\ Lower\ Level\ Problem$$

It is important to note that -as with every linearization technique- the result depends on the steps considered by the discretization. Therefore, the bigger k, the smaller is the step size, and hence, the closer the solution would be to the global optimum.

V. Storage Representation

This section will intuitively present the representative days' approach for storage modelling. Let us keep in mind that the main concern with storage modelling, when time granularity is simplified, is the tradeoff between misrepresentation of intra-day constraints and misrepresentation of inter-day constraints. With the representative period approach presented here, we intend to achieve a good enough representation of both types of constraints.

As an example, let us consider two weeks of the year, W1 and W2, as shown in Figure 6, and let us represent these weeks by choosing (employing a clustering technique) 4 representatives days, simplifying the actual 14 days of both weeks, that represent well-enough the two weeks considered.

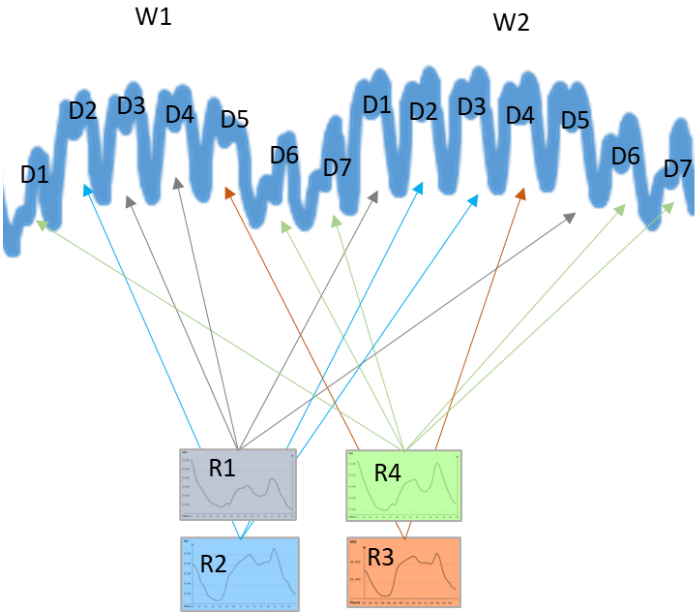

Figure 6: Representative Days Correspondance

In principle, a representative day approach will characterize intra-day operation properly as it considers each one of the 24 hours within a day. Let us show the logic behind the method on how to represent storage balance as depicted in Figure 7.

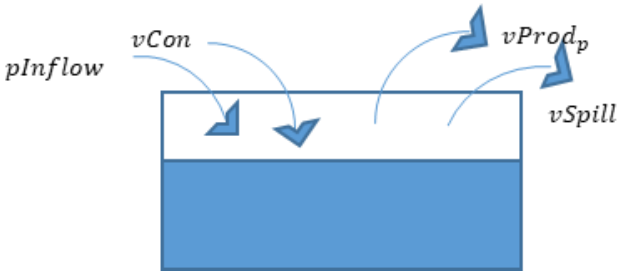

Figure 7: Storage Balance

A balance equation states that the level of a reservoir (either a dam or a battery) is equal to the level at the period (hour) before, plus the natural inflows and consumption (charge) in the current period minus the production (discharge) and the spillage in the current period. When using representative days, the following equation fully represents the intra-day functioning of charging and discharging of BESS.

$$vLevel_p = vLevel_{p-1} + pInflow_p - vProd_p + vCon_p - vSpill_p \forall p, \qquad (V.1)$$

However, inter-day constraints can be misrepresented. To solve this issue, we use the information obtained when creating the representative day, namely the correspondence of each actual day of the week to each representative day, as shown in Figure 6. For a hydro reservoir (whose balance is weekly or monthly), a complete representation of the balance equations in those weeks will include the inflows, consumption, production and spillage at every hour of the 7 days of each week. However, given that we consider only 4 representative days, we will represent the production, consumption and spillage only for each hour of the 4 representative days (reducing the number of variables).

In particular, As shown in the Figure 6 we have the information on which representative day represents each actual day. The RP1 represents D5 of W1 and D4 and D5 of W2, and similarly for the rest of the representative days.

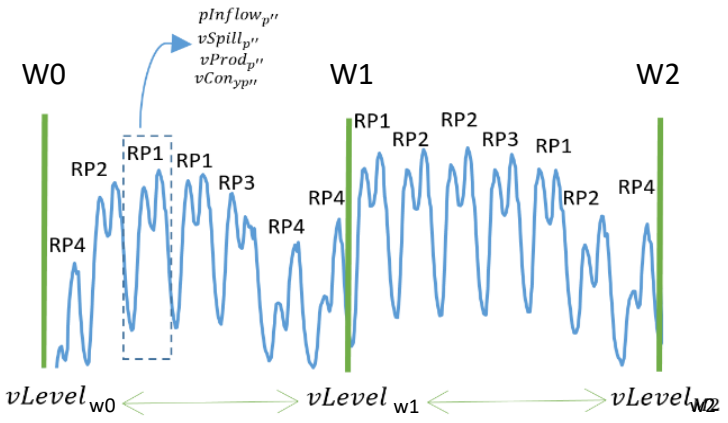

Figure 8: Representative's Day Representation for Balance Equations

As shown in the Figure 8, we have an approximation of the inflows, spillage, production and consumption in W1 by adding those variables for each one of the representative days corresponding to W1.

$$vLevel_p = vLevel_{p-W} + \sum_{p'}^{p} \sum_{p''} (pInflow_{p''} - vProd_{p''} + vCon_{p''} - vSpill_{p''})$$

As a summary, we see that with such approach, we have the information to represent the intraday equations because we have the hourly data of the representative days, and on the other hand, we can have an approximation to inter-day equations by using the correspondence between the representative days and the actual days of the year.