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Investment planning for flexibility sources and transmission lines in the presence of renewable generation

Dina Khastieva

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Contents

Abstract

- Title: Investment planning for flexibility sources and transmission lines in the presence of renewable generation
- Language: English
- Author: Dina Khastieva
- Division of Electric Power and Energy Systems, EECS school, KTH Royal Institute of Technology

Environmental and political factors determine long-term development for renewable generation around the world. The rapid growth of renewable generation requires timely changes in power systems operation planning, investments in additional flexible assets and transmission capacity.

The development trends of restructured power systems suggest that the current tools and methodologies used for investment planning are lacking the coordination between transmission and flexibility sources. Moreover, a comprehensive analysis is required for efficient investment decisions in new flexibility sources or transmission assets. However, literature does not provide an efficient modeling tool that will allow such a comprehensive analysis.

This dissertation proposes mathematical modeling tools as well as solution methodologies to support efficient and coordinated investment planning in power systems with renewable generation. The mathematical modeling tools can be characterised as large scale, stochastic, disjunctive, nonlinear optimization problems. Corresponding solution methodologies are based on combination of linearization and reformulation techniques as well as tailored decomposition algorithms. Proposed mathematical tools and solution methodologies are then used to provide an analysis of transmission investment planning, energy storage investments planning as well as coordinated investment planning. The analysis shows that to achieve socially optimal outcome transmission investments should be regulated. Also, the results of the simulations show that coordinated investment planning of transmission, energy storage and renewable generation will result in much higher investments in

renewable generation as well as more efficient operation of renewable generation plants. Consequently, coordinated investment planning with regulated transmission investments results in the highest social welfare outcome.

Sammanfattning

- Title: Investment planning for flexibility sources and transmission lines in the presence of renewable generation
- Language: Swedish
- Author: Dina Khastieva
- Division of Electric Power and Energy Systems, EECS school, KTH Royal Institute of Technology

Miljöfrågor och politiska faktorer styr den långsiktiga utvecklingen för förnybar elproduktion runtom i världen. Den snabba ökningen av förnybar elproduktin kräver att drift och planering av elsystem ändras i god tid, investeringar i ytterligare flexibla resurser och ytterligare transmissionskapacitet.

Utvecklingstrenderna för omstrukturerade elsystem antyder att de nuvarande verktygen och metoderna för investeringsplanering saknar koordinering mellan transmission och flexibla resurser. Dessutom krävs en omfattande analys för investeringsbeslut i flexibla resurser eller transmissionssystem. Det finns dock inte i litteraturen en effektiv modell som möljliggör en sådan omfattande analys.

Den här avhandlingen föreslår matematiska modelleringsverktyg såväl som lösningsmetoder för att stödja effektiv och koordinerad investeringsplanering i elsystem med förnybar elproduktion. De föreslagna matematiska verktygen och lösningsmetoderna används sedan för att tillhandahålla en analys av investeringsplanering för transmissionssystem respektive energilager samt koordinerad investeringsplanering. De matematiska modellerna kan beskrivas som storskaliga, stokastiska, disjunktiva, icke-linjära optimseringsproblem. Lösningsmetoderna för dessa problem är baserade på en kombination av linjärisering och omformulering samt skräddarsydda dekomponeringsalgoritmer. Analysen visar att för att uppnå maximal samhällsnytta bör investeringar in transmissionssystem vara reglerad. Dessutom visar resultaten från simuleringarna att koordinerad investeringsplanering för transmission,

energilager och förnybar elproduktion kommer att resultera i större investeringar i förnybar elproduktion samt ett mer effektivt utnyttjande av de förnybara kraftverken. Följdaktligen resulterar koordinerad investeringsplanering med reglerade investeringar i transmission ger det bästa utfallet ur samhällsekonomisk synvinkel.

Abstract

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Ecologische en politieke factoren bepalen de lange termijn planning voor duurzame elektriciteitsproductie over de hele wereld. De snelle groei van hernieuwbare productie vereist tijdige veranderingen in de operationele planning van energiesystemen, investeringen in aanvullende ondersteunende flexibele centrales en extra transmissiecapaciteit.

De ontwikkelingstrends van geherstructureerde energiesystemen suggereren dat de huidige tools en methodologieën die worden gebruikt voor investeringsplanning, de coördinatie tussen transmissie- en flexibiliteitsbronnen missen. Bovendien is een uitgebreide analyse vereist voor efficiënte investeringsbeslissingen in nieuwe flexibiliteitsbronnen of transmissiecapaciteit. De literatuur voorziet echter nog niet in een efficiënte modelleertool voor een dergelijke samenhangende analyse.

Dit proefschrift presenteert wiskundige modelleertools voor, evenals oplossingsmethoden ter ondersteuning van efficiënte en gecoördineerde investeringsplanning in energiesystemen met hernieuwbare opwekking. Deze wiskundige tools en oplossingsmethoden worden vervolgens gebruikt om een analyse te geven van de planning van investeringen in transmissiecapaciteit, energieopslag en de gecoördineerde investeringsplanning. Uit de analyse blijkt dat transmissie-investeringen gereguleerd moeten worden om een welvaartsoptimaal resultaat te bereiken. Ook laten de resultaten van de numerieke simulaties zien dat een gecoördineerde investeringsplanning voor transmissie, energieopslag en hernieuwbare opwekking zal leiden tot veel hogere investeringen in hernieuwbare opwekking en in een efficiëntere exploitatie van installaties

voor hernieuwbare opwekking. Bijgevolg resulteert gecoördineerde investeringsplanning met gereguleerde transmissie-investeringen in de hoogste welvaartsuitkomst.

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List of Acronyms

ESS	Energy Storage Systems
BSS	Battery Storage Systems
ISS	Incremental Subsidy Surplus
TSO	Transmission System Operator
ISO	Independent System Operator
SO	System Operator
MO	Market operator
KKT	Karush-Kuhn-Tucker
H-R-G-V	Hesamzadeh-Rosellon-Gabriel-Vogelsang mechanism
H-R-V	Hogan-Rosellon-Vogelsang
MPEC	Mathematical program with equilibrium constraints
LP	Linear problem
MILP	Mixed-integer linear problem
MINLP	Mixed-integer nonlinear problem
NLPEC	Nonlinear disjunctive program with equilibrium constraints
CAES	Compressed air energy storage
JCR	Journal Citation Report
RES	Renewable Energy Sources
NRECA	National Rural Electric Cooperative Association
EENS	Expected Energy Not Served
LOLP	Lost of load probability

List of Symbols

a_{etks} Energy storage charge/discharge indicator;

z_{mt},y_{mt} Transmission investment decision variables;

$I_n^{(d)}$ Incidence matrix element of load d, node n;

$J_n^{(g)}$ Incidence matrix element of generator g, node n;

$R_n^{(l)}$ Incidence matrix element of receiving node n, line l;

$\overline{R}_n^{(m)}$ Incidence matrix element of receiving node n, line m;

$S_n^{(l)}$ Incidence matrix element of sending node n, line l;

$\overline{S}_n^{(m)}$ Incidence matrix element of sending node n, line m;

$W_n^{(w)}$ Incidence matrix element of generator w, node n;

A_d Load d marginal utility;

$C_e^{(ch)}$ Cycling cost of charging energy storage unit e;

$C_e^{(dh)}$ Cycling cost of discharging energy storage unit e;

$C_{et}^{(E)}$ Investment cost of energy storage energy capacity for candidate unit e at period t;

C_g Marginal cost of generator unit g;

$C_{et}^{(P)}$ Investment cost of energy storage power capacity for candidate unit e at period t;

$C_{mt}^{(T)}$ Investment cost of transmission line m at period t;

$C^{(W)}_{wt}$	Investment cost of renewable unit w at period t;
D_d	Maximum capacity of load d at period t;
F_l	Maximum capacity of existing transmission line l;
$\widehat{F}_m$	Maximum capacity of candidate transmission line m;
G_g	Maximum capacity of generator g;
$\widehat{G}_w$	Maximum capacity of renewable generator w;
π_s	Probability of scenario s;
Ψ	Number of operational periods in an investment period;
i_t	Interest rate;
Θ	Maximum voltage angle;
ϱ_{wtks}	Stochastic output of renewable generator w at period t, k, scenario s;
Ξ_m, Ξ	Sufficiently large constants;
X_l	Reactance of existing transmission line l;
X_m	Reactance of candidate transmission line m;
$\underline{\vartheta}_{etks}$	Lagrange multiplier for constraint (4.15c)
$\overline{\vartheta}_{etks}$	Lagrange multiplier for constraint (4.15c)
$\underline{\omega}_{dtks}$	Lagrange multiplier for constraint (4.2p)
$\overline{\omega}_{dtks}$	Lagrange multiplier for constraint (4.2p)
$\underline{\kappa}_{etks}$	Lagrange multiplier for constraint (4.15b)
$\overline{\kappa}_{etks}$	Lagrange multiplier for constraint (4.15b)
σ_{ltks}	Lagrange multiplier for constraint (4.2d)
$\underline{\sigma}_{ltks}$	Lagrange multiplier for constraint (4.2g)
$\overline{\sigma}_{ltks}$	Lagrange multiplier for constraint (4.2g)
$\underline{\nu}_{gtks}$	Lagrange multiplier for constraint (4.2k)
$\overline{\nu}_{gtks}$	Lagrange multiplier for constraint (4.2k)
$\overline{\vartheta}_{htks}$	Lagrange multiplier for constraint (4.2h)
$\underline{\vartheta}_{htks}$	Lagrange multiplier for constraint (4.2h)

$\underline{\rho}_{htks}$	Lagrange multiplier for constraint (4.2j)
ϑ_{et}	Lagrange multiplier for constraint (4.16b)
κ_{et}	Lagrange multiplier for constraint (4.16a)
η_{wt}	Lagrange multiplier for constraint (4.16c)
$\underline{\varrho}_{mtks}$	Lagrange multiplier for constraint (4.19b)
$\underline{\xi}_{mtks}$	Lagrange multiplier for constraint (4.19c)
$\overline{\xi}_{mtks}$	Lagrange multiplier for constraint (4.19c)
$\overline{\varrho}_{mtks}$	Lagrange multiplier for constraint (4.19a)
$\underline{\gamma}_{mtks}$	Lagrange multiplier for constraint (4.10)
$\overline{\gamma}_{mtks}$	Lagrange multiplier for constraint (4.10)
τ_{etks}	Lagrange multiplier for constraint (4.2e)
$\underline{\rho}_{etks}$	Lagrange multiplier for constraint (4.15d)
θ_{htks}	Lagrange multiplier for constraint (4.2f)
$\overline{\theta}_{htks}$	Lagrange multiplier for constraint (4.2i)
$\underline{\theta}_{htks}$	Lagrange multiplier for constraint (4.2i)
$\overline{\rho}_{etks}$	Lagrange multiplier for constraint (4.15d)
$\lambda 0_{ntks}$	Lagrange multiplier for constraint (4.2q)
$\underline{\kappa}_{ftks}$	Lagrange multiplier for constraint (4.15a)
$\overline{\kappa}_{ftks}$	Lagrange multiplier for constraint (4.15a)
λ_{nts}	Lagrange multiplier for constraint (4.2b)
$e \in \mathcal{E}$	Set of energy storages;
$d \in \mathcal{D}$	Set of loads;
$g \in \mathcal{G}$	Set of generators;
$k \in \mathcal{K}$	Set of operation periods;
$l \in \mathcal{L}$	Set of existing lines;
$m \in \mathcal{M}$	Set of candidate lines;
$n \in \mathcal{N}$	Set of nodes;

$h \in \mathcal{H}$ Set of hydro generators;

$s \in \mathcal{S}$ Set of scenarios;

$t \in \mathcal{T}$ Set of investment periods;

$w \in \mathcal{W}$ Set of renewable-energy generators;

$\tilde{d}_{etks}$ Charge of energy storage e at period t, k, scenario s;

d_{dtks} Demand of load d at period t, k, scenario s;

e_{et} Energy capacity of energy storage e at period t;

f_{ltks} Flow of line l at period t, k, scenario s;

$\widehat{f}_{mtks}$ Flow of line m at period t, k,scenario s;

$\tilde{g}_{etks}$ Discharge of energy e at period t, k, scenario s;

g_{gtks} Generation of generator g at period t, k, scenario s;

$\overline{g}_{htks}$ Generation of generator h at period t, k, scenario s;

u_{htks} Inflow of generator h at period t, k, scenario s;

m_{ht-1ks} Reservoir level of generator h at period t, k, scenario s;

s_{htks} Spillage of generator h at period t, k, scenario s;

$\widehat{g}_{wtks}$ Renewable output of unit w at period t, k, scenario s;

p_{et} Power capacity of energy storage e at period t;

Φ_t Fixed fee at period t;

q_{etks} State of charge of energy e at period t, k, scenario s;

θ_{ntks} Voltage angle at node n at period t, k, scenario s;

u_{wt} Investment level in renewable generator w at period t;

Chapter 1

Introduction

Power systems face continuous transition; demand levels are continuously changing; infrastructure is aging, new regulation is being adopted each year; new technologies are developing; prices of fuels and material as well as capital costs of technologies are changing. All these changes and transformations are highly uncertain and, as a result, create challenges for investment planning in the power sector. For example, transmission infrastructure development highly depends on regulation and changing needs of the power system while integration of energy storage technologies depends not only on changing flexibility and storage needs but equally on technology and material development. Investment planning in power systems is especially complicated because it involves decision making in large and expensive assets with long construction time. More importantly, successful investments require a reliable long-term outlook on power system development. A long-term outlook consists of various assumptions and forecasts with respect to fuel prices, market and regulatory changes as well as development of new technologies and their costs. All power system development assumptions are highly interdependent and form a complex multisector and multidisciplinary system. In order to create a reliable long-term outlook, ideally, a comprehensive stochastic simulation tool of the power sector would be required. However, given the current state of operational research tools and computational capability, this is not possible. Therefore, it is important to simplify the system by fixing a set of assumptions based on expert opinion and adapting simulation tools with simplified models of the power system sector. The simplifications are especially relevant for power systems with large scale renewable generation due to uncertainty connected to short-term renewable generation as well as uncertainty connected to technological developments (i.e., energy storage technologies and transmission network) to support the intermittent nature of renewable generation. As a result, an important question arises; "which parameters can be treated as external assumptions and which should be treated as variables in the investment planning of an asset?". Moreover, another important question is, "to which extent should an investment planning problem be simplified without losing reliability of the result?". This dissertation implicitly addresses the aforementioned questions and provides modeling and solution methodologies for investment planning while considering the multisector and multidisciplinary characteristics of the power sector.

This chapter introduces the literature gap and research objectives of this dissertation. The chapter begins with a short introduction into investment planning in Section 1.1. Section 1.2 provides the motivation and identifies the knowledge gap on investment planning in systems with large scale renewable generation penetration. Motivated by the identified literature gap, Section 1.3 states the research objectives of this thesis as well as proposed methodologies to achieve these objectives. The list of publications is presented in Section 1.4 followed by Section 1.5 where the main contributions and conclusions of this dissertation are summarized. Finally, Section 1.6 presents the outline for the remaining chapters.

1.1 Background

Initially, the first power systems evolved as natural monopolies. The technically complicated operational structure of a power system was not able to accommodate market based interaction between generators, transmission and demand while at the same time guaranteeing constant and reliable supply of electricity. However, with the developments in telecommunication, operational research and economic theory, the transition to market based operation became possible. The transition began with the development of electricity markets where loads, generators and other eligible parties buy or sell electricity. The generation and demand sectors of the majority of European and American power systems were successfully liberalized and nowadays can be operated through competitive market rules. On the other hand, transmission infrastructure still remains a natural monopoly and relies on various subsidies and other incentives from a governing entity (which is the case in USA) or very high transmission fees and grid tariffs allocated to loads (which is the case in Sweden). Nowadays, the most common power system governance structure consists of an independent profit maximizing load, energy storage and generation utilities, an independent transmission company (profit maximizing or state owned), a regulatory entity, and a market operator and can be illustrated as in Figure 1.1.

In Figure 1.1, the bottom layer illustrates customers of the power grid which consists of loads, generation and energy storage utilities. Nowadays, pure energy storage utilities are quite rare and energy storage technologies are more commonly owned and operated by a generation or load utility. However, the expected growth of energy storage projects makes it likely to expect a higher share of pure energy storage utilities. Load utilities include large loads and retail companies. The mid-layer consists of entities which are responsible for operation and planning in power systems. Market Operator illustrates a centralized entity responsible for operation and market clearance in a power system while Transmission Company is used to illustrate a centralized entity responsible for operation and planning of power flows

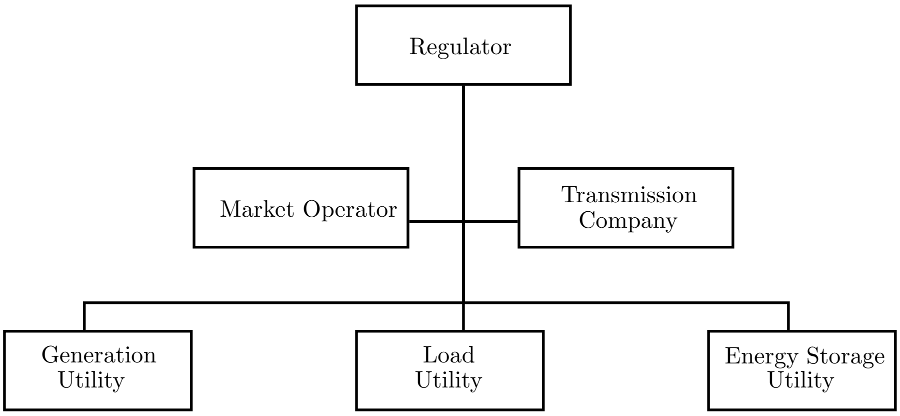


Figure 1.1: Power system governance structure

between nodes and investments and maintenance of transmission assets. The upper layer (Regulator) illustrates any centralized entity which is responsible for any incentives and other regulatory measures required in a power system.

The transition from vertically integrated to horizontally integrated economy in power systems is accompanied by the increasing concern about climate change and, as a result, the change in the desirable generation mix. The worldwide view on the future generation mix is consolidated under the idea that carbon dioxide (CO_2) emitting power plants should be reduced to a minimum number or eliminated entirely. The projected growth of electricity demand around the world not only does not allow to simply close CO_2 emitting power plants but requires an efficient and fossil free generation alternative. Renewable and CO_2 neutral generation such as wind and solar is seen as one of the promising alternatives to replace CO_2 emitting power plants.

The renewable energy industry is growing rapidly around the world. The development of new technologies and various environmental and political factors are gradually making renewable generation desirable and affordable. Threats of global climate change followed by carbon dioxide emission reduction targets force governments around the world to provide additional incentives for renewable generation investments, e.g., through subsidies, green certificates, etc. According to the International Energy Agency, wind based generation capacity alone will cover 18% of the world's electricity consumption by 2050. At the same time numerous European countries such as Germany, Sweden, France and Belgium have an ambition to reach 100% CO_2 free electricity generation by 2050. Policy driven generation investments resulted in a large number of wind farm installations around Europe, China and USA just over the last decade [1]. Moreover, policies and governmental support allowed renewable technology to reach a mature state in a short period of time. Appropriately designed incentive mechanisms resulted in large scale integration of renewable generation capacity, development of more efficient technologies, as well as reduced capital and operational costs of renewable generation. However, the surrounding system development including flexibility assets and transmission infrastructure develops at a much slower rate. The slower rate of development can be connected to lack of price signals and incentive mechanisms. As a result not all benefits and available capacities of renewable generation are fully utilized. For example, a wind investment project will not take place unless necessary transmission infrastructure is in place or under development. If a wind generation project will precede transmission expansion then the wind generation project owner will not be able to operate and sell energy while waiting for transmission project to be built. Thus, the wind generation project owner will lose income due to the decreased operational lifetime of the project. At the same time transmission investments and grid reinforcements will not take place unless there is an existing need (generation or load already in place). Moreover, delayed development of flexibility assets and transmission may result in operation disturbances of a power system with high shares of renewable generation.

Small and geographically well distributed wind installations do not usually induce alarming disturbances to power systems. However, a large amount of wind based generation at one location could be a potential problem for power system security. Variability and unpredictability of large wind farms may require better balancing of the power grid such as improved frequency control and larger reserve capacities [2]. The balancing need of power systems with large wind generation penetration has been studied in [3],[4] and [5] and in more recent publications such as [6],[7],[8] and [9].

In addition, the literature suggests that available transmission capacities will not be sufficient to accommodate large shares of renewable generation and, as a consequence, additional transmission investments may be required [10]. Moreover, due to the natural monopoly of transmission infrastructure, such investments cannot be guaranteed with competitive markets rules. Therefore additional regulatory mechanisms should be in place [11].

The challenges posed by large wind based generation installation can be divided into three main types:

- *Uncertainty* related to limited predictability of wind speed. Increased uncertainty in operation and planning of power systems will require large reserve capacity and additional flexibility sources such as energy storage with fast ramping capability.

- *Variability* of the wind speed. Similar to uncertainty, increased variability may require improvements in ramping capability of power systems. The variability of the wind speed is especially important for large scale wind farms. Wind power production can change rapidly over a short period of time. Thus, in combination with approximately uniform wind speed throughout a small geographic area, a small change in wind speed may cause a drastic change in power output.

- *Geographical distribution* of large scale wind farms. Wind generation output is dependent on wind speed. Oftentimes, the windy and attractive areas for wind installations are poorly connected to the power grid. Thus, additional transmission infrastructure or reinforcements of transmission infrastructure are necessary.

The main investment problems in power systems with high shares of renewable generation can be divided into two main areas: investments in flexibility sources and investment in transmission infrastructure.

1.1.1 Investment planning process

Every utility in the power sector adopts its own investment planning procedures. While the details of the procedures may vary, the overall process has major similarities and follows the same steps. The steps of the investment planning can be described as:

- First, potential feasible technologies are identified and monitored.
- Second, major assumptions on market structures of the future and regulation are made
- Third, a long-term power system outlook is performed using mathematical models. The outcome of such long-term outlook is usually capacity developments of selected technologies and long-term price curves of selected electricity markets.
- Fourth, based on the long-term power system outlook, individual investment decisions are evaluated and taken.

For instance, consider a utility which wants to invest in an energy storage project. In order to calculate profitability and risks, the utility would need to to use long-term price curves under different market development scenarios. Additionally, in order to forecast long-term price curves a utility needs to have an outlook on the development of the power system as a whole. This outlook is usually created by simulating the development of the power system and including all monitored technologies which were selected as the most promising, meaning an optimization investment model should be developed where investment in various assets are performed simultaneously. Once an outlook is finalized, price curves are developed and the profitability and risks are estimated, a utility can take an informed decision on energy storage investment. The investment process is illustrated in 1.2.

Table 1.1 provides a summary of the main technologies currently considered in

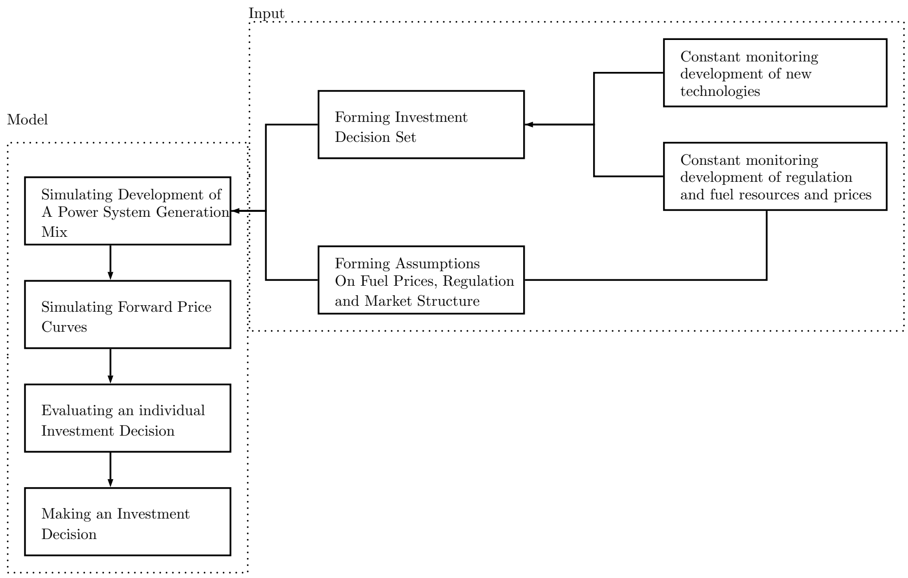


Figure 1.2: Investment planning process

the future power system planning in the majority of utilities to accommodate high shares of renewable generation.

Group	Technologies	Description
Baseload Technologies	CCGT Hydro power	Large scale generators with fast response and good ramping rate
Peaking power	Diesel generators OCGT	Small scale generators with fast response and fast start up
Demand response	Background processes Manufacturing processes Aggregated loads	Large scale industrial or aggregated small scale loads
Energy Storage	Lithium-ion batteries Pumped Storage	Scalable Energy storage assets which can be used for various applications
Transmission	Reinforced New transmission links	Controllable large scale transmission links

Table 1.1: Technologies considered for the future development of the power sector

Most of the literature addresses the investment planning in the technologies listed in Table 1.1 separately and under fixed long-term outlook. Generally, the literature which covers coordinated investment planning both in flexibility sources and transmission infrastructure is very limited. Literature reviews on flexibility sources and transmission infrastructure are presented in Section 1.1.2 and in Section 1.1.3 respectively. These sections also include literature where coordinated investment planning was taken into account but the main focus was flexibility sources or transmission infrastructure.

1.1.2 Literature review on operation and planning of flexibility sources

Investments in flexible generation technologies such as gas turbines were addressed in [12] and [13]. Thermal generation investments have been studied in-depth and do not contain a large literature gap. At the same time, investments in hydro power plants are complicated due to geographical and location restrictions. On the other hand, energy storage technologies are considered to be the most popular source of flexibility which can be potentially integrated in the transmission system and support further development of large scale wind based generation. Various references provide an overview on possible applications and assessment of energy storage benefits. In [14], a comprehensive analysis of possible energy storage applications and suitable energy storage technologies are presented. Applications may vary from energy arbitrage to grid upgrade investment deferral. The most promising applications for energy storage include energy arbitrage, balancing services and renewable generation support. Different ways how energy storage systems can be used for balancing applications, especially in the presence of a large amount of variable renewable generation, were studied in [15] and in [16], while [17] includes benefits of energy storage as a flexibility source. In addition, [18] and [19] analyze how energy storage can be beneficial for supporting variable wind power generation and [20] presents benefits of energy storage from a technical point of view and its effect on maximum wind power penetration. A review of modeling techniques of energy storage given different objectives is provided in [21] and includes more than 150 papers on the energy storage assessment subject. The literature provides evidence that energy storage is beneficial for renewable generation support and can be profitable under certain assumptions, however, high capital cost is seen as the main obstacle in energy storage market development. Cost evaluation and calculation of different energy storage technologies is presented in [22] and [23].

The aforementioned papers have shown that additional capacity of flexibility sources such as energy storage will be required to reach future renewable targets. Also literature suggests that energy storage might be profitable in systems with a high share of renewables. However, the financial profitability of the energy storage is still strongly dependent on the size and location of the deployed energy storage system. Optimal planning of energy storage under different conditions and objectives has been studied in [18],[24],[25],[26],[27],[28],[29] and [30]. In addition,

[31],[32],[33],[34],[35] investigated joint optimal allocation and sizing of energy storage. In [36], the authors also show that energy storage is beneficial for renewable generation expansion and that joint optimization of renewable generation and flexibility sources including energy storage results in much higher cost savings than when investment planning is performed separately. However, these papers consider centralized investment planning which does not ensure profitability of the energy storage system itself and does not consider profit maximizing behavior of the energy storage investor. It is an open question whether flexibility sources such as energy storage should be a market asset or system asset. Under current European regulation energy storage cannot be used to obtain profit if it is owned by system operators. Thus, the current development of energy storage will mostly depend on various independent investors (e.g., generation utility, energy storage utility) which have profit maximizing objectives and other constraints on expected profit. A profit maximizing bilevel approach for investment planning of energy storage systems which will ensure that the owner of the energy storage will maximize its benefits has been proposed in [37],[38] and [31]. In [39] a bilevel approach is used to simulate merchant energy storage while accounting for optimal bidding strategy. However, neither of the proposed models includes other sources of flexibility such as hydro power and flexible demand which are currently the main competitors of emerging energy storage systems. Moreover, these models do not take into account possible growth of renewable generation or development of transmission infrastructure. These research gaps were addressed in publications $J1$,$J2$ and $J4$ (see Section 1.4) and is used to formulate the general contribution points of this dissertation $C1$, and $C3$-$C5$ (see Section 1.5).

1.1.3 Literature review on incentive based transmission investments

Liberalization of electricity markets decoupled operation and planning of major players of power system's markets (e.g., generation, demand, energy storage, transmission) with the aim of increasing competition and increasing the security of supply. For consumers of electricity markets (e.g., generation, demand and energy storage) the transition from centralized power market to competitive markets was successful regardless of various challenges and milestones. On the other hand, the full transition from a centralized operation and planning to competitive market-based operation and planning did not take place in the transmission sector. In the majority of states, the transmission sector transitioned to a natural monopoly or oligopoly. Due to the vital importance of transmission infrastructure for security of supply and functioning of any power system, transmission operation and planning are highly regulated. The regulation aims to achieve social welfare maximum operation and planning of transmission infrastructure.

The transmission operation and planning were addressed in various references. In [40] and [27] transmission investment planning is studied accounting for uncertainties (e.g., uncertainties from renewable generation). However, the majority of the literature, including the aforementioned, does not consider the existing regulation or market influence and assumes perfect information exchange between all actors of a power system. In [41] and [42], the authors propose market-based transmission expansion planning under uncertainty formulated through bilevel mixed-integer MPEC models. In [43], a three-level model is proposed for market-based transmission and generation expansion. Publications [44] and [45] propose mathematical models for coordination of strategic generation investments and transmission investments. In [46], a game-theoretical approach is used for the operation and planning of a transmission company in coordination with strategic generators. The presented methods prove that the market based approach can be efficient in the transmission planning. However, these papers do not include regulation or incentive mechanisms which can be used to ensure socially optimal investment planning.

The incentive problem for the transmission expansion planning has been addressed elsewhere in relevant literature: Physical characteristics of electricity (such as loop flows), economies of scale, and dynamics between the forward transmission market and other markets are mentioned as complicating factors in the analysis of incentives for the transmission expansion planning [47], [48]. Various incentive mechanisms were proposed to tackle the incentive problem. They can be divided into two major groups; subsidy mechanisms and constraint mechanisms. Subsidy mechanisms were initially introduced by [49] and further developed by [50] where an incremental surplus subsidy scheme (ISS) was proposed. The mechanism then was applied to transmission pricing and investments in [51]. On the other hand, constraint mechanisms were proposed in [52] and [53], where price-cap constraints were proposed for incentivizing transmission expansion planning by a transmission company. Under certain conditions, these mechanisms lead to a transmission expansion plan which maximizes social welfare [54]. Reference [55] proposes a reward/penalty mechanism. In this mechanism, the regulator rewards the Transco when the transmission network is expanded and the congestion rents are decreased. Reference [56] proposes an out-turn mechanism. The out-turn is defined as the difference between actual electricity prices and prices without transmission congestion. The Transco is responsible for total out-turn cost and any transmission losses. References [54] and [57] extend the work in [52] and propose the H-R-V (Hogan-Rosellon-Vogelsang) mechanism for transmission expansion planning. In the H-R-V mechanism, the Transco maximizes its profit (sum of merchandising surplus and a fixed fee minus transmission investment costs) subject to the price-cap constraint introduced in [52]. The H-R-V mechanism has been numerically tested in simplified models of Northwestern Europe and the Northeast U.S. [54], [58]. Mathematically, the H-R-V model is a nonlinear disjunctive program with equilibrium constraints (NLPEC). Local optimizers have been used to solve the corresponding model but with no guarantee of global optimality. Moreover, complex algorithms used to solve such problems have a high computation time and they are hardly applicable to large scale problems with many decision variables. More recently, an alternative incentive mechanism for transmission expansion planning is proposed in [11] following the incentive mechanisms in [50] and [54]. The H-R-G-V (Hesamzadeh-

Rosellon-Gabriel-Vogelsang) mechanism proposes a dynamic interaction between a profit-maximizing Transco, the regulator and an Independent System Operator (ISO).

In [11] the authors prove in analytic models that the H-R-G-V mechanism will lead to the socially maximum investment planning decisions. However, the direct application of the mechanism to the transmission planning will lead to a bilevel nonlinear disjunctive program with equilibrium constraints. As it was mentioned before, it is hard to guarantee the convergence to the globally optimal solution of such type of problems. As a result, finding an optimal incentive mechanism for transmission expansion planning is an open question both in theory and in practice. This research gap is addressed in the publication $J2 - J4$ (see Section 1.4) and is used to formulate a general contribution points of this dissertation $C2$-$C5$ (see Section 1.5).

1.2 Research objectives

Based on the above literature review and identified literature gaps in Section 1.1.2 and Section 1.1.3, the following research objectives can be summarized:

- Mathematical models used for investment decisions should consider long-term development of the power sector, as well as financial markets in the life-time of the asset under consideration. Thus, the first objective of this thesis is to understand key driving factors of the investment in flexibility sources and transmission assets as well as to identify sources of uncertainty which might increase the risks of the investment into transmission lines and energy storage systems.

- Various incentive regulations can be used to stimulate investments into transmission lines or flexibility assets. Various economic theories were proposed in the literature in order to address the investment incentive problem. However, a comprehensive analysis is needed to derive the optimal incentive policy for transmission and energy storage to accommodate the growth of renewable energy. Thus, the second objective of this thesis is to select the most promising incentive mechanism which will provide the most socially beneficial investments.

- In order to include all identified drivers and sources of uncertainty, a comprehensive mathematical model is required to find the optimal values and allocation of transmission and energy storage investments. Moreover, the formulation of such comprehensive models should be as efficient as possible and avoid unnecessary constraints and variables. Thus, the third objective of this thesis is to provide concise but comprehensive mathematical model formulations for transmission and energy storage investment planning problems.

- Comprehensive models are usually large and often nonlinear. This is also the case with the majority of transmission and energy storage investment models. A solution methodology is needed in order to address the challenges of the proposed models and improve computational tractability. Thus, the final objective of this thesis is to provide a generalized solution methodology applicable to a wide class of investment planning problems including transmission and energy storage investment models.

1.3 Methodology

Investment planning in power systems is complicated due to unique characteristics of the system. The decisions should be taken not only considering financial aspects, but also however including technical and regulatory constraints applied to the whole system under consideration.

The main aim of any investment planning is to discover an investment decision and an appropriate time for investment which will lead to the maximum difference between expected benefits in the future and the investments costs. The driving forces for investment planning in power systems can be classified into two groups: driving forces of an independent investor who owns the assets and driving forces of the system as an independent agent itself. From the independent owner point of view these driving forces are straightforward and can be fit into a few points:

- Revenue generation
- Risk minimization
- Back-up for other existing assets in the portfolio
- Advanced replacement of aged assets
- Adaptation to regulatory measures

The system goals, on the other hand, differ from purely technical to socially oriented goals. System goals include:

- Improvement of reliability of the system
- Improvement of delivery and quality
- Social benefits
- Environmental concerns
- Anticipated future needs

Any investment decision involves certain levels of risks. Risks can be associated with various long term or short term uncertainty. Long term risks are consequences of long term uncertainty such as investment costs, new technology development and regulation while short term risks are associated with operational uncertainty such as outages, electricity and fuel prices and wind generation forecast errors. Risks are subjective factors. However, they can be quantified and analyzed. Risks appear when any kind of uncertainty is involved. Prediction and forecast tools are used to simulate uncertainty and estimate risks.

In general, any intuitive methodology used to facilitate investment planning in power system includes three major steps:

- Identification of uncertainty and scenario generation for corresponding uncertainty
- Simulation of the decision making which includes mathematical modeling and optimization
- Analysis of the expected values and quantification of costs, benefits and risks

This thesis mainly contributes to the second step of the investment planning methodology and provides simulation and mathematical modeling tools which can support investment decisions.

1.4 List of publications

In this section a complete list of published and submitted publications is presented.

Published journal articles in journals listed in Journal Citation Report (JCR):

- *J1*: Khastieva, D., Dimoulkas, I., and Amelin, M., "Optimal Investment Planning of Bulk Energy Storage Systems," *Sustainability*, 10(3), 610, 2018. Dina Khastieva planned and wrote the paper under the supervision of Mikael Amelin. Dina Khastieva formulated and simulated mathematical models used in the paper and performed analysis of the results as well as wrote the main part of the text. Ilias Dimoulkas assisted in scenario generation used for renewable generation modeling and assisted in writing the paper.
- *J2*: Khastieva, D, Hesamzadeh, M. R., Vogelsang, I., Rosellón, J., and Amelin, M., "Value of energy storage for transmission investments," *Energy Strategy Reviews*, 24, 94-110, 2019 Dina Khastieva planned and wrote the paper under the supervision of Mikael Amelin and Mohammad Reza Hesamzadeh. Dina Khastieva formulated and simulated mathematical models used in the paper and performed analysis of the results as well as wrote the main part of the text. Mohammad Reza Hesamzadeh, Ingo Vogelsang and Juan Rosellón contributed to the paper with economic theory of H-R-G-V incentive mechanism. In addition, Ingo Vogelsang and Juan Roselló assisted in writing the paper and analyzing the results.

Working papers and submitted articles in journals listed in JCR:

- *J3*:Khastieva, D, Hesamzadeh, M. R., Vogelsang, I., and Rosellón, J., "Transmission Network Investment Using Incentive Regulation: A Disjunctive Programming Approach," *Networks and Spatial Economics* - Springer (Under review since March 2018) Dina Khastieva planned and wrote the paper under the supervision of Mohammad Reza Hesamzadeh. Dina Khastieva formulated and simulated mathematical models used in the paper and performed analysis of the results as well as wrote the main part of the text. Mohammad Reza Hesamzadeh, Ingo Vogelsang and Juan Rosellón contributed to the paper with economic theory of H-R-G-V, H-R-V and ISS incentive mechanisms. In addition, Ingo Vogelsang and Juan Roselló assisted in writing the paper and analysing the results.

- *J4*: Khastieva, D, Mohammadi S, Hesamzadeh, M. R. "Merchant-Regulatory Coordination of Transmission Investment with Optimal Battery-Storage Capacity" *IEEE Transactions on Control Systems Technology* Dina Khastieva planned and wrote the paper under the supervision of Mohammad Reza Hesamzadeh. Dina Khastieva formulated and simulated mathematical models used in the paper and performed analysis of the results as well as wrote the main part of the text. Mohammad Reza Hesamzadeh contributed to the paper with economic theory of ISS incentive mechanism. Saeed Mohammadi helped with writing down the decomposition technique used in the paper.

Peer-reviewed articles published in proceeding of conferences:

- *P1* Khastieva, D., and Amelin, M. (2016, July), "Short-term planning of hydro-thermal system with high wind energy penetration and energy storage," in IEEE Power and Energy Society General Meeting (pp. 1-5), IEEE, 2016. Dina Khastieva planned and wrote the paper under the supervision of Mikael Amelin. Dina Khastieva formulated and simulated mathematical models used in the paper and performed analysis of the results as well as wrote the main part of the text.

1.5 Research contributions

The contributions of the dissertation can be summarized by the following points:

- *C1* In order to simulate the investment planning process of energy storage that reflects the profit maximizing objective (merchant planning objective) of the corresponding investment planner (energy storage utility) a comprehensive mathematical model is proposed. The model assumes that energy storage capacity size and allocation may affect the capacity development of renewable generation. Moreover, the reverse assumption also applies - the capacity development of renewable generation affects investment decisions of a merchant energy storage utility. Thus, the capacity and allocation decisions of energy storage and wind generation should be modeled jointly. In order to simulate the aforementioned assumption, the model is formulated as a bilevel problem where the upper level simulates merchant energy storage investment planning by considering revenues from energy arbitrage while the lower level is used to simulate market clearance and renewable generation capacity development. The results of the lower level are then considered in the revenue estimation of an energy storage utility while investment decisions in energy storage are considered in renewable generation capacity development and market clearance. This contribution part of publication $J1$ and is partially addressed in publication $J4$.

- *C2* Unlike an energy storage utility, a transmission utility cannot be modeled using a pure merchant approach. The transmission sector is a natural monopoly and consequently should be modeled using a merchant-regulated approach. This means that the mathematical model used to simulate transmission planning should consider the profit maximizing objective of the merchant (profit maximizing) transmission planner as well as regulatory limitations and incentives enforced by the regulator. In this thesis, a comprehensive mathematical model is proposed for a regulated merchant transmission investment planning. The model consists of three planning levels: transmission investment planning, regulatory decision on incentive mechanism and simulation of power system operation, dispatch and market clearance. However, the mathematical model is formulated as a bilevel model where transmission investment planning and regulatory decisions are formulated in the upper level while the lower level simulates operation, planning and market clearance of the power system. This contribution is a part of publications $J2$-$J4$.

- *C3* Energy storage and wind generation are usually considered as complementary technologies. On the other hand, transmission assets and energy storage can be seen either as complements or as substitutes. In any case, transmission investments, energy storage investment and renewable generation capacity investment should be considered together and coordinated to achieve an efficient and socially beneficial planning of the power system. Thus, a comprehensive mathematical model for coordinated investment planning in transmission, energy storage and wind generation is proposed. The model combines the techniques used in contributions *C1* and *C2* and is formulated as a bilevel problem where regulated transmission planning is addressed in the upper level while energy storage and wind generation investment planning is simulated in the lower level using the assumption of perfect competition and perfect information. This contribution is part of publications $J2$ and $J4$.

- *C4* The mathematical models described in *C1*-*C3* are nonlinear and multilevel problems. In order to address these shortcomings of the proposed models additional, reformulation and linearization techniques are proposed. The reformulation and linerization techniques are based on finding the suitable algebraic transformation techniques to find linear and convex equivalents of the nonlinear terms used in the models. This contribution is part of publications $J1$-$J4$.

- *C5* In addition to reformulation and linearizaion technique, the complexities of the models proposed in *C1-C3* are addressed by proposing decomposition techniques. The proposed decomposition techniques are efficiently adapted to the unique structures of the models and are based on a Benders'-like algorithm. Furthermore, the tractability of the proposed decomposition techniques are then accelerated using various customized heuristics. This contribution is part of publications $J3$-$J4$.

1.6 Thesis organization

Chapter 1 is an introduction to investment planning problems in power systems. In Chapter 2, investment planning in energy storage systems and flexibility sources is discussed. Energy storage systems are considered as the most promising flexibility sources which should be integrated into system in order to facilitate growth of renewable generation. In addition, the chapter compares various sources of flexibility such as flexible thermal generation and hydro power and shows that all these sources of flexibility can be modeled in a unified fashion.

As a next step, in Chapter 3, transmission investment planning is presented. The chapter focuses on incentive-based regulation which can support socially optimal transmission investments.

In Chapter 4, comprehensive and detailed mathematical models applied to transmission investment planning are presented. This chapter also includes various reformulation and linearization techniques, as well as novel decomposition algorithms.

Finally, Chapter 5 presents a list of main conclusions. In the Appendix of this thesis, all published and submitted manuscripts are attached in the following order: first, accepted and published manuscripts J1 and J2; second, submitted manuscripts J3 and J4; third, conference paper P1.

Chapter 2

Investments in flexibility sources

This chapter provides a broad introduction to publications $J1$,$J2$,$J4$ and $P1$ and partially addresses contribution $C1$. In addition, the chapter provides material which is further used in Chapter 4 to develop mathematical models for investment planning in flexibility assets and partially addresses contribution $C3$ by providing a generalized mathematical formulation for flexibility sources.

Flexibility in power systems is a broad term. The term flexibility is used to describe any ability of a system to adapt to controllable or uncontrollable changes. The term flexibility does not have a unique definition; however, it is widely used in the recent literature especially in the literature focused on variable renewable integration problems. Various authors make an attempt to define flexibility in power systems while the definition varies widely and depends on the target field of the publication. For example, [59] defines flexibility of the power system as the available capacity for a certain ramp capability and ramp duration. In [60], the authors define flexibility as "a power system's ability to respond to short-term variations in demand and supply" and [61] defines flexibility as "the possibility of deploying the available resources to respond in an adequate and reliable way to the load and generation variations during time at acceptable cost". In [62], flexibility is defined as "the ability of a system to deploy its resources to respond to changes in net load, where net load is defined as the remaining system load not served by variable generation". The authors of [63] define flexibility as flexibility of operation and give the following definition: "the ability of a power system to respond to change in demand and supply is a characteristic of all power systems." Reference [64] defines operational flexibility as the "combined available operational flexibility that an ensemble of, potentially very diverse, power system units in a geographically confined grid zone can provide in each time-step during the operational planning, given load demand and Renewable Energy Sources (RES) forecast information, as well as in real-time in case of a contingency".

Despite the difference in definitions, all authors emphasize the importance of presence of flexibility in the power systems especially with large share of variable

Flexibility classification	Reason for flexibility
Short-term flexibility	Wind, solar and load forecast errors Wind, solar and load variability Outages
Medium-term flexibility	Seasonal price fluctuation Seasonal hydro reservoir levels Seasonal load fluctuation Seasonal wind and solar fluctuations
Long-term flexibility	Policy development Capacity markets Load growth Renewable generation growth Generation retirement

Table 2.1: Flexibility classification

renewable generation. Analysis presented in [65] shows that flexibility sources can have additional advantage and exercise market power by acting strategically.

The term flexibility can be used to describe a part of the power system operation as well as generally characterize the system. Defining the term flexibility and distinguishing different types of flexibility is essential to discuss the future development of power systems with high share of renewables. Flexibility in a power system can follow the same classification as power system operation and planning and can be divided into short-, medium- and long-term. Short-term and medium-term flexibility are commonly referred to as operational flexibility and include the ability of the system to balance supply and demand by varying generation, flexible demand, energy storage, or other flexible and dispatchable sources and transmission infrastructure. Short-term flexibility is directly related to balancing needs of the system in real time while medium term flexibility can be used to describe the ability of the system to smooth fluctuations in longer time periods up to one year. In addition, frequency regulation is also a part of short-term flexibility. This dissertation mainly focuses on flexibility of a power system provided in the time frame of five minutes and longer. Frequency regulation is left for power system stability problem analysis. Long-term flexibility of a power system refers to the ability of the system to adapt to long-term changes in the system such as new technology development, forced mandates, newly developed regulation, etc.

The following characteristics may be used as indicators for a lack of flexibility in a power system:

- high price volatility due to binding ramping constraints and line flow limits
- higher prices in an area or node compared to any neighboring area or node
- negative prices

- violation of safety margins of power system assets
- frequent outages / load shedding
- variable renewable generation curtailment
- possibility to exercise market power

A number of different assets can contribute to the flexibility of a power system. A widely discussed and promising technology for future power systems is the family of energy storage technologies. The most important characteristic of energy storage is that it can be used to improve power system flexibility on all time scales and, depending on the technology, to provide a broad variety of services. In the following sections, the specifics of energy storage investments are described, followed by a general description of flexibility sources and generalized modeling methodology.

2.1 Energy storage investments

Rapid growth of renewable generation as well as stricter carbon emission standards make energy storage technologies an attractive solution to solve rising flexibility problems in power systems. Energy storage systems are capable of providing additional flexibility on different time frames to power system operation by charging at peak hours and discharging when additional electricity is required. Such flexibility is very desirable for systems with high shares of variable renewable generation. In addition, energy storage technologies are very fast and can change their output depending on the needs of the system. According to Energy Storage Outlook 2019 provided by BloombergNEF the need in additional storage capacity worldwide is expected to increase from 17 GWh (existing installed capacity as of 2018) to 2,850 GWh by 2040. The forecasted increase in energy storage installations is mostly due to renewable generation capacity increase and additional balancing needs. Similar forecast are provided in [66]. However, aforementioned reports do not explain how investments in energy storage capacities will be procured and what will be business applications.

The problem of storing electricity has been a big issue since the inception of power systems. In order to store electricity it has to be converted into another form of energy such as chemical, mechanical (kinetic or potential), and then converted back to electrical when it is needed. There are different types of energy storage systems already available in the market and several technologies under development stage. They can be classified by the form of energy used to convert to and store electrical energy: mechanic energy, electrochemical energy, thermal energy and electrical energy.

Each type of electricity storage technologies can be considered for providing a range of services to the electric power grid. The range of services is differing based on characteristics of energy storage technology. These characteristics includes:

- Round tip efficiency.
- Self discharge rate
- Power capacity
- Energy capacity
- Response time

Sandia National Laboratories in collaboration with NRECA conducted a vast amount of research on the analysis of different types of energy storage systems and their benefit for different type of applications and provides very comprehensive technical reports on this topic [15]. Moreover, most of technical characteristics as well as cost component of existing energy storage technologies including estimated characteristics of technologies under development could be found in these reports. In addition, Sandia National Laboratories provides a web database with full list of existing projects around the world on energy storage [67].

Reference [68] analyzes influence of large scale energy storage systems such as CAES and Pumped Hydro on economic cost reduction of electric power system. However, some other technologies such as flywheel [69], Sodium-sulfur Battery, Lead acid battery energy storage was successfully tested for providing services to the grid on TSO level and utility level [70], [68], [71].

Energy storage systems have multiple applications and can be beneficial at different levels in the power system. Various literature provide an overview on possible applications and assessment of energy storage benefits. In [14] a comprehensive analysis of possible energy storage applications and suitable energy storage technologies is presented. Applications may vary from energy arbitrage to grid upgrade investments deferral. The most promising applications for energy storage include energy arbitrage, balancing (ancillary) services and renewable generation support. Based on its characteristics energy storage technology can be applicable for different range of services. For example, pumped hydro is the most suitable for energy arbitrage and seasonal storage, battery is suitable for energy arbitrage and ancillary services such as primary control, while flywheels can be applied only for primary regulation and proved to be inefficient and not economical for energy arbitrage due to its high self-discharge. In general, the application range depends on ratio between energy capacity and power capability, self-discharge as well as reaction time. Table 2.2 provides list of possible applications and relative energy storage characteristics required to qualify for each application.

Application	**Low** self-discharge	**Large energy** capacity	**High** power	**Fast** reaction	**High** efficiency
Regulation and balancing (short-term flexibility)			✓	✓	✓
Short-term energy arbitrage (medium-term flexibility)	✓		✓		✓
Long-term energy arbitrage (long-term flexibility)	✓	✓			✓
Transmission support (short- medium- and long-term flexibility)	✓	✓		✓	✓
Black start	✓	✓	✓	✓	

Table 2.2: Energy storage applications and matching characteristics

Different ways how energy storage systems can be used for balancing and regulation, especially in presence of a large amount of variable renewable generation, were studied in [15, 16], while [17] includes benefits of energy storage as a flexibility source. In addition, [18, 19] analyze how energy storage can be beneficial for supporting variable wind power generation and [20] presents benefits of energy storage from a technical point of view and its effect on maximum wind power penetration. A review of modeling techniques of energy storage given different objectives is provided in [21] and includes more than 150 papers on the energy storage assessment subject. The literature provides evidence that energy storage is beneficial for renewable generation support and can be profitable under certain assumptions, however high capital cost is seen as the main obstacle in energy storage market development.

The capital cost of any energy storage technologies consists of two distinct parts. The first part is the component cost (e.g., water reservoir and a dam for pump storage, battery rack for battery, etc.) which determines the energy storage capacity and other characteristics such as as self-discharge. The second part is the cost of power electronics and energy conversion components (e.g., pumps for pump storage, converters for batteries) which determines the power capacity of an energy storage unit. Detailed cost evaluations and calculations for different energy storage technologies are presented in [22, 23] while [72] provides an analysis on future cost development projections. Mature energy storage technologies such as pumped storage and compressed air energy storage are already fully developed, and as a result, the capital cost does not change over time. However, recent interest in battery technologies boosted research and development activities in the sector and capital costs of battery technologies (both, existing and under development) is expected to decrease by 50% by 2030. This decrease in capital cost is expected mostly for electrochemical and electrical energy storage technologies due to the development of new chemicals and materials which will allow to store energy safely and more efficiently. For other types of energy storage technologies, such as mechanical and thermal storage, capital cost is expected to remain on similar levels.

In general, the definition of energy storage system implies technologies which can convert surplus electricity into another form of energy, store it, and then convert it back when it is needed. Mathematically, energy storage operation constraints can be described in general form as:

$$\tilde{e}^e_{etk} = \tilde{e}^e_{etk-1} - \Gamma \tilde{g}^e_{etk} + \frac{1}{\Gamma}\tilde{d}^e_{etk} \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{2.1a}$$

$$0 \leq \tilde{e}^e_{etk} \leq E_e \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{2.1b}$$

$$0 \leq \tilde{g}^e_{etk} \leq \epsilon_e E_e a_{etk} \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{2.1c}$$

$$0 \leq \tilde{d}^e_{etk} \leq \epsilon_e E_e (1 - a_{etk}) \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}, \tag{2.1d}$$

where $\tilde{e}^e_{etk}$, $\tilde{g}^e_{etk}$ and $\tilde{d}^e_{etk}$ are variables used to simulate the state of charge, charged energy and discharged energy at each operation period k. The operation of the energy storage is limited by the available energy capacity E_e and installed power capability $\epsilon_e E_e, \epsilon_e E_e$. The energy balance constraint (2.1a) represents the state of charge of the energy storage unit. The energy storage will convert surplus of electricity and store it in a different form of energy or in the form of an electromagnetic field and then convert it back when it is demanded [73]. The conversion of electricity into another form of energy brings about some losses. These losses can be represented through efficiency coefficient Γ of the energy storage. Binary variables a_{etk} are used to ensure that energy storage does not charge and discharge at the same time[1].

The available energy capacity and power capability of energy storage can be easily expanded. The majority of energy storage technologies come in different scales and can be easily scaled up or down depending on the need. Any bulk scale energy storage (except pumped hydro) consists of blocks (cells) of small scale energy storage units which together compose an energy storage system.

Merchant energy storage investment planning can be described as:

Maximize Total profit from arbitrage + profit from ancillary services
- Total energy storage investment cost (2.2a)
Subject to:
Energy storage operation constraint (2.2b)
Energy storage investment constraints (2.2c)
Minimize Total operation cost
Subject to: (2.2d)
System energy balance constraints (2.2e)
Power flow constraints (2.2f)
Upper and lower operation limits (2.2g)

[1] Binary variables a_{etk} can be dropped under certain conditions which are described in Chapter 4

The profit of energy storage depends on energy arbitrage and provision of ancillary services. The revenue in both cases is generated using price differences between charge and discharge. In the case of energy arbitrage, the electricity prices at the moment of charge and discharge are assumed to be cleared using market rules while for ancillary services one of the prices can be predetermined or additional payments can be applied (such as reserved capacity payment). In order for the energy storage operation to be profitable in the short run, the returns of the stored electricity should be greater than sum of the efficiency over price and short run marginal[2] costs of the energy storage technology. Assume, P is the profit of one cycle of an energy storage operation, P_b is the electricity price or payment with which electricity was bought or charged with, P_s is the price or payment with which electricity was sold or discharged with. Γ is the efficiency of an energy storage, θ is self-discharge parameter of an energy storage and c_e is short-run marginal cost. $\delta\tau$ is the time between charge and discharge moments. If self-discharge of an energy storage is low, the profit from one cycle of that energy storage can be measured as:

$$P = P_s - \frac{P_b}{\Gamma} - c_e \tag{2.3}$$

For an energy storage with a high self-discharge parameter such as flywheels the profit of energy storage can be measured as:

$$P = (1 - \theta) * \delta\tau P_s - \frac{P_b}{\Gamma} - c_e \tag{2.4}$$

An energy storage unit will generate profit if and only if $P > 0$.

2.2 Generalized mathematical formulation of flexibility sources

Certain power system technologies are usually considered to be flexible due to high ramp limits and other technical parameters. Any technology which can change generation or demand by a large amount and in a short period of time can be considered a flexibility source. Various existing technologies can be used in the daily power system operation and provide additional flexibility to power systems with high shares of renewable generation. The following existing and commercially available technologies are considered as possible flexibility providers for power systems:

- Hydro power
- Thermal generation

[2]The majority of energy storage technologies does not use additional fuel to maintain operation of the unit, however each cycle of an energy storage unit usually involves some degradation cost. Thus, short-run marginal costs can be applied in order to reflect degradation and cycling costs of an energy storage unit.

- Combined heat and power
- Flexible demand
- Intermittent renewable generation (can be used for down regulation)

Following the mathematical formulation of energy storage, the aforementioned flexibility sources can be mathematically described in a unified format. A unified mathematical formulation helps to compare flexibility sources and improves the mathematical formulation of investment planning problems when multiple flexibility sources are considered. A compact representation of flexibility technology operation can be formulated as:

$$\tilde{e}^f_{ftk} = \tilde{e}^f_{ftk-1} - \gamma_f \tilde{g}^f_{ftk} + \theta_f \tilde{d}^f_{ftk} \quad \forall f \in \mathcal{F}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.5a}$$

$$\tilde{e}^f_{ftk=0} = \tilde{E}^0_{ft} \quad \forall f \in \mathcal{F}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.5b}$$

$$0 \leq \tilde{e}^f_{ftk} \leq E_f + \widehat{E}_{ft} \quad \forall f \in \mathcal{F}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.5c}$$

$$0 \leq \tilde{g}^f_{ftk} \leq P^g_f + \widehat{P}^g_{ft} \quad \forall f \in \mathcal{F}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.5d}$$

$$0 \leq \tilde{d}^f_{ftk} \leq P^d_f + \widehat{P}^d_{ft} \quad \forall f \in \mathcal{F}, t \in \mathcal{T}, k \in \mathcal{K}, \tag{2.5e}$$

where $f \in \mathcal{F}$ indexes all flexibility assets, $t \in \mathcal{T}$ indexes all investment planning periods, $k \in \mathcal{K}$ indexes operation periods. The energy level of a flexibility asset is described by $\tilde{e}^f_{ftk}$ (the state of charge variable for energy storage). Decrease and increase in energy level (discharge and charge variables for energy storage) is described by variables $\tilde{g}^f_{ftk}$ and $\tilde{d}^f_{ftk}$, respectively. Parameters E_f, P^g_f and P^d_f are used to set the upper limits for energy level, energy level increase and energy level decrease. Parameter $\tilde{E}^0_{ft}$ is used to describe the initial energy level and parameters $\widehat{E}_{ft}$, $\widehat{P}^g_{ft}$ and $\widehat{P}^d_{ft}$ are added (invested) capacities or power capabilities.

In the following sections, the mathematical representation as well as the derivation to the generalized form is described for each flexibility source separately.

2.2.1 Thermal generation

Thermal generation with fast ramp rate and hydro generation is the most mature and exploited flexibility source available in modern power systems. A broad variety of technologies is available for thermal generation. The flexibility level of dispatchable generation varies along with marginal and capital costs. Additional flexibility from dispatchable generation be obtained by additional capacity or by improving the ramping capability of the generator. Thus, two types of investments can be considered to improve the flexibility level of the power system: investments in installed capacity of a thermal generator; investments in improvements of ramping capability of a thermal generator.

The standard linear mathematical model of a thermal generator can be described as a set of constraints:

$$0 \leq g_{gtk} \leq G_g \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}} \tag{2.6a}$$

$$-RD_{gt}\delta\tau \leq g_{gtk} - g_{gtk-1} \leq RU_{gt}\delta\tau \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}} \tag{2.6b}$$

This set of constraints includes capacity limit and ramping constraints. The capacity constraints are presented in (2.6a) and ramping constraints are presented in (2.6b). Variable g_{gtks} is used to describe energy output for each operation hour. Parameters G_g, $RU_{gt}\delta\tau$ and $RD_{gt}\delta\tau$ are used for maximum installed capacity, ramp-up and ramp-down capability, respectively. At each operation period, a thermal generator is scheduled to produce at constant power g_{gtks} for the whole operation period k. Such representation assumes that all the variables and parameters are measured in MWh.

A flexible thermal generator can be represented by the sum of a non-flexible generator with constant output and a fictive energy storage with efficiency equal to one. Ramp-down of a thermal generator can be seen as a combination of constant generation and charge of energy storage while ramp-up can be treated as a combination of constant generation and discharge of an energy storage unit. The charge $\tilde{d}^g_{gtk}$ and discharge $\tilde{g}^g_{gtk}$ of the fictive energy storage then can be described as:

$$\tilde{g}^g_{gtk} = (g_{gtk} - g_{gtk-1}) \quad if((g_{gtk} - g_{gtk-1}) \geq 0)$$
$${\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}}$$
$$\tilde{d}^g_{gtk} = (g_{gtk} - g_{gtk-1}) \quad if((g_{gtk} - g_{gtk-1}) \leq 0)$$
$${\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}}$$

The generation of a thermal unit g_{gtk} is assumed to be constant and is a decision variable of the first hour of operation $k = 0$. The constant output of the generator also sets the initial state of charge of the fictive energy storage. Then the technical ramping boundaries will create operational limits for charge and discharge of the fictive energy storage unit while maximum generation capacity will create the upper limit for energy storage capacity. Thus, the traditional mathematical formulation of a thermal generator can be represented by an energy storage-like formulation:

$$0 \leq g_{gtk=0} \leq G_g \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}} \tag{2.7a}$$

$$\tilde{e}^g_{gtk=0} = g_{gtk=0} \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}} \tag{2.7b}$$

$$\tilde{e}^g_{gtk} = \tilde{e}^g_{gtk-1} - \tilde{g}^g_{gtk} + \tilde{d}^g_{gtk} \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}} \tag{2.7c}$$

$$0 \leq \tilde{e}^g_{gtk} \leq E_g \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}} \tag{2.7d}$$

$$0 \leq \tilde{g}^g_{gtk} \leq P_{gt} \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}} \tag{2.7e}$$

$$0 \leq \tilde{d}^g_{gtk} \leq P_{gt} \quad {\scriptstyle \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}} \tag{2.7f}$$

Such representation allows to consider flexibility of thermal generation operation in various time scales and allows for comparison to other flexibility sources such as energy storage.

2.2.2 Hydro power generation

There are three main types of hydro power plants: run-of-river power plants (also known as diversion), power plants with water reservoirs and dams (also known as impoundment) and pumped storage systems. All three types of hydro power plants can be mathematically described by a set of constraints. The operation of the run-of-river plant can be formulated using the same approach as for the thermal generator in (2.7). However, the flexibility of a hydro power plant is limited not by ramping capabilities of the plant but by natural flow limits of the water.

The mathematical formulation of hydro power with reservoirs can be formulated as:

$$m_{htk} = m_{ht-1k} - v_{htk} + u_{htk} - s_{htk} \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.8a}$$

$$0 \leq m_{htk} \leq M_h \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.8b}$$

$$0 \leq v_{htk} \leq V_h \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.8c}$$

$$\overline{g}_{htk} = v_{htk} \Upsilon_h \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.8d}$$

$$0 \leq s_{htk} \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K}, \tag{2.8e}$$

where $h \in \mathcal{H}$ is used to index hydro reservoirs, variables m_{htk}, v_{htk} and s_{htk} represent water levels of reservoirs, water outflow and water spillage. The generation of a hydro power plant is simulated through variable $\overline{g}_{htk}$. Parameters M_h and V_h are used to set upper limits for reservoir levels and hydro output.

The mathematical formulation of a hydro power plant with hydro reservoirs is very close to the energy storage formulation (2.1). A hydro power plant stores energy in form of water in the reservoirs. This can be formulated as in (2.8a). The stored water comes from natural inflows u_{htk} into reservoirs. Water reservoir levels and hydro outflow is limited by maximum water reservoir volumes and maximum outflow capability. The upper limits are enforced through constraints (2.8b) and (2.8c). By assuming a constant production equivalent Υ_h the generation of a hydro power plant can be estimated by constraint (2.8d).

Hydro power with reservoir is not considered to be an energy storage unit since it does not fall into the definition of energy storage used in the power system related literature and presented earlier in this chapter. Moreover, unlike most of energy storage technologies, hydro power with a reservoir can produce electricity at a constant rate, even with an empty reservoir and only limited by the water inflow. Thus, similar to thermal generation and run-of-river hydro, a hydro power plant with a reservoir can be considered as a generator with constant power and an energy storage unit. The constant generation of the hydro power plant is equal to the inflow of the reservoir. The flexibility of the hydro power plant with reservoir is then limited by the maximum generation capability of the plant and energy equivalent of the water reservoir capacity. The new mathematical formulation of a hydro power plant with reservoirs can be described as:

$$\tilde{e}^h_{htk} = \tilde{e}^h_{htk-1} - \gamma_f \tilde{g}^h_{htk} + \theta_f \tilde{d}^h_{htk} \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.9a}$$

$$\tilde{e}^h_{htk=0} = \tilde{E}^0_{ht} \quad \forall h \in \mathcal{H}, t \in \mathcal{T} \tag{2.9b}$$

$$0 \leq \tilde{e}^h_{htk} \leq E_f \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.9c}$$

$$0 \leq \tilde{g}^h_{htk} \leq P^g_f \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.9d}$$

$$0 \leq \tilde{d}^h_{htk} \leq P^d_f \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.9e}$$

$$0 \leq \overline{g}_{htk} = u_{htk} \Upsilon_h \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.9f}$$

2.2.3 Flexible demand

A reformulation of the mathematical formulation of flexible demand into energy storage-like constraints is performed using similar steps as for thermal generation. Demand has a base component which does not depend on price and is defined as $\underline{D}_d$ and a flexible component d_{dtk} with constant utility function α_i. Flexible demand is restricted by maximum contracted flexible load capacity, D_d. In addition, the flexible part of the demand is assumed to be dispatchable and can be changed upwards or downwards. This is represented by two additional variables; $\tilde{g}^d_{dtk}$ and $\tilde{d}^d_{dtk}$. $\tilde{g}^d_{dtk} \geq 0$ and $\tilde{d}^d_{dtk} = 0$ if load is decreased while $\tilde{d}^d_{dtk} \geq 0$ and $\tilde{g}^d_{dtk} = 0$ if load is increased.

$$\tilde{g}^d_{dtk} = (d_{dtk} - d_{dtk-1}) \Upsilon((d_{dtk} - d_{dtk-1}) \leq 0)$$
$$\forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K}$$
$$\tilde{d}^d_{dtk} = (d_{dtk} - d_{dtk-1}) \Upsilon((d_{dtk} - d_{dtk-1}) \geq 0)$$
$$\forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K}$$

The flexible operation of demand is described by (2.10). Flexible load is assumed to consist of energy limited sources and the deviation from the base load d_{dtk} is limited by E_g which represents the maximum dispatchable demand at each operational period $k < \widehat{K}$ and should be equal to d_{dtk} at the last operational period $k = \widehat{K}$. By doing this, the energy balance constraint ensures that if demand is decreased at time k it will need to be increased at a later time period. Flexibility of dispatchable load is also restricted by technical constraints which does not allow load increase ($\tilde{d}^d_{dtk}$) or decrease ($\tilde{g}^d_{dtk}$) on full capacity through upper limits D_d and G_d. Available flexible load capacity can be increased by contracting additional load from the base component.

$$\tilde{e}^{d}_{dtk} = \tilde{e}^{d}_{dtk-1} - \tilde{g}^{d}_{dtk} + \tilde{d}^{d}_{dtk} \quad \forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.10a}$$

$$\tilde{e}^{d}_{dtk=0} = \underline{D}_{d} \quad \forall d \in \mathcal{D}, t \in \mathcal{T} \tag{2.10b}$$

$$0 \leq \tilde{e}^{d}_{dtk} \leq E_{g} + \widehat{E}_{gt} \quad \forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.10c}$$

$$0 \leq \tilde{d}^{d}_{dtk} \leq D_{d} \quad \forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.10d}$$

$$0 \leq \tilde{g}^{d}_{dtk} \leq G_{d} \quad \forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K} \tag{2.10e}$$

Thus, investment planning models for flexibility sources can be generalized to follow a similar structure as energy storage investment models where efficiencies and capital costs vary dependent on the technology and type of flexibility source.

The application of a generalized mathematical formulation in mathematical models allows to mathematically represent flexibility sources in a compact way and model them as an aggregated energy storage unit. In this way, computational tractability of the mathematical models can be improved and flexibility needs in power system can be determined in an aggregated way. Detailed mathematical models for investment planning for flexibility sources can be found in Chapter 4 of this thesis. In addition, accepted publications $J1$ and $J2$ are also addressing the problem of flexibility investment planning.

Chapter **3**

Incentive-based transmission investments

This chapter provides a theoretical background to transmission investments planning including a description of several incentive mechanisms. The chapter can be used as complementary material to publications $J2$, $J3$ and $J4$. Furthermore, contributions $C2$ and $C3$ are addressed in this chapter. The provided theoretical background is further used in Chapter 4 to develop mathematical models for investment planning in transmission assets and for coordinated transmission planning.

The aim of any transmission investment planning is to answer the following three questions:

- **where** should a transmission line be built?
- **which** technical characteristics transmission line should have?
- **when** should a transmission line be built?

The answers to these questions may seem straightforward. However, in reality the answer to these questions is complicated due to various uncertainty sources and ambiguities. For example, benefits can be quantified as future cash flows obtained from owning and operating an invested transmission line, or, benefits can be evaluated as total added values to networks participants. An average transmission project takes 10 years to build and practice shows that more than 50% of the projects are delayed or rescheduled [74]. Thus, at the time of completion, the additional transmission capacity can become no longer beneficial and strongly depends on interaction of other system participants such as generation, load and storage. Moreover, reference [74] shows that capital cost estimations of more than 60% of the projects are underestimated. At the same time, reference [52] reports that market based revenues of a transmission company can cover only 25% of the transmission project's total capital cost. As a result, efficient transmission investments require additional incentives from governing entities as well as a properly designed regulatory environment. Furthermore, a growing need for additional wind and solar generation integration requires additional transmission capacities which are well coordinated with the renewable generation investment as well as with flexibility assets such as energy storage.

This chapter addresses all aforementioned challenges associated with transmission investment planning. In Section 3.1 the main principles of transmission investment planning in power systems are described. Benefits and costs of transmission investment are discussed in Section 3.2. Uncertainty sources are presented in Section 3.3. Finally, incentive mechanisms are described in detail in 3.4.

3.1 Transmission investments

The quantification of benefits of an investment project depends on the objectives of a transmission investment as well as on the ownership type. Theoretically, depending on the utility structure of a power system network, a transmission company can be [75]:

- 1. owned and operated by a centralized entity (centrally owned transmission company).
- 2. owned by an independent transmission company and operated based only on market rules (merchant transmission company).
- 3. owned by an independent transmission company and operated based on regulation and market rules (regulated merchant transmission company).

Investment planning of a centrally owned transmission company aims to maximize the social welfare of the network. This means that the transmission investment under the centralized approach should result in the best possible outcome for loads, generators and energy storage. However, such an approach does not take into account market signals from deregulated agents such as generation, load and storage. Thus, in order to achieve the desired outcome, a centrally owned transmission company requires access to all information from all agents which is restricted and protected by regulation. On the other hand, the merchant approach is suitable for deregulated electricity markets and allows to plan investments based purely on market signals. However, the merchant approach has the same drawbacks as the centralized approach. Theoretically, the merchant approach may lead to the same outcome as the centralized one if the perfect information and perfect competition assumptions are satisfied. However, merchant approach have never been successfully implemented in practice. Such an approach is practically hard to implement and was proven to have several economic and regulatory hurdles [76]. Another approach proposed in the literature as well as implemented in various forms in practice is the mixed approach. The mixed approach is commonly known as regulated-merchant approach and combines the benefits of both centralized and merchant approach by capturing price signals from deregulated agents while aiming to maximize socially optimal outcome through regulation and incentives. However, in order to achieve socially optimal results, the proper incentive mechanisms have to be adopted by the regulator.

The regulated-merchant approach assumes that two different independent entities are involved in the decision to invest in transmission assets:

- Regulator.

- Independent Transmission Company or Transmission System Operator (TSO).

The objective of a transmission investment can differ depending on the ownership structure listed above. Ownership structure corresponding to 1,2 and 3 is defined as I, II and III respectively:

- I. Minimization of total investment and system operation costs; maximizing reliability; minimizing expected failures. (centrally owned)

- II. Maximization of market based profits from operation of a transmission asset. (merchant)

- III. Maximization of market based profits from operation of a transmission asset and additional monetary incentives. (regulated merchant)

Despite different objectives of the transmission planning project the main goal of transmission investment is to satisfy the need for additional transmission capacity and to maximize social welfare. Overall, any transmission planning will have to follow social welfare maximizing direction regardless of the type of the objective. The need for additional transmission capacity depends on the current state of the transmission infrastructure as well as the development of generation, demand and development of various electricity market designs. For example, the European goal to develop integrated and harmonized electricity markets is challenged by limited cross border capacities. In order to ensure fair trade between the states while providing sufficient reliability of operation large transmission investments will be required. On the other hand, many electricity markets are subject to internal congestion problems and lack of network investments. For example, in the U.S. (PJM) the market based approach did not obtain the needed transmission investment and the system suffers from severe congestion. Moreover, increased uncertainty of expanding renewable generation results in additional transmission needs and, as a consequence, increased transmission investment cost [77].

In order to decide on additional transmission capacities a comprehensive mathematical model should be developed. Such model will have different levels of complexity depending on the utility structure of the system.

3.2 Benefits, profitability and cost of transmission investments

The benefits of transmission investments can be evaluated in different ways depending on the objectives of the investment planner: (i) improved reliability of the system; (ii) increased profits from the operation of the transmission system; (iii) added societal value.

Improvement of reliability can be measured using various indices such as Loss of Load Probability (LOLP), Expected Energy Not Served (EENS), and many more. However, in the restructured electricity markets monetary benefits are more relevant. The transmission infrastructure owner can generate revenue by providing transmission services to other customers of the system such as generators, loads, and energy storage. Depending on the structure of the system the revenues can be generated through transmission tariffs or other operational charges such as financial transmission rights (FTR).

Transmission tariffs are usually designed in order to recover the maintenance and investment costs of all transmission assets. On the other hand, FTRs correspond to congestion rents. A congestion rent reflects the value of a transmission line in linking two different nodes with different prices.

Apart from congestion rent, the societal benefits can further be quantified by changes in economic indicators such as social welfare and consumer surplus. The change in the total social welfare can be evaluated as the summed surplus of all consumers in the power system. Here, the term consumers includes loads, generation utilities and energy storage utilities. The change in social welfare ΔSW can be quantified as:

$$\Delta SW = \Delta LS + \Delta GS + \Delta SS + \Delta TS - C, \tag{3.1}$$

where ΔLS is the change in total load surplus, ΔGS is the change in total generation surplus, ΔSS is the change in total energy storage surplus, ΔTS is the change in total transmission surplus and C is the total investment costs associated with load utilities, generation utilities, energy storage utilities or the transmission company.

3.3 Uncertainty in transmission planing

Transmission investment planning is subject to various uncertainty sources. Renewable generation and load uncertainty can congest the transmission system, especially, when the penetration is high. On the other hand, outages and other malfunctions of the equipment are also hard to predict and therefore can affect the reliable operation of a power system. Therefore, these uncertainty sources should be taken into account when decisions on transmission line investments are made. Moreover, under the market based transmission investment planning, the cost of the equipment and other economic aspects also have a large impact.

Reliability standards vary for each system and are customarily adapted based on changing characteristics of the system such as, for instance, the generation mix. Reliability standards can be incorporated in any transmission planning by enforcing additional technical constraints on transmission operation and planning. Under centralized planning reliability standards can be seen as the main criteria for investments. However, under market based transmission planning the objective of a transmission investor is profit maximization. Yet, the reliability criteria can be still be enforced by a regulator or a system operator (ISO). The system operator can enforce additional technical reliability constraints which have to be met for the secure operation of the system. A common example for additional constraints is the N-1 criterion. This method will lead to socially optimal investments while reliability criteria are satisfied. From an economic prospective, such reliability constraints may result in additional charges to the consumers. The regulator can relax reliability criteria constraints and promote reliability by assigning monetary weights for each criteria. Thus, the reliability of the power system will become a part of the profit structure of the transmission company.

3.4 Incentive mechanisms

The need for additional incentive mechanisms appears when market signals can no longer guarantee socially beneficial behaviour of a commercial entity. According to [52], congestion rents account for only 25% of the total transmission investment costs. This means that existing market signals such as congestion rents alone cannot provide sufficient incentives for a transmission company to expand the transmission network. Furthermore, market signals are reactive incentives, i.e., price signals can support investment decision only after the scarcity has occurred. The large-scale integration of renewable energy sources requires a significant transmission expansion which should be performed in a proactive way, i.e., before or alongside the expansion of renewable energy capacity. Thus, additional proactive incentives may be necessary to facilitate adequate growth of transmission infrastructure in order to support growth of renewable generation.

Additional incentives are usually controlled by a regulatory entity which can design an appropriate incentive mechanism to facilitate adequate and socially beneficial development of the electricity sector.

Various types of incentive mechanisms were proposed in the literature. However, the effect of incentive mechanisms cannot be analyzed in a unified way and depends on the type of the investment [78]. Two main types of investments can be distinguished:

- Investments which result in end product cost reduction.
- Investments which support infrastructure development.

Transmission investments can be allocated in both categories. Additional transmission capacity may result in electricity price reduction by allowing more efficient operation of cheaper power plants. At the same time the transmission network is the vital infrastructure of any power system.

Similar to the investment classification, two main groups of investment mechanisms can be distinguished:

- Cost-Plus mechanisms. A regulatory entity fixes the rate of return on a particular investment. The regulator sets a maximum allowed charge which a utility can collect from customers to reach a predefined return on investment costs. The charge can include all maintenance and operation costs as well as investment costs. In simple words, the Cost-Plus mechanism allows a utility to reimburse all its costs plus a predefined premium.

- Price-Cap (revenue-cap) mechanisms. A regulatory entity fixes the maximum revenue a utility can earn or maximum price it can charge for a product or service.

Cost-Plus mechanisms are considered to be more suitable for infrastructure investments while Price-Cap mechanism are considered to be more effective for cost reduction investments [79]. This is due to the basic characteristics of each mechanism. The Cost-Plus mechanism reimburses all the costs associated with the investment and operation. As a result the utility has no incentive to reduce investment or operation costs. On the contrary, by setting a maximum boundary on the revenue the regulator implicitly motivates the utility to reduce its costs in order to achieve higher profits. Furthermore, the effectiveness of any incentive mechanism depends on the accuracy of the design and parameter tuning. The effectiveness of incentive regulation can be quantified by its impact on social welfare as illustrated in Fig. 3.1. For example, under the Cost-Plus mechanism, if the rate of return is chosen too low it might result in underinvestment. On the other hand, if the rate of return is selected to be too high then the utility will be incentivized to overinvest. Similarly, if revenue cap is selected too low under the Price-Cap mechanism the firm might go bankrupt and will not have an incentive to operate at all, while, if the price cap is too high there will be no incentive to reduce operational costs. A more comprehensive comparison of these two categories of incentive mechanisms can be found in [80].

References [52] and [53] propose Price-Cap regulatory mechanisms for incentivizing transmission investments of a transmission company. Under certain conditions, these regulatory mechanisms lead to a transmission expansion plan which maximizes social welfare [54]. Reference [55] proposes a reward/penalty regulatory mechanism. In this regulatory mechanism, the regulator rewards the transmission company when the transmission network is expanded and the congestion rents are decreased. Reference [56] proposes an out-turn regulatory mechanism. The out-turn is defined as the difference between actual electricity prices and prices without transmission congestion. The transmission company is responsible for total out-turn cost and any transmission losses. References [54] and [57] extend the work in [52] and propose the incentive-based mechanism for transmission investment. In

Table 3.1: Comparison of different incentive mechanisms.

Advantages:	Cost-Plus	ISS	H-R-G-V
Does not involve subsidies	**yes**	no	**yes**
Guarantees socially optimal investments	no	**yes**	**yes**
Based on market information	no	**yes**	**yes**
Promotes competitive behavior	no	no	**yes**
Simple to model	**yes**	**yes**	**yes**
Convergence to a global solution is guaranteed	**yes**	**yes**	**yes**

this incentive-based regulatory mechanism, the transmission company maximizes its profit (sum of merchandising surplus and a fixed charge) subject to the Price-Cap constraint introduced in [52].

Furthermore, incentive mechanisms can be classified based on the information available to the regulator. Two different scenarios of information availability as well corresponding preferred regulatory schemes can be distinguished:

- The regulator has superiority in accessing all the monetary information in the power system operation and planning of all agents of the system including regulated firms. In this scenario, the regulator can exploit all available information and choose to apply the Bayesian incentive scheme.

- The regulator has limited information on costs structures and operations of a regulated firm (in this thesis, a transmission firm). Under limited available information the regulator cannot apply the Bayesian incentive mechanism efficiently. Thus, a non-Bayesian incentive scheme should be preferred.

Earlier it was mentioned that transmission investment can be classified as system cost reduction investments as well as infrastructure investments. Thus, both Cost-Plus and Price-Cap mechanisms can be considered by a regulator. However, since transmission companies are usually natural monopolies and independent profit maximizing entities only non-Bayesian incentive schemes can be applied to support transmission planning. One of the most famous and oldest non-Bayesian incentive mechanisms is the Incremental Subsidy Surplus (ISS) mechanism. The ISS mechanism employs characteristics of Price-Cap mechanism and incentivizes the transmission company to operate in a social welfare maximizing way. Furthermore, extensive research was performed to combine the main characteristics of Cost-Plus and Price-Cap mechanisms into a single non-Bayesian incentive mechanism [81], [54], [11]. The latter publication [11] presents an H-R-G-V (Hesamzadeh-Rosellon-Gabriel-Vogelsang) mechanism and shows promising performance of the proposed mechanism when applied on transmission investment planning. A comparison of benefits and drawbacks between different incentive mechanisms is presented in Table 3.1

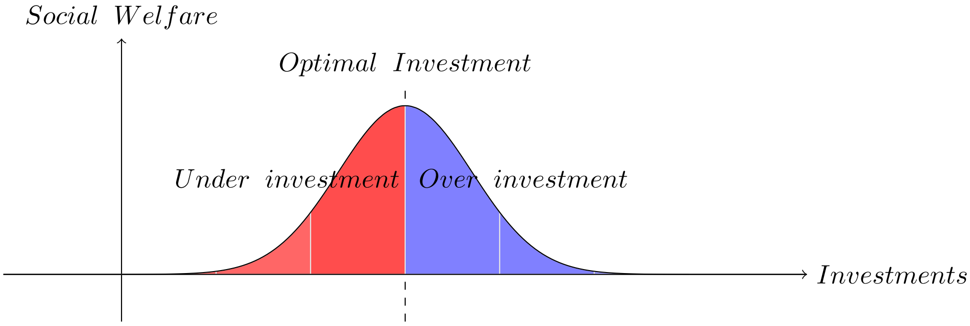


Figure 3.1: Social welfare changes based on accuracy of incentive mechanism design.

3.4.1 Application of the incentive mechanism

Under the incentive-based merchant-regulatory approach the transmission company maximizes its profit by expanding its transmission network while considering regulatory constraints and additional subsides or taxes set by the regulator and depending on incentive mechanisms of choice. In this chapter, three different incentive mechanisms are analyzed: Cost-Plus, ISS and H-R-G-V. All three aforementioned incentive mechanisms require the regulator to design a regulatory constraint and set a fixed fee to reimburse the transmission company based on its performance. The transmission company communicates transmission investment decisions to the regulator and to a system operator (ISO) or equivalent centralized power system operation entity such as a market operator. The ISO dispatches the system and communicates the required information such as load levels, electricity prices, recent capacity changes and system operation costs to the regulator. The regulator uses the information provided by the ISO to recalculate the fixed fee using predefined regulatory constraints and reimburses the transmission company.

For illustrative purposes the following assumptions are taken in this chapter:

- Transmission lines are built at the same time as the decision is taken.
- Generators, loads, and energy storage are independent profit maximizing utilities and comply with perfect competition and perfect information assumptions.
- The transmission company does not share the information on its operation and investment costs.

Then the incentive-based transmission investments can be described as:

$$\begin{aligned} &\textit{Maximize Total congestion rent + Fixed fee} \\ &\qquad \textit{- Total transmission investment cost} \qquad (3.2a) \\ &\textit{Subject to:} \end{aligned}$$

The regulatory constraint (3.2b)
Transmission investment constraints (3.2c)
Maximize social welfare (3.2d)
Subject to:
Power system operation constraints (3.2e)

The merchant-regulated transmission company maximizes its total profit which consists of market based revenues (congestion rent) and additional fixed incentive payment (fixed fee). Congested rent is calculated by simulating a market clearing process which can be described as a social welfare maximization problem (3.2d). In this chapter, only the generalized mathematical welfare maximization problem formulation is presented. However, Chapter 4 provides detailed models for centralized market operation and dispatch. The fixed fee is decided by the regulator according to regulatory constraint (3.2b). The regulatory constraint varies depending on the incentive mechanism chosen by the regulator. In the following sections, different incentive mechanisms and the corresponding regulatory constraint are described.

In general form the problem can be mathematically formulated as:

$$Maximize \sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Phi_t - \overline{C}_t) \tag{3.3a}$$

$$Subject\ to:$$

$$f(\Phi_t) = 0 \ \ \forall t \tag{3.3b}$$

$$Maximize \sum_t (\mathbb{E}[\pi^G_{st}] + \mathbb{E}[\pi^S_{st}] + \mathbb{E}[\pi^T_{st}] + \mathbb{E}[\pi^L_{st}]$$

$$Subject\ to: \text{Power system operation constraints} \tag{3.3c}$$

where $\mathbb{E}[\pi^G_{st}]$ is the expected net profit (including investment costs) of all generation units including wind, thermal, hydro, nuclear and solar. $\mathbb{E}[\pi^T_{st}]$ is the expected short-term net profit of the transmission company obtained by operating the transmission network using competitive market rules and does not include a fixed fee or investment costs. $\mathbb{E}[\pi^L_{st}]$ is the expected total net profit of all loads which includes investment costs and assumes that the utility function of each load is known. $\mathbb{E}[\pi^S_{st}]$ is the expected net profit of energy storage utilities which includes investment costs. $\overline{C}_t$ and Φ_t are the total transmission investment cost and the fixed fee respectively. β_t is the discount rate of the transmission company and is assumed between 0 and 1 ($0 < \beta_t < 1$). The function $f(\Phi_t) = 0$ represents the regulatory constraint and is used to calculate the fixed fee which will be discussed below.

3.4.2 Cost-Plus regulation

Cost-Plus is one of the simplest incentive mechanisms. Cost-Plus incentivizes a transmission company by gradually reimbursing shares of transmission investment costs plus a certain mark-up. The mark-up is usually added in order to guarantee that the transmission company will meet its target return while making investment decisions. In addition, the mark-up is designed such that it reimburses the reduced congestion rent and covers interest rates (opportunity cost of transmission company). The regulatory constraint of the Cost-Plus mechanism can be formulated as:

$$\Phi_t = (1 + R_t)\overline{C}_t \tag{3.4}$$

where R_t is the mark-up coefficient set by the regulator. The fixed fee in the objective function (3.3a) of the transmission company can be replaced by $(1+R_t)\overline{C}_t$. The total profit of the transmission company can then be reformulated as:

$$\sum_t (1 + \beta_t)(\mathbb{E}[\pi^T_{st}] + R_t\overline{C}_t) \tag{3.5}$$

by rewriting the fixed fee according to regulatory constraint (3.4). If the mark-up is chosen such that:

$$R_t\overline{C}_t = \mathbb{E}[\pi^G_{st}] + \mathbb{E}[\pi^T_{st}] + \mathbb{E}[\pi^L_{st}] + \mathbb{E}[\pi^S_{st}] - \overline{C}_t \tag{3.6}$$

then transmission investments can result in social welfare maximizing outcome. However, the tuning of the mark-up to optimality is an informationally complex task and requires the regulator to know also the investment costs of the transmission company. In practice, however, th einvestment costs of the transmision company are usually not made unavailable. Thus, the optimality of the mark-up cannot be guaranteed.

Furthermore, if the mark-up is not tuned to optimality, the transmission company has a strong incentive to over-invest. In (3.5) it can be observed that under the Cost-Plus incentive mechanism the transmission company maximizes the transmission investment costs. In practice, this results in a situation where a more expensive alternative of the investment projects will be chosen by the transmission company. In addition, the Cost-Plus incentive mechanism does not incentivize the transmission company to look forward in its investment planning and, as a result, the Cost-Plus mechanism is unlikely to support proactive transmission planning.

3.4.3 Incremental Subsidy Surplus mechanism (ISS)

The ISS mechanism is a non-Bayesian incentive mechanism and does not require the regulator to know cost functions of the transmission company. Moreover, the ISS mechanism has characteristsics of a Price-Cap incentive mechanism. The main idea behind the ISS incentive mechanism is to reward the transmission company based on its contribution to the change in social welfare by providing an upper limit on its profits through the regulatory constraint. The ISS mechanism calculates the change in social welfare for each investment planning period and redistributes the social welfare according to the contribution of the transmission company. The ISS incentive mechanism can be formulated as:

$$\Phi_t = \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] - \mathbb{E}[\pi^T_{st-1}] + \overline{C}_{t-1} \tag{3.7}$$

The regulatory constraint (3.7) of the ISS incentive regulation calculates the fixed fee Φ_t based on total change in social welfare which is equivalent to the sum of changes in generation, energy storage and load profits.
By replacing the fixed fee with the right hand side of constraint (3.7), the objective function of the transmission company (3.3a) becomes:

$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Phi_t - \overline{C}_t) =$$
$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] - \mathbb{E}[\pi^T_{st-1}] - \Delta\overline{C}_t) =$$
$$(1+\beta_{t=T})(\mathbb{E}[\pi^T_{st=T}] + \mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^S_{st=T}] + \mathbb{E}[\pi^G_{st=T}]) + \sum_t (\beta_{t-1} - \beta t)(\mathbb{E}[\pi^T_{st=T}] +$$
$$\mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^S_{st=T}]) - (1+\beta_{t=0})(\mathbb{E}[\pi^T_{st=0}] - \mathbb{E}[\pi^G_{st=0}] - \mathbb{E}[\pi^L_{st=0}] -$$
$$\mathbb{E}[\pi^S_{st=0}]) - \overline{C}_{t=1} - \sum_t (\beta_{t-1} - \beta t)\overline{C}_t - \overline{C}_{t=T} \tag{3.8}$$

In the scope of this thesis, Δ refers to the change of the respective parameter between two consecutive investment planning periods, e.g., before and after a transmission investment. Equation (3.8) shows that transmission investment planning under the ISS incentive regulation has a social welfare maximizing objective. However, the objective of the transmission company highly depends on the discount rate β_t in each investment period. Moreover, ISS incentive regulation guarantees that in the long-run and in the course of the whole investment planning horizon the transmission company will likely invest in social welfare maximizing transmission capacity. By considering future social welfare changes, the ISS mechanism promotes proactive transmission planning. However, ISS does not guarantee a social welfare maximizing outcome for each planning period. Furthermore, while ISS incentive regulation leads to maximum social welfare the proof is dependent on the discount rate which is outside of regulators knowledge. Thus, some complications may arise. For example, if the discount rate is small and does not vary over time, the objective of the transmission company is reduced to

$$(\mathbb{E}[\pi^T_{st=T}] + \mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^S_{st=T}] + \mathbb{E}[\pi^G_{st=T}]) - (\mathbb{E}[\pi^T_{st=0}] + \mathbb{E}[\pi^G_{st=0}] + \mathbb{E}[\pi^S_{st=0}] +$$
$$\mathbb{E}[\pi^L_{st=0}]) + \overline{C}_{t=1} - \overline{C}_{t=T} \tag{3.9}$$

and at each investment period the revenue of the transmission company consists of the total welfare of the system calculated for that period minus a constant which is the sum of load and generation welfare of the initial investment period.

3.4.4 Hesamzadeh-Rosellon-Gabriel-Vogelsang mechanism (H-R-G-V)

The H-R-G-V incentive mechanism employs similar principles as the ISS incentive mechanism. The H-R-G-V mechanism is non-Bayesian and has Price-Cap characteristics. As in the ISS, the transmission company receives payments corresponding to the change in social welfare. However, unlike the ISS, the H-R-G-V regulation depends recursively on the fixed fee in the preceding time period. This allows the H-R-G-V mechanism to dynamically adjust the fixed fee for each period based on the change in social welfare as well as on the performance of the transmission company during previous years. In comparison, the ISS mechanism can decide on the fixed fee based only on the current performance of the transmission company. The regulatory constraint for transmission investments under the H-R-G-V incentive regulation can be formulated as:

$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] \tag{3.10}$$

The objective function (3.3a) can with this regulatory constraint be reformulated as:

$$\begin{aligned}\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Phi_t - \overline{C}_t) = \sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \\ \Delta\,\mathbb{E}[\pi^L_{st}] - \Phi_{t-1} - \overline{C}_t) \approx \sum_t (1+\beta_t)(\mathbb{E}[\pi^G_{st}] + \mathbb{E}[\pi^T_{st}] + \mathbb{E}[\pi^L_{st}] + \mathbb{E}[\pi^S_{st}] - \overline{C}_t)\end{aligned} \tag{3.11}$$

The reformulated objective function shows that the regulated objective function of the transmission company is equivalent to the social welfare maximizing objective. The transmission company is rewarded by the sum of changes in load, energy storage and generation surplus in each investment period t. The changes in surplus relate to the benefits that load, energy storage and generation receive from additional transmission capacity. If the change in surplus is larger than the investment costs of the transmission company then the additional transmission capacity will be invested on. Unlike ISS, H-R-G-V regulation does not depend on the discount rate and, as a result, ensures that investments are optimal for each investment planning period. In H-R-G-V, the merchandising surplus and fixed fee of the transmission company reflect the social welfare. As a result, a profit maximizing transmission company will contribute to social welfare maximization and, consequently, to welfare-optimal electricity prices. In addition, by exploiting forward-looking, the H-R-G-V mechanism promotes proactive transmission planning and results in efficient and sustainable transmission investments.

3.4.5 Coordinated investments

This section covers contribution $C3$ of this thesis by extending theoretical formulations of ISS and H-R-G-V regulatory mechanisms to coordinated investment planning in power systems. In the previous subsection, three main incentive mechanisms were described. It was shown that under certain conditions all three mechanisms can result in social welfare maximizing outcome. One of the assumptions taken in the calculation of the social welfare was that installed capacities of generation, load and energy storage remain unchanged. However, the main need in transmission expansion arises due to growing renewable generation and energy storage capacities. Thus, additional investment in wind and energy storage capacities should be taken into account by the regulator when deciding on incentives for transmission companies.

In the case of Cost-Plus mechanism, the contribution of a transmission investment to socially optimal capacity development of wind and energy storage should be taken into account when calculating the mark-up parameter R_t. However, in the case of ISS and H-R-G-V regulation, the regulatory constraints should be adjusted to accommodate the changes in social welfare and investment costs associated with added wind and energy storage capacities.

In general form, the problem of coordinated transmission, wind and energy storage expansion planning can be mathematically formulated as:

$$Maximize \sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Phi_t - \overline{C}_t) \tag{3.12a}$$

$$Subject\ to:$$

$$f(\Phi_t) = 0 \ \ \forall t \tag{3.12b}$$

$$Maximize \sum_t (\mathbb{E}[\pi^G_{st}] + \mathbb{E}[\pi^S_{st}] + \mathbb{E}[\pi^T_{st}] + \mathbb{E}[\pi^L_{st}] - \widehat{C}_t - \underline{C}_t$$

$$Subject\ to: \tag{3.12c}$$

$$\text{Power system operation constraints} \tag{3.12d}$$

$$\text{Investment constraints} \tag{3.12e}$$

where, $\underline{C}_t$ and $\widehat{C}_t$ are investment costs of wind generators and energy storage units.

The ISS regulatory constraint can be rewritten as:

$$\Phi_t = \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] - \mathbb{E}[\pi^T_{st-1}] + \overline{C}_{t-1} - \overline{C}_t - \widehat{C}_t \tag{3.13}$$

Similarly, the H-R-G-V regulatory constraint can be rewritten as:

$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] - \Delta\widehat{C}_t - \Delta\underline{C}_t \tag{3.14}$$

Following the steps described in the previous subsection, it can be shown that both ISS and H-R-G-V incentive mechanism, enforced through constraints 3.13 and 3.14, respectively, will result in socially optimal coordinated investments in wind generation and energy storage units. Considering joint investments in transmission assets, energy storage and wind generation, the social welfare SW_t for time period t can be calculated as:

$$SW_t = \mathbb{E}[\pi^G_{st}] + \mathbb{E}[\pi^T_{st}] + \mathbb{E}[\pi^L_{st}] + \mathbb{E}[\pi^S_{st}] - \overline{C}_t - \widehat{C}_t - \underline{C}_t \tag{3.15}$$

By replacing the fixed fee variable in the objective function of regulated-merchant transmission company (3.12a) with the right hand side of the ISS regulatory constraint (3.13) the following new objective function is obtained:

$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] - \mathbb{E}[\pi^T_{st-1}] + \overline{C}_{t-1} -$$
$$\overline{C}_t - \widehat{C}_t - \overline{C}_t) =$$
$$(1+\beta_{t=T})(\mathbb{E}[\pi^T_{st=T}] + \mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^S_{st=T}] + \mathbb{E}[\pi^G_{st=T}]) + \sum_t (\beta_{t-1} - \beta t)(\mathbb{E}[\pi^T_{st=T}] +$$
$$\mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^G_{st=T}] + \mathbb{E}[\pi^S_{st=T}]) - (1+\beta_{t=0})(\mathbb{E}[\pi^T_{st=0}] - \mathbb{E}[\pi^G_{st=0}] - \mathbb{E}[\pi^L_{st=0}] -$$
$$\mathbb{E}[\pi^S_{st=0}]) - \overline{C}_{t=1} - \sum_t (\beta_{t-1} - \beta t)\overline{C}_t - \overline{C}_{t=T} - \widehat{C}_t - \underline{C}_t \approx$$
$$SW_{t=T} - SW_{t=1} - \sum_{1<t<T} (\overline{C}_{t=T} - \widehat{C}_t) \tag{3.16}$$

By applying ISS regulatory constraint for coordinated investment planning the objective function of a regulated-merchant transmission company becomes equivalent to maximizing overall social welfare change over the planning horizon and minimizing overall investments in energy storage and wind.

Similarly, when the H-R-G-V regulatory constraint is applied the objective function (3.12a) can be reformulated as:

$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{st}] + \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] + \Delta\,\mathbb{E}[\pi^L_{st}] - \Delta\widehat{C}_t - \Delta\underline{C}_t - \Phi_{t-1} - \overline{C}_t) \approx$$
$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^G_{st}] + \mathbb{E}[\pi^T_{st}] + \mathbb{E}[\pi^L_{st}] + \mathbb{E}[\pi^S_{st}] - \overline{C}_t - \widehat{C}_t - \underline{C}_t) \tag{3.17}$$

By applying the H-R-G-V regulatory constraint for coordinated investment planning, the objective function a regulated-merchant transmission company becomes equivalent to maximization of total social welfare.

3.4.6 Illustrative examples

Consider the two-bus example system presented in Fig. 3.2. The transmission company has to perform an investment planning and can choose to build two transmission lines $M1$ and $M2$. The system consists of two loads $D1$ and $D2$, a wind generator $W1$ and a thermal generator unit $G2$. In this illustrative example it is assumed that transmission expansion planning should be performed over four planning periods. Each planning period represents one year and includes 8760 hours of operation. The maximum demand for the first period is set to 300 MW with a 10 % increase for each consecutive planning period. Wind is also considered as a dispatchable source of energy with zero marginal cost. Moreover, it is assumed that maximum capacities of generators $W1$ and $G2$ remain unchanged for all four planning periods. The production form wind generators is considered to be only source of uncertainty.

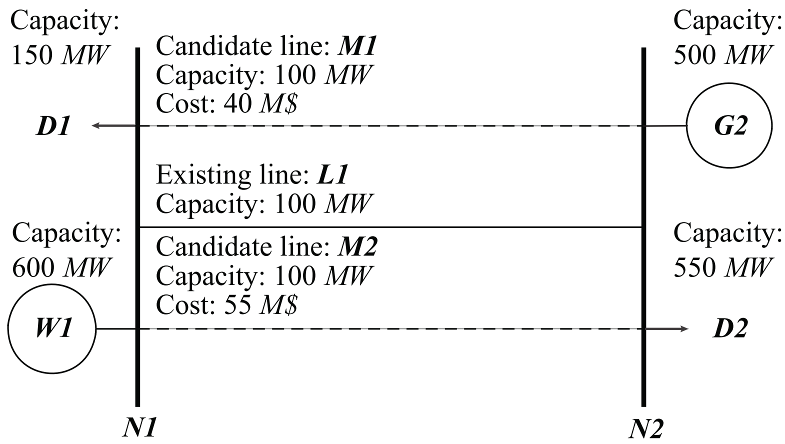


Figure 3.2: Illustration of the two-bus system used for transmission investment planning.

The illustrative example is a reduced version of the full scale model presented in Chapter 4. The results of the illustrative example are applied to the situation where no regulation is used, the case where Cost-Plus mechanism is applied, the case with ISS regulatory constraint, and the case with H-R-G-V regulation. In order to compare the results, an additional example of investment planning with social welfare maximizing objective is performed. The results [1] for each simulation are presented in Table 3.2-Table 3.6. In the case where no regulation is used, no investment in transmission assets are made. On the other hand, in the case where Cost-Plus mechanism is applied the transmission company invests in both lines, even though the investments result in lower social welfare. On the contrary, when H-R-G-V and ISS incentive mechanisms are used, the transmission company invests in $M1$. Moreover, exactly the same investment decisions are made under a centralized social welfare maximizing approach which represents the ideal investment planning. On the other hand, in the case study where no regulation is applied, no transmission investment are made. This result is consistent with the theoretical conclusion provided earlier in this chapter that unregulated investment planning may result in under-investing.

[1]It should be noted that social welfare results presented in the tables are discounted by interest rate and therefore are decreasing over time.

Table 3.2: Investment results without regulation in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	0	0	0	0
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	29.1	27.82	25.11	22.4
Wind curtailed (%)	7	5	3	2	1
Tran. Inv. Cost ($)	0	0	0	0	0

Table 3.3: Investment results under the Cost-Plus regulatory mechanism in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	**1**	**1**	**1**	**1**
M2 (1,2)	0	**1**	**1**	**1**	**1**
Social Welfare (M$)	38.45	30.4	30.1	29.2	28.7
Wind curtailed (%)	7	1	0	0	0
Tran. Inv. Cost (k$)	0	95 000	0	0	0

Table 3.4: Investment results under the ISS regulatory mechanism in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	**1**	**1**	**1**	**1**
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	31.2	30.51	29.9	29.1
Wind curtailed (%)	7	1	0	0	0
Tran. Inv. Cost (k$)	0	40 000	0	0	0

Table 3.5: Investment results under the H-R-G-V regulatory mechanism in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	**1**	**1**	**1**	**1**
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	31.2	30.51	29.9	29.1
Wind curtailed (%)	7	1	0	0	0
Tran. Inv. Cost (k$)	0	40 000	0	0	0

Table 3.6: Investment results under the centralized investments planning in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	**1**	**1**	**1**	**1**
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	31.2	30.51	29.9	29.1
Wind curtailed (%)	7	1	0	0	0
Tran. Inv. Cost (k$)	0	40 000	0	0	0

In the example above it was assumed that the maximum capacity of wind generator $W1$ remains unchanged for all planning periods. Now, consider a slightly different example system setup which is illustrated in Fig. 3.3. Storage unit $S1$ with installed energy capacity of 50 MWh and 25 MW power capacity is added at node $N2$. In addition, it is assumed that wind investment and energy storage investments can be performed by independent companies alongside transmission investments, i.e., installed capacities of units $W1$ and $S1$ can be increased with the corresponding investment costs of 600 $k\$$ per MW and 1000 $k\$$ per MWh.

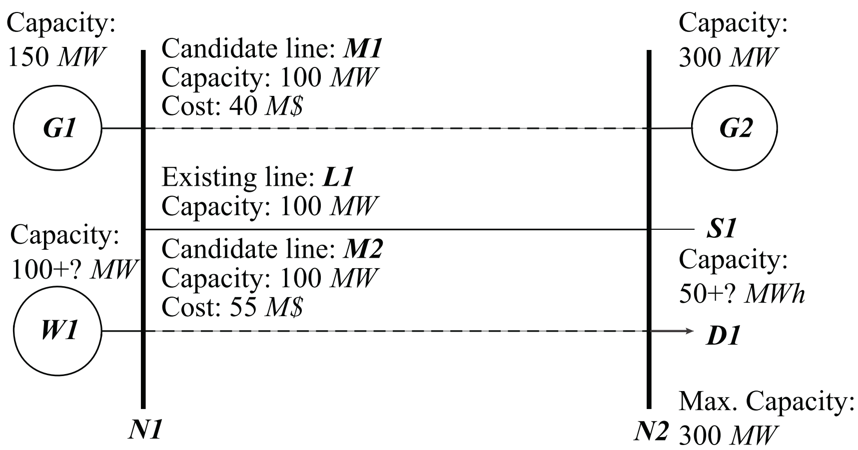


Figure 3.3: Illustration of the two-bus system used for coordinated investment planning.

The results [2] of this illustrative example are presented in Table 3.7 for the unregulated example, in Table 3.8 for Cost-Plus mechanism, in Table 3.9 for ISS mechanism, and in Table 3.10 for H-R-G-V.

[2]It should be noted that social welfare results presented in tables are discounted by interest rate and therefore are decreasing over time.

Table 3.7: Coordinated investment results without regulation in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	0	0	0	0
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	30.1	27.82	25.11	22.4
Wind curtailed (%)	0	10	5	3	2
Tran. Inv. Cost ($)	0	0	0	0	0
ES. Inv. Cost (k$)	0	20 000	0	0	0
Wind. Inv. Cost (M$)	0	4.1	0	0	0

Table 3.8: Coordinated investment results under the Cost-Plus regulatory mechanism in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
l1 (1,2)	0	**1**	**1**	**1**	**1**
l2 (1,2)	0	**1**	**1**	**1**	**1**
Social Welfare (M$)	38.45	32.9	32.22	29.9	29.4
Wind curtailed (%)	0	2	1	0.5	0
Tran. Inv. Cost (k$)	0	95 000	0	0	0
ES. Inv. Cost (k$)	0	15 000	0	0	0
Wind. Inv. Cost (M$)	0	3.7	0	0	0

Table 3.9: Coordinated investment results under the ISS regulatory mechanism in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	**1**	**1**	**1**	**1**
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	33.9	31.44	30.01	29.1
Wind curtailed (%)	0	0.5	0	0	0
Tran. Inv. Cost (k$)	0	40 000	0	0	0
ES. Inv. Cost (k$)	0	25 000	0	0	0
Wind. Inv. Cost (M$)	0	2.1	1.3	0	0

Table 3.10: Coordinated investment results under the H-R-G-V regulatory mechanism in the 2-bus system. Tran: Transmission; Inv: Investment.

	$t = 1$	$t = 2$	$t = 3$	$t = 4$	$t = 5$
M1 (1,2)	0	**1**	**1**	**1**	**1**
M2 (1,2)	0	0	0	0	0
Social Welfare (M$)	38.45	33.9	31.44	30.01	29.1
Wind curtailed (%)	0	0.5	0	0	0
Tran. Inv. Cost (k$)	0	40 000	0	0	0
ES. Inv. Cost (k$)	0	25 000	0	0	0
Wind. Inv. Cost (M$)	0	2.1	1.3	0	0

It can be observed that under the ISS and H-R-G-V mechanisms more efficient investment in wind generation and energy storage are performed. This observation supports the conclusion that ISS incentive mechanism and H-R-G-V mechanism promote a forward-looking approach and result in proactive transmission investment planning. Illustrative examples and case studies for transmission planning and coordinated investment planning applied to larger test systems can be found in publications $J2$, $J3$, and $J4$ of this thesis.

Chapter 4

Mathematical models and derivations

This chapter presents detailed mathematical models which can be used to support investment decision and capacity expansion processes in power systems. First, the mathematical models are described in Section 4.1-Section 4.4. Second, mathematical reformulations and linearizations are proposed in order to simplify the problems and improve computational tractability of the proposed models in Section 4.5. Third, in order to further improve computational tractability of the proposed and reformulated models tailored decomposition techniques are proposed and described in details in Section 4.6. All models presented in this chapter assume that the network consists of an interconnected transmission network, dispatchable loads with predefined utility function, hydro generation, thermal generation, energy storage units, and wind generation.

4.1 Centrally operated dispatch model

The short-term operation of a power system can be simulated in various ways depending on the assumptions about the utility structure, competition, etc. The comprehensive simulation of the short-term operation of a deregulated power system should include detailed simulation of each utility, electricity market, transmission company as well as regulatory entity. However, such comprehensive model will be computationally intractable and consequently not provide any solution or meaningful results. The short-term operation of a power system can be simplified by assuming perfect competition and perfect information. Then, the short-term operation can be reduced to simulation of the system operator (equivalently market operator) and formulated as a centrally operated dispatch model.

In this thesis, it is considered that a power system consists of independent loads, energy storage, generation utilities and an independent transmission company. Furthermore, the power system is operated by a system operator (market operator) under the perfect competition market rules and the assumption of perfect information between system operator, loads, energy storage and generation utilities is valid. In general form the centrally operated dispatch model of a system operator can be described as:

$$\underset{\Omega}{Maximize} \text{ Total gross consumer surplus} \tag{4.1a}$$

$Subject\ to:$

Short-term operational and technical constraints of a power system:

$a.$ Transmission power flow constraints (4.1b)

$b.$ Energy storage operation constraints (4.1c)

$c.$ Hydro power operation constraints (4.1d)

$d.$ Wind generation constraints (4.1e)

$e.$ Thermal Generation technical constraints (4.1f)

$f.$ Upper and lower limit operational constraints (4.1g)

The objective of the centrally operated dispatch model is to ensure that the supply of electricity is equal to the electricity demand at each operational period in the most cost effective way. This objective can be achieved by maximizing the difference between the total benefits obtained by the demand (utility function of demand multiplied by the total demand) and the overall costs of supply (marginal costs of generating and storage units). The objective function can be formulated mathematically as:

$$\underset{\Omega}{Maximize} \sum_{t\in\mathcal{T}} \frac{\Psi}{(1+i_t)^{t-1}} \Big(\sum_{s\mathcal{S}k\in\mathcal{K}} \pi_s (\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g\, g_{gtks} - \sum_{e\in\mathcal{E}} (C_e^{(dh)} \tilde{d}_{etks} + C_e^{(ch)}\ \tilde{g}_{etks})) \tag{4.2a}$$

The balance between demand and supply at each node of the system is achieved through power balance constraint:

$$\sum_{g\in\mathcal{G}} J_n^{(g)} g_{gtks} + \sum_{w\in\mathcal{W}} W_n^{(w)} \widehat{g}_{wtks} - \sum_{d\in\mathcal{D}} I_n^{(d)} d_{dtks} + \sum_{e\in\mathcal{E}} E_n^{(e)} \tilde{g}_{etks} + \sum_{h\in\mathcal{H}} H_n^{(h)} \overline{g}_{htks} - \sum_{e\in\mathcal{E}} E_n^{(e)} \tilde{d}_{etks} - \sum_{l\in\mathcal{L}} S_n^{(l)} f_{ltks} + \sum_{l\in\mathcal{L}} R_n^{(l)} f_{ltks} \quad \forall n\in\mathcal{N}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.2b}$$

The dispatch problem of a system operator is also subject to various technical constraints of the transmission network, generators and energy storage units. Transmission network consists of various transmission lines which connect one node of the system to another. Power flows in transmission lines are subject to Kirchhoff's law and consist of active and reactive power. Mathematically the active power flow of transmission line l can be modeled as:

$$f_{ltks} = \frac{R_l}{R_l^2+X_l^2}[\sum_{n\in\mathcal{N}} S_n^{(l)}\theta_{ntks}^2 - \sum_{n\in\mathcal{N}} S_n^{(l)}\theta_{ntks}R_n^{(l)}\theta_{ntks}cos(\sum_{n\in\mathcal{N}} S_n^{(l)}\sigma_n - \sum_{n\in\mathcal{N}} R_n^{(l)}\sigma)]+$$
$$\frac{X_l}{R_l^2+X_l^2}sin(\sum_{n\in\mathcal{N}} S_n^{(l)}\sigma_n - \sum_{n\in\mathcal{N}} R_n^{(l)}\sigma_n) \quad \forall l\in\mathcal{L},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.2c}$$

where R_l and X_l are resistance and reactance of transmission line l. The power flow formulation (4.2c) is nonlinear. However, the following assumptions[1] can be adopted in order to simplify the formulation to a linear representation of power flows:

- Line resistance can be neglected due to its relatively small numerical value and can be approximated to be equal to 0. $R_l^2 \approx 0$.
- Voltage values can be approximated to be equal to 1 p.u..
- Voltage angle difference between sending and receiving nodes is small. This leads to $sin(S_n^{(l)}\sigma_n - R_n^{(l)}\sigma_n) \approx S_n^{(l)}\sigma - R_n^{(l)}\sigma_n$and $cos(S_n^{(l)}\sigma_n - R_n^{(l)}\sigma_n) \approx 0$.

Using aforementioned assumption the power flow constraint can be reduced to:

$$f_{ltks} = \frac{100}{X_l}(\sum_{n\in\mathcal{N}} S_n^{(l)}\theta_{ntks} - \sum_{n\in\mathcal{N}} R_n^{(l)}\theta_{ntks}) = 0 \quad \forall l\in\mathcal{L},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}. \tag{4.2d}$$

Energy limited assets such as energy storage and hydro power can be modeled through a series of time coupled constraints. Energy storage operation involves keeping track of the state of charge which can be formulated as:

$$q_{etks} = q_{et(k-1)s} - \frac{1}{\Gamma}\tilde{g}_{etks} + \Gamma\tilde{d}_{etks} \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}. \tag{4.2e}$$

Similarly operation of hydro power plants requires control over the water reservoir levels. The changes in water reservoir levels can be modeled through hydrological balance constraints as:

$$m_{htks} = m_{ht-1ks} - \frac{1}{\Upsilon_h}\overline{g}_{htks} + u_{htks} - s_{htks} \quad \forall h\in\mathcal{H},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.2f}$$

Generation, load, energy storage charge and discharge as well as transmission power flows and hydro power reservoir levels have technical limits. These limits can be formulated as upper and lower bounds of the variables.

Transmission power flows are described through variables f_{ltks} which are positive if n is the sending node and negative if n is the receiving node. Upper and lower limit of power flows represent thermal limits of each line and are modeled as:

$$-F_l \le f_{ltks} \le F_l \quad \forall l\in\mathcal{L},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.2g}$$

[1]Resistance and reactance are assumed to be per unit values.

Operation of the hydro power is restricted by technical limits of the turbine

$$0 \leq v_{htks} \leq V_h \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}, \tag{4.2h}$$

maximum level of the hydro reservoir

$$0 \leq m_{htks} \leq M_h \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2i}$$

and the maximum water flow capacity of the spillways

$$0 \leq s_{htks} \quad \forall h \in \mathcal{H}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2j}$$

Operation of thermal generation is restricted by its maximum capacity

$$0 \leq g_{gtks} \leq G_g \quad \forall g \in \mathcal{G}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2k}$$

Similarly, wind generation cannot exceed its maximum installed capacity. However, wind generation output is also restricted by the wind energy available during the operation period. Thus, ϱ_{wtks} parameter is introduced to describe available (foretasted) wind generation as a percentage of known installed capacity. On the other hand, in this model it is assumed that wind generation can be curtailed. Resulting upper and lower limits are described as:

$$0 \leq \widehat{g}_{wtks} \leq (\widehat{G}_w) \varrho_{wtks} \quad \forall w \in \mathcal{W}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2l}$$

Energy storage operation is limited by the maximum power capability of an energy storage unit which is considered to be the same both for charge and discharge operation mode. On the other hand, most of energy storage units including battery and pump storage cannot charge and discharge at the same time. Thus, binary variables a_{etks} are introduced to ensure that charge and discharge does not happen simultaneously. Charge and discharge upper and lower limits then can be modeled as:

$$0 \leq \tilde{g}_{etks} \leq a_{etks} \widehat{P}_{et} \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2m}$$

$$0 \leq \tilde{d}_{etks} \leq (1 - a_{etks}) \widehat{P}_{et} \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2n}$$

The state of charge of an energy storage unit cannot exceed maximum energy capacity. Thus an additional constraint is introduced:

$$0 \leq q_{etks} \leq \widehat{E}_{et} \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2o}$$

Loads depend on predefined utility function and can vary accordingly, however, they cannot exceed the predefined maximum level:

$$0 \leq d_{dtks} \leq D_d \quad \forall d \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.2p}$$

Finally, the voltage of a slack (reference) node is set to be zero.

$$\theta_{ntks} = 0 \quad \forall t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}, n = n_1 \tag{4.2q}$$

The decision space of the centrally operated dispatch problem can be summarized as $\Omega = \{d_{dtks}, \tilde{d}_{etks}, \tilde{g}_{etks}, q_{etks}, \overline{g}_{htks}, v_{htks}, m_{htks}, g_{gtks}, \widehat{g}_{wtks}, f_{ltks}, \theta_{ntks} \in \Re\}$

4.2 Merchant energy storage operation and planning model

The objective of a merchant energy storage utility is to determine how much to invest in which asset or technology and where to allocate these investments so the investment target returns are satisfied and the maximum profit is achieved. The problem of a merchant energy storage utility in general form can be described as:

$$\underset{\Omega}{Maximize} \text{ Total short-term profits - total investment costs} \tag{4.3a}$$

$$subject\ \ to:$$

$$\quad \textit{Short-term operational technical constraints} \tag{4.3b}$$

$$\quad \textit{Investment return targets} \tag{4.3c}$$

$$\quad \textit{centrally operated dispatch:}$$

$$\quad\quad \textit{Minimize}\ \ \textit{Total operation cost} \tag{4.3d}$$

$$\quad\quad \textit{Subject to:}$$

$$\quad\quad\quad \textit{Power balance} \tag{4.3e}$$

$$\quad\quad\quad \textit{Power flow constraints} \tag{4.3f}$$

$$\quad\quad\quad \textit{Generation constraints} \tag{4.3g}$$

$$\quad\quad\quad \textit{Upper and lower operation limits} \tag{4.3h}$$

The objective function of a merchant energy storage utility consists of summed profits over the whole life-time of an asset or for a reasonable amount of time which will allow recovery of the investment cost minus total investment costs associate with the energy storage project. The profit of an energy storage depends on the business application and consists of overall revenues minus operational costs. In this chapter it is assumed that the main business application of an energy storage unit is energy arbitrage. The profit from energy arbitrage can be modeled as revenues from selling electricity while discharging minus costs from buying electricity while charging and minus additional costs associated with degradation (the case for batteries) or pumping (the case of pumped hydro and compress air energy storage). Total investment costs usually can be divided into two parts. First, investment costs associate with energy capacity of an energy storage unit such as costs of battery rack for batteries or water reservoirs for pumped hydro. Second, investment costs associated with power capability which determines the charge and discharge speed and maximum power an energy storage unit can provide. An example of cost associated with power capability expansion of an energy storage unit is power electronics costs for batteries or pumps and generators for pump storage's. To better reflect the reality of an energy storage investment process in this thesis it is assumed that the investments are performed in discrete manner. This means an energy storage utility can choose between energy storage modules of different technologies, where each module has fixed energy capacity, power capability and other technical parameters such as self-discharge and efficiency. Mathematically the objective function of a merchant energy storage utility can be described as:

$$\underset{x_{et},q_{etks},\tilde{g}_{etks},\tilde{d}_{etks}}{Maximize} \sum_{t,e} \frac{1}{(1+i_t)^{t-1}} (\sum_{k,s} \Psi\pi_s(E_n^{(e)}\lambda_{ntks}(\tilde{g}_{etks} - \tilde{d}_{etks}) - C_e^{(ch)}(\tilde{g}_{etks}+$$
$$\tilde{d}_{etks}) + FC_{tk}q_{etks} if(k=K)) - (C_{et}^{(E)} + C_{et}^{(P)})(x_{et} - x_{et-1})) \tag{4.4a}$$

The short-term revenues and as a result the maximization of the objective function is subject to short-term operational constraints, investment return targets as well as bidding strategy of the utility in the wholesale electricity market. An energy storage utility has to decide how much charge and discharge maximum capacities should be made available for a central dispatch problem. Moreover, merchant energy storage utility needs to maintain the technical limits of an energy storage unit and keep track of the state of charge of the unit. The operational constraint of energy storage units can be described through energy balance constraints and upper and lower limits of charge, discharge and energy levels at each operational period. Mathematically operational constraints of energy storage system which consists of several energy storage units can be formulated as:

$$q_{etks} = q_{et(k-1)s} - \frac{1}{\Gamma}\tilde{g}_{etks} + \Gamma\tilde{d}_{etks} \quad {\scriptstyle \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}} \tag{4.4b}$$
$$0 \le \widehat{g}_{etks} \le p_{et} \quad {\scriptstyle \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}} \tag{4.4c}$$
$$0 \le \widehat{d}_{etks} \le p_{et} \quad {\scriptstyle \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}} \tag{4.4d}$$
$$0 \le q_{etks} \le e_{et}x_{et} \quad {\scriptstyle \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}} \tag{4.4e}$$
$$0 \le p_{et}0 \le p_{et}^{(Inv)}x_{et} \quad {\scriptstyle \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}} \tag{4.4f}$$

This model represents only investment decision process while divestment decision is not modelled and assumed to be not an option for an energy storage utility. This means that invested capacities can only increase overtime and never decrease. Non-deceasing property of investment the decision can be represented through additional constraints as:

$$x_{et} \ge x_{et-1} {\scriptstyle \forall t\in\mathcal{T}} \tag{4.4g}$$

On the other hand, in order to maintain risks on an acceptable level any investment planner has certain constraints on expected returns on investments. Such constraint mathematically can be modeled as:

$$\sum_{t,e} \frac{1}{(1+i_t)^{t-1}} (\sum_{k,s} \Psi\pi_s(E_n^{(e)}\lambda_{ntks}(\tilde{g}_{etks} - \tilde{d}_{etks}) - C_e^{(ch)}(\tilde{g}_{etks} + \tilde{d}_{etks}) \ge$$
$$IR\sum_{t,e}(C_{et}^{(E)} + C_{et}^{(P)})(x_{et} - x_{et-1}) \tag{4.4h}$$

The investment decision process of a merchant energy storage uses spot prices to estimate profits. Spot prices can be simulated using short-term dispatch model presented in Section 4.1. However, since the actual operation of energy storage units are performed by a merchant energy storage utility, the energy storage state of charge operation constraints can be dropped from short-term dispatch model. On the other hand, the upper and lower limit constraints can be reformulated as in 4.5d and 4.5d to represent the bids and offers of an energy storage utility. The bids $\widehat{g}_{etks}$ and offers $\widehat{d}_{etks}$ of an energy storage utility are used to replace maximum and minimum available capacities in equations 4.2m and 4.2n respectively. The bids $\widehat{g}_{etks}$ and offers $\widehat{d}_{etks}$ of an energy storage utility are the limits which can be dispatch by a centrally operated market operator. By doing this, spot prices as well as actual dispatched charge and discharge amounts can be modeled as:

$$\tilde{d}_{etks}, \tilde{g}_{etks}, \lambda_{ntks} \in \tag{4.5a}$$

$$\arg \underset{\Omega_{ST}}{Maximize} \sum_{t\in\mathcal{T}} \frac{\Psi}{(1+i_t)^{t-1}} \Big(\sum_{s\in\mathcal{S},k\in\mathcal{K}} \pi_s (\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g\, g_{gtks} - \sum_{e\in\mathcal{E}} (C_e^{(dh)} \tilde{d}_{etks} + C_e^{(ch)}\ \tilde{g}_{etks})) \tag{4.5b}$$

$$Subject\ to\ :\ (4.2b) - (4.2l), (4.2o) - (4.2q) \tag{4.5c}$$

$$0 \le \tilde{g}_{etks} \le a_{etks} \widehat{g}_{etks}\ :(\underline{\kappa}_{etks}, \overline{\kappa}_{etks}) \quad \forall e\in\mathcal{E}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.5d}$$

$$0 \le \tilde{d}_{etks} \le (1-a_{etks}) \widehat{d}_{etks}\ :(\underline{\vartheta}_{etks}, \overline{\vartheta}_{etks}) \quad \forall e\in\mathcal{E}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.5e}$$

where $\Omega_{ST} = \{d_{dtks}, \tilde{d}_{etks}, \tilde{g}_{etks}, q_{etks}, \overline{g}_{htks}, v_{htks}, m_{htks}, g_{gtks}, \widehat{g}_{wtks}, f_{ltks}, \theta_{ntks} \in \Re\}$

Publication $J1$ utilizes similar model for energy storage investment planning and provides numerical test results which can be used to validate the model presented in this chapter. Publication $J1$ can be found in the Appendix of this thesis.

4.3 Regulated-merchant transmission planning model

Investment planning of a regulated-merchant transmission planner differs from the investment planning of merchant energy storage utility due to additional regulatory measures applied on the transmission revenues. The regulator can incetivize the merchant transmission company to invest in more socially beneficial transmission lines by offering an additional fixed payment (fixed fee) if the investment increased the social welfare. On the other hand the regulator has to decide how to calculate this fixed fee and which incentive mechanism to use. The choice of the regulator on incentive mechanism is a static process and is not influenced by the transmission decisions. Thus, the calculation of the fixed fee can be integrated into the transmission investment planning model. In this section H-R-G-V incentive mechanism is used to simulate calculation of the fixed fee. H-R-G-V incentive mechanism is chosen for illustrative purpose. Similar models can be formulated for other incentive mechanisms such as ISS and Cost-Plus mechanisms by reformulating regulatory constraint according to the incentive mechanism design. In general form the investment planning problem of a merchant-transmission planner can be formulated as:

Maximize: Total congestion rent + Fixed fee
- Total transmission investment cost (4.6a)
Subject to:
H-R-G-V regulatory constraint for each planning period (4.6b)
Linear transmission investment constraints (4.6c)
Centrally operated dispatch:
Minimize: Total operation cost (4.6d)
Subject to:
Power balance (4.6e)
Power flow constraints (4.6f)
Upper and lower operation limits (4.6g)

The theory behind the objective function of regulated-merchant transmission company and regulatory constraint was discussed in Chapter 3, while centrally operated dispatch was described in details in Section 4.1 of this chapter. The objective of the merchant-transmission company is to maximize its total short-term profits plus fixed fee from the regulator minus total investment costs. In short-term transmission company earns by providing transmission services between nodes which have price differences. The short-term profits ($\mathbb{E}[\pi^T_{st}]$) can be calculated as congestion rent which is the summed differences between nodal prices connected by the transmission multiplied by the corresponding generation or load and mathematically can be formulated as:

$$\mathbb{E}[\pi^T_{st}] = \sum_{snk} \lambda_{ntks}(\sum_{dk} I^{(d)}_n d_{dtks} + \sum_{ne} E^{(e)}_n \lambda_{ntks}(\tilde{d}_{etks} - \tilde{g}_{etks}) - \sum_{gk} J^{(g)}_n g_{gtks} - \sum_{wk} W^{(w)}_n \widehat{g}_{wtks})_{\forall t \in \mathcal{T}} \tag{4.7}$$

The objective function of the transmission company then can be mathematically modeled as:

$$\underset{z_{mt}, y_{mt}}{\text{Maximize:}} \sum_{t \in \mathcal{T}} \frac{\Phi_t + \mathbb{E}[\pi^T_{st}] - \sum_{m \in \mathcal{M}} C^{(T)}_{mt} y_{mt}}{(1+i_t)^{t-1}} \tag{4.8a}$$

The transmission investment process is simulated using integer variables y_{mt} and z_{mt}. The integer variable y_{mt} represent a decision to invest into a line m at the investment planning period t while z_{mt} represents existence of the line at the investment planning period t. A line m exists only if an investment decision was taken at investment planning period t or earlier. The existence of the line m is modeled as:

$$z_{mt} = \sum_{\widehat{t} \leq t} y_{m,\widehat{t}} \quad \forall m \in \mathcal{M}, t \in \mathcal{T} \setminus t_1 \tag{4.8b}$$

Where $\widehat{t}$ are the investment planning periods which happen before or at current investment planning period t. The transmission investment decision is assumed to be irreversible and can be taken only once. This property is modeled through additional transmission investment constraints:

$$\sum_{t \in \mathcal{T}} y_{mt} \leq 1 \quad \forall m \in \mathcal{M}, t \in \mathcal{T} \tag{4.8c}$$

$$z_{mt}, y_{mt} \in \{0, 1\} \tag{4.8d}$$

In addition, the first investment planning period is assumed to be a status-quo period and therefore no investment decision is taken and the fixed fee is also set to zero.

$$z_{mt} = 0 \quad \forall m \in \mathcal{M}, t = t_1 \in \mathcal{T} \tag{4.8e}$$

$$\Phi_{(t=t_1)} = 0 \tag{4.8f}$$

The Fixed fee Φ_t is calculated for each investment planning period where investment decision can be taken according to the regulatory constraint designed by the regulator. The regulatory constraint for H-R-G-V mechanism is simulated as:

$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi^L_{st}] + \Delta\,\mathbb{E}[\pi^G_{st}] + \Delta\,\mathbb{E}[\pi^S_{st}] \quad \forall t \in \mathcal{T} \setminus t_1 \tag{4.8g}$$

The regulatory constraint evaluates the change in the social welfare caused by the transmission investment decision and compares and sets fixed fee according to the change. The social welfare consist of the generation surplus $\mathbb{E}[\pi^G_{st}]$, load surplus $\mathbb{E}[\pi^L_{st}]$ and energy storage surplus $\mathbb{E}[\pi^S_{st}]$. Generation surplus includes hydro generation, wind generation a thermal generation surpluses and calculated as difference between revenue from selling electricity and costs from generation electricity:

$$\mathbb{E}[\pi^G_{st}] = \sum_{s \in \mathcal{S} g \in \mathcal{G} k \in \mathcal{K}} \Big(\sum_{n \in \mathcal{N}} J^{(g)}_n \lambda_{ntks} g_{gtks} - \Psi C_g g_{gtks}\Big) + \sum_{s \in \mathcal{S} n \in \mathcal{N} w \in \mathcal{W} k \in \mathcal{K}} W^{(w)}_n \lambda_{ntks} \widehat{g}_{wtks} + \sum_{s \in \mathcal{S} n \in \mathcal{N} h \in \mathcal{H} k \in \mathcal{K}} H^{(h)}_n \lambda_{ntks} \overline{g}_{htks} \forall t \in \mathcal{T} \tag{4.8h}$$

Similarly, load surplus is calculated as overall difference between benefits of consuming electricity and costs of buying electricity:

$$\mathbb{E}[\pi^L_{st}] = \sum_{s \in \mathcal{S} d \in \mathcal{D} k \in \mathcal{K}} \Big(\Psi A_d d_{dtks} - \sum_{n \in \mathcal{N}} I^{(d)}_n \lambda_{ntks} d_{dtks}\Big) \forall t \in \mathcal{T} \tag{4.8i}$$

Energy storage surplus is calculated as difference between revenues from selling electricity and costs of buying electricity and operational costs.

$$\mathbb{E}[\pi^{S}_{st}] = \sum_{s\in\mathcal{S} n e\in\mathcal{E} k\in\mathcal{K}} (E^{(e)}_{n}\lambda_{ntks}(\tilde{g}_{etks} - \tilde{d}_{etks}) + \Psi(C^{(dh)}_{e}\tilde{d}_{etks} - C^{(ch)}_{e}\ \tilde{g}_{etks}))\forall t \in \mathcal{T} \tag{4.8j}$$

The regulated-merchant transmission investment planning requires additional knowledge on spot prices in order to estimate fixed fee and make an investment decision. The spot prices can be simulated using short-term centrally operated dispatch model. However, the short-term dispatch model presented in Section 4.1 should be updated to include additional invested lines in the dispatch. The candidate lines can be modeled through disjunctive constraint:

$$\begin{bmatrix} \widehat{f}_{mtks} = 0 \\ z_{mt} = 0 \end{bmatrix} \vee \begin{bmatrix} \widehat{f}_{mtks} - \frac{100}{X_m}(\sum_{n\in\mathcal{N}} \overline{S}^{(m)}_{n}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}^{(m)}_{n}\theta_{ntks}) = 0 \\ z_{mt} = 1 \end{bmatrix}$$
$$\forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.9}$$

and upper and lower constraint of candidate lines:

$$-\widehat{F}_{m} \leq \widehat{f}_{mtks} \leq \widehat{F}_{m} \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.10}$$

Furthermore the power balance constraint also should be update to include power flows of newly invested transmission lines:

$$\sum_{g\in\mathcal{G}} J^{(g)}_{n} g_{gtks} + \sum_{w\in\mathcal{W}} W^{(w)}_{n}\widehat{g}_{wtks} - \sum_{d\in\mathcal{D}} I^{(d)}_{n} d_{dtks} + \sum_{e\in\mathcal{E}} E^{(e)}_{n}\tilde{g}_{etks} + \sum_{h\in\mathcal{H}}\sum_{h\in\mathcal{H}} H^{(h)}_{n}\overline{g}_{htks} -$$
$$\sum_{e\in\mathcal{E}} E^{(e)}_{n}\tilde{d}_{etks} - \sum_{l\in\mathcal{L}} S^{(l)}_{n} f_{ltks} + \sum_{l\in\mathcal{L}} R^{(l)}_{n} f_{ltks} - \sum_{m\in\mathcal{M}} \overline{S}^{(m)}_{n}\widehat{f}_{mtks} +$$
$$\sum_{m\in\mathcal{M}} \overline{R}^{(m)}_{n}\widehat{f}_{mtks} = 0 \ : (\lambda_{ntks}) \quad \forall n\in\mathcal{N}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.11}$$

By implementing aforementioned modifications in short term dispatch model spot prices, dispatched loads, generation, energy storage charge and discharge can be obtained as:

$$\tilde{d}_{etks}, \tilde{g}_{etks}, d_{dtks}, g_{gtks}, \overline{g}_{htks}, \widehat{g}_{wtks}, \lambda_{ntks} \in$$
$$\arg \underset{\Omega_{TR}}{Maximize} \sum_{t\in\mathcal{T}} \frac{\Psi}{(1+i_t)^{t-1}} \Big(\sum_{s\in\mathcal{S}, k\in\mathcal{K}} \pi_s (\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g\, g_{gtks} -$$
$$\sum_{e\in\mathcal{E}} (C^{(dh)}_{e}\tilde{d}_{etks} + C^{(ch)}_{e}\ \tilde{g}_{etks})) \tag{4.12a}$$
$$Subject\ to\ :\ (4.2b) - (4.2q), (4.18), (4.10) \tag{4.12b}$$

where $\Omega_{TR} = \{d_{dtks}, \tilde{d}_{etks}, \tilde{g}_{etks}, q_{etks}, \overline{g}_{htks}, v_{htks}, m_{htks}, g_{gtks}, \widehat{g}_{wtks}, f_{ltks}, \widehat{f}_{mtks}, \theta_{ntks} \in \Re\}$ The complete transmission investment problem of a regulated-merchant transmission company is then becomes a bilevel stochastic disjunctive problem.

A transmission investment problem of a regulated-merchant transmission company is also described in publication $J3$. Furthermore publication $J2$ contains numerical test results which can be used to validate the model. Publication $J3$ can be found in the Appendix of this thesis.

4.4 Coordinated operation and planning model

Development of transmission, renewable generation or energy storage cannot be evaluated in isolated way. Renewable generation capacity development affects the needs in additional transmission infrastructure as well additional flexibility which can be provided though energy storage. On the other hand, transmission infrastructure and energy storage capacities can be equivalently treated as substitutes or complements. Transmission and energy storage both can support development and integration of variable and uncertain renewable generation. On the other hand, transmission and energy storage cannot fully solve all challenges of renewable generation integration when applied alone. Moreover, both transmission and energy storage can affect electricity price levels and volatility and consequently indirectly influence to each other revenue streams. Thus, in order to achieve the best social welfare maximizing outcome the development of renewable generation, transmission and energy storage should be evaluated in a coordinated manner.
In general form coordinated investment planning of renewable generation, energy storage and transmission can be described as:

Maximize Total congestion rent + Fixed fee
- Total transmission investment cost (4.13a)

Subject to:

(A) Regulatory constraint for each planning period (4.13b)

(B) Linear transmission investment constraints (4.13c)

(C) ISO dispatch and capacity expansion planning (4.13d)

Minimize Total operation cost +
Generation investment costs+Energy Storage Investment costs (4.13e)

Subject to:

Linear generation investment constraints (4.13f)

Linear energy storage investment constraints (4.13g)

Power balance (4.13h)

$$\textit{Power flow constraints} \tag{4.13i}$$

$$\textit{Upper and lower operation limits} \tag{4.13j}$$

The objective as well as the objective function of transmission investment planning problem remains the same as for merchant-transmission investment planning and can be modeled as:

$$\underset{z_{mt},y_{mt}}{\text{Maximize:}} \sum_{t \in \mathcal{T}} \frac{\Phi_t + \mathbb{E}[\pi_{st}^T] - \sum_{m \in \mathcal{M}} C_{mt}^{(T)} y_{mt}}{(1+i_t)^{t-1}} \tag{4.14a}$$

The profit of transmission planner is still calculated as in (4.7). The investment decision constraints can be formulated as:

$$\sum_{t \in \mathcal{T}} y_{mt} \leq 1 \;\; \forall m \in \mathcal{M}, t \in \mathcal{T} \tag{4.14b}$$

$$z_{mt} = 0 \; \forall m \in \mathcal{M}, t = t_1 \in \mathcal{T} \tag{4.14c}$$

$$z_{mt}, y_{mt} \in \{0, 1\} \tag{4.14d}$$

On the other hand, additional capacity expansion of energy storage and wind generation has to be reflected in the calculation of the social welfare change. The idea is that transmission expansion should support the most cost efficient capacity decisions on energy storage and wind generation and as a result the calculation of fixed fee should depend on the investment costs. If transmission expansion caused investment in more expensive asset then the fixed fee will be lower, however, if the additional transmission line made it possible to invest in cheaper asset then transmission company will be compensated by higher fixed fee. Thereby, the regulatory constraint should be updated accordingly. H-R-G-V regulatory constraint adapted for coordinated expansion planning can be formulated as:

$$\Phi_{(t=t_1)} = 0 \tag{4.14e}$$

$$\begin{aligned}&\Delta\Phi_t = \Delta\,\mathbb{E}[\pi_{st}^L] + \Delta\,\mathbb{E}[\pi_{st}^G] + \Delta\,\mathbb{E}[\pi_{st}^S] + \\ &P_t(-\sum_{w \in \mathcal{W}} C_{wt}^{(W)}(u_{wt} - u_{w(t-1)}) - \sum_{e \in \mathcal{E}} C_{et}^{(E)}(e_{et} - e_{e(t-1)}) - \\ &\sum_{e \in \mathcal{E}} C_{et}^{(P)}(p_{et} - p_{e(t-1)})) \; \forall t \in \mathcal{T} \backslash t_1\end{aligned} \tag{4.14f}$$

Furthermore, transmission investments have to be coordinated with energy storage and wind generation capacity developments in the system. Under the assumption of perfect competition and perfect information energy storage and wind generation capacity decisions can be combined with centrally operated dispatch and market operation. To do so, the objective function of centrally operated short-term dispatch (4.2a) should be rewritten to include costs of investments into energy storage and wind generation as in $4.17a$. Wind generation investment costs at each investment planning period and for each wind location can be modeled as $C_{wt}^{(W)}(u_{wt} - u_{w(t-1)})$. Energy storage investment costs are modeled for each investment planning period and for each energy storage site as summed investment costs of power electronics components $C_{et}^{(P)}(p_{et} - p_{e(t-1)})$ and investment costs of energy capacity $C_{et}^{(E)}(e_{et} - e_{e(t-1)})$. Upper limit constraint of wind generation (4.2l) and energy storage (4.2l)-(4.2o) should be updated to include additional investment capacities:

$$0 \leq \widehat{g}_{wtks} \leq (\widehat{G}_w + u_{wt})\varrho_{wtks} : \quad \forall w \in \mathcal{W}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.15a}$$

$$0 \leq \tilde{g}_{etks} \leq a_{etks}(\widehat{P}_{et} + p_{et}) \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.15b}$$

$$0 \leq \tilde{d}_{etks} \leq (1 - a_{etks})(\widehat{P}_{et} + p_{et}) \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.15c}$$

$$0 \leq q_{etks} \leq \widehat{E}_{et} + e_{et} \quad \forall e \in \mathcal{E}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{4.15d}$$

Availability of invested energy storage and wind generation capacities are enforced through additional investment constraint which ensure that invested capacities are in place at each period of time after the investment decision took place. Energy storage and wind generation investment constraints are modeled as:

$$e_{et} - e_{e(t-1)} \geq 0 \;\; \forall e \in \mathcal{E}, t \in \mathcal{T} \tag{4.16a}$$

$$p_{et} - p_{e(t-1)} \geq 0 \;\; \forall e \in \mathcal{E}, t \in \mathcal{T} \tag{4.16b}$$

$$u_{wt} - u_{w(t-1)} \geq 0 \;\; \forall w \in \mathcal{W}, t \in \mathcal{T} \tag{4.16c}$$

Then, the parameters $\tilde{d}_{etks}, \tilde{g}_{etks}, d_{dtks}, g_{gtks}, \overline{g}_{htks}, \widehat{g}_{wtks}, \lambda_{ntks}$, u_{wt}, e_{et}, p_{et} used in the transmission planning problem can be obtained as:

$$\begin{aligned}
&\tilde{d}_{etks}, \tilde{g}_{etks}, d_{dtks}, g_{gtks}, \overline{g}_{htks}, \widehat{g}_{wtks}, \lambda_{ntks}, u_{wt}, e_{et}, p_{et} \in \\
&\arg \underset{\Omega^{CDC}}{Maximize} \sum_{t \in \mathcal{T}} \frac{\Psi}{(1+i_t)^{t-1}} \Big(\sum_{s \in \mathcal{S}, k \in \mathcal{K}} \pi_s (\sum_{d \in \mathcal{D}} A_d d_{dtks} - \sum_{g \in \mathcal{G}} C_g \, g_{gtks} - \\
&\sum_{e \in \mathcal{E}} (C_e^{(dh)} \tilde{d}_{etks} + C_e^{(ch)} \, \tilde{g}_{etks})) - \frac{1}{(1+i_t)^{t-1}} (\sum_{w \in \mathcal{W}} C_{wt}^{(W)} (u_{wt} - u_{w(t-1)}) + \\
&\sum_{e \in \mathcal{E}} C_{et}^{(E)} (e_{et} - e_{e(t-1)}) + \sum_{e \in \mathcal{E}} C_{et}^{(P)} (p_{et} - p_{e(t-1)}))
\end{aligned} \tag{4.17a}$$

The operational constraints of short-term dispatch will remain the same except the the decision space will increase to include capacity decision on candidate energy storage assets and wind generation. Thus, the maximization problem 4.17a is a subject to the following operational constraints:

$$(4.16), (4.2b) - (4.2k), (4.2p) - (4.2q), (4.15) \tag{4.17b}$$

$$(4.18), (4.10) \tag{4.17c}$$

The decision space of the dispatch problem combined with capacity decision problem is $\Omega^{CDC} = \{d_{dtks}, \tilde{d}_{etks}, \tilde{g}_{etks}, q_{etks}, \overline{g}_{htks}, v_{htks}, m_{htks}, g_{gtks}, \widehat{g}_{wtks},$

$f_{ltks}, \widehat{f}_{mtks}, \theta_{ntks}, u_{wt}, p_{et}, e_{et} \in \Re\}$ In this model energy storage and wind generation capacity decision are considered to be continuous. Due to scailability of wind farms and energy storage systems such assumption will still reflect investment planning in reality. The coordinated investment planning problem is then becomes a bilevel stochastic disjunctive nonlinear problem.

A coordinated investment planning problem for transmission investments and energy storage investments is presented and analyzed in publication $J2$. In publication $J3$ a comprehensive coordinated investment planning problem for transmission, wind and energy storage is presented and applied on numerical test cases. Both, publication $J2$ and publication $J3$, can be found in the Appendix of this thesis.

4.5 Additional mathematical derivations

The problems described above require a long-term forward price curves to evaluate investments. In this thesis the long-term forward curves are simulated using centrally operated dispatch and dispatch coupled with capacity development models (4.2), (4.12) and (4.17). The lower-level models (4.2), (4.12) and (4.17) are solved simultaneously with the respective investment planning problems (4.4),(4.8) and (4.17) and are formulated as a lower level problems. Thus, investment planning models presented in this chapter are stochastic, nonlinear or disjunctive nonlinear bilevel problems and as a result are hard to solve using commercial state-of-the-art solvers such as CPLEX or GUROBI. In this chapter, simple but yet effective reformulation techniques which can be applied on computationally challenging problems such as (4.4),(4.8) and (4.17) are presented. It is shown that bilevel, nonlinear and disjunctive problems can be reformulated into a single-level linear or mixed integer linear equivalent models using simple algebraic transformation and properties of first-order optimality conditions.

For illustrative purposes only one bilevel model from presented above was selected, namely the model (4.8). However, techniques presented in this chapter can be applied to any nonlinear disjunctive bilevel problems with similar properties to (4.8) which is the case for problems (4.4) and (4.8).

4.5.1 McCormic linearization technique for disjunctive constraints

Disjunctive constraints [2] such as constraint (4.18) are complicating constraints since they are nonconvex. Disjunctive constraints can be linearized using McCormic linearization technique also known as big-M reformulation. McCormic linearization technique were well studied in [82] and [83] and allows to reformulate disjunctive constraint into mixed-integer linear constraints with disjunctive parameters (also known as big-M parameters). The choice of disjunctive parameters is critical for mixed-integer linear reformulation of disjunctive constraints. The parameters

[2] See Section 4.6.1 for more information on disjunctive programming

should be chosen big enough that the original feasibility set does not change and not too big because the reformulated constraints should be as tight as possible in order to avoid computational intractability. If the disjunctive parameter is chosen carefully then the reformulated problem will be equivalent to the original one. Using this technique, the disjunctive constraints (4.18) can be reformulated as linear constraints in (4.19). Disjunctive constraint (4.18) in its original form is written as:

$$\begin{bmatrix} \widehat{f}_{mtks} = 0 \\ z_{mt} = 0 \end{bmatrix} \vee \begin{bmatrix} \widehat{f}_{mtks} - \frac{100}{X_m}(\sum_{n\in\mathcal{N}} \overline{S}_n^{(m)}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}_n^{(m)}\theta_{ntks}) = 0 \\ z_{mt} = 1 \end{bmatrix}$$
$$\forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.18}$$

Disjunctive constraint (4.18) is a nonlinear constraint and enforces the following logic into the decision making:

- if $z_{mt} = 1$ then power flow of line m is determined as: $\widehat{f}_{mtks} - \frac{100}{X_m}(\sum_{n\in\mathcal{N}} \overline{S}_n^{(m)}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}_n^{(m)}\theta_{ntks}) = 0$
- if $z_{mt} = 0$ then power flow of line m is equal to zero $\widehat{f}_{mtks} = 0$

The same logic can be enforced through a set of linear constraints (4.19). If $z_{mt} = 0$ then equations (4.19c) ensure that $\widehat{f}_{mtks} = 0$. Similarly, if $z_{mt} = 1$ equations (4.19a) and (4.19b) ensure that $\widehat{f}_{mtks} - \frac{100}{X_m}(\sum_{n\in\mathcal{N}} \overline{S}_n^{(m)}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}_n^{(m)}\theta_{ntks}) = 0$. In this case disjunctive parameter Ξ_m should be chosen big enough so the power flows $\widehat{f}_{mtks}$ are not restricted, meaning disjunctive parameter Ξ_m should be greater or equal to thermal limits of power lines m.

$$\widehat{f}_{mtks} - \frac{100}{X_m}(\sum_{n\in\mathcal{N}} \overline{S}_n^{(m)}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}_n^{(m)}\theta_{ntks}) \leq$$
$$\Xi_m(1 - z_{mt}) \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.19a}$$
$$\widehat{f}_{mtks} - \frac{100}{X_m}(\sum_{n\in\mathcal{N}} \overline{S}_n^{(m)}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}_n^{(m)}\theta_{ntks}) \geq$$
$$-\Xi_m(1 - z_{mt}) \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.19b}$$
$$-z_{mt}\Xi_m \leq \widehat{f}_{mtks} \leq z_{mt}\Xi_m \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.19c}$$

The tuning of the disjunctive parameter Ξ_m used in the example above is not complicated since the upper limits of the power flows are known. However, McCormic linearization technique also can be applied to a broader range of disjunctive constraints where upper limits of variables are not known and problem of tuning disjunctive parameter Ξ_m may occur. The problem of tuning disjunctive parameter Ξ_m is discussed in Section 4.6.1 of this chapter. Furthermore, a solution technique which does not involve disjunctive parameter Ξ_m is proposed in Section 4.6.5 of this chapter.

4.5.2 Linearization of energy storage charge and discharge operational constraints

Another complicating constraints of the lower-level problem are energy storage charge and discharge constraints (4.15b)-(4.15c). In order to simulate technical limitation and inability of an energy storage to charge an discharge at the same time additional integer variables are used in constraints (4.15b)-(4.15c). The presence of integer variables in the lower-level problem implies noncovex structure and as a result complicates solution process of the bilevel problem and limits convergence accuracy to the global optima. However, using Lemma 1 it can be shown that for the lower-level problems presented in this thesis integer variables involved in charge and discharge constraints can be dropped and constraints (4.15b)-(4.15c) can be formulated as:

$$0 \leq \tilde{g}_{etks} \leq (\widehat{P}_{et} + p_{et}) \quad \forall e\in\mathcal{E}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.20a}$$

$$0 \leq \tilde{d}_{etks} \leq (\widehat{P}_{et} + p_{et}) \quad \forall e\in\mathcal{E}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.20b}$$

The following Lemma[3] for energy storage operation constrains used in the models (4.2), (4.12) and (4.17).

Lemma 1. *The binary variables in the energy storage operation constraints modeled as in (4.15b)-(4.15c) can be dropped without allowing simultaneous charge and discharge operation of the energy storage system in the models of the same or similar structure as in (4.2). This means that relaxed LP formulation of (4.2) without charge and discharge binary variables is equivalent to the mixed integer LP formulation with charge and discharge binary variables.*

Proof. Assume that the binary variables are not in place (the problem (4.2) is formulated as an LP problem and equations (4.15b)-(4.15c) are replaced with (4.20)) but charge and discharge happen simultaneously, i.e., $\tilde{d}_{etks} > 0$ and $\tilde{g}_{etks} > 0$. This implies that KKT optimality conditions can be derived for relaxed LP formulation of (4.2). In addition, since charge and discharge limit constraints are nor binding, Lagrangian multipliers of constraints (4.15b)-(4.15c) will be equal to zero, $\underline{\kappa}_{etks} = 0$ and $\underline{\vartheta}_{etks} = 0$. Using stationary conditions (4.21a) and (4.21b) of the relaxed LP model of 4.2:

$$\frac{-\Psi}{(1+i_t)^{t-1}} \pi_s C_e^{(ch)} - \sum_{n\in\mathcal{N}} E_n^{(e)} \lambda_{ntks} + \Gamma \tau_{etks} + \underline{\vartheta}_{etks} - \overline{\vartheta}_{etks} = 0 \; \forall e\in\mathcal{E}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.21a}$$

$$\frac{-\Psi}{(1+i_t)^{t-1}} \pi_s C_e^{(dh)} + \sum_{n\in\mathcal{N}} E_n^{(e)} \lambda_{ntks} - \frac{1}{\Gamma} \tau_{etks} + \underline{\kappa}_{etks} - \overline{\kappa}_{etks} = 0 \; \forall e\in\mathcal{E}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.21b}$$

[3] Lemma 1 is an extended version of the Lemma presented in publication *J4*. Lemma 1 and its proof is extended to the mathematical formulations of energy storage which accounts for round-trip efficiencies.

the following equality constraints can be derived

$$\sum_{n\in\mathcal{N}} E_n^{(e)}\lambda_{ntks} \overset{(4.21a)}{=} -\frac{\Psi}{(1+i_t)^{t-1}}\pi_s C_e^{(ch)} + \Gamma\tau_{etks} + \underline{\vartheta}_{etks} - \overline{\vartheta}_{etks}$$
$$\overset{(4.21b)}{=} \frac{\Psi}{(1+i_t)^{t-1}}\pi_s C_e^{(dh)} + \frac{1}{\Gamma}\tau_{etks} - \underline{\kappa}_{etks} + \overline{\kappa}_{etks} \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}. \tag{4.22a}$$

Previously it was assumed that $\tilde{d}_{etks}>0$ and $\tilde{g}_{etks}>0$ which leads to (4.22b).

$$-\frac{\Psi\pi_s}{(1+i_t)^{t-1}}(C_e^{(dh)} + C_e^{(ch)}) + (\Gamma - \frac{1}{\Gamma})\tau_{etks} = \overline{\vartheta}_{etks} + \overline{\kappa}_{etks} \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.22b}$$

Under the assumption $\tilde{d}_{etks} > 0$ and $\tilde{g}_{etks} > 0$ the sum of $\overline{\vartheta}_{etks} + \overline{\kappa}_{etks}$ on the right-hand side of the equation (4.22b) will be either 0 or a strictly positive while the expression $-P_t\Psi\pi_s C_e^{(dh)} - P_t\Psi\pi_s C_e^{(ch)} + (\Gamma - \frac{1}{\Gamma})\tau_{etks}$ on the left-hand side is strictly negative. This leads us to contradiction and to the conclusion that the assumption $\tilde{d}_{etks} > 0$ and $\tilde{g}_{etks} > 0$ does not hold. Thus, energy storage will not charge and discharge at the same time and at least one of the variables $\tilde{d}_{etks}$ or $\tilde{g}_{etks}$ should be equal to zero in the optimal solution. Furthermore, LP equivalent reformulation is a relaxation of the original MILP, meaning the solution of the LP equivalent ($SW_{LP}(\boldsymbol{y}^*)$) is greater than or equal to the original MILP solution ($SW_{MILP}(\boldsymbol{x}^*)$), where $\boldsymbol{y}^*$ and $\boldsymbol{x}^*$ are optimal solution vectors of the original MILP and the LP equivalent. On the other hand, since it was proved that the disjunctive property of constraints (4.15b)-(4.15c) are maintained in $\boldsymbol{y}^*$, the following inequalities hold $SW_{MILP}(\boldsymbol{y}^*) \leq SW_{MILP}(\boldsymbol{x}^*)$). Therefore, $SW_{MILP}(\boldsymbol{y}^*) \leq SW_{MILP}(\boldsymbol{x}^*) \leq SW_{LP}(\boldsymbol{y}^*)$). Moreover, since the SW_{MILP} and SW_{LP} are linear functions, $SW_{MILP}(\boldsymbol{x}^*) = SW_{LP}(\boldsymbol{y}^*)$ and $\boldsymbol{x}^* = \boldsymbol{y}^*$. □

Using Lemma 1 and McCormic linearization technique, the lower-level disjunctive problem (4.17) can be transformed to an equivalent LP models.

4.5.3 Single-level equivalent reformulation for bilevel models

By employing McCorminc linearization technique for disjunctive constraints and Lemma 1, the mathematical model (4.17) is transformed into an equivalent linear problem 4.23:

$$\underset{\Omega^{CDC}}{Maximize} \sum_{t\in\mathcal{T}} \frac{\Psi}{(1+i_t)^{t-1}}\Big(\sum_{s\in\mathcal{S},k\in\mathcal{K}} \pi_s (\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g\, g_{gtks} -$$
$$\sum_{e\in\mathcal{E}} (C_e^{(dh)}\tilde{d}_{etks} + C_e^{(ch)}\ \tilde{g}_{etks})) - \frac{1}{(1+i_t)^{t-1}}(\sum_{w\in\mathcal{W}} C_{wt}^{(W)}(u_{wt} - u_{w(t-1)}) + \tag{4.23a}$$

$$\sum_{e \in \mathcal{E}} C_{et}^{(E)}(e_{et} - e_{e(t-1)}) + \sum_{e \in \mathcal{E}} C_{et}^{(P)}(p_{et} - p_{e(t-1)}))$$

$Subject\ \ to:$

$$(4.16)(4.2b) - (4.2l), (4.2o) - (4.2q) \tag{4.23b}$$

$$(4.19), (4.10), (4.20) \tag{4.23c}$$

Where, $\Omega^{CDC} = \{d_{dtks}, \tilde{d}_{etks}, \tilde{g}_{etks}, q_{etks}, \overline{g}_{htks}, v_{htks}, m_{htks}, g_{gtks}, \widehat{g}_{wtks}, f_{ltks}, \widehat{f}_{mtks}, \theta_{ntks}, u_{wt}, p_{et}, e_{et} \in \Re\}$ Since (4.23) is a linear problem then the Karush-Kuhn-Taker (KKT) optimality conditions are necessary and sufficient [84]. Thus, the optimal solution of (4.23) can be equivalently reformulated as a set of primal, dual and complementary constraints. Furthermore, a set of primal, dual and complementary constraints can be equivalently described as a set of primal and dual constraints and strong duality condition. The reformulation steps based on optimality conditions are illustrated in Fig. 4.1. Assume that a linear problem with objective function f, equality constraints $h(y) = 0$ and inequality constraints $g(y) \leq 0$ exists. Then, the linear problem can be equivalently reformulated as its KKT conditions. KKT conditions of an optimization problem consist of primal constraints ($h(y) = 0$ and $g(y) \leq 0$) of the optimization, Stationary conditions (which are also known as dual constraints ($\bigtriangledown f(y) + \lambda \bigtriangledown g(y) + \mu \bigtriangledown h(y) = 0$)) and Complementary slackness conditions ($\mu g(y) = 0$). Primal constraints are original constraint of the optimization problem while dual constraints are constraints of the dual problem of the optimization problem and correspond to primal variables. By reformulating the optimization problem as a set of primal and dual constraint we ensure that the solution of the set of constraints is feasible in primal and in dual optimization problems. Furthermore, the Duality Theorem (see [85] for more details and the proof) proves that if the solution of an optimization problem is optimal then variables in primal problem complement constraints in dual problem and vice versa. The Duality Theorem implies that if dual variable is strictly greater than zero then corresponding primal constraint is binding. This relationship between primal and dual variables and constraints is enforced by Complementary slackness conditions. Thus, the global optimal point of a linear optimization problem can be found not only by solving the optimization problem but by solving a set of constraints: primal constraint; stationary conditions and complementary slackness constraints.

Complementary slackness conditions, however, are nonlinear and therefore might complicate solution process. On the other hand, complementary slackness conditions can be equivalently enforced by a strong duality condition (a constraint which ensures that the objective function of primal problem is equal to the objective function of the dual problem $f = f^{dual}$), which is linear. Thus, a linear optimization problem can be equivalently reformulated as a set of linear constraints: primal constraints, stationary conditions and complementary slackness constraints.

Figure 4.1: Reformulation steps from bilevel model to single-level equivalent model

Step 1		*Step 2*		*Step 3*
Optimization	$\equiv$	*KKT conditions :*	$\equiv$	*KKT conditions :*
$\underset{y}{Min} f$		$h(y)=0$		$h(y)=0$
S.t:		$g(y)\le 0$		$g(y)\le 0$
$h(y)=0\ :(\lambda)$		$\{Stationary\ \ conditions\}:$		$\{Stationary\ \ conditions\}$
$g(y)\le 0\ :(\mu)$		$\bigtriangledown f(y)+\lambda\bigtriangledown g(y)+\mu\bigtriangledown h(y)=0$		$\bigtriangledown f(y)+\lambda\bigtriangledown g_{LL}(y)+\mu\bigtriangledown h(y)=0$
		$\{Complimentary\ \ slackness\ \ conditions\}$		$\{Strong\ \ duality\ \ condition\}$
		$\mu g(y)=0$		$f=f^{dual}$
		$\mu\ge 0$		$\mu\ge 0$

The stationary and complementary slackness conditions of the problem (4.23) are derived in (4.24) and (4.25) respectively.

$$\frac{\Psi\pi_s}{(1+i_t)^{t-1}}A_d-\sum_{n\in\mathcal{N}}I_n^{(d)}\lambda_{ntks}+\underline{\omega}_{dtks}-\overline{\omega}_{dtks}=0 \quad \forall d\in\mathcal{D},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24a}$$

$$\frac{-\Psi\pi_s}{(1+i_t)^{t-1}}C_g+\sum_{n\in\mathcal{N}}J_n^{(g)}\lambda_{ntks}+\underline{\nu}_{gtks}-\overline{\nu}_{gtks}=0 \quad \forall g\in\mathcal{G},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24b}$$

$$\frac{-\Psi\pi_s}{(1+i_t)^{t-1}}C_e^{(ch)}-\sum_{n\in\mathcal{N}}E_n^{(e)}\lambda_{ntks}+\Gamma\tau_{etks}+\underline{\vartheta}_{etks}-\overline{\vartheta}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24c}$$

$$\frac{-\Psi\pi_s}{(1+i_t)^{t-1}}C_e^{(dh)}+\sum_{n\in\mathcal{N}}E_n^{(e)}\lambda_{ntks}-\frac{1}{\Gamma}\tau_{etks}+\underline{\kappa}_{etks}-\overline{\kappa}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24d}$$

$$-\tau_{etks}+\tau_{et(k+1)s}+\underline{\rho}_{etks}-\overline{\rho}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24e}$$

$$\sum_{n\in\mathcal{N}}W_n^{(w)}\lambda_{ntks}+\underline{\kappa}_{ftks}-\overline{\kappa}_{ftks}=0 \quad \forall w\in\mathcal{W},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24f}$$

$$\sum_{n\in\mathcal{N}}R_n^{(l)}\lambda_{ntks}-\sum_{n\in\mathcal{N}}S_n^{(l)}\lambda_{ntks}+\sigma_{ltks}+\underline{\sigma}_{ltks}-\overline{\sigma}_{ltks}=0 \quad \forall l\in\mathcal{L},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24g}$$

$$-\sum_{n\in\mathcal{N}}\overline{S}_n^{(m)}\lambda_{ntks}+\sum_{n\in\mathcal{N}}\overline{R}_n^{(m)}\lambda_{ntks}+\underline{\varrho}_{mtks}-\overline{\varrho}_{mtks}+$$
$$\underline{\gamma}_{mtks}-\overline{\gamma}_{mtks}+\underline{\xi}_{mtks}-\overline{\xi}_{mtks}=0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24h}$$

$$-\frac{100}{X_l}\sum_{l\in\mathcal{L}}S_n^{(l)}\sigma_{ltks}+\frac{100}{X_l}\sum_{l\in\mathcal{L}}R_n^{(l)}\sigma_{ltks}+\xi_{n=1tks}-$$
$$\frac{100}{X_m}\sum_{m\in\mathcal{M}}\overline{S}_n^{(m)}\underline{\varrho}_{mtks}+\frac{100}{X_m}\sum_{m\in\mathcal{M}}\overline{R}_n^{(m)}\underline{\varrho}_{mtks}+$$

$$\frac{100}{X_m}\sum_{m\in\mathcal{M}}\overline{S}_n^{(m)}\overline{\varrho}_{mtks}-\frac{100}{X_m}\sum_{m\in\mathcal{M}}\overline{R}_n^{(m)}\overline{\varrho}_{mtks}=0 \quad \forall n\in\mathcal{N},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.24i}$$

$$\frac{-1}{(1+i_t)^{t-1}}C_{et}^{(E)}+\kappa_{et}-\kappa_{et+1}+\sum_{k\in\mathcal{K},s\in\mathcal{S}}\overline{\rho}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T} \tag{4.24j}$$

$$\frac{-1}{(1+i_t)^{t-1}}C_{et}^{(P)}+\vartheta_{et}-\vartheta_{et+1}+\sum_{k\in\mathcal{K},s\in\mathcal{S}}\overline{\kappa}_{etks}+\sum_{k\in\mathcal{K},s\in\mathcal{S}}\overline{\vartheta}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T} \tag{4.24k}$$

$$\frac{-1}{(1+i_t)^{t-1}}C_{wt}^{(W)}+\eta_{wt}-\eta_{wt+1}+\sum_{k\in\mathcal{K},s\in\mathcal{S}}\overline{\kappa}_{ftks}\varrho_{wtks}=0 \quad \forall w\in\mathcal{W},t\in\mathcal{T} \tag{4.24l}$$

$$u_{wt}\eta_{wt}=u_{w(t-1)}\eta_{wt} \quad \forall w\in\mathcal{W},t\in\mathcal{T} \tag{4.25a}$$

$$e_{et}\kappa_{et}=e_{e(t-1)}\kappa_{et} \quad \forall e\in\mathcal{E},t\in\mathcal{T} \tag{4.25b}$$

$$p_{et}\vartheta_{et}=p_{e(t-1)}\vartheta_{et} \quad \forall e\in\mathcal{E},t\in\mathcal{T} \tag{4.25c}$$

$$(\widehat{f}_{mtks}-\frac{100}{X_m}(\sum_{n\in\mathcal{N}}\overline{S}_n^{(m)}\theta_{ntks}-\sum_{n\in\mathcal{N}}\overline{R}_n^{(m)}\theta_{ntks}))\overline{\varrho}_{mtks}=$$

$$\Xi_m(1-z_{mt})\overline{\varrho}_{mtks} \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25d}$$

$$-(\widehat{f}_{mtks}-\frac{100}{X_m}(\sum_{n\in\mathcal{N}}\overline{S}_n^{(m)}\theta_{ntks}-\sum_{n\in\mathcal{N}}\overline{R}_n^{(m)}\theta_{ntks}))\underline{\varrho}_{mtks}=$$

$$\Xi_m(1-z_{mt})\underline{\varrho}_{mtks} \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25e}$$

$$f_{ltks}\overline{\sigma}_{ltks}=F_l\overline{\sigma}_{ltks} \quad \forall n\in\mathcal{N},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25f}$$

$$-f_{ltks}\underline{\sigma}_{ltks}=F_l\underline{\sigma}_{ltks} \quad \forall n\in\mathcal{N},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25g}$$

$$\widehat{f}_{mtks}\overline{\gamma}_{mtks}=\widehat{F}_m\overline{\gamma}_{mtks} \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25h}$$

$$-\widehat{f}_{mtks}\underline{\gamma}_{mtks}=\widehat{F}_m\underline{\gamma}_{mtks} \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25i}$$

$$-\widehat{f}_{mtks}\underline{\xi}_{mtks}=z_{mt}\Xi_m\underline{\xi}_{mtks} \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25j}$$

$$\widehat{f}_{mtks}\overline{\xi}_{mtks}=z_{mt}\Xi_m\underline{\xi}_{mtks} \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25k}$$

$$g_{gtks}\underline{\nu}_{gtks}=0 \quad \forall g\in\mathcal{G},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25l}$$

$$g_{gtks}\overline{\nu}_{gtks}=G_g\overline{\nu}_{gtks} \quad \forall g\in\mathcal{G},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25m}$$

$$\widehat{g}_{wtks}\underline{\kappa}_{ftks}=0 \quad \forall w\in\mathcal{W},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25n}$$

$$\widehat{g}_{wtks}\overline{\kappa}_{ftks}=(\widehat{G}_w+u_{wt})\varrho_{wtks}\overline{\kappa}_{ftks} \quad \forall w\in\mathcal{W},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25o}$$

$$\tilde{g}_{etks}\underline{\kappa}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25p}$$

$$\tilde{g}_{etks}\overline{\kappa}_{etks}=(p_{et}+\widehat{P}_{et})\overline{\kappa}_{etks} \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25q}$$

$$\tilde{d}_{etks}\underline{\vartheta}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25r}$$

$$\tilde{d}_{etks}\overline{\vartheta}_{etks}=(p_{et}+\widehat{P}_{et})\overline{\vartheta}_{etks} \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25s}$$

$$q_{etks}\underline{\rho}_{etks}=0 \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25t}$$

$$q_{etks}\overline{\rho}_{etks} = (e_{et} + \widehat{E}_{et})\overline{\rho}_{etks} \quad \forall e\in\mathcal{E},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25u}$$
$$d_{dtks}\underline{\omega}_{dtks} = 0 \quad \forall d\in\mathcal{D},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25v}$$
$$d_{dtks}\overline{\omega}_{dtks} = D_d\overline{\omega}_{dtks} \quad \forall d\in\mathcal{D},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{4.25w}$$

On the other hands, using duality theorem complementary slackness conditions (4.25) can be enforced through strong duality condition 4.26:

$$\sum_{t\in\mathcal{T}} P_t \langle \sum_{s\in\mathcal{S},k\in\mathcal{K}} \pi_s \Psi(\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g \; g_{gtks}) -$$
$$\sum_{e\in\mathcal{E}} (C_e^{(dh)} \tilde{d}_{etks} + C_e^{(ch)} \; \tilde{g}_{etks}) - P_t \sum_{e\in\mathcal{E}} C_{et}^{(E)} (e_{et} - e_{e(t-1)}) -$$
$$P_t \sum_{e\in\mathcal{E}} C_{et}^{(P)} (p_{et} - p_{e(t-1)}) \rangle = \sum_{t\in\mathcal{T}} \langle \sum_{d\in\mathcal{D}} D_d \overline{\omega}_{dtks} + \sum_{g\in\mathcal{G}} G_g \overline{\nu}_{gtks} + \sum_{w\in\mathcal{W}} \widehat{G}_w \varrho_{wtks} \overline{\kappa}_{ftks} +$$
$$\sum_{e\in\mathcal{E}} (\widehat{P}_{et} \overline{\vartheta}_{etks} + \widehat{P}_{et} \overline{\kappa}_{etks} + \widehat{E}_{et} \overline{\rho}_{etks}) + \sum_{l\in\mathcal{L}} F_l (\underline{\sigma}_{ltks} + \overline{\sigma}_{ltks}) +$$
$$\sum_{m\in\mathcal{M}} \widehat{F}_m (\underline{\gamma}_{mtks} + \overline{\gamma}_{mtks}) +$$
$$\Xi_m (1 - z_{mt})(\overline{\varrho}_{mtks} + \underline{\varrho}_{mtks}) + \Xi_m z_{mt} (\overline{\xi}_{mtks} + \underline{\xi}_{mtks}) \rangle \tag{4.26}$$

By reformulating lower-level problem (4.17) as a combination of primal feasibility constraints, dual feasibility constraints and a strong duality condition the bilevel problem (4.14) can be transformed to a one-level equivalent formulation:

$$\underset{z_{mt},y_{mt}}{\text{Maximize}} \sum_{t\in\mathcal{T}} \frac{\Phi_t + \mathbb{E}[\pi_{st}^T] - \sum_{m\in\mathcal{M}} C_{mt}^{(T)} y_{mt}}{(1+i_t)^{t-1}} \tag{4.27a}$$
$$\textit{Subject to}:$$
$$z_{m,t=1} = 0 \; \forall m \tag{4.27b}$$
$$z_{mt} = \sum_{\widehat{t}\leq t} y_{m,\widehat{t}} \; \forall m, \forall t \geq 2 \tag{4.27c}$$
$$\sum_{t\in\mathcal{T}} y_{mt} \leq 1 \; \forall m, \forall t \tag{4.27d}$$
$$\Phi_{t=1} = 0 \tag{4.27e}$$
$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi_{st}^L] + \Delta\,\mathbb{E}[\pi_{st}^G] + \Delta\pi_t^W + \Delta\,\mathbb{E}[\pi_{st}^S] +$$
$$P_t(-\sum_{w\in\mathcal{W}} C_{wt}^{(W)} (u_{wt} - u_{w(t-1)}) - \sum_{e\in\mathcal{E}} C_{et}^{(E)} (e_{et} - e_{e(t-1)}) -$$
$$\sum_{e\in\mathcal{E}} C_{et}^{(P)} (p_{et} - p_{e(t-1)})) \; \forall t \geq 2 \tag{4.27f}$$
$$(4.16)(4.2b) - (4.2l), (4.2o) - (4.2q) \tag{4.27g}$$

$$(4.19), (4.10), (4.20) \tag{4.27h}$$

$$(4.26), (4.24) \tag{4.27i}$$

$$\underline{\omega}_{dtks}, \overline{\omega}_{dtks}, \underline{\nu}_{gtks}, \overline{\nu}_{gtks}, \underline{\kappa}_{ftks}, \overline{\kappa}_{ftks}, \sigma_{ltks},$$
$$\overline{\xi}_{mtks}, \overline{\lambda}_{ntks}, \underline{\lambda}_{ntks} \geq 0 \tag{4.27j}$$

$$z_{mt}, y_{mt} \in \{0, 1\} \tag{4.27k}$$

4.5.4 Linearization using algebraic transformations and KKT conditions

In the previous section it was shown that bilevel models such as (4.4), (4.8) and (4.14) can be transformed into one level equivalent model formulations as in example (4.27). However, in the example (4.27) the problem still remains non convex due to nonlinear terms in the upper-level. In this section it is shown that in some cases these terms can be transformed into equivalent linear terms by using simple algebraic transformations and optimality conditions. The proposed transformations follow similar logic as transformations presented in the appendix of [11] and publications $J1$-$J4$. Using KKT conditions of the problem 4.23 it can be proved that the term

$$\sum_{n\in\mathcal{N} d\in\mathcal{D}} I_n^{(d)} \lambda_{ntks} d_{dtks} - \sum_{n\in\mathcal{N} g\in\mathcal{G}} J_n^{(g)} \lambda_{ntks} g_{gtks} +$$
$$\sum_{n\in\mathcal{N} e\in\mathcal{E}} E_n^{(e)} \lambda_{ntks} (\tilde{d}_{etks} - \tilde{g}_{etks}) - \sum_{n\in\mathcal{N} w\in\mathcal{W}} W_n^{(w)} \lambda_{ntks} \widehat{g}_{wtks} \tag{4.28}$$

is equal to

$$\sum_{l\in\mathcal{L}} F_l(\overline{\sigma}_{ltks} + \underline{\sigma}_{ltks}) + \sum_{m\in\mathcal{M}} \widehat{F}_m(\overline{\gamma}_{mtks} + \underline{\gamma}_{mtks})_{\forall t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S}} \tag{4.29}$$

The initial bilinear expression is stated as:

$$\sum_{n\in\mathcal{N}, d\in\mathcal{D}} I_n^{(d)} \lambda_{ntks} d_{dtks} - \sum_{n\in\mathcal{N}, g\in\mathcal{G}} J_n^{(g)} \lambda_{ntks} g_{gtks} -$$
$$\sum_{n\in\mathcal{N}, w\in\mathcal{W}} W_n^{(w)} \lambda_{ntks} + \sum_{n\in\mathcal{N}, e\in\mathcal{E}} E_n^{(e)} \lambda_{ntks} (\tilde{d}_{etks} - \tilde{g}_{etks}) \widehat{g}_{wtks} \tag{4.30}$$

The nodal prices can be extracted from these terms, i.e.,

$$\sum_{n\in\mathcal{N}} \lambda_{ntks} \underbrace{\begin{pmatrix} \sum_{d\in\mathcal{D}} I_n^{(d)} d_{dtks} + \sum_{ne} E_n^{(e)} (\tilde{d}_{etks} - \tilde{g}_{etks}) - \\ \sum_{g\in\mathcal{G}} J_n^{(g)} g_{gtks} - \sum_{w\in\mathcal{W}} W_n^{(w)} \widehat{g}_{wtks} \end{pmatrix}}_{L1} \quad \forall t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.31}$$

The term L1 also appears in the power flow constraint (4.11) and can thus be replaced by the sum of the power flows:

$$\begin{aligned}
&\sum_{l\in\mathcal{L}}\lambda_{ntks}(-\sum_{n\in\mathcal{N}}S_n^{(l)}f_{ltks}+\sum_{n\in\mathcal{N}}R_n^{(l)}f_{ltks})+\\
&\sum_{m\in\mathcal{M}}\lambda_{ntks}(-\sum_{n\in\mathcal{N}}\overline{S}_n^{(m)}\widehat{f}_{mtks}+\sum_{n}\overline{R}_n^{(m)}\widehat{f}_{mtks})=\\
&\sum_{l\in\mathcal{L}}f_{ltks}\underbrace{(-\sum_{n\in\mathcal{N}}S_n^{(l)}\lambda_{ntks}+\sum_{n\in\mathcal{N}}R_n^{(l)}\lambda_{ntks})}_{L2}+\\
&\sum_{m\in\mathcal{M}}\widehat{f}_{mtks}\underbrace{(-\sum_{n\in\mathcal{N}}\overline{S}_n^{(m)}\lambda_{ntks}+\sum_{n}\overline{R}_n^{(m)}\lambda_{ntks})}_{L3}\forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}
\end{aligned}\tag{4.32}$$

Terms L2 and L3 are parts of stationary condition constraints (4.24g) and (4.24h) respectively. Thus L2 and L3 equivalently can be represented as a linear combination of dual variables from constraints (4.24g) and (4.24h):

$$\begin{aligned}
&\sum_{l\in\mathcal{L}}f_{ltks}(\overline{\sigma}_{ltks}-\underline{\sigma}_{ltks}-\sigma_{ltks})+\sum_{m\in\mathcal{M}}\widehat{f}_{mtks}(\underline{\varrho}_{mtks}-\overline{\varrho}_{mtks}+\\
&\underline{\gamma}_{mtks}-\overline{\gamma}_{mtks}+\underline{\xi}_{mtks}-\overline{\xi}_{mtks})\forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}
\end{aligned}\tag{4.33}$$

Using complementary slackness conditions (4.25d)-(4.25k) and stationary condition (4.24i) constraint (4.33) can be equivalently reformulated as:

$$\begin{aligned}
&\sum_{l\in\mathcal{L}}F_l(\overline{\sigma}_{ltks}+\underline{\sigma}_{ltks})+\sum_{m\in\mathcal{M}}\widehat{F}_m(\overline{\gamma}_{mtks}+\underline{\gamma}_{mtks})+\\
&\sum_{m\in\mathcal{M}}\underbrace{z_{mt}\Xi_m(\underline{\xi}_{mtks}+\overline{\xi}_{mtks})}_{T1}+\\
&\sum_{m\in\mathcal{M}}\underbrace{\Xi_m(1-z_{mt})(\overline{\varrho}_{mtks}+\underline{\varrho}_{mtks})}_{T2}\forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}
\end{aligned}\tag{4.34}$$

The terms $T1 = z_{mt}\Xi_m(\underline{\xi}_{mtks}+\overline{\xi}_{mtks})$ and $T2 = (1-z_{mt})(\overline{\varrho}_{mtks}+\underline{\varrho}_{mtks})$ include the disjunctive parameters Ξ_m and used to formulate power flow constraints of candidate transmission lines (4.19a)-(4.19c) are complicated because they include variables both from the upper and lower level problems and are thus nonlinear. However, each of these terms are always equal to zero. If the disjunctive parameters are tuned properly, i.e., large enough that they do not limit power flows on accepted candidate lines but small enough to avoid poorly conditioned matrices, then the constraints (4.19c) will never be binding. Similar reasoning was used in [11] to drop disjunctive parameters from the objective function. However, terms $T1$ and

$T2$ cannot be drop if they are located elsewhere than only in the objective function. Instead, equations $T1 = 0$ and $T2 = 0$ have to be enforced.

$$\text{if } z_{mt}=0 \Rightarrow \overline{\varrho}_{mtks} + \underline{\varrho}_{mtks} = 0 \Rightarrow T1=0, T2=0 \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.35a}$$

$$\text{if } z_{mt}=1 \Rightarrow \overline{\xi}_{mtks} + \underline{\xi}_{mtks} = 0 \Rightarrow T1=0, T2=0 \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.35b}$$

If z_{mt} is equal to zero then the Lagrangian multipliers $\overline{\varrho}_{mtks}$ and $\underline{\varrho}_{mtks}$ are equal to zero due to the complementary slackness condition, resulting in both expression T1 and T2 to be equal to zero. By analogy when z_{mt} is equal to one then $(1 - z_{mt})$ is equal to zero and using complimentary slackness conditions $\underline{\xi}_{mtks}$ and $\overline{\xi}_{mtks}$ are zero leading to T1 and T2 equal to zero.This property can be formulated mathematically through set of linearized disjunctive constraints:

$$-\Xi_m z_{mt} \leq \overline{\varrho}_{mtks} + \underline{\varrho}_{mtks} \leq \Xi_m z_{mt} \tag{4.36a}$$

$$-\Xi_m(1 - z_{mt}) \leq \overline{\xi}_{mtks} + \underline{\xi}_{mtks} \leq \Xi_m(1 - z_{mt}) \tag{4.36b}$$

Such reformulation will remove bilinear terms and will not affect the decision space. Similarly, the strong duality (4.26) of the problem (4.12) can be reformulated using (4.35) as in (4.37)

$$\begin{aligned}
&\sum_{t\in\mathcal{T}} \frac{\Psi}{(1+i_t)^{t-1}} \Big(\sum_{s\in\mathcal{S},k\in\mathcal{K}} \pi_s (\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g \; g_{gtks}) - \\
&\sum_{e\in\mathcal{E}} (C_e^{(dh)} \tilde{d}_{etks} + C_e^{(ch)} \; \tilde{g}_{etks}) - (\sum_{e\in\mathcal{E}} C_{et}^{(E)} (e_{et} - e_{e(t-1)}) - \\
&\sum_{e\in\mathcal{E}} C_{et}^{(P)} (p_{et} - p_{e(t-1)}) - \sum_{w\in\mathcal{W}} C_{wt}^{(W)} (u_{wt} - u_{w(t-1)}) \Big) = \\
&\sum_{t\in\mathcal{T}} \Big(\sum_{d\in\mathcal{D}} D_d \overline{\omega}_{dtks} + \sum_{g\in\mathcal{G}} G_g \overline{\nu}_{gtks} + \sum_{w\in\mathcal{W}} \widehat{G}_w \varrho_{wtks} \overline{\kappa}_{ftks} + \\
&\sum_{e\in\mathcal{E}} (\widehat{P}_{et} \overline{\vartheta}_{etks} + \widehat{P}_{et} \overline{\kappa}_{etks} + \widehat{E}_{et} \overline{\rho}_{etks}) + \sum_{l\in\mathcal{L}} F_l (\underline{\sigma}_{ltks} + \overline{\sigma}_{ltks}) + \\
&\sum_{m\in\mathcal{M}} \widehat{F}_m (\overline{\gamma}_{mtks} + \underline{\gamma}_{mtks}) \Big)
\end{aligned} \tag{4.37a}$$

$$-\Xi_m z_{mt} \leq \overline{\varrho}_{mtks} + \underline{\varrho}_{mtks} \leq \Xi_m z_{mt} \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.37b}$$

$$-\Xi_m(1 - z_{mt}) \leq \overline{\xi}_{mtks} + \underline{\xi}_{mtks} \leq \Xi_m(1 - z_{mt}) \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{4.37c}$$

By doing algebraic reformulations described above the nonlinear problem (4.27) is transformed into a linear equivalent model which can be formulated as:

$$\underset{z_{mt},y_{mt},\Omega_s}{Maximize} \sum_{t\in\mathcal{T}} \langle \sum_{s\in\mathcal{S}} \pi_s (\sum_{l\in\mathcal{L}} F_l(\overline{\sigma}_{ltks} + \underline{\sigma}_{ltks}) +$$

$$\sum_{m\in\mathcal{M}} \widehat{F}_m(\overline{\gamma}_{mtks} + \underline{\sigma}_{ltks}) + \Phi_t - P_t \sum_{m\in\mathcal{M}} C^{(T)}_{mt} y_{mt} \rangle \tag{4.38a}$$

$Subject\ to:$

$$z_{m,t=1} = 0\ \forall m \tag{4.38b}$$

$$z_{mt} = \sum_{\widehat{t}\leq t} y_{m,\widehat{t}}\ \forall m, \forall t \geq 2 \tag{4.38c}$$

$$\sum_{t\in\mathcal{T}} y_{mt} \leq 1\ \forall m, \forall t \tag{4.38d}$$

$$\Phi_{t=1} = 0 \tag{4.38e}$$

$$\Phi_t = \sum_{s\in\mathcal{S}} \pi_s \sum_{k\in\mathcal{K}} (\sum_{d\in\mathcal{D}} A_d d_{dtks} - \sum_{g\in\mathcal{G}} C_g g_{gtks} +$$

$$\sum_{e\in\mathcal{E}} (C^{(ch)}_e \tilde{g}_{etks} + C^{(dh)}_e \tilde{d}_{etks}) - \sum_{l\in\mathcal{L}} F_l(\overline{\sigma}_{ltks} + \underline{\sigma}_{ltks}) -$$

$$\sum_{m\in\mathcal{M}} \widehat{F}_m(\overline{\gamma}_{mtks} + \overline{\sigma}_{ltks})) - \sum_{s\in\mathcal{S}} \pi_s \sum_{k\in\mathcal{K}} (\sum_{d\in\mathcal{D}} (A_d d_{d(t-1)ks} -$$

$$\sum_{g\in\mathcal{G}} C_g g_{g(t-1)ks}) + \sum_{e,k} (C^{(ch)}_e \tilde{g}_{e(t-1)ks} + C^{(dh)}_e \tilde{d}_{e(t-1)ks}) +$$

$$P_t(\sum_{m\in\mathcal{M}} C^{(T)}_{mt} y_{m(t-1)} - \sum_{w\in\mathcal{W}} C^{(W)}_{wt} (u_{wt} - u_{w(t-1)}) -$$

$$\sum_{e\in\mathcal{E}} C^{(E)}_{et} (e_{et} - e_{e(t-1)}) - \sum_{e\in\mathcal{E}} C^{(P)}_{et} (p_{et} - p_{e(t-1)}))\ \forall t \geq 2 \tag{4.38f}$$

$$(4.24), (4.37) \tag{4.38g}$$

$$(4.16), (4.2b) - (4.2l), (4.2o) - (4.2q) \tag{4.38h}$$

$$(4.19), (4.10), (4.20) \tag{4.38i}$$

$$\underline{\omega}_{dtks}, \overline{\omega}_{dtks}, \underline{\nu}_{gtks}, \overline{\nu}_{gtks}, \underline{\kappa}_{ftks}, \overline{\kappa}_{ftks}, \sigma_{ltks},$$

$$\overline{\xi}_{mtks}, \overline{\lambda}_{ntks}, \underline{\lambda}_{ntks} \geq 0 \tag{4.38j}$$

$$z_{mt}, y_{mt} \in \{0, 1\} \tag{4.38k}$$

All four publications $J1$, $J2$, $J3$ and $J4$ attached to this thesis make use of the linearization and reformulation techniques presented in this chapter.

4.6 Decomposition techniques

Detailed investment planning problems presented in Section 4.1-Section 4.4 and later reformulated using techniques presented in Section 4.5 include a big range of parameters and variables. In addition, these problems include integer variables which are in fact a part of disjunctive constraints which model the investment decisions (to invest or not invest in particular asset). Presence of integer variables and disjunctive constraints makes aforementioned problems complex and computationally expensive. As a result, the solution process may take an extensive amount of time to provide the optimal result, moreover, in certain cases even commercially available solvers will fail to provide optimal results due to time limitations or limited memory capacity. Various decomposition techniques were proposed in the literature to tackle the problem of computational tractability of investment planning problems. Benders' decomposition by far is the most applied algorithm and it was proved to be effective on a big range of investment problems. However, Benders' decomposition has its limitations and can be less efficient when applied on problems with disjunctive parameters. In [86] Benders' based decomposition (further referred to as Beans' decomposition) was proposed as an attempt to remove the effect of disjunctive parameter. Beans' decomposition technique is based on Benders' decomposition algorithm where feasibility cut was modified and the effect of disjunctive parameter was removed. While this modification strengthen master problem of Beans' decomposition the subproblem still contains disjunctive parameter and may cause instabilities.

This section first briefly introduces theoretical background for disjunctive programs and for original Benders' decomposition applied on disjunctive problems. Benders' decomposition algorithm is then followed by original Beans' decomposition. Finally, the chapter contributes to the literature by providing a series of novel modifications and acceleration techniques applied on Beans' decomposition.

4.6.1 Disjunctive program

Disjunctive programming is a field in optimization theory where optimization (maximization or minimization)is performed on a problem which contains one or more disjunctive sets[4] [87]. Models (4.3) and (4.4) are two stage stochastic problems with first stage disjunctive constraints. Mathematically, the structure of a stochastic program with disjunctive constraints can be expressed in general mathematical form as:

[4]Disjunctive sets are also known as disjoint sets and can be described as sets which do not have any elements in common. In transmission expansion problem (4.3) disjunctive sets are introduced through power flow constraint of candidate lines (4.18)

$$\underset{x,\tilde{x}_s}{Minimize}\;\; cx + \mathbb{E}[d_s\tilde{x}_s] \tag{4.39a}$$

$$Subject\ to\ :$$

$$Ax + B\tilde{x}_s \leq b_s \;\; \forall s \in \mathcal{S} \tag{4.39b}$$

$$\vee_{i\in\mathcal{D}} \begin{bmatrix} Y_i \\ K_i x = p_i \end{bmatrix} \tag{4.39c}$$

$$Y_i \in \{True, False\} \;\; \forall i \in \mathcal{D} \tag{4.39d}$$

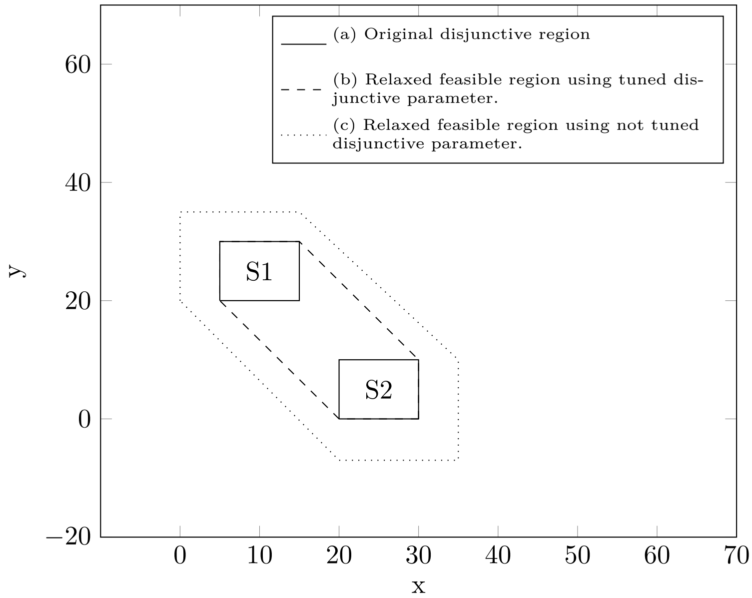
Constraints (4.39c) should hold if and only if corresponding logic condition Y_i is True. The logic condition Y_i in disjunctive problems is a variable and usually represented though integer variable. For example, in transmission investment decision problem logic condition Y_i is True (or equal to 1) if investment decision in line i is taken and False (or equal to 0) otherwise. At the same time if the investment decision in line i is taken power flow constraint constraints corresponding to line i should hold. This corresponds to disjunctive constraint (4.39c).

A disjunctive problem in its standard form can be relaxed using convexification techniques. A disjunctive program can be reformulated into a mixed-integer program using several existing techniques including convex hull, cutting planes and McCormick linearization. All these methods provide a reformulation of the original feasible sets and limitations specific for each method. Convex hull methods are proved to provide tight reformulation in a sense that the feasibility region of the reformulated problem will be as close as possible to the original feasibility region. Nevertheless, the approach requires additional variables and constraints which considerably increase the size of the problem and make it practically impossible to implement for large scale investment planning problems. On the other hand, the McCormick linearization does not affect the size of the problem. However, the disjunctive parameters involved in the reformulation create computational issues for the solver.

The impact of disjunctive parameter tuning on the relaxed feasible region is conceptually illustrated in Figure 4.2. $S1$ and $S2$ are original feasible regions with disjunctive property (either $S1$ or $S2$ is the feasible region). Relaxed feasible region using optimally tuned disjunctive parameters and the case when disjunctive parameter is not optimally tuned are demonstrated as region (b) and region (c), respectively. Consequently, region (b) is a tighter relaxation.

A disjunctive parameter that is not tuned affects the convergence of the problem [88]. The literature provides several methods to tune the disjunctive parameter. The methodologies for tuning disjunctive parameter can be found in [83] and [88]. The methods are proved to provide good approximations of the disjunctive parameters under certain conditions but additional large scale optimization problems should be solved for each case and the optimality still cannot be guaranteed. The problem of the disjunctive parameter tuning becomes especially hard when the reformulation involves variables without physical upper or lower limits which is the

Figure 4.2: The impact of disjunctive parameter tuning on the relaxed feasible region. Region corresponds to area inside dashed or solid lines.



case in the complementary slackness condition constraints or any other constraints which involve Lagrange multipliers.

4.6.2 McCormick linearization

McCormick linearization is used to linearize disjunctive linear sets and reformulate disjunctive program into mixed integer linear problem (MILP). A disjunctive program (4.39) reformulated using McCormick linearization can be mathematically expressed as:

$$\underset{x,\tilde{x}_s}{Minimize} \;\; cx + \mathbb{E}[d_s \tilde{x}_s] \tag{4.40a}$$

$$Subject\ to\ :$$

$$Ax + B\tilde{x}_s \leq b_s \;\; \forall s \in \mathcal{S} : (\mu_s) \tag{4.40b}$$

$$K_i x \leq p_i + (1 - y_i)H \;\; \forall i \in \mathcal{D} : (\overline{\sigma}_i) \tag{4.40c}$$

$$K_i x \geq p_i - (1 - y_i)H \;\; \forall i \in \mathcal{D} : (\underline{\sigma}_i) \tag{4.40d}$$

$$\sum_{i \in \mathcal{D}} y_i = 1 \tag{4.40e}$$

$$y_i \in \{0, 1\} \tag{4.40f}$$

The variables $\mu_s, \overline{\sigma}_i, \underline{\sigma}_i$ presented in the brackets and separated by colon are the corresponding Lagrange multipliers. The corresponding dual of the reformulated problem with fixed integer variables (4.40) is:

$$\underset{\tilde{x}_s}{Maximize} \sum_{s \in \mathcal{S}} b_s \mu_s + \sum_{i \in \mathcal{D}} (\overline{\sigma}_i (p_i + (1 - y_i) H) + \underline{\sigma}_i (p_i + (1 - y_i) H)) \tag{4.41a}$$

$$Subject\ to\ :$$

$$\sum_{s \in \mathcal{S}} A \mu_s + \sum_{i \in \mathcal{S}} K_i \overline{\sigma}_i + \sum_i K_i \underline{\sigma}_i \leq 0 \tag{4.41b}$$

$$B \mu_s \leq 0 \ \ \forall s \in \mathcal{S} \tag{4.41c}$$

$$\mu_s, \overline{\sigma}_i, \underline{\sigma}_i \geq 0 \ \forall s \in \mathcal{S}, i \in \mathcal{D} \tag{4.41d}$$

4.6.3 Benders' decomposition technique

The MILP model (4.40) has a special decomposable structure. Such structure allows us to decompose the problem into a number of independent optimization problems by separating the variables into two vectors. The first vector consists of continuous variables and the second one consists of integer variables. One of the decomposition methods for such types of problems is the Benders' decomposition [89]. Benders' decomposition algorithm is a widely used technique applied to reduce the computational burden of the problems with complicating variables, for example, such as integer variables. Various authors use a Benders' decomposition in investment decision problems in power systems. In [90] and [91], the Benders' decomposition is used to reduce computational time considering the uncertainty in the system. In [92], a modified version of the Benders' decomposition is applied on transmission investment game model and in [93], a modified Benders' algorithm is applied on bidding strategy optimization problem. In [94] and [95], modified Bender's decomposition is used to solve complex second-order cone problem. The Benders' decomposition proves to be an effective tool and helps to reduce the computational time substantially. In [90] the authors also apply Benders' decomposition technique without detailed discussion on the issues of tuning the disjunctive parameter and the disjunctive parameter is still present in the optimization and in the decomposition algorithm. In [96], additional Gomory cuts are introduced along with the traditional Benders' decomposition which allows one to approximate disjunctive parameter.

The Benders' decomposition algorithm includes two separate steps at each iteration. First, duality theory is used to determine upper bounds through fixing complicating integer variables (assuming a minimization program). The second step is to find a lower bound by solving the relaxed problem. The iteration between upper- and lower-bound programs is performed until the upper and lower bounds are close enough and the optimal solution is found. Accordingly, the Benders' decomposition simplifies the original MILP by splitting it into easier to solve

MILP and LP problems. In addition, such decomposition can be used on proposed MILP to remove the effect of the disjunctive parameter.

The standard Benders' decomposition algorithm applied to such types of problems includes a master problem (4.43) and a sub-problem (4.42) solved iteratively. The sub-problem at each decomposition iteration is formulated based on the dual of the original problem with fixed complicating variables. In the case of problem (4.40) the complicating variables are integer variables y_i. By fixing integer variables y_i as $y_i^{(a)}$ and counting it as a parameter the sub-problem can be formulated as the dual of the original problem with fixed integer variables described in (4.41). For clarity the formulation of the sub-problem is restated here:

$$\underset{\tilde{x}_s}{Maximize} \sum_{s\in\mathcal{S}} b_s\mu_s + \sum_{i\in\mathcal{D}}(\overline{\sigma}_i(p_i + (1-y_i)H) + \underline{\sigma}_i(p_i + (1-y_i)H)) \tag{4.42a}$$

$$Subject\ to\ :$$

$$\sum_{s\in\mathcal{S}} A\mu_s + \sum_{i\in\mathcal{D}} K_i\overline{\sigma}_i + \sum_{i\in\mathcal{D}} K_i\underline{\sigma}_i \leq 0 \tag{4.42b}$$

$$B\mu_s \leq 0 \ \ \forall s\in\mathcal{S} \tag{4.42c}$$

$$\mu_s, \overline{\sigma}_i, \underline{\sigma}_i \geq 0 \ \ \forall s\in\mathcal{S}, i\in\mathcal{D} \tag{4.42d}$$

The variables of the sub-problem μ_s, $\overline{\sigma}_i$ and $\underline{\sigma}_i$ are used as input parameters for $\mu_{s,a}^{(a)}$, $\overline{\sigma}_{i,a}^{(a)}$ and $\underline{\sigma}_{i,a}^{(a)}$ for the master problem. The master problem of Benders' decomposition applied on problem (4.40) can be formulated as:

$$\underset{z_a, y_i}{Maximize} \quad z_a \tag{4.43a}$$

$$Subject\ to:$$

$$z_a \leq \sum_{s\in\mathcal{S}} b_s\mu_{s,a}^{(a)} + \sum_{i\in\mathcal{D}}(\overline{\sigma}_{i,a}^{(a)}(p_i + (1-y_i)H) + \underline{\sigma}_{i,a}^{(a)}(p_i + (1-y_i)H)) \ \forall a\in\mathcal{G} \tag{4.43b}$$

$$\sum_{i\in\mathcal{D}} y_i = 1 \tag{4.43c}$$

$$y_i \in \{0,1\} \ \ \forall i\in\mathcal{D} \tag{4.43d}$$

By solving the master problem (4.43) the values of the integer variables y_i are obtained. These values are used in the next iteration of the decomposition to update the parameters of the sub-problem ($y_i^{(a)}$). The standard Benders' decomposition algorithm is described in Algorithm 1

4.6.4 Beans' decomposition technique

Benders' decomposition presented in the previous section consists a master problem and sub-problem where both of them contain a disjunctive parameter H. As it was

Algorithm 1 Benders' decomposition algorithm

procedure BENDERS' DECOMPOSITION
  $y_i^{(a)}$ =initial feasible solution UB=∞; LB=$-\infty$
Solve sub-problem (4.42)
Update $\mu_{s,a}^{(a)}$, $\overline{\sigma}_{i,a}^{(a)}$ and $\underline{\sigma}_{i,a}^{(a)}$

  while UP-LB> ϵ **do**
    Append constraint (4.43b)
    Solve master problem (4.43)
    Update $y_i^{(a)}$
    Solve sub-problem (4.42)
    Update $\mu_{s,a}^{(a)}$, $\overline{\sigma}_{i,a}^{(a)}$ and $\underline{\sigma}_{i,a}^{(a)}$
  end while
  return Optimal solution y_i
end procedure

previously mentioned presence of disjunctive parameter can affect the computational tractability of the problem. Moreover, presence of the disjunctive parameter in the feasibility cut (4.43b) might also affect convergence to optimality of the whole algorithm. In order to avoid the effect of disjunctive parameter [86] proposes to reformulate the master problem of the Benders' technique into an equivalent set partitioning problem while the sub-problem remains the same. In this chapter the technique proposed in [86] is referred to as Beans' decomposition technique as the last name of the author of the publication. The master problem proposed in [86] is formulated as:

$$\underset{w_a, w_0, y_i}{Maximize} \sum_{a \in \mathcal{G}} P_a w_a + M w_0 \tag{4.44a}$$

$$Subject\ to\ :$$

$$\sum_{i \in \Omega_a^{(1)}} y_i + \sum_{i \in \Omega_a^{(2)}} (1 - y_i) \leq |\Omega_a^{(1)}| + |\Omega_a^{(2)}| - 1 + \sum_{a' \Upsilon (P_{a'} \geq P_a)} w_a \ \forall a \in \mathcal{G} \tag{4.44b}$$

$$\sum_{a \in \mathcal{G}} w_a = 1 \tag{4.44c}$$

$$\sum_{i \in \mathcal{D}} y_i = 1 \tag{4.44d}$$

$$y_i \in \{0, 1\} \ \ \forall i \in \mathcal{D} \tag{4.44e}$$

Similar to Benders' decomposition the variables of the sub-problem are used to form feasibility cuts. However, unlike the Benders' decomposition the solution of the variables are not included directly in the cut but used to form new sets,$\Omega_a^{(1)}$ and $\Omega_a^{(2)}$. The solution of the variable is included in the set $\Omega_a^{(1)}$ or $\Omega_a^{(2)}$ if it is an extreme point. The sets $\Omega_a^{(1)}$ and $\Omega_a^{(2)}$ are used to represent index sets for extreme points corresponding to constraints with integer variables. The objective of the master problem is to select the best possible solution of the relaxed sub-problems, P_a. Input parameter P_a of the master problem is the objective function value of the sub-problem at each iteration a. The constraint (4.44b) represents feasibility cuts modeled according to the approach presented in [86]. Ancillary variables w_a are used to activate corresponding feasibility cut while w_0 is used to prevent unbounded solution, respectively. The solution of the master problem (4.44) is used as an input to the sub-problem (4.45). The sub-problem (4.45) is exactly the same as the sup-problem of Benders' decomposition (4.42) and restated here for clarity.

$$\underset{\tilde{x}_s}{Maximize} \sum_{s\in\mathcal{S}} b_s\mu_s + \sum_{i\in\mathcal{D}} (\overline{\sigma}_i(p_i + (1-y_i)H) + \underline{\sigma}_i(p_i - (1-y_i)H)) \tag{4.45a}$$

$$Subject\ to\ :$$

$$\sum_{s\in\mathcal{S}} A\mu_s + \sum_{i\in\mathcal{D}} K_i\overline{\sigma}_i + \sum_{i\in\mathcal{D}} K_i\underline{\sigma}_i \leq 0 \tag{4.45b}$$

$$B\mu_s \leq 0 \ \ \forall s \tag{4.45c}$$

$$\mu_s, \overline{\sigma}_i, \underline{\sigma}_i \geq 0 \ \ \forall i \in \mathcal{D}, s\in\mathcal{S} \tag{4.45d}$$

The decomposition procedure of the Beans' technique can be formulated as in Algorithm 2

Algorithm 2 Beans' decomposition algorithm

procedure BEANS' DECOMPOSITION
    y_i =initial feasible solution UB=∞; LB=$-\infty$
Solve sub-problem (4.45)
Update $\Omega_a^{(1)}$ and $\Omega_a^{(2)}$
Set the maximum number of solutions in the solution pool
    while UP>LB **do**
        Append constraints (4.44b)
        Solve master problem (4.44)
        Update the value of fixed complicating variables $y_i^{(a)}$
        Solve sub-problem (4.45)
        Update $\Omega_a^{(1)}$ and $\Omega_a^{(2)}$
    end while
    return Optimal solution y_i
end procedure

4.6.5 Modified Beans' decomposition

The original Beans' decomposition presented in the previous section allows to avoid the effect of the disjunctive variable on the feasibility cut. However, the sub-problem (4.45) still contains the disjunctive parameters H which should be tuned to optimality. Such tuning is possible only for disjunctive parameters with known upper and lower limits. Thus, the presence of the disjunctive parameter in the sub-problem may still cause computational issues. In order to fully eliminate the effect of disjunctive parameter the following modifications are proposed. The proposed modifications are a part of the C4 contribution of this thesis.

The sub-problem (4.45) can be reformulated using Lemma 2 such that the disjunctive parameters are eliminated.

Lemma 2. If the disjunctive parameter H is tuned properly and optimization problem (4.45) is solved to optimality, then the objective function of (4.45):

$$\sum_s b_s \mu_s + \sum_i \overline{\sigma}_i (p_i + (1 - y_i)H) + \underline{\sigma}_i (p_i - (1 - y_i)H) \tag{4.46}$$

can be equivalently reformulated as a combination of a new objective function without disjunctive parameters and additional equality constraints:

$$\sum_s b_s \mu_s + \sum_i (\overline{\sigma}_i (p_i) + \underline{\sigma}_i (p_i)) \tag{4.47}$$

$$\overline{\sigma}_i ((1 - y_i)) = 0 \ \ \forall i \in \mathcal{D} \tag{4.48}$$

$$\underline{\sigma}_i ((1 - y_i)) = 0 \ \ \forall i \in \mathcal{D} \tag{4.49}$$

Proof. Assume that the disjunctive parameter H is tuned properly and optimization problem (4.45) can be solved to optimality. Then for the optimal solution to be reached the when the Karush-Kuhn-Tucker (KKT) conditions including the following complementary slackness conditions of the problem (4.40) are necessary to be satisfied:

$$\overline{\sigma}_i (K_i x - p_i + (1 - y_i)H) = 0 \ \ \forall i \in \mathcal{D} \tag{4.50}$$

$$\underline{\sigma}_i (-K_i x - p_i + (1 - y_i)H) = 0 \ \ \forall i \in \mathcal{D} \tag{4.51}$$

If y_i is equal to 0 then the constraints (4.40c) and (4.40d) are not active and the Lagrange multiplier $\overline{\sigma}_i$ and $\underline{\sigma}_i$ are strictly positive. Thus, the terms $\overline{\sigma}_i((1 - y_i)H)$ and $\underline{\sigma}_i((1 - y_i)H)$ are equal to 0. Similarly, if y_i is equal to 1 then the constraints (4.40c) and (4.40d) are active and the Lagrange multiplier $\overline{\sigma}_i$ and $\underline{\sigma}_i$ are equal to 0. Again, the terms $\overline{\sigma}_i((1 - y_i)H)$ and $\underline{\sigma}_i((1 - y_i)H)$ are equal to 0. Thus, the terms $\overline{\sigma}_i((1 - y_i)H)$ and $\underline{\sigma}_i((1 - y_i)H)$ are always equal to 0 if an optimal solution is reached. □

Using Lemma 2 the sub-problem (4.45) can be reformulated as:

$$\underset{\tilde{x}_s}{Maximize} \sum_{s\in\mathcal{S}} b_s\mu_s + \sum_{i\in\mathcal{D}}(\overline{\sigma}_i p_i + \underline{\sigma}_i p_i) \tag{4.52a}$$

$$Subject\ to\ :$$

$$\sum_s A\mu_s + \sum_i K_i\overline{\sigma}_i + \sum_i K_i\underline{\sigma}_i \leq 0 \tag{4.52b}$$

$$B\mu_s \leq 0 \ \ \forall s \in \mathcal{S} \tag{4.52c}$$

$$\overline{\sigma}_i((1-y_i)) = 0 \ \ \forall i \in \mathcal{D} \tag{4.52d}$$

$$\underline{\sigma}_i((1-y_i)) = 0 \ \ \forall i \in \mathcal{D} \tag{4.52e}$$

$$\mu_s, \overline{\sigma}_i, \underline{\sigma}_i \geq 0 \ \ \forall s \in \mathcal{S}, i \in \mathcal{D} \tag{4.52f}$$

4.6.6 Accelerated modified Beans' decomposition

Authors in [97] propose a technique to strengthen Benders' feasibility cuts. A similar procedure can be applied on Modified Beans' decomposition. By applying cut strengthening technique computational tractability of the Modified Beans decomposition is improved and convergence time is accelerated. The aforementioned acceleration is a part of contribution C4 of this thesis.

The idea behind cut strengthening technique applied on Modified Beans decomposition is that the master problem of a decomposition algorithm in the early interactions may have multiple optimal solutions and, as a result, the steps between iterations might be too big. Too big steps between iteration may result in slower convergence rate. Thus, by analogy to technique presented in [97] in the early iterations additional constraint (4.53c) which limits the steps between iteration can be introduced. The master problem of Modified Beans' decomposition with additional constraint is formulated as:

$$\underset{w_a,w_0,y_i}{Maximize} \sum_{a\in\mathcal{G}} P_a w_a + Mw_0 \tag{4.53a}$$

$$Subject\ to\ :$$

$$\sum_{i\in\Omega_a^{(1)}} y_i + \sum_{i\in\Omega_a^{(2)}} (1-y_i) \leq |\Omega_a^{(1)}| + |\Omega_a^{(2)}| - 1$$

$$+ \sum_{a\Upsilon(P_{a'}\geq P_a)} w_a \ \forall a \in \mathcal{G} \tag{4.53b}$$

$$\sum_{i\Upsilon(y_i^a=1)} (1-y_i) + \sum_{i\Upsilon(y_i^a=0)} y_i \leq L_a \ \forall a \tag{4.53c}$$

$$\sum_a w_a = 1 \tag{4.53d}$$

$$\sum_{i\in\mathcal{D}} y_i = 1 \tag{4.53e}$$

$$y_i \in \{0,1\} \;\; \forall i \in \mathcal{D} \tag{4.53f}$$

The constraint (4.53c) greatly improves the convergence of the Modified Beans decomposition, however, the parameter L_a depends on the starting point and the iteration number and it is hard to identify. The parameter L_a should be manually tuned for each case study. Thus, in order to avoid such tuning we propose to penalize large steps at each iteration in the objective function using a penalty factor β_a. Penalty factor β_a does not need tuning and simply ensures that if master problem of the Modified Beans' decomposition technique has multiple optimal solutions the closest to the previous iteration will be chosen. The resulting Accelerated Modified Beans' master problem is formulated as.

$$\underset{w_a,w_0,y_i}{Maximize} \sum_{a\in\mathcal{G}} P_a w_a + M w_0 - \beta_a\Big(\sum_{i\Upsilon(y_i^a=1)} (1-y_i) + \sum_{i\Upsilon(y_i^a=0)} y_i \Big) \tag{4.54a}$$

$$Subject\ to\ :$$

$$\sum_{i\in\Omega_a^{(1)}} y_i + \sum_{i\in\Omega_a^{(2)}} (1-y_i) \le |\Omega_a^{(1)}| + |\Omega_a^{(2)}| - 1$$

$$+ \sum_{a\Upsilon(P_{a'}\ge P_a)} w_a \;\; \forall a \in \mathcal{G} \tag{4.54b}$$

$$\sum_{a\in\mathcal{G}} w_a = 1 \tag{4.54c}$$

$$\sum_{i\in\mathcal{D}} y_i = 1 \tag{4.54d}$$

$$y_i \in \{0,1\} \;\; \forall i \in \mathcal{D} \tag{4.54e}$$

The proposed acceleration improves computational tractability of the master problem. On the other hand the master problem can be further accelerated using the parallel computing. The master problem during the initial iterations might have multiple optimal solutions. At each iteration, these multiple solutions are found and then the sub-problems associated to these optimal solutions are solved in parallel. The proposed accelerated algorithm is detailed in Algorithm 3 and illustrated in Fig. 4.3.

Algorithm 3 Accelerated decomposition algorithm

procedure SOLUTION ALGORITHM
    $y_i^{(a)}$ =initial feasible solution UB=∞; LB=$-\infty$
Solve sub-problem (4.52)
Update $\Omega_a^{(1)}$ and $\Omega_a^{(2)}$
Set the maximum number of solutions in the solution pool
    while UP>LB **do**
        Append constraints (4.54*b*)
        Solve master problem (4.54)
        Populate solution pool
        Solve sub-problems (4.52) in parallel for each element in the solution pool
        Update $\Omega_a^{(1)}$ and $\Omega_a^{(2)}$
    end while
    return Optimal solution y_i\$
end procedure

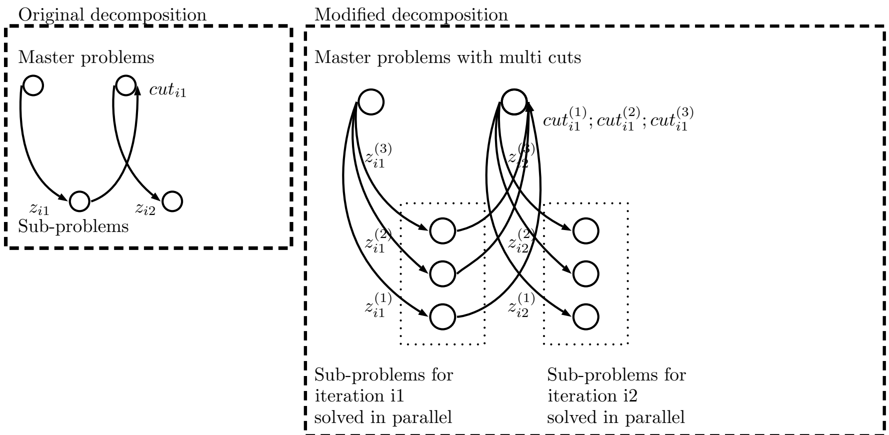


Figure 4.3: Accelerated Beans' decomposition algorithm

4.6.7 Performance

In order to test the performance of the Modified Beans' decomposition algorithm and Accelerated Beans' decomposition algorithm the transmission investment planning problem applied on IEEE 30-bus, 118-bus and 300-bus test systems is used. Data for the IEEE test systems are taken from data files of Matpower software, [98]. The additional data used for simulations can be found in Table 4.1. The performance of the Modified Beans' decomposition algorithm and Accelerated Beans'

Table 4.1: Input data for case studies.

	IEEE 30-bus	IEEE 118-bus	IEEE 300-bus
Number of candidate lines	20	30	60
Number of existing lines	30	175	411
Conventional Generation,(MWh)	335	4300	20678
Wind Generation, (MWh)	450	2500	12000
Scenarios, (N)	20	20	20
Operation subperiods, (N)	24	105	72
Maximum Load, (MWh)	600	4242	23526
Number of periods	10	10	15

Table 4.2: Results for IEEE 30-bus case study.

	Number of New Lines	Objective Function, ($)	Computation Time, (h)	Iterations
Without decomposition	4	145.15	0.485	-
Benders' decomposition algorithm	4	145.15	1.48	584
Modified Beans' algorithm	4	145.15	1.35	570
Accelerated Modified Beans' algorithm	4	145.15	0.456	152

decomposition algorithm is compared to the performance of the Standard Benders' decomposition algorithm and to the performance of the direct application of commercially available state-of-the-art CPLEX solver (without decomposition)[5]. All decomposition algorithms were implemented in GAMS software. The CPLEX solver is used to solve the MILP master problem and the sub-problem of each decomposition algorithm with the relative gap parameter set to zero. [6] The simulations are run on a computer with two processors and 128 GB of RAM.

[5]The disjunctive parameters included in the formulation which is solved by the CPLEX solver are tuned for relaxed problem (integer variables are fixed) using an iterative method where disjunctive parameters were increased till the point where the further change in the disjunctive parameters did not affect significantly the solution of the problem. It should be noted that we cannot guarantee that disjunctive parameters were tuned to optimality. We are not aware of any methodology which allows one to tune the disjunctive parameters without known upper bound to optimality.

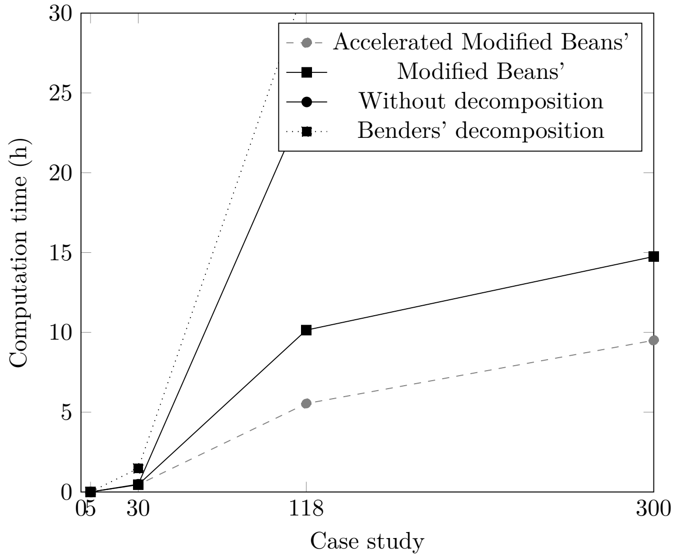
[6]This setting can be relaxed to allow for a small relative gap for both Bean and Benders' decomposition algorithms. However, one should keep in mind that the strength of the cuts might be compromised. This is especially the case for Benders' decomposition algorithm.

Table 4.3: Results for IEEE 118-bus case study.

	Number of New Lines	Objective Function, ($)	Computation Time, (h)	iterations
Without decomposition	23	3859	24.5	-
Benders' decomposition algorithm	23	3859	31.9	7319
Modified Beans' algorithm	23	3859	10.15	5012
Accelerated Modified Beans' algorithm	23	3859	5.3	2510

Table 4.4: Results for IEEE 300-bus case study.

	Number of New Lines	Objective Function, ($)	Computation Time, (h)	iterations
Without decomposition	no solution after 100 hours of simulation			
Benders' decomposition algorithm	15	10159	89	44 000
Modified Beans' algorithm	15	10159	14.75	13 000
Accelerated Modified Beans' algorithm	15	10159	9.5	3192



The results show that both Modified and Accelerated Modified Beans' decomposition outperforms Standard Benders' Decomposition. Moreover proposed acceleration techniques allow further improve computational tractability of the decomposiion and find an optimal solution in a reasonable time even for a large case studies such as IEEE 300-bus test system.

Publications $J3$ and $J4$ employ decomposition techniques presented in this chapter and provide numerical analysis.

Chapter **5**

Conclusion and future work

The aim of this final chapter is to summarize main conclusions and outcomes of this dissertation as well as provide an outline of future research possibilities.

5.1 Summary

This thesis introduces mathematical models and solution methodologies which can be used to support investment planning in power systems. Proposed models are formulated to reflect the rising complexity of the investment decision process in power systems with growing share of renewable generation and corresponding need for flexibility sources.

This thesis started with the analysis of short-term planning of energy storage technologies and resulted in a conference paper C1. However, the literature review performed during the publication of the conference paper showed that short-term planning of energy storage is very close to hydro power planning and an extensive amount of literature on the subject was already present. One challenge not addressed in the literature was identified in optimal allocation and sizing of energy storage.

In order to cover that literature gap and analyze the investment planning problem of an energy storage owner under the competitive market rules a mathematical model was developed. The analysis showed that energy storage investments depend largely on transmission infrastructure. Under different system typologies energy storage and transmission lines can be seen either as substitutes[1] or complements[2]. In either case, in order for investments in energy storage to be economical and feasible, there needs to be sufficient transmission network capacity.

[1] Energy storage and transmission are considered to be substitutes when reduction in energy storage capacity results in symmetric revenue growth for transmission company and vice versa

[2] Energy storage and transmission are considered to be complements when reduction in energy storage capacity results in symmetric revenue decrease for transmission company and vice versa

Merchant investment planning fully depends on power prices which are more complex to simulate. Two different approaches can be used to simulate power prices and integrate them into merchant investment planning. The first approach is to generate various price scenarios and use them as input parameters when deciding on location and capacities. The second approach is to incorporate the market operation problem inside the investment planning problem. Both approaches result in large scale problems. The first approach requires a vast number of scenarios to cover the uncertainty range of future price development while the second approach requires a complex multilevel mathematical model which can be hard to solve. While both approaches are not ideal, the second approach where market operation is incorporated inside investment planning tends to provide a more accurate picture of the market operation and anticipate the effect of investment decisions on power prices. The integrated approach also allows to simulate coordinated investments including the effect of regulatory measures.

5.2 Concluding remarks

It can be concluded that transmission investments are prerequisite for energy storage investments. This is due to the relatively short life span of an energy storage, long contraction time of transmission lines and degradation of energy storage which will happen regardless if energy storage is under operation or not. Thus, energy storage is most likely to follow a transmission investment decision and not vice versa. A similar logic can be applied to wind investment decisions. While energy storage and generation companies follow competitive market laws, transmission companies are highly regulated and can be characterized as natural monopolies. Without proper regulation such regulatory segregation results in limited information exchange between transmission companies and other utilities such as generation or energy storage companies. Consequently, transmission companies are unable to anticipate or forecast the future development of independently owned utilities and therefore to perform investment planning. This results in a situation when transmission investment is performed only after the investment planning of independently owned utilities is finalized. Thus, a contradiction arises where independent utilities can not invest due to limited transmission and transmission companies do not invest due to limited development in generation and energy storage. As a result, a stagnation in power system development appears. In order to avoid stagnation the investment planning in transmission, generation, and energy storage assets should be performed in a coordinated manner. In a deregulated economy coordinated investment planning is problematic due to competitive driving forces and limited information exchange.

One solution may be a regulatory entity that can support efficient development of the power sector by coordinating investment planning of different utilities and transmission companies. This coordination can be achieved by providing various incentive mechanisms for investment planning when price signals are not sufficient.

Incentive mechanisms are especially relevant for transmission investments where price signals cannot cover high capital costs of transmission lines. The analysis provided in this thesis as well as in publications J2-J4 show that, in particular, H-R-G-V and ISS incentive mechanisms are efficient and provide social welfare maximizing outcome. Moreover, the application of H-R-G-V and ISS invective mechanisms results in proactive transmission investments. Numerical studies and simulations on transmission planning support the analytical argument that unregulated transmission planning may result in under investment while Cost-Plus incentive mechanism may result in over investment.

The analysis of regulated investment planning also supports the conclusion that transmission investments are prerequisite for investments in energy storage and wind generation. Timely and efficient transmission expansion results in social welfare maximizing investments in energy storage and wind generation (as it was shown in the case studies provided in J2 and J4).

Incentive mechanism and regulatory measures can be integrated into investment planning by modeling decision making of a regulatory entity or by directly integrating incentive mechanism (or a regulatory measure) through regulatory constraints. Either approach complicates mathematical models used to simulate investment planning in power systems. If an investment planning problem is simulated considering a large power system, such as IEEE 300 node test system, the corresponding problem can become intractable and commercially available solvers will not be able to provide an optimal solution. (One such example where an investment problem becomes intractable is provided in publication J3.)

In some cases, a complex and large scale model can be efficiently relaxed to its simplified equivalent and decomposed into a series of smaller problems. In Chapter 4 of this thesis, a reformulation methodology consisting of a series of algebraic transformations and relaxations is used to convert a bilevel, nonlinear problem into a one-level linear equivalent problem with a decomposable structure. The obtained structure is then used to design a tailored decomposition algorithm which allows to improve the computational tractability of the problem. The reformulation methodology and decomposition technique depends on the initial structure of the model, and can be easily modified to adapt small changes in the model design. Moreover, regardless of the technology, most of the investment planning problems in power systems can be simulated using models provided in this thesis and consequently the reformulation methodology and decomposition techniques can be applied on these models as well. The proposed reformulation methodology and decomposition techniques can be used to support investment planning processes in various power system utilities as well as to support the decision making of a regulatory utility.

5.3 Open questions and future work

Investment models and solution methodologies provided in this thesis can be used to gain valuable insights into the future developments of power systems and to support investment planning processes. However, the presented investment models use several assumptions which may limit the analysis such as:

- The models assume perfect information and perfect competition to simulate market operation. While most of the electricity markets aim to achieve perfect information and perfect competition, in practise utilities can withhold crucial information to manipulate the market.
- The performance of assets such as energy storage in electricity markets depends largely on its bidding strategy. In this thesis, the bidding strategy is not considered when the revenue stream is computed.
- The main revenue stream of generators and energy storage is assumed to come from energy only markets and is based on spot prices.
- The models use representative days in order to simulate long-term planning. Representative days are chosen as average (representative) days for each season. While the logic behind such selection methodology has been widely used in the literature, the accuracy of the methodology was not validated.
- The decomposition techniques presented in this thesis assume that integer variables are present in the upper-level only and are not applicable for models with integer variables on the lower level.

In order to have a deeper understanding of investment planning problems and regulatory frameworks the aforementioned assumptions can be changed and the following improvements can be performed.

- Market clearance and the operation of each asset such as energy storage, generator, or load can be formulated as decoupled models. The asset operation models will then require modeling of the bidding strategy under the profit maximizing objective.
- Market operation can be extended to include joint clearing of a combination of multiple markets such as spot market and balancing markets as well as ancillary services to the system (e.g., frequency regulation, reserves).
- A methodology to select representative days can be developed so the minimum number of representative days is used and the accuracy of the revenue stream estimation is not compromised.
- Bean's decomposition technique can be extended for the general bilevel problem decomposition by utilizing disjunctive properties of the lower-level problem.

Some of these open questions and future work suggestions were partially addressed during the PhD study and resulted in several paper drafts which are in prepapration to be submitted to peer-reviewed publications in the near future.

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Curriculum vitae

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Work Experience

Current-Mar 2019 Quantitative Risk Analyst at Vattenfall AB, Stockholm, Sweden
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Teaching: During my PhD studies I was involved in course planning and lecturing for master level courses. I planned and gave lectures on stochastic short-term operation for Power Generation, Environment and Markets course. I gave lectures on short-term planning and mathematical modeling for Power Generation Operation and Planning course.

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Developed mathematical models for energy storage operation and planning under various balancing and reserve markets

Summer 2012 Intern at group of companies "Centre" , Kazan, Russia
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Scholarships and Certificates

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Optimal Investment Planning of Bulk Energy Storage Systems

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Abstract: Many countries have the ambition to increase the share of renewable sources in electricity generation. However, continuously varying renewable sources, such as wind power or solar energy, require that the power system can manage the variability and uncertainty of the power generation. One solution to increase flexibility of the system is to use various forms of energy storage, which can provide flexibility to the system at different time ranges and smooth the effect of variability of the renewable generation. In this paper, we investigate three questions connected to investment planning of energy storage systems. First, how the existing flexibility in the system will affect the need for energy storage investments. Second, how presence of energy storage will affect renewable generation expansion and affect electricity prices. Third, who should be responsible for energy storage investments planning. This paper proposes to assess these questions through two different mathematical models. The first model is designed for centralized investment planning and the second model deals with a decentralized investment approach where a single independent profit maximizing utility is responsible for energy storage investments. The models have been applied in various case studies with different generation mixes and flexibility levels. The results show that energy storage system is beneficial for power system operation. However, additional regulation should be considered to achieve optimal investment and allocation of energy storage.

Keywords: energy storage; power system planning; wind power generation; stochastic processes

1. Introduction

1.1. Motivation

The flexibility of a power system is defined by how well it can cope with variability and uncertainty and balance the production and consumption. Variability and uncertainty come from various sources such as time-varying demand and generation based on variable renewable sources as well as different contingencies such as line and generation outages.

Power systems are designed to handle demand variability and uncertainty as well as the majority of the contingencies. However, the increasing interest in variable renewable generation such as wind-based generation raises concerns on the need to increase the flexibility of the systems to accommodate large scale varying renewable energy sources. The capacity of wind energy installations is constantly increasing. For example, in Europe, the share of wind-based energy increased from 2.5 to 15.6% just over 15 years [1]. Current percentage of wind-based electricity generation in the European generation mix is now even greater than hydro based electricity generation which is 15.5%. Such a share of variable wind energy is still considered relatively low. In addition, the current state of a flexibility of the majority European power systems is proved to be sufficient to handle variability and uncertainty of the present wind based generation. However, if the trend will continue, power systems might have to improve the flexibility of the system. Based on current European targets, 20% consumption of energy should come from renewable generation by the year 2020. The target has been set by 2020 Climate and Energy package and will require even higher installed capacity of renewable generation due to variability and uncertainty of the renewable sources. Thus, wind power penetration is expected to grow substantially just over next few years. In addition, more ambitious targets are expected to be set for 2030 by Winter Package which is still under development. Increase in large scale renewable generation will contribute to higher volatility of wholesale electricity prices, higher balancing costs and system maintenance costs as well as large curtailments of renewable generation output. Thus, additional flexibility will be required [2,3].

The flexibility of the power system is provided mainly through flexible generation units with fast response time and flexible demand. One of the most flexible and least expensive generation units is hydro. The presence of hydropower in a power system clearly has a positive impact on the flexibility of the system. Hydrothermal power systems generally have good ramping capability and energy storage possibility in the form of hydro reservoirs. Thus, power system operators can use the flexibility of the hydropower generation to balance variable renewable electricity generation and load. However, for a large-scale expansion of wind power (or other variable generation such as solar) existing hydro flexibility might not be sufficient. More importantly, expansion of hydropower generation is difficult and in some cases is even impossible due to limited natural resources. In addition to hydropower, the flexibility of the system can then be improved by increasing the capacity of existing power plants, adding additional fast-ramping thermal generation capacity, demand response or energy storage capability. In this paper, we address the possibility to provide additional flexibility by adding energy storage capacity considering different storage technologies.

1.2. Knowledge Gap

Energy storage is not a new concept and was used for decades in power system, however predominantly pumped-hydro energy storage was in operation. Almost 99% of installed bulk energy storage capacity comes from pumped hydro and new installation of such energy storage is limited due to the same reasons as hydropower. However, other technologies such as compressed air energy storage (CAES) and various types of batteries are mature and available for applications on transmission level. In addition, other technologies for energy storage systems (ESS) are also under development and will be commercially available in foreseeable future. A database with a list of existing energy storage projects around the world is available in [4]. Energy storage systems are capable of providing additional flexibility on different time frames to power system operation by charging at peak hours and discharging when additional electricity is required. Such flexibility is very desirable for systems with high share of variable renewable generation. In addition, energy storage technologies are very fast and can be deployed at different capacities and power capabilities depending on the needs of the system. According to [5] the need in additional storage capacity in Europe alone is expected to double by 2050 mostly due to renewable generation capacity increase and additional balancing needs connected to that growth.

Energy storage systems (ESS) have multiple applications and can be beneficial at different levels of the electricity system. Various literature provide an overview on possible applications and assessment of energy storage benefits. In [6] a comprehensive analysis of possible energy storage applications and suitable energy storage technologies is presented. Applications may vary from energy arbitrage to grid upgrade investments deferral. The most promising applications for energy storage include energy arbitrage, balancing services and renewable generation support. Different ways how energy storage systems could be used for balancing applications, especially in presence of a large amount of variable renewable generation, were studied in [7,8], while [9] includes benefits of energy storage as a flexibility source. In addition, [10,11] analyze how energy storage can be beneficial for supporting variable wind power generation and [12] presents benefits of energy storage from a technical point of view and its effect on maximum wind power penetration. A review of modeling techniques of energy storage given different objectives is provided in [13] and includes more than 150 papers on the energy storage assessment subject. The literature provides evidence that energy storage is beneficial for renewable generation support and can be profitable under certain assumptions, however high capital cost is seen as the main obstacle in energy storage market development. Cost evaluation and calculation of different energy storage technologies is presented in [14,15].

The aforementioned papers have shown that additional capacity of flexibility sources such as energy storage will be required to reach future renewable targets and energy storage might be profitable in the systems with a high share of renewables but the financial profitability of the energy storage is still strongly dependent on the size and location of the deployed energy storage system. Optimal planning of energy storage under different conditions and objectives have been studied in [10,16–22]. In addition, [23–27] investigated joint optimal allocation and sizing of energy storage. In [28] the authors also show that energy storage is beneficial for renewable generation expansion and that joint optimization of renewable generation and flexibility sources including energy storage results in much higher cost savings than when investment planning is procured separately. However, these papers consider centralized investments planning which does not ensure profitability of the energy storage system itself and does not consider profit maximizing behaviour of the energy storage investor. Should flexibility sources such as energy storage be a market asset or system asset is an open question in power systems. Under current European regulation energy storage cannot be used to obtain profit if it is owned by system operators. Thus, current development of energy storage will mostly depend on independent investors which have profit maximizing objectives and other constraints on expected profit. A profit maximizing bilevel approach for investment planning of energy storage systems which will ensure that the owner of the energy storage will maximize its benefits has been proposed in [23,29,30]. However, neither of the proposed models include other sources of flexibility such as hydro and flexible demand which are currently the main competitors of emerging energy storage systems. Moreover, these models do not take into account possible growth of renewable generation.

1.3. Modeling Methodology

As in [23] this paper proposes a bilevel investment planning of strategic energy storage investor following the modeling approach proposed in [31] for generation investment planning. The approach allows to model behaviour of the strategic investor considering power system operation and locational marginal prices as an output of the operation. The modeling approach proposed in [31] allows to simulate operation of power system close to realistic operation and including many details such as dynamics of energy limited resources including energy storage, hydro power and flexible demand. Thus, the prices obtained to calculate energy storage profit are more realistic than using other mathematical models. In addition, the paper uses a technique to reformulate bilevel problem into single level linear program. Thus the obtained optimization problem can be solved with standard solvers such as CPLEX.

1.4. Contribution

This paper proposes two different mathematical models for joint energy storage sizing and allocation along with renewable generation expansion. The renewable generation expansion is ensured by expected renewable generation target constraint which sets the lower bound on renewable generation as a percentage of total consumption. The first model is for a centralized operation and investment planning while the second model is designed for an independent energy storage owner who is responsible for energy storage investments while the operation is still on a centralized planner. The proposed models can manage different generation sources (including thermal, hydro and variable renewable generation) along with flexible demand. The energy storage investment decisions are made over a portfolio of different energy storage technologies with varying properties for efficiency, self-discharge, etc. The owner of energy storage systems can decide which energy storage units to invest in and where to allocate them. The model has been applied to a case study under different cost parameters and various levels of installed flexibility. The proposed models and case study in this paper differ from the ones existing in the literature on four main points:

- First, the investment planning includes other sources of the flexibility of the system (hydro power and consumption flexibility) which can create competition for energy storage systems and affect the revenue stream.
- Second, energy storage investments are made along with renewable generation expansion and takes into account renewable generation targets present nowadays in Europe and USA.
- Third, the decentralized planning model in addition to investment return constraints includes payback period constraint which make the simulation of investment decision on energy storage closer to real life investment planning. Moreover, a solution to the bilevel problem has been suggested.
- Fourth, the paper presents a comparative analysis based on several case studies of systems with different generation mix and different levels of congestion. The results contribute to an understanding of the benefits of energy storage under different planning strategies and dependency of existing flexibility and type of flexibility on the profitability of the energy storage and possible effect on system congestion.

The models in this paper will be effective not only to help independent investment planning of energy storage owner considering expected growth of renewable generation but also to analyze the influence of existing flexibility in the system on energy storage investments.

1.5. Structure of the Paper

The paper is organized as follows. Section 2 introduces a centralized planning model followed by a bilevel mathematical formulation of a decentralized approach and a brief description of a one-level reformulation and linearization techniques. Section 3 presents case studies, results and an analysis of results. Finally, Section 4 provides conclusions and a discussion on a future work.

2. Energy Storage Investment Decision and Allocation Problem

The models in this paper consider two investment decisions: wind power generation expansion and energy storage investments. The first model (which is referred to as the centralized model) assumes perfect competition which could effectively be modeled by assuming that all operation and investment decisions are made by a single cost minimizing entity. The second model (which is referred to as the decentralized model) it is assumed that a separate entity makes decisions about energy storage investments, while the rest of the system remains a perfectly competitive market environment. The model assumes that the energy storage investor is a leader while the centralized planner is a follower meaning that first the decision on energy storage is made and afterwards based on that decision the centralized planner can expand renewable generation capacity and decide on operation dispatch. Thus, the energy storage entity can benefit from taking decision beforehand and strategically place energy storage while the centralized player can react to the investments and update its renewable generation capacity based on new flexibility in the system.

Both of the approaches have to take into account power system operation decisions, however the objectives are different. Thus, two different mathematical models were created in order to address the energy storage investment decision problem from two different ownership prospective. The following assumptions on energy storage investment decisions are taken for both models:

1. The energy storage investor can choose between energy storage modules of different technologies, where each module has fixed energy capacity, power capability and other technical parameters such as self-discharge and efficiency.
2. The energy storage charge and discharge efficiency as well as the self-discharge rate are fixed parameters and do not vary based on the charge/discharge output level or the energy level of the storage.

Additional assumptions are taken for each player.

1. The centralized player is responsible for generation expansion investments into renewable energy.
2. An independent investor will only make investments which will reach break-even within a given time. For example, typical expected payback period in long term investment planning is five years.
3. An independent investor has a lower limit on minimum investments returns.
4. The financial benefit of the energy storage is obtained through energy arbitrage.
5. The energy storage utility can exchange information with the centralized player which is in charge of the optimal dispatch of the generation, flexible load and energy storage in the system. The centralized player receives information from energy storage owner about invested and available energy storage energy capacity and power capability of each unit. On the other hand the centralized player provides information about dispatch of each energy storage unit and electricity prices.
6. The power system is represented by a DC load flow model.

2.1. Centralized Energy Storage Investment Decision and Allocation Problem

The investment decision problem for a centralized player is described in this section. The centralized player is responsible for the short-term operation of the power system and for the decisions on renewable generation expansion and investments and allocation of energy storage units. The problem is formulated as a mixed integer linear problem. Integer variables are used to allocate energy storage units while wind power generation investments are assumed to be continuous variables.

The objective function is described through Equation (1) and reflects the cost minimization of the whole system. The total cost consists of three main parts. The objective function is to minimize the cost of the scheduled day ahead generation dispatch $A_{p,s}$ based on the marginal generation cost of thermal units mc_j, energy storage charge and discharge cost mc_e and charges to activate flexible load Δd_d. The marginal cost of the energy storage charging or discharging is usually equal to zero (except for compressed air energy storage which uses natural gas or fuel in the discharging process). However, to take into account fast degradation connected to the cycling of some energy storage technologies such as batteries, an additional variable cost is assigned to each charge and discharge. In order to evaluate operation of energy limited resources with storage capability we also consider future value of stored energy in hydro reservoirs and energy storage systems calculated in $B_{k,t,s}$. FC_k is expected future price of electricity at the end of each operational period k. In addition to the variable costs, the system operator also minimize the investment cost into generation expansion and energy storage C_t. In this model we do not simulate all hours of operation of power system. Instead, we use selected days (for example number of seasons k = 4, number of selected days d = 1 and number of operation periods of each day l = 24 h). Thus, in order to match the simulated short-term operation costs of each year with and investment costs we use scale factor ψ which can be calculated through simple formula $\frac{8760}{k*l*d}$ (for the given example it will be equal to 91.25).

$$\underset{\Omega_s}{Minimize} : f_{LL} = \sum_t (\psi \sum_s \pi_s (\sum_{k,l} A_{p,s} - \sum_k B_{k,t,s}) + C_t) \tag{1}$$

where:

$$A_{p,s} = \sum_j mc_j g_{j,p,s} + \sum_d mc_d (\uparrow \Delta d_{d,p,s} + \downarrow \Delta d_{d,p,s}) + \sum_e mc_e (g^{ch}_{e,p,s} + g^{dch}_{e,p,s}) \tag{2}$$

$$B_{k,t,s} = FC_{k,t} (\sum_e SOC_{e,t,k,L,s} + \sum_h \sigma_h v_{h,t,k,L,s}) \tag{3}$$

$$C_t = \sum_w C_{w,t} (G^{max}_{w,t} - G^{max}_{w,t-1}) + \sum_e C_{e,t} (y_{e,t} - y_{e,t-1}) \tag{4}$$

The minimization problem is a subject to various constraints.

Energy storage investment constraint (5) ensures that invested energy storage unit is available at the later time periods after the investment was made.

$$y_{e,t} \geq y_{e,t-1} \forall e, t \tag{5}$$

Equation (6) represents the power balance for each node of the system. Total generation and net injection should be equal to the total demand.

$$\begin{aligned} &\sum_j I_{n,j} g_{j,p,s} - \sum_e I_{n,e}(g^{ch}_{e,p,s} - g^{dch}_{e,p,s}) + \sum_h I_{n,h} g_{h,p,s} + \sum_w I_{n,w} g_{w,p,s} - \sum_d I_{n,d} D_{d,p} \\ &- \sum_d I_{n,d} \uparrow \Delta d_{d,p,s} + \sum_d I_{n,d} \downarrow \Delta d_{d,p,s} + \sum_m I_{n,m} f_{n,m,p,s} = 0 \ : (\lambda_{n,p,s}) \quad \forall p, s, n. \end{aligned} \tag{6}$$

The energy balance constraint (7) represents the state of the charge of the energy storage unit. The dynamics of energy storage are very similar to hydropower. The main difference is that energy storage will convert surplus of electricity and store it in a different form of energy or in the form of an electromagnetic field and then convert it back when it is demanded [32]. The conversion of electricity into another form of energy induces some losses. These losses could be represented through efficiency coefficient ϵ_e of the energy storage. Also, the energy storage have a self-discharge rate ϕ_e which also cause the losses of energy. The use of efficiencies in the modeling also prevents energy storage to charge and discharge at the same time, therefore binary variables are not required.

$$SOC_{e,p,s} = \phi_e SOC_{e,t,k,l-1,s} + \epsilon_e g^{ch}_{e,p,s} - 1/\epsilon_e g^{dch}_{e,p,s} \ : (\lambda^{SOC}_{e,p,s}) \ \forall p, s, e. \tag{7}$$

Renewable generation operation constraints (8). In this model the wind-based generation could be spilled when there is an excess of generation or not enough ramping capability. Thus, (8) is used to determine actually utilized wind power $g_w(p,s)$.

$$0 \leq g_{w,p,s} \leq wp_{p,s} G_w + wp_{p,s} G^{max}_{w,t} \ : (\underline{\nu}_{w,p,s}, \overline{\nu}_{w,p,s}) \quad \forall p, s, w. \tag{8}$$

Equation (9) reflects the renewable generation penetration target which is set by the system (regulator). The equation ensures that expected wind generation at target year (RTY) and further on will be greater or equal to target values (RG^{min}).

$$\sum_s \pi_s \sum_{w,k,l} g_{w,p,s} \geq RG^{min} \sum_{d,k,l} D_{d,p} \ : (\beta_t) \quad \forall t \geq RTY. \tag{9}$$

Wind power generation investment constraints (10) which ensures that invested generation capacity stays on in the further periods.

$$0 \leq G^{max}_{w,t-1} \leq G^{max}_{w,t} \ : (\tau_{w,t}) \quad \forall t, w. \tag{10}$$

Hydro power operation constraints. The hydrological balance constraint (11) represents the hourly reservoir water level including previous content, direct inflow fl_h, spillage s_h and hydro discharge u_h used for power generation. The power generated by hydro units is determined through a linear function (12). This means that the efficiency of the hydro unit is assumed to be constant. Another approach is to use a piecewise linear function. This method is described in detail in [33].

$$\begin{aligned} &v_{h,p,s} = v_{h,t,k,l-1,s} - u_{h,p,s} - s_{h,p,s} + fl_{h,k,l} + \sum_{h^*} u_{h^*,t,k,l-\tau_{h^*},s} + \sum_{h^*} s_{h^*,t,k,l-\tau_{h^*},s} \ : (\lambda^{res}_{h,p,s}) \\ &\forall t, k, l, s, h. \end{aligned} \tag{11}$$

$$g_{h,p,s} = \sigma_h u_{h,p,s} : (\lambda^{Gen}_{h,p,s}) \ \forall p, s, h. \tag{12}$$

Ramping constraints of thermal generation units and hydro power units (13) and (14).

$$-RD_j^{max} \leq g_{j,t,k,l,s} - g_{j,t,k,l-1,s} \leq RU_j^{max} \ : (\underline{\kappa}_{j,p,s}, \overline{\kappa}_{j,p,s}) \quad \forall t,k,l,s,j. \tag{13}$$

$$-RD_h^{max} \leq g_{h,t,k,l,s} - g_{h,t,k,l-1,s} \leq RU_h^{max} \ : (\underline{\kappa}_{h,p,s}, \overline{\kappa}_{h,p,s}) \quad \forall t,k,l,s,h. \tag{14}$$

The problem considers DC power flows. Power flows $f_{n,m}$ are calculated using Equation (15) and are subject to power flow limits (21).

$$f_{n,m,p,s} - \frac{100}{X_{n,m}}(\theta_{n,p,s} - \theta_{m,p,s}) = 0 \ : (\lambda^{Line}_{n,m,p,s}) \quad \forall n,m,p,s. \tag{15}$$

The flexible demand can be increased or decreased. Thus, two different variables are used for upward demand change $\uparrow \Delta d_{d,p,s}$ and for downwards $\downarrow \Delta d_{d,p,s}$ for each hour. However, the total energy should be maintained for each operational period. Equation (16) is enforced to ensure that the total energy demand for each operational period is equal to the initial value.

$$\sum_l \uparrow \Delta d_{d,t,k,l,s} = \sum_l \downarrow \Delta d_{d,t,k,l,s} : (\lambda^D_{d,t,k,s}) \quad \forall t,k,s,d. \tag{16}$$

$$0 \leq \uparrow \Delta d_{d,p,s} \leq D_d^{max} \ : (\uparrow \underline{\omega}_{d,p,s}, \uparrow \overline{\omega}_{d,p,s}) \quad \forall p,s,d. \tag{17}$$

Upper and lower limit constraints (18)–(29) of decision variables.

$$SOC_e^{min} y_{e,t} \leq SOC_{e,p,s} \leq SOC_e^{max} y_{e,t} \ : (\overline{\gamma}_{e,p,s} \underline{\gamma}_{e,p,s}) \ \forall p,s,e. \tag{18}$$

$$-\Theta \leq \theta_{n,p,s} \leq \Theta \ : (\underline{\rho}_{n,p,s}, \overline{\rho}_{n,p,s}) \ \forall n,p,s. \tag{19}$$

$$\theta_{n=1,p,s} = 0 \ : (\rho 0_{p,s}) \ \forall p,s \tag{20}$$

$$-T_{n,m}^{max} \leq f_{n,m,p,s} \leq T_{n,m}^{max} \ : (\underline{\mu}_{n,m,p,s}, \overline{\mu}_{n,m,p,s}) \quad \forall n,m,p,s. \tag{21}$$

$$G_h^{min} \leq g_{h,p,s} \leq G_h^{max} \ : (\underline{\nu}_{h,p,s}, \overline{\nu}_{h,p,s}) \quad \forall p,s,h. \tag{22}$$

$$G_j^{min} \leq g_{j,p,s} \leq G_j^{max} \ : (\underline{\nu}_{j,p,s}, \overline{\nu}_{j,p,s}) \quad \forall p,s,j. \tag{23}$$

$$0 \leq \downarrow \Delta d_{d,p,s} \leq D_d^{max} \ : (\downarrow \underline{\omega}_{d,p,s}, \downarrow \overline{\omega}_{d,p,s}) \quad \forall p,s,d. \tag{24}$$

$$V_h^{min} \leq v_{h,p,s} \leq V_h^{max} \ : (\overline{\sigma}_{h,p,s} \underline{\sigma}_{h,p,s}) \quad \forall p,s,h. \tag{25}$$

$$0 \leq u_{h,p,s} \leq U_h^{max} \ : (\overline{\vartheta}_{h,p,s} \underline{\vartheta}_{h,p,s}) \quad \forall p,s,h. \tag{26}$$

$$0 \leq s_{h,p,s} \leq S_h^{max} \ : (\overline{\theta}_{h,p,s} \underline{\theta}_{h,p,s}) \quad \forall p,s,h. \tag{27}$$

$$0 \leq g^{ch}_{e,p,s} \leq G_e^{max} y_{e,t} \ : (\overline{\xi}^{ch}_{e,p,s}, \underline{\xi}^{ch}_{e,p,s}) \quad \forall p,s,e. \tag{28}$$

$$0 \leq g^{dch}_{e,p,s} \leq G_e^{max} y_{e,t} \ : (\overline{\xi}^{dch}_{e,p,s}, \underline{\xi}^{dch}_{e,p,s}) \quad \forall p,s,e. \tag{29}$$

It should be noted, that set p is used to simplify the notation. It contains all time period indices (year, t, season, k, and hour, l). The index p is used in the equation when all these sets are indexed together. If the equation is used just for one of the subsets, the set p is not used and the original three sets are written.

The decisions of the system operator include short term operation of the power system and investments into expansion of wind-based generation for each candidate node. $\Omega_s = \{g_j, g_w, g_h, g_e^{ch}, g_e^{dch}, \uparrow \Delta d_d, \downarrow \Delta d_d, f_{n,m}, SOC_e, u_h, v_h, s_h, G_w^{max}, y_{e,t}\}$ is the set of decision variables of the problem.

2.2. Independent Investment Planning. MPEC Model

This section describes the model when energy storage investment decisions are taken by an independent, profit-maximizing player while generation expansion decisions are in the hands of a centralized player. The problem can be described as a mathematical problem with an equilibrium constraint (MPEC) trough a bilevel program. In the upper level the energy storage owner can decide in which energy storage units to invest and where to put them while obtaining the prices and charge/discharge dispatches from the centralized player. Therefore, the optimal operation and generation investment planning model is included as a lower level problem.

$$\begin{aligned} &\underset{y_{e,t}}{Maximize} \\ &f_{UL} = \sum_{t,e} Pw_t(\psi \sum_{k,l,s} \pi_s(\lambda_{n,p,s} I_{n,e}(g^{dch}_{e,p,s} - g^{ch}_{e,p,s}) - mc_e(g^{ch}_{e,p,s} + g^{dch}_{e,p,s}) + FC_{k,t} SOC_{e,p,s} \Upsilon(l = L)) \\ &-C_{e,t}(y_{e,t} - y_{e,t-1})) \end{aligned} \tag{30}$$

S.t:

$$\psi \sum_{t^*=t,k,l,e,s}^{t+PBP} \pi_s(\lambda_{n,t^*,k,l,s} I_{n,e}(g^{dch}_{e,t^*,k,l,s} - g^{ch}_{e,t^*,k,l,s}) - mc_e(g^{ch}_{e,t^*,k,l,s} + g^{dch}_{e,t^*,k,l,s})) \geq \sum_e C_{e,t}(y_{e,t} - y_{e,t-1}) \quad \forall t \tag{31}$$

$$\psi \sum_{p,s,e} \pi_s(\lambda_{n,p,s} I_{n,e}(g^{dch}_{e,p,s} - g^{ch}_{e,p,s}) - mc_e(g^{ch}_{e,p,s} + g^{dch}_{e,p,s})) \geq IR \sum_{t,s,e} C_{e,t}(y_{e,t} - y_{e,t-1}) \tag{32}$$

$$y_{e,t} \geq y_{e,t-1} \quad \forall e, t \tag{33}$$

where

$$\begin{aligned} &\left\{\lambda_{n,p,s}, g^{ch}_{e,p,s}, g^{dch}_{e,p,s}\right\} \in \arg \underset{\Omega_s / y_{e,t}}{Min} \quad f^*_{LL} = \sum_t (\psi \sum_s \pi_s (\sum_{k,l} A_{p,s} - \sum_k B_{k,t,s}) \\ &+ \sum_w C_{w,t}(G^{max}_{w,t} - G^{max}_{w,t-1})) \end{aligned} \tag{34}$$

S.t:

$$(6) - (29) \tag{35}$$

The described problem is a stochastic, mixed integer problem which is optimized over t investment planning periods where each of the them consists of k seasons and l operation hours. The objective function (30) is to maximize the profit from energy storage operation which consists of a revenue stream from selling energy at price $\lambda_{n,p,s}$ while the energy storage discharges $g^{dch}_{e,p,s}$ minus the costs of buying energy for charging $g^{ch}_{e,p,s}$, the operational costs and the investments costs. Short term operation revenue and cost are multiplied by a discount factor ψ to scale the operation and investment costs and make them comparable. Equation (31) enforces the break-even constraint for energy storage investment, i.e., that the overall investments for each period should payback in a given amount of years, whereas (32) ensures that returns on the investments will be sufficiently large. Charge, discharge and price variables are obtained through the lower level problem (34).

The proposed model is a bilevel mixed integer problem. Bilevel programming models are a powerful tool for problems with multiple-criteria decision-making models. Such models can be solved in various ways and one of the them is by reformulating the given bilevel model into a one-level model. The reformulation is illustrated in Figure 1. Step 1 shows the original bilevel formulation. The lower level is a linear problem and therefore could be equivalently represented by the Karush-Kuhn-Taker (KKT) optimality conditions. KKT optimality conditions consist of primal feasibility equations, stationary conditions and complementary slackness conditions. This reformulation will not affect the optimality since the KKT conditions are both necessary and sufficient [34]. The result of replacing the lower level problem by its KKT conditions is shown Step 2. However, the optimization problem in Step 2 is non-linear and therefore the complementary slackness conditions are replaced by the strong duality condition which implies that $f^{\star}_{UL} = f^{\star dual}_{UL}$. The final reformulated problem is shown in Step 3.

The reformulation steps described above were applied on the independent investment planing problem (30)–(35). The model was transformed from a bilevel mixed integer non-linear model into an equivalent one-level mixed integer non-linear problem. Stationary conditions and complementary slackness conditions for lower level problem (34) are derived in the Appendix of this paper. Two set of non-linearities were identified. The following sections explain how these non-linearities can be reformulated.

Step 1		Step 2		Step 3
$\underset{x,y}{Minimize}: f_{UL}$		$\underset{x,y}{Minimize}: f_{UL}$		$\underset{x,y}{Minimize}: f_{UL}$
S.t:		S.t:		S.t:
$h_{UL}(x,y) = 0$		$h_{UL}(x,y) = 0$		$h_{UL}(x,y) = 0$
$g_{UL}(x,y) \leq 0$		$g_{UL}(x,y) \leq 0$		$g_{UL}(x,y) \leq 0$
$Where\ \{y\} \in$	$\equiv$	$KKTconditions:$	$\equiv$	$KKTconditions:$
$\arg \underset{y}{Min} f_{LL}$		$h_{LL}(y) = 0$		$h_{LL}(y) = 0$
S.t:		$g_{LL}(y) \leq 0$		$g_{LL}(y) \leq 0$
$h_{LL}(y) = 0\ :(\lambda)$		$\{Stationary\ \ conditions\}:$		$\{Stationary\ \ conditions\}$
$g_{LL}(y) \leq 0\ :(\mu)$		$\bigtriangledown f_{LL}(y) + \lambda \bigtriangledown g_{LL}(y) + \mu \bigtriangledown h_{LL}(y) = 0$		$\bigtriangledown f_{LL}(y) + \lambda \bigtriangledown g_{LL}(y) + \mu \bigtriangledown h_{LL}(y) = 0$
		$\{Complimentary\ \ slackness\ \ conditions\}$		$\{Strong\ \ duality\ \ condition\}$
		$\mu g_{LL}(y) = 0$		$f_{LL} = f_{LL}^{dual}$
		$\mu \geq 0$		$\mu \geq 0$

Figure 1. One-level equivalent reformulation steps.

2.3. Strong Duality Condition

One set of non-linearities appears in the strong duality conditions of the reformulated one-level problem and are reformulated using the big-M approach.

$$
\begin{aligned}
&\textstyle\sum_{s,p} \big[\sum_d (D_d^{max}(\uparrow \overline{\omega}_{d,p,s} + \downarrow \overline{\omega}_{d,p,s}) + \sum_n I_{n,d} D_{d,p} \lambda_{n,p,s}) + \sum_w wp_{p,s} G_w \overline{v}_{w,p,s} + \sum_j (G_j^{max} \overline{v}_{j,p,s} + \\
&RU_j^{max} \overline{\kappa}_{j,p,s} + RD_j^{max} \underline{\kappa}_{j,p,s} - \sum_j G_j^{min} \underline{v}_{j,p,s}) + \sum_h (G_h^{max} \overline{v}_{h,p,s} + RU_h^{max} \overline{\kappa}_{h,p,s} + RD_h^{max} \underline{\kappa}_{h,p,s} - G_h^{min} \underline{v}_{h,p,s} + \\
&V_h^{max} \overline{\sigma}_{h,p,s} - V_h^{min} \underline{\sigma}_{h,p,s} + U_h^{max} \overline{\vartheta}_{h,p,s} + S_h^{max} \overline{\theta}_{h,p,s} + fl_{h,k,l} \lambda_{h,p,s}^{res}) + \sum_n \Theta(\overline{\rho}_{n,p,s} + \underline{\rho}_{n,p,s}) + \\
&\textstyle\sum_{n,m} T_{n,m}^{max} (\underline{\mu}_{n,m,p,s} + \overline{\mu}_{n,m,p,s}) + \underbrace{\sum_e G_e^{max} \underbrace{\overline{\xi}_{e,p,s}^{ch} y_{e,t}}_{\widehat{\xi}_{e,p,s}^{ch}}}_{L1} + \underbrace{\sum_e G_e^{max} \underbrace{\overline{\xi}_{e,p,s}^{dch} y_{e,t}}_{\widehat{\xi}_{e,p,s}^{dch}}}_{L2} + \underbrace{\sum_e SOC_e^{max} . \underbrace{\overline{\gamma}_{e,p,s} y_{e,t}}_{\widehat{\gamma}_{e,p,s}^{u}}}_{L3} - \\
&\underbrace{\sum_e SOC_e^{min} . \underbrace{\underline{\gamma}_{e,p,s} y_{e,t}}_{\widehat{\gamma}_{e,p,s}^{l}}}_{L4} \big] - \textstyle\sum_t RG^{min} \sum_{d,k,l} D_{d,p} \beta_t = -\sum_t (\psi \sum_s \pi_s (\sum_{k,l} A_{p,s} - \sum_k B_{k,t,s}) \\
&+ \textstyle\sum_w C_{w,t} (G_{w,t}^{max} - G_{w,t-1}^{max}))
\end{aligned}
\tag{36}
$$

The non-linear terms L1, L2, L3 and L4 can be reformulated by introducing new variables $\widehat{\xi}_{e,p,s}^{ch}$, $\widehat{\xi}_{e,p,s}^{dch}$, $\widehat{\gamma}_{e,p,s}^{u}$, $\widehat{\gamma}_{e,p,s}^{l}$ and using big-M reformulation technique. Stationary conditions and complementary slackness conditions for lower level problem (34) used in the linearizion process are derived as in Equations (A1)–(A16) and (A17)–(A49) respectively in the Appendix of this paper.

$$
\left.
\begin{array}{l}
\widehat{\xi}_{e,p,s}^{ch} - \overline{\xi}_{e,p,s}^{ch} \leq M(1 - y_{e,t}) \ \ \forall e,p,s \\
\widehat{\xi}_{e,p,s}^{ch} \leq M y_{e,t} \ \ \forall e,p,s \\
\widehat{\xi}_{e,p,s}^{ch} \geq 0 \ \ \forall e,p,s
\end{array}
\right\} \ L1
\tag{37}
$$

$$\left.\begin{array}{l}\widehat{\xi}^{dch}_{e,p,s} - \overline{\xi}^{dch}_{e,p,s} \leq M(1-y_{e,t}) \;\; \forall e,p,s \\ \widehat{\xi}^{dch}_{e,p,s} \leq My_{e,t} \;\; \forall e,p,s \\ \widehat{\xi}^{dch}_{e,p,s} \geq 0 \;\; \forall e,p,s\end{array}\right\} L2 \tag{38}$$

$$\left.\begin{array}{l}\widehat{\gamma}^{u}_{e,p,s} - \overline{\gamma}_{e,p,s} \leq M(1-y_{e,t}) \;\; \forall e,p,s \\ \widehat{\gamma}^{u}_{e,p,s} \leq My_{e,t} \;\; \forall e,p,s \\ \widehat{\gamma}^{u}_{e,p,s} \geq 0 \;\; \forall e,p,s\end{array}\right\} L3 \tag{39}$$

$$\left.\begin{array}{l}\widehat{\gamma}^{l}_{e,p,s} - \underline{\gamma}_{e,p,s} \leq M(1-y_{e,t}) \;\; \forall e,p,s \\ \widehat{\gamma}^{l}_{e,p,s} \leq My_{e,t} \;\; \forall e,p,s \\ \widehat{\gamma}^{l}_{e,p,s} \geq 0 \;\; \forall e,p,s\end{array}\right\} L4 \tag{40}$$

Big-M reformulation technique is used to convert a logical constraint into a set of linear constraints corresponding to the same feasible set. If the disjunctive parameter is chosen carefully then the reformulated problem will be equivalent to the original one. The big-M reformulation does not affect the size of the problem. However, the disjunctive parameters involved in the reformulation create computational issues for the solver. A disjunctive parameter that is not tuned affects the convergence of the problem [35]. The literature provides several methods to tune the big-M parameter. The methodologies for tuning big-M can be found in [35,36]. The methods are proved to provide good approximations of the big-M parameters under certain conditions but additional large scale optimization problems should be solved for each case and the optimality still cannot be guaranteed. The problem of the disjunctive parameter tuning becomes especially hard when the reformulation involves variables without physical upper or lower limits which is the case in our proposed model. In this paper we use a simple iterative method to tune big-M parameters. We iteratively solve the proposed model while increasing the big-M parameter till it does not affect the solution of the problem.

2.4. Reformulation of the Objective Function

Another set of non-linearities $\lambda_{n,p,s} I_{n,e}(g^{dch}_{e,p,s} - g^{ch}_{e,p,s})$ is found in objective function (30) and can be linearized following algebraic manipulation steps as shown below.

First step is to express $\lambda_{n,p,s}$ as a linear combination of other decision variables using stationary conditions of the lower level problem (A13) and (A14)

$$\begin{array}{l}\sum_{p,e}\lambda_{n,p,s}I_{n,e}(g^{dch}_{e,p,s} - g^{ch}_{e,p,s}) \overset{(A13),(A14)}{=} \sum_{p,e}((-\psi\pi_s mc_e + 1/\epsilon_e\lambda^{SOC}_{e,p,s} - \underline{\xi}^{dch}_{e,p,s} \\ +\overline{\xi}^{dch}_{e,p,s})g^{dch}_{e,p,s} + (-\psi\pi_s mc_e - \epsilon_e\lambda^{SOC}_{e,p,s} - \underline{\xi}^{ch}_{e,p,s} + \overline{\xi}^{ch}_{e,p,s})g^{ch}_{e,p,s})\forall s\end{array} \tag{41}$$

Using complementary slackness conditions (A32)–(A35) for Equations (28) and (29) respectively we can further simplify the previous algebraic expression (41) as in (42):

$$\begin{array}{l}\sum_{p,e}((-\psi\pi_s mc_e + 1/\epsilon_e\lambda^{SOC}_{e,p,s})g^{dch}_{e,p,s} + G^{max}_e\overline{\xi}^{dch}_{e,p,s} + (-\psi\pi_s mc_e - \epsilon_e\lambda^{SOC}_{e,p,s})g^{ch}_{e,p,s} + G^{max}_e\overline{\xi}^{ch}_{e,p,s}) = \\ \sum_{p,e}(G^{max}_e(\overline{\xi}^{dch}_{e,p,s} + \overline{\xi}^{ch}_{e,p,s}) - \psi\pi_s mc_e(g^{dch}_{e,p,s} + g^{ch}_{e,p,s}) - \lambda^{SOC}_{e,p,s}(\epsilon_e g^{ch}_{e,p,s} - 1/\epsilon_e g^{dch}_{e,p,s}))\end{array} \tag{42}$$

Equation (42) still contains non-linear term $\lambda^{SOC}_{e,p,s}(\epsilon_e g^{ch}_{e,p,s} - 1/\epsilon_e g^{dch}_{e,p,s})$. Thus, we apply additional algebraic manipulations. We first use energy balance constraint of energy storage (7) and express the charge and discharge variables $g^{ch}_{e,p,s}$ and $g^{dch}_{e,p,s}$ through state of charge variables $SOC_{e,t,k,l,s}$ and then we use stationary condition (A15) to represent the primary state of charge variables $SOC_{e,t,k,l,s}$ through linear combination of Lagrange multipliers.

$$\begin{aligned}&\textstyle\sum_{p,e}\lambda^{SOC}_{e,p,s}(\epsilon_e g^{ch}_{e,p,s}-1/\epsilon_e g^{dch}_{e,p,s})\overset{(7)}{=}\sum_{p,e}(\lambda^{SOC}_{e,p,s}(SOC_{e,p,s}-\phi_e SOC_{e,t,k,l-1,s}))=\\&\textstyle\sum_{p,e}(SOC_{e,p,s}(\lambda^{SOC}_{p}-\phi_e\lambda^{SOC}_{e,t,k,l+1,s}))\overset{(A15)}{=}\sum_{p,e}(SOC_{e,p,s}(-\overline{\gamma}_{e,p,s}+\underline{\gamma}_{e,p,s}-\psi\pi_s FC_{k,t}\Upsilon(l=L)))\forall s\end{aligned}\tag{43}$$

Using complementary slackness conditions (A36) and (A37) for Equation (18) we can simplify Equation (43) and replace the rest of the non-linear terms through linear combination of linear terms as in (44).

$$\sum_{p,e}(-SOC^{max}_e\widehat{\gamma}^u_{e,p,s}+SOC^{min}_e\widehat{\gamma}^l_{e,p,s}-\psi\pi_s FC_{k,t}SOC_{e,L,k,t,s}\Upsilon(l=L))\forall s\tag{44}$$

By combining the algebraic expressions obtained in (42) and (44) we can now present the non-linear term $\lambda_{n,p,s}I_{n,e}(g^{dch}_{e,p,s}-g^{ch}_{e,p,s})$ through linear combination of linear terms as in (45)

$$\begin{aligned}&\textstyle\sum_{p,e}(\lambda_{n,p,s}I_{n,e}(g^{dch}_{e,p,s}-g^{ch}_{e,p,s}))\overset{(42),(44)}{=}\sum_{p,e}(G^{max}_e(\widehat{\xi}^{dch}_{e,p,s}+\widehat{\xi}^{ch}_{e,p,s})-\psi\pi_s mc_e(g^{dch}_{e,p,s}+g^{ch}_{e,p,s})\\&+SOC^{max}_e\widehat{\gamma}^u_{e,p,s}-SOC^{min}_e\widehat{\gamma}^l_{e,p,s}+\psi\pi_s FC_{k,t}SOC_{e,l,k,t,s}\Upsilon(l=L))\forall s\end{aligned}\tag{45}$$

2.5. One-Level Problem Formulation

The initial bilevel problem is now transformed into a one-level mixed integer linear problem, which is repeated here for the sake of clarity.

$$\begin{aligned}&\underset{\Omega_s\cup\Omega_p}{Maximize}:\\&f_{UL}=\textstyle\sum_{e,t}Pw_t(\psi\sum_{l,k,s}\pi_s W(p,e,s)-C_{e,t}(y_{e,t}-y_{e,t-1}))\end{aligned}\tag{46}$$

S.t:

$$\begin{aligned}&W(p,e,s)=G^{max}_e(\widehat{\xi}^{dch}_{e,p,s}+\widehat{\xi}^{ch}_{e,p,s})-(\psi\pi_s+1)mc_e(g^{dch}_{e,p,s}+g^{ch}_{e,p,s})+SOC^{max}_e\widehat{\gamma}^u_{e,p,s}-SOC^{min}_e\widehat{\gamma}^l_{e,p,s}\\&+(\psi\pi_s+1)FC_{k,t}SOC_{e,L,k,t,s}\end{aligned}\tag{47}$$

$$y_{e,t}\geq y_{e,t-1}\forall e,t\tag{48}$$

$$\psi\sum_{t^*=t+1,k,l,e}^{t+PBP}\pi_s W(p,e,s)\geq\sum_{e}C_{e,t}(y_{e,t}-y_{e,t-1})\ \ \forall t\tag{49}$$

$$\psi\sum_{p,e,s}\pi_s W(p,e,s)\geq IR\sum_{t,e}C_{e,t}(y_{e,t}-y_{e,t-1})\tag{50}$$

$$(6)-(29)\tag{51}$$

{Stationary condition}

$$(A1)-(A16)\tag{52}$$

{Strong duality condition}

$$\begin{aligned}&\textstyle\sum_{s,p}\big[\sum_d(D^{max}_d(\uparrow\overline{\omega}_{d,p,s}+\downarrow\overline{\omega}_{d,p,s})+\sum_n I_{n,d}D_{d,p}\lambda_{n,p,s})+\sum_w wp_{p,s}G_w\overline{\nu}_{w,p,s}+\sum_j(G^{max}_j\overline{\nu}_{j,p,s}+\\&RU^{max}_j\overline{\kappa}_{j,p,s}+RD^{max}_j\underline{\kappa}_{j,p,s}-\textstyle\sum_j G^{min}_j\underline{\nu}_{j,p,s})+\sum_h(G^{max}_h\overline{\nu}_{h,p,s}+RU^{max}_h\overline{\kappa}_{h,p,s}+RD^{max}_h\underline{\kappa}_{h,p,s}-G^{min}_h\underline{\nu}_{h,p,s}+\\&V^{max}_h\overline{\sigma}_{h,p,s}-V^{min}_h\underline{\sigma}_{h,p,s}+U^{max}_h\overline{\vartheta}_{h,p,s}+S^{max}_h\overline{\theta}_{h,p,s}+fl_{h,k,l}\lambda^{res}_{h,p,s})+\textstyle\sum_n\Theta(\overline{\rho}_{n,p,s}+\underline{\rho}_{n,p,s})+\\&\textstyle\sum_{n,m}T^{max}_{n,m}(\underline{\mu}_{n,m,p,s}+\overline{\mu}_{n,m,p,s})+\sum_e(SOC^{max}_e\widehat{\gamma}^u_{e,p,s}-SOC^{min}_e\widehat{\gamma}^l_{e,p,s}+G^{max}_e(\widehat{\xi}^{ch}_{e,p,s}+\widehat{\xi}^{dch}_{e,p,s}))\big]-\\&\textstyle\sum_t RG^{min}\sum_{d,k,l}D_{d,p}\beta_t=-\sum_t(\psi\sum_s\pi_s(\sum_{k,l}A_{p,s}-\sum_k B_{k,t,s})+\sum_w C_{w,t}(G^{max}_{w,t}-G^{max}_{w,t-1}))\end{aligned}\tag{53}$$

{Big-M reformulation constraints}

$$(37) - (40) \tag{54}$$

where:

$$\Omega_p = \{\lambda_n, \lambda_e^{SOC}, \lambda_h^{res}, \tau 0_w, \tau_w, \phi_w, \underline{\xi}_e^{ch}, \overline{\xi}_e^{ch}, \underline{\xi}_e^{dch}, \overline{\xi}_e^{dch}, \underline{\mu}_{n,m}, \overline{\mu}_{n,m}, \overline{\sigma}_h, \underline{\sigma}_h, \underline{\nu}_j, \overline{\nu}_j, \underline{\kappa}_h, \overline{\kappa}_h, \underline{\kappa}_j, \overline{\kappa}_j, \underline{\nu}_w, \overline{\nu}_w, \underline{\omega}_d, \overline{\omega}_d, \underline{\gamma}_e, \overline{\gamma}_e, \underline{\vartheta}_h, \overline{\vartheta}_h, \underline{\theta}_h, \overline{\theta}_h, \widehat{\gamma}_e, \widehat{\xi}_e^{ch}, \widehat{\xi}_e^{dch}\}$$

3. Case Study

The case study tries to answer the following questions. First, how will the presence of energy storage investment option affect system operation cost, electricity prices and wind-based generation expansion? Second, how will the planning approach (centralized and decentralized) affect the investment decisions on energy storage and will the results be different for systems with congested transmission capacity? Third, can energy storage benefit from congestion in the system under decentralized planning? Therefore the following simulation steps were performed. First, the centralized planning model without energy storage investment possibility was simulated, Case 1. Second, energy storage investment option was added and centralized and decentralized planning were simulated under different flexibility set-ups, Case 2 and Case 3 respectively. Third, the second step was repeated for the systems with and without transmission congestion. In addition, a case study without renewable generation expansion was performed, Case 4. In this case study we fix renewable generation capacity in the level to satisfy renewable penetration target and simulate energy storage investment planning under both centralized and decentralized planning models.

The models from section II have been tested on the IEEE 30-node test system. The generation mix has been varied to obtain different flexibility levels of the system and compare optimal energy storage investments. In the first and second set-ups, which is referred to as the thermal system (T) and thermal system with demand response (T+D), the generation consists of thermal units and wind power in set-up T and thermal units, wind power and flexible demand in system T-D. In the third and fourth set-ups, which is referred to as the hydro-thermal (H-T) system and hydro-thermal system with flexible demand (H-T+D), some of the thermal units of T and T+D system respectively are replaced by hydro units. The total installed capacity of generation units remains the same; however, the total expected ramping capability of the system is changed based on the thermal unit characteristics. The generation mix and total expected ramping capability can be found in Table 1.

The total expected ramping capability (*R_Total*) of the system is measured in MW per minute and calculated as an expected maximum reserves which could be provided by each plant, energy storage and flexible demand. A formula is provided to calculate total expected ramping capability of the system:

$$R\_Total = \sum_s \pi_s \tfrac{1}{T*l} (\sum_p (\sum_j min\{RU_j^{max}, G_j^{max} - g_{j,p,s}\} + \sum_h min\{RU_h^{max}, G_h^{max} - g_{h,p,s}\} + \sum_e (SOC_{e,p,s} - SOC_e^{min}) + \sum_d (D_d^{max} - \downarrow \Delta d_{d,p,s}))) \tag{55}$$

The total expected ramping capability is used to compare the flexibility levels of different case study set-ups. It is calculated based on hourly available energy capacity of the thermal and hydro generation considering ramping limits and available energy which can be obtained through energy storage and demand response. Energy storage and demand response are considered to have very fast ramping capability and therefore no ramping limits are imposed on these sources of flexibility. However, it should be noted that this approach will not capture the full dynamics of energy limited resources such as hydro power, flexible demand and energy storage, but can be used to approximate the flexibility of the system. A more exact measurement of flexibility of the system is outside of the scope of this paper. The measurement is calculated based on the up-ramping capability of the system and a similar index can be calculated based on the down-ramping capability of the system. However, in this system, the down-ramping capability is always larger than the up-ramping capability (especially if consider possibility to curtail wind power) and is therefore not analyzed any further. The transmission capacity connecting wind-based generation with load were reduced in order to create congestion in the system and analyze the impact of additional flexibility and behaviour of both planning strategies. In addition, the systems with initially congested transmission capacity were compared to the cases where transmission capacity was increased and congestion was eliminated.

Table 1. Test system input data.

	Thermal		Hydro-Thermal	
	Capacity	**Node**	**Capacity**	**Node**
Thermal, (MW)	600	1, 2, 22, 27, 23, 13	300	1, 2, 23
Hydro, (MW)	-	-	300	22, 27
Wind, (MW)	100	5, 6	100	5, 6
Max. demand, (MW)	600	-	600	-
Flexible demand	10%	-	10%	-
Transmission limits, (MW)	100	-	100	-
Congested transmission limits, (MW)	70	-	70	-
Ramping capability, (MW)	300	-	420	-
Renewable generation target	20%	-	20%	-

3.1. System Description

The IEEE 30-node test system was chosen to test and analyze presented investment models. The initial input data is presented in Table 1. The installed capacity is chosen to be almost the same as the peak demand in order to force additional investments into renewable generation. Practically, this situation reflects the decision to close large power plants in the system such as nuclear or coal and replace the required generation by investments into a wind-based generation and an additional flexibility source such as energy storage unit. In addition, the investments in renewable generation is ensured through lower limit constraint on expected generation from renewable generation.

A moment matching technique is used to generate the wind power generation scenarios [37]. The technique provides various advantages. The main one is that the technique allows to use a relatively few numbers of distinct scenarios and therefore reduces the computational difficulty for solving the stochastic program. The investment decisions in energy storage are made considering two different energy storage technologies available: compressed air energy storage (CAES) and batteries. Both of these technologies could be used for bulk energy storage, mature and commercially available. Each technology represented through a set of energy storage units of fixed energy capacity and power capability which could be invested in. The technical characteristics of each unit of each technology as well as the energy capacity and the power capability are presented in Table 3.

Case studies presented in this paper consider different levels of capital costs of energy storage. Initially, capital costs were assumed to be high to represent current state of the energy storage market. We expect a cost reduction each year of up to 5 % , i.e., $C_{e,t} = 0.95C_{e,t-1}$, to take into account predicted reduction of the capital costs in the future and development of new technologies. The initial capital costs for the first year were taken from [15] for energy storage and from [38] for wind power. The costs were updated using the present worth factor based on (56) and parameters presented in Table 2 and in Table 4.

$$Pw_t = \frac{(1+inf)^t}{(1+dis)^t} \tag{56}$$

Table 2. Investment cost assumptions.

Parameter	Value
Annual inflation rate, (*inf*)	2%
Discount rate, (*dis*)	10%

Thus, the investment decisions could be delayed for later periods when the conditions will be more financially favourable. Investment decision planning includes 10 consecutive periods which represent years. Each year consists of four consecutive operational periods which represent each season of that year. Figure 2 shows the time line for the operation planning and investments decisions.

Table 3. Energy storage characteristics.

Technology	CAES	Battery
Energy storage capacity, SOC_e^{max}, (MWh)	100	15
Power limit, G_e^{max}, (MW)	20	6
Energy conversion efficiency, (ε)	0.75	0.85
Self discharge of energy storage, (η)	0.78	0.99
Initial state of charge	50%	50%
Capital cost, Energy, (\$/kWh)	5	400
Capital cost, Power, (\$/kW)	700	400
Maximum number of units	5	10

For the hydro-thermal generation mixes the limits for hydro reservoirs at the end of the each operational period were set based on the outputs of the weekly schedule and are allowed to be deviated up to 10% of the scheduled amount for each operational period of each year. This was done to simulate long term hydro power scheduling and avoid overuse of hydropower.

Table 4. Investment parameters.

Parameter	Value
Planning period, (T)	10 years
Investments return parameter, (IR)	1.2
Payback period limit, (PBP)	5
Short term operation period, (l)	74 h
Renewable penetration target year, (RTY)	5th year

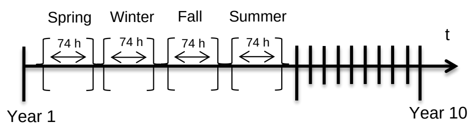

Figure 2. Investment planning time line.

3.2. Results and Discussions

Tables 5 and 6 present the results for the case studies listed above. Table 5 presents the summarized investment results and the influence of these investments on operation cost, renewable generation spillage and presence of congestion in the system. Table 6 presents more detailed data on energy storage investment, such as the time period when the investment was made, which technology was chosen and the node it was placed in.

First of all, the results show that energy storage could be a financially beneficial investment both, under centralized and decentralized planning. However, in hydro-thermal systems energy storage investments are not profitable for independent investors. No investments were made under decentralized planning in hydro-thermal systems while under centralized planning 45 MW of energy storage were installed which is 8% of the total installed generation capacity of the system. Considerable investments were made under decentralized planning in thermal only systems. 90 MW of energy storage consisting of batteries were installed compared to 115 MW of storage capacity consisting of CAES and a batteries under centralized planning. While decentralised planning ensures that the owner of energy storage system earns sufficient benefits in a fixed payback period time, the investments made are still beneficial for the whole system by reducing electricity prices and relieving transmission congestion. However, the benefits are much lower than under centralized planning and mainly due to lower investments in energy storage and as a consequence in renewable generation expansion. For example in the thermal only system the investments made under decentralized planning resulted in 12% price reduction compared to 20% price reduction under centralized planning while the standard deviation of the price was reduced from 12.6 to 6.2 in decentralized planning and till 4.3 under centralized planning. Curtailed wind remained relatively high (5%) under decentralized planning while centralized planning allowed to almost completely eliminate wind curtailment. Moreover energy storage investments reduced substantially installed capacity of the wind power generation which was required by renewable generation target set by the system. In centralized planning 115 MW of energy storage investment in thermal system helped to reduce required installed capacity of wind generation from 288 MW to 241 MW.

Another interesting observation was that in the system with congested transmission capacity, an independent profit maximizing energy storage owner will choose the placement of large energy storage units in such a way to keep the congestion in the system. On the other hand, under centralized planning more investments will be made just to relieve the congestion and reduce the renewable generation spillage and total operation cost. The difference is noticeable when comparing the system with three congested lines to the system without congestion. The average price and variability of the price is reduced under both centralized and decentralized planning with all generation mix set-ups while energy storage investments are also lower than in the case studies with congested lines with the same generation mix set-ups. For example the results in Table 6 show that similar quantities of energy storage were deployed under decentralized planning for congested and not congested systems but the nodes of placement were different. In the congested system under decentralized planning energy storage was placed at nodes 4, 6 and 8. In addition, the average price difference between centralized and decentralized planning was 9 % while in the non-congested system the price difference was equal to zero and the energy storage units were placed at nodes 4, 8 and 25. In centralized planning energy storage investments contribute to substantial reduction of wind power spillage and wind power generation investments which were forced by renewable generation target. Moreover, average price and price variability also were significantly lowered by additional energy storage investments. Decentralized planning also resulted in energy storage investments however the overall benefits of the system from these investments was lower.

In addition decentralized planning of energy storage especially in already congested systems can have a negative impact on system operation and further congested power system. This could be the case when variable renewable generation is planned beforehand and the flexibility requirements are set afterword. Thus, the flexibility providers can benefit from strategic placement and internalize existing system congestion. However, the results of the case studies show that independent energy storage investments will still contribute to congestion relief but in much lower volumes than in centralized planning. Congestion relief under decentralized planning is mainly due to the assumption that system operator follows energy storage investment decision and expands renewable generation according to the decision made on upper level. Thus, energy storage owner can not congest system further and considerably influence on locational marginal prices at the congested nodes. The case study Case 4 also proves this. The investments on energy storage when renewable generation capacity was fixed considerably increased price volatility and did not relieve congestion at all.

Table 5. Case study results.

	Congested				Not Congested	
	T	**T+D**	**H-T**	**H-T+D**	**T**	**H-T**
Case 1. Base case (no ES investments)						
Available capacity, (MW)	600	600	600	600	600	600
Wind power investments, (MW)	288	274	273	271	281	271
Ramping capability, (MWh)	300	360	420	480	300	420
Number of congested lines	3	1	3	1	0	0
Curtailed wind, (%)	10	8	11	6	7	5
Std of price	14.2	13.1	5.2	5.7	13.3	4.5
Average price, ($)	52	45	32	32	45	34
Case 2. Centralized planning						
Wind power investments, (MW)	241	235	232	238	248	236
Energy storage investments, (MW)	115	45	45	45	100	30
Ramping capability, (MWh)	390	390	455	510	384	447
Std of price	4.3	3.9	3.4	3.1	4.3	3.1
Average price, ($)	40	40	30	30	40	30
Number of congested lines	1	0	1	0	0	0
Curtailed wind, (%)	≥1	≥1	≥1	≥1	≥1	≥1
Case 3. Decentralized planning						
Wind power investments, (MW)	257	241	273	271	270	271
Energy storage investments, (MW)	90	45	0	0	45	0
Ramping capability, (MWh)	330	390	420	480	390	420
Std of price	6.2	5.4	5.2	5.7	5.2	4.5
Average price, ($)	44	40	35	35	40	34
Number of congested lines	2	1	2	1	0	0
Curtailed wind, (%)	6	6	9	6	7	4
Case 4. Decentralized planning with fixed wind investments						
Energy storage investments, (MW)	90	45	45	45	100	30
Ramping capability, (MWh)	330	390	420	480	384	447
Std of price	6.9	6.1	5.8	5.9	4.3	3.1
Average price, ($)	46	41	38	37	40	30
Number of congested lines	3	1	3	1	0	0
Curtailed wind, (%)	6.5	6.8	9	6	≥1	≥1

In addition, the investments in energy storage under independent investment planning were done predominately in batteries while in centralized planning the investments also include compressed air energy storage (CAES). Under centralized planning both congested and non-congested systems deployed one CAES unit while none of the case studies under decentralized planning invested in CAES. The large size of CAES and associated high total capital cost makes it harder for independent investors to get the payback of the investments in reasonable time. Thus, the payback limit constraints introduced in independent planning model restricts these investments.

Based on the case study results we can suggest that centralized ownership model provides more benefits to the power systems and ensures an effective short-term operation. However, current regulations existing in Europe prohibit the use of energy storage technologies for energy arbitrage if they are owned by the system operator. Thus, decentralized ownership model is the only valid option to provide energy arbitrage. The decentralized ownership of energy storage without proper regulation may potentially congest the system and result in inefficient development of power system and reduced deployments of renewable generation such as wind. Additional research on various regulations on energy storage investments should be performed in order to fully answer the question who should be responsible for energy storage investments.

Table 6. Energy storage investment results. Bat: Battery.

	Congested				Not Congested			
	Centralized		Decentralized		Centralized		Decentralized	
	CAES	Bat.	CAES	Bat.	CAES	Bat.	CAES	Bat
Thermal system								
Time period, (t)	t1	t1	-	t5	t1	t1	-	t5
Node, (n)	3	25	-	4, 6, 8	4	25	-	4, 8, 25
Number of units	1	6	-	1	1	3	-	
Hydro-Thermal system								
Time period, (t)	-	t1	-	-	-	t1	-	-
Node, (n)	-	3, 25, 15	-	-	-	3, 25	-	-
Number of units	-	3	-	-	-	2	-	-

4. Conclusions

This paper presents two mathematical models for centralized and decentralized investment planning of energy storage and wind power generation expansion. The decentralized investment planning is formulated as MPEC model, where a single energy storage investor is interacting with a centralized operator representing a perfect market environment. Both models are useful to investigate the interactions between variability of renewable generation and the flexibility provided by energy storage. The models include a wide range of generation mixes which allows to model different types of the system with different flexibility levels just by varying the input parameters.The proposed models allow to evaluate the differences between centralized and decentralized planning. Additional constraint on investments return and payback periods express the constraints of a profit maximizing company when it faces investment planning decisions. The models were applied on a case studies with various levels of flexibility and different levels of congestion in transmission capacity.

The following main conclusions were obtained from the case studies:

- First, energy storage can be beneficial to the whole system by reducing spillage of renewable generation and relieving congestion of transmission capacity under both centralized and decentralized planning approaches. However, there are still a big gap between centralized and decentralized planning approaches. More investments are made under centralized planning and the cost and the average price reduction under centralized planning is much higher.
- Second, if treated as a market asset (decentralized planning) energy storage can profit from strategically placing energy storage units and contribute on increase to transmission congestion of power system and additional wind spillage.
- Third, negative impact of strategic behavior of energy storage can be reduced if renewable generation decisions are taken simultaneously.
- Fourth, the case studies demonstrate that decentralized unregulated allocation planning for energy storage potentially may cause congestion in the system. Thus, additional studies on proper regulation for energy storage is necessary.

The gap between centralized and decentralized planning could be reduced if independent energy storage owner were able to have additional profits apart from energy arbitrage. An additional profit stream could increase the investments in energy storage under decentralized planning. This is the case especially in hydro-thermal system where investments in energy storage are generally less profitable under both centralized and decentralized investment planning. The revenue streams can include participation in balancing markets and provision of reserves. On the other hand increasing penetration of variable renewable generation will also increase the potential profitability and need in energy storage systems. Based on case study results energy storage considerably reduces wind spillage and therefore coordinated investment planning with renewable generation might increase investments in energy storage even under decentralized planning. Otherwise, in order to ensure sufficient flexibility in the system grid, the owner should be eligible and responsible for investments in energy storage. For example such a strategy was chosen in California and Oregon by passing energy storage mandates on energy storage installations.

Future research steps could be identified as the following.

- First, proposed decentralized model considers monopoly on energy storage investments and does not take into account additional competition from investments made on other flexibility sources such as hydro, flexible demand or flexible generators. Thus, an EPEC model could be developed to coordinate the investment and evaluate the dependency.
- Second, the models consider only one revenue stream which comes from providing energy arbitrage, however additional revenue streams such as provision of balancing services should be also considered to further evaluate the profitability of energy storage.
- Third, the initial formulation of the decentralized planning model is presented as a mixed integer non-linear bilevel model and later reformulated as a mixed integer linear one-level problem. The suggested technique for reformulation and linearization reduces the complexity of the model and makes it possible to find an optimal solution with reasonable computational time. However, the linearized model is still complex and a higher number of nodes and decision variables will increase the computational time. In order to apply the models to larger systems, it could be beneficial to investigate decomposition techniques (ex. Benders decomposition).
- Fourth, the choice of the number of days and operational hours also affects the computational time and the energy storage evaluation require rather large operational period to observe the charge and discharge cycles. Thus, the selection of the critical operational periods for energy storage evaluation is also a subject for future research.

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Nomenclature

Indices	
d	Demand;
e	Energy storage systems;
h	Hydro based generation;
j	Thermal generation;
k	Operation period (seasons);
l	Operation period (hours);
n, m	Nodes of the system;
p	Superset for l, k, t;
s	Scenarios;
t,t^*	Planning period (years);
w	Wind based generation;
Binary Variables	
y_e	Energy storage investment decision variable
Continuous Variables	
$\uparrow \Delta d_d, \downarrow \Delta d_d$	Up and down regulated flexible load, (MW);
$f_{n,m}$	Power flow between node n and m, (MW);
g_e^{ch}, g_e^{dch}	Charge and discharge of energy storage, (MW);
g_j,g_h,g_w	Output of thermal, hydro and wind generation units, (MW);
G_w^{max}	Expanded wind generation capacity, (MW);
s_h	Spillage of a hydro unit h;

SOC_e	State of charge of an energy storage, (MWh);
u_h	Hydro discharge of a hydro unit h
v_h	Reservoir level of a hydro unit h;
θ_n	Voltage angles at node n, ($p.u$);
λ_n	Price at node n, ($\$/MW$);
λ_e^{SOC}	Lagrange multipliers, ($\$/MW$), for energy balance constraint for ES;
$\lambda_{n,m}^{Line}$	Lagrange multipliers, ($\$/MW$), for power flow constraints;
λ_d^{D}	Lagrange multipliers, ($\$/MW$), for demand response constraints;
$\lambda_{h,p,s}^{Gen}$	red Lagrange multipliers,($\$/MW$), for hydro power generation constraint
λ_h^{res}	Lagrange multipliers, ($\$/MW$), for hydrological balance constraints;
$\tau 0_w, \tau_w$	Lagrange multipliers ($\$/MW$) for generation investment constraints;
$\underline{\xi}_e^{ch}, \overline{\xi}_e^{ch}$	Lagrange multipliers, ($\$/MW$), for energy storage charge constraints;
$\underline{\xi}_e^{dch}, \overline{\xi}_e^{dch}$	Lagrange multipliers, ($\$/MW$), for energy storage discharge constraints;
$\underline{\mu}_{n,m}, \overline{\mu}_{n,m}$	Lagrange multipliers, ($\$/MW$), for line constraints;
$\overline{\sigma}_h, \underline{\sigma}_h$	Lagrange multipliers, ($\$/MW$), for water reservoir volume constraints;
$\underline{\nu}_j, \overline{\nu}_j$	Lagrange multipliers, ($\$/MW$), for generator j constraints;
$\underline{\nu}_h, \overline{\nu}_h$	Lagrange multipliers, ($\$/MW$), for generator h constraints;
$\underline{\nu}_w, \overline{\nu}_w$	Lagrange multipliers, ($\$/MW$), for generator w constraints;
$\underline{\kappa}_j, \overline{\kappa}_j$	Lagrange multipliers, ($\$/MW$), for generator j constraints;
$\underline{\kappa}_h, \overline{\kappa}_h$	Lagrange multipliers, ($\$/MW$), for generator h constraints;
$\underline{\rho}_n, \overline{\rho}_n, \rho$	Lagrange multipliers, ($\$/MW$), for voltage angle constraints;
$\uparrow \underline{\omega}_d, \uparrow \overline{\omega}_d$	Lagrange multipliers, ($\$/MW$), for demand d constraints;
$\downarrow \underline{\omega}_d, \downarrow \overline{\omega}_d$	Lagrange multipliers, ($\$/MW$), for demand d constraints;
$\underline{\gamma}_e, \overline{\gamma}_e$	Lagrange multipliers, ($\$/MW$) for energy storage SOC constraints;
$\underline{\vartheta}_h, \overline{\vartheta}_h$	Lagrange multipliers, ($\$/MW$), for spillage constraints;
$\underline{\theta}_h, \overline{\theta}_h$	Lagrange multipliers, ($/MW), for water flow constraints;
β_t	Lagrange multipliers for renewable target constraint;
Parameters	
C_w	Capital cost of wind gen. expansion, ($\$/MW$);
C_e	Capital cost of energy storage block, ($\$/block$);
D_d	Non-dispatchable load, (MW);
D_d^{max}, D_d^{min}	Limits of flexible load, (MW);
dis	Discount rate;
FC	Expected future cost of electricity for period k ;
fl_h	Inflow of hydro unit h;
σ_h	Efficiency of hydro unit h;
τ_{h^*}	Hydro discharge time delay;
G_j^{max},G_h^{max},G_e^{max}	Upper generation limits, (MW);
G_j^{min},G_h^{min},G_e^{min}	Lower generation limits, (MW);
G_w	Existing capacity of wind power generation (MW);
inf	Annual inflation rate;
$I_{n,j}$,$I_{n,h}$,$I_{n,w}$	Incidence matrix for thermal, hydro and wind generation units;
$I_{n,e}$	Incidence matrix for energy storage units;
$I_{n,d}$	Incidence matrix for flexible demand units;
$I_{n,m}$	Incidence matrix for transmission;
IR	Investments return coefficient;
L	Operation time period;
M	Big-M parameter,sufficiently large number;
PBP	Payback period, (years) ;
Pw_t	Present worth factor ;
RG^{min}	Renewable generation penetration target ;
R_Total	Total expected ramping capability of a system ;
RU_j^{max},RU_h^{max}	Ramp-up hourly limits, (MW);
RD_j^{max},RD_h^{max}	Ramp-down hourly limits, (MWh);

S_h^{max}	Maximum spillage of hydro units;
SOC_e^{max}	Storage capacity, (MWh);
$T_{n,m}^{max}$	Transmission line capacity, (MW);
T	Investment planning period;
RTY	Target year for renewable generation penetration;
U_h^{max}	Maximum flow of hydro units;
V_h^{max}	Maximum reservoir of hydro units;
$wp_{p,s}$	Wind power output for each scenario as percentage of capacity;
ϵ_e	Energy conversion efficiency;
ϕ_e	Self discharge of energy storage;
π_s	Scenario probability;
mc_e, mc_j, mc_d	marginal costs of energy storage units,thermal units and flexible demand units
ψ	Scaling factor for operation and investment values
$\Upsilon(*)$	1 if $*$ is true and 0 otherwise;

Appendix A. Stationary Conditions

$$\psi\pi_s mc_d + I_{n,d}\lambda_{n,p,s} + \uparrow \underline{\omega}_{d,p,s} - \uparrow \overline{\omega}_{d,p,s} + \lambda^D_{d,t,k,s} = 0 \;\; \forall d,p,s \tag{A1}$$

$$\psi\pi_s mc_d - I_{n,d}\lambda_{n,p,s} + \downarrow \underline{\omega}_{d,p,s} - \downarrow \overline{\omega}_{d,p,s} - \lambda^D_{d,t,k,s} = 0 \;\; \forall d,p,s \tag{A2}$$

$$\psi\pi_s mc_j + I_{n,j}\lambda_{n,p,s} + \underline{\nu}_{j,p,s} - \overline{\nu}_{j,p,s} + \underline{\kappa}_{j,p,s} - \overline{\kappa}_{j,p,s} - \underline{\kappa}_{j,t,k,l+1,s} + \overline{\kappa}_{j,t,k,l+1,s} = 0 \;\; \forall j,p,s \tag{A3}$$

$$I_{n,w}\lambda_{n,p,s} + \beta_t \Upsilon(t \geq RTY) + \underline{\nu}_{w,p,s} - \overline{\nu}_{w,p,s} = 0 \;\; \forall w,p,s \tag{A4}$$

$$I_{n,h}\lambda_{n,p,s} + \underline{\nu}_{h,p,s} - \overline{\nu}_{h,p,s} + \lambda^{res}_{h,p,s} + \underline{\kappa}_{h,p,s} - \overline{\kappa}_{h,p,s} - \underline{\kappa}_{h,t,k,l+1,s} + \overline{\kappa}_{h,t,k,l+1,s} = 0 \;\; \forall h,p,s \tag{A5}$$

$$\underline{\vartheta}_{h,p,s} - \overline{\vartheta}_{h,p,s} + \lambda^{res}_{h,p,s} = 0 \;\; \forall h,p,s \tag{A6}$$

$$\underline{\theta}_{h,p,s} - \overline{\theta}_{h,p,s} + \lambda^{res}_{h,p,s} = 0 \;\; \forall h,p,s \tag{A7}$$

$$\underline{\sigma}_{h,p,s} - \overline{\sigma}_{h,p,s} - \lambda^{res}_{h,p,s} + \lambda^{res}_{h,t,k,l+1,s} - \pi_s\sigma_h FC_{k,t}\Upsilon(l = L) = 0 \;\; \forall h,p,s \tag{A8}$$

$$\underline{C}_{w,t} + \tau 0_w - \tau_{w,t=2} + \sum_{s,p} wp_{p,s}\overline{\nu}_{w,p,s} = 0 \;\; \forall w \; (t=1) \tag{A9}$$

$$\tau_{w,t} - \tau_{w,t-1} + \sum_{s,p} wp_{p,s}\overline{\nu}_{w,p,s} = 0 \;\; \forall w,t \; (1 < t < T) \tag{A10}$$

$$-\underline{C}_{w,t} + \tau_{w,T} - \phi_{w,T} + \sum_{s,p} wp_{p,s}\overline{\nu}_{w,p,s} = 0 \;\; \forall w \; (t=T) \tag{A11}$$

$$-\lambda_{n,p,s} + \underline{\mu}_{n,m,p,s} - \overline{\mu}_{n,m,p,s} + \lambda^{Line}_{n,m,p,s} = 0 \;\; \forall n,m,p,s \tag{A12}$$

$$\psi\pi_s mc_e - I_{n,e}\lambda_{n,p,s} + \epsilon_e\lambda^{SOC}_{e,p,s} + \underline{\xi}^{ch}_{e,p,s} - \overline{\xi}^{ch}_{e,p,s} = 0 \;\; \forall e,p,s \tag{A13}$$

$$\psi\pi_s mc_e + I_{n,e}\lambda_{n,p,s} - 1/\epsilon_e\lambda^{SOC}_{e,t,l,s} + \underline{\xi}^{dch}_{e,p,s} - \overline{\xi}^{dch}_{e,p,s} = 0 \;\; \forall e,p,s \tag{A14}$$

$$-\overline{\gamma}_{e,p,s} + \underline{\gamma}_{e,p,s} - \lambda^{SOC}_{e,p,s} + \phi_e\lambda^{SOC}_{e,t,k,l+1,s} - \psi\pi_s FC_{k,t}\Upsilon(l = L) = 0 \;\; \forall e,p,s \tag{A15}$$

$$-\sum_m \frac{100}{X_{n,m}}\lambda^{Line}_{n,m,t,p} + \sum_m \frac{100}{X_{m,n}}\lambda^{Line}_{m,n,t,p} + \underline{\rho}_{n,t,p} - \overline{\rho}_{n,t,p} + \rho 0_{p,s}\Upsilon(n=1) = 0 \;\; \forall n,p,s \tag{A16}$$

Appendix B. Complementary Slackness Conditions for Lower Level Problem

$$(g_{w,p,s} - wp_{p,s}G_w + wp_{p,s}G^{max}_{w,t})\overline{\nu}_{w,p,s} = 0 \ : (\underline{\nu}_{w,p,s},) \quad \forall p, s, w. \tag{A17}$$

$$g_{w,p,s}\underline{\nu}_{w,p,s} = 0 \quad \forall p, s, w. \tag{A18}$$

$$(RG^{min}\sum_{d,k,l} D_{d,p} - \sum_{s} \pi_s \sum_{w,k,l} g_{w,p,s})\beta_t = 0 \quad \forall t \geq RTY. \tag{A19}$$

$$(G^{max}_{w,t-1} - G^{max}_{w,t})\tau_{w,t} = 0 \quad \forall t, w. \tag{A20}$$

$$G^{max}_{w,t1}\tau 0_w = 0 \quad \forall w. \tag{A21}$$

$$((g_{j,t,k,l,s} - g_{j,t,k,l-1,s}) + RD^{max}_j)\underline{\kappa}_{j,p,s} = 0 \quad \forall t, k, l, s, j. \tag{A22}$$

$$((g_{j,t,k,l,s} - g_{j,t,k,l-1,s}) - RU^{max}_j)\overline{\kappa}_{j,p,s} = 0 \quad \forall t, k, l, s, j. \tag{A23}$$

$$((g_{h,t,k,l,s} - g_{h,t,k,l-1,s}) + RD^{max}_h)\underline{\kappa}_{h,p,s} = 0 \quad \forall t, k, l, s, h. \tag{A24}$$

$$((g_{h,t,k,l,s} - g_{h,t,k,l-1,s}) - RU^{max}_h)\overline{\kappa}_{h,p,s} = 0 \quad \forall t, k, l, s, h. \tag{A25}$$

$$(g_{h,p,s} - G^{min}_h)\underline{\nu}_{h,p,s} = 0 \quad \forall p, s, h. \tag{A26}$$

$$(g_{h,p,s} - G^{max}_h)\overline{\nu}_{h,p,s} = 0 \quad \forall p, s, h. \tag{A27}$$

$$(g_{j,p,s} - G^{min}_j)\underline{\nu}_{j,p,s} = 0 \quad \forall p, s, j. \tag{A28}$$

$$(g_{j,p,s} - G^{max}_j)\overline{\nu}_{j,p,s} = 0 \quad \forall p, s, j. \tag{A29}$$

$$(s_{h,p,s} - S^{max}_h)\overline{\theta}_{h,p,s} = 0 \quad \forall p, s, h. \tag{A30}$$

$$s_{h,p,s}\underline{\theta}_{h,p,s} = 0 \quad \forall p, s, h. \tag{A31}$$

$$(g^{ch}_{e,p,s} - G^{max}_e y_{e,t})\overline{\xi}^{ch}_{e,p,s} = 0 \quad \forall p, s, e. \tag{A32}$$

$$g^{ch}_{e,p,s}\underline{\xi}^{ch}_{e,p,s} = 0 \quad \forall p, s, e. \tag{A33}$$

$$(g^{dch}_{e,p,s} - G^{max}_e y_{e,t})\overline{\xi}^{dch}_{e,p,s} = 0 \quad \forall p, s, e. \tag{A34}$$

$$g^{dch}_{e,p,s}\underline{\xi}^{dch}_{e,p,s} = 0 \quad \forall p, s, e. \tag{A35}$$

$$(SOC_{e,p,s} - SOC^{max}_e y_{e,t})\overline{\gamma}_{e,p,s} = 0 \quad \forall p, s, e. \tag{A36}$$

$$(SOC_{e,p,s} - SOC^{min}_e y_{e,t})\underline{\gamma}_{e,p,s} \quad \forall p, s, e. \tag{A37}$$

$$(\theta_{n,p,s} + \Theta)\underline{\rho}_{n,p,s} = 0 \ \forall n, p, s. \tag{A38}$$

$$(\theta_{n,p,s} - \Theta)\overline{\rho}_{n,p,s} = 0 \ \forall n, p, s. \tag{A39}$$

$$(f_{n,m,p,s} + T^{max}_{n,m})\underline{\mu}_{n,m,p,s} = 0 \quad \forall n, m, p, s. \tag{A40}$$

$$(f_{n,m,p,s} - T^{max}_{n,m})\overline{\mu}_{n,m,p,s} \quad \forall n, m, p, s. \tag{A41}$$

$$(\uparrow \Delta d_{d,p,s} - D_d^{max}) \uparrow \overline{\omega}_{d,p,s} = 0 \quad \forall p,s,d. \tag{A42}$$

$$\uparrow \Delta d_{d,p,s} \uparrow \underline{\omega}_{d,p,s} = 0 \quad \forall p,s,d. \tag{A43}$$

$$(\downarrow \Delta d_{d,p,s} - D_d^{max}) \downarrow \overline{\omega}_{d,p,s} = 0 \quad \forall p,s,d. \tag{A44}$$

$$\downarrow \Delta d_{d,p,s} \downarrow \underline{\omega}_{d,p,s} = 0 \quad \forall p,s,d. \tag{A45}$$

$$(v_{h,p,s} - V_h^{max})\overline{\sigma}_{h,p,s} = 0 \quad \forall p,s,h. \tag{A46}$$

$$(v_{h,p,s} - V_h^{min})\underline{\sigma}_{h,p,s} = 0 \quad \forall p,s,h. \tag{A47}$$

$$u_{h,p,s}\underline{\vartheta}_{h,p,s} = 0 \quad \forall p,s,h. \tag{A48}$$

$$(u_{h,p,s} - U_h^{max})\overline{\vartheta}_{h,p,s} = 0 \quad \forall p,s,h. \tag{A49}$$

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Value of Energy Storage for Transmission Investments

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Abstract

This paper investigates joint investment planning of transmission lines and energy storage. Energy storage can be seen as a complement to transmission infrastructure and can be used for transmission deferral. On the other hand, under certain conditions, when the expected profit of both sectors depends on congestion in the system, transmission and energy storage can be seen as competitors. The transmission sector is in this study assumed to be a natural monopoly and operation and planning of transmission lines is performed by an independent company whereas the energy storage owner company operates and invests under competitive market rules. Three main questions are addressed in this paper. First of all, will additional energy storage capacity contribute to the growth of social welfare? Second, how will incentive regulation of the transmission network affect the need for energy storage? Third, how will the choice of incentive regulation affect the value of energy storage. This paper first provides an overview of incentive regulation which can be applied to transmission investments. Then case studies based on a 6-node power system network and the IEEE 118-node system are proposed in order to answer the aforementioned questions. The results of the case studies show that energy storage investments complement transmission expansion and contribute to higher social welfare values. The benefits from energy storage investments are significantly higher under two investigated incentive regulations as compared to the case without incentive regulation. Thus, the transmission investment planning process should consider energy storage options.

Keywords: Transmission investments, Energy storage, Incentive regulation, Wind generation, Stochastic programming

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1. Introduction

The operation and planning of transmission infrastructure depends on the transmission owner and the system operator. Depending on regulation and market set-ups the transmission owner and the system operator can be the same or separated entities. In the majority of European electricity markets transmission owners and system operators are the same entity, commonly called TSO [1]. On the other hand, in other markets such as California and PJM, investments in transmission capacity are manged by independent transmission companies (Transco)[2]. In this paper we consider that transmission investments are managed by the Transco while system and market operations are carried out through the market operator (MO)[3]. Furthermore, we consider that the Transco is regulated by an independent regulatory entity (Regulator). The interaction between aforementioned independent entities is illustrated in Fig. 1. The figure shows that loads, energy storage and generators are operated by the MO. In order to dispatch loads, energy storage and generation, the MO has to account for available transmission capacities. The Transco provides information of transmission availability to the MO. The Regulator observes the market situation and imposes an appropriate regulation on the Transco's revenue. This arrangement is known in the literature as merchant-regulatory investment planning.

While centralized planning is proved to maximize social welfare, the planning of Transcos has a profit maximizing objective and, thus, may not guarantee the same level of social welfare and transmission investments. Under merchant-regulatory investment planning the Transco owns and operates the transmission network and obtains profits from congestion rent for providing transmission services and usage of the electricity grid. Congestion rents account only for 25% of the investments which may result in under investment in transmission [1]. Moreover, increased uncertainty of expanding renewable generation results in additional transmission needs and as a consequence increased transmission investment costs [2]. Thus, additional incentives may be necessary to facilitate adequate growth of transmission infrastructure. Incentives can be introduced through incentive regulations.

The rapid growth of renewable generation puts a lot of pressure on the transmission infrastructure and may result in severe congestion in the system. Congestion can be eased by additional investments in transmission lines or by non-transmission alternatives such as energy storage technologies. Transmission infrastructure owners are tasked to take investment decision on new transmission capacity. Regulation of the transmission sector prohibits transmission owners to exercise control or any right over any asset which can be considered

[1]European Network of Transmission System Operators for Electricity (ENTSO-E) defines TSO as "a natural or legal person responsible for operating, ensuring the maintenance of and, if necessary, developing the transmission system in a given area and, where applicable, its interconnections with other systems, and for ensuring the long term ability of the system to meet reasonable demands for the transmission of electricity".

[2]Transco has similar functions as TSO. Transco owns transmission infrastructure and has the responsibility to maintain transmission network and ensure secure transmission of electricity.

[3]The market operator is introduced in this paper as a separate entity and is used to describe the functioning of the market and system operations.

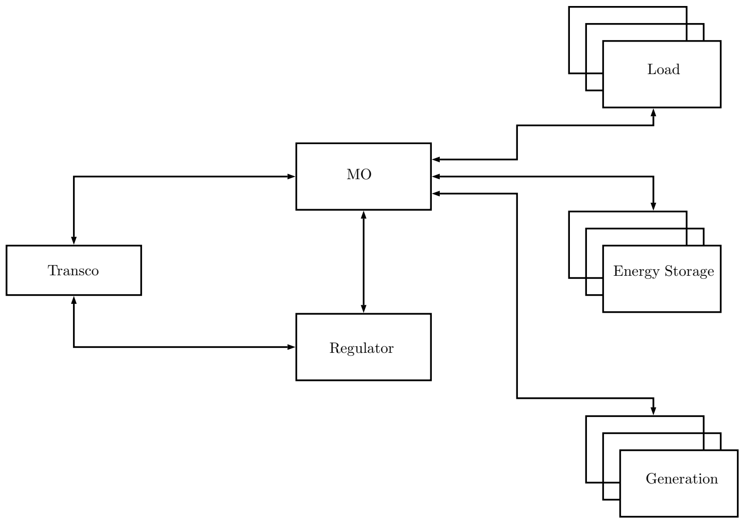

Figure 1: Power system agents interaction set-up

as generation or supply. Energy storage can be considered as generation when discharging and a load when charging. Thus, transmission companies cannot own or operate any energy storage system and operation and planning of energy storage systems are left to the competitive markets. Hence, there is a challenge to efficiently integrate non-transmission alternatives such as energy storage into the transmission investment decision process.

Any measure which motivates a regulated entity such as a Transco to invest in new transmission capacity can be seen as an incentive regulation. Regulators choose incentive regulation based on few simple principles [3]. First of all, the cost of transmission investments should be allocated to the profiting entities such as generation and loads by fair shares. Second, investments should reflect the needs of new generation and loads. Third, transmission investments should contribute to the social welfare maximization. Fourth, investments should not contribute to increase in market power of any entity or participant of the electricity market in a regional or local power system. Fifth, transmission investments must facilitate competition among generators, loads and flexibility providers such as energy storage.

Current transmission investment planning processes generally do not account for non-transmission alternatives [4]. This creates huge obstacles for emerging technologies with high capital costs such as energy storage. On the other hand the growing interest and need for balancing technologies also boost governmental support for energy storage. Thus, in some states of U.S.A such as California energy storage mandates are accepted [5]. The mandates set a target for energy storage installed capacity. Moreover, while various directives set clear rules for unbundling of the functions of electricity generation, load and transmission services, energy storage is not mentioned in any directives and thus clear rules on operation and planning of energy storage do not exist. As a result, electricity storage is generally considered as a generation system when it discharges and a load when it charges. Energy storage profit mainly consists of energy arbitrage at different time periods and payments for various regulation services such as frequency regulation. Existing congestion in a power system can positively impact energy arbitrage opportunities and thereby increase the profit of energy storage. Similarly, limited transmission capacity can also increase the need for regulation services and as a result further increase the profit of energy storage. However, in this paper we consider profits from energy arbitrage only.[4]

Various incentive regulations have been proposed to tackle the incentive problem. They can be divided into two major groups: subsidy regulations and constraint regulations. Subsidy regulation were initially introduced by [6] and further developed by [7] where an incremental surplus subsidy scheme (ISS) was proposed. The regulation then was applied to transmission pricing and investments in [8]. On the other hand, constraint regulations were proposed in [9] and [10], where price-cap (Cost-Plus incentive regulation) constraints were proposed for incentivizing transmission investments by a Transco. Under certain conditions, these regulations lead to a transmission expansion plan which maximizes social welfare [11]. Reference [12] proposes a reward/penalty regulation. In this regulation, the regulator rewards the Transco when the transmission network is expanded and the congestion rents are decreased. Reference [13] proposes an out-turn regulation. The out-turn is defined as the difference between actual electricity prices and prices without transmission congestion. The Transco is responsible for total out-turn cost and any transmission losses. References [11] and [14] extend the work in [9] and propose the H-R-V (Hogan-Rosellon-Vogelsang) regulation for transmission investments. In the H-R-V regulation, the Transco maximizes its profit (sum of merchandising surplus and a fixed fee minus transmission investment costs) subject to the price-cap constraint introduced in [9]. The H-R-V regulation has been numerically tested in simplified models of Northwestern Europe and the Northeast U.S.A. [11], [15]. Mathematically, the H-R-V model is a non-linear program with equilibrium constraints (NLPEC). Local optimizers have been used to solve the corresponding model but with no guarantee of global optimality. Moreover, complex algorithms used to solve such problems have a high computation time and they are hardly applicable to large scale problems with many decision variables. As a result, finding an optimal incentive regulation for transmission investments is an open question both in theory and in practice. More recently, an alternative incentive regulation for transmission investments is proposed in [16] following the incentive regulations in [7] and [11]. The H-R-G-V (Hesamzadeh-Rosellon-Gabriel-Vogelsang) regulation proposes a dynamic interaction between a profit-maximizing Transco, the regulator and an a Market Operator (MO). In [16] the authors prove analytically that the H-R-G-V regulation will lead to socially maximum investment planning decisions.

While the literature provides proof that Cost-Plus incentive regulation and ISS incentive regulation under certain conditions will lead to maximal social welfare and H-R-G-V incentive regulation will converge to social welfare maximum at all times. However, the literature

[4]Regulation service requirements and payments for providing regulation services can be considered in the analysis by including reserve market operation along with the energy market.

on incentive regulations does not account for non-transmission assets and energy storage in particular. Thus, additional study is necessary.

Transmission and energy storage planning has been studied in various literature. Similarly to transmission investment planning the problem of joint transmission and energy storage planning was looked under different assumptions as well. In [17],[18], [19] and [20] authors propose to study the joint transmission and energy storage planning under a social welfare maximizing objectives. In [21] the authors assume that the system does not have congestion, however the responsibility of the transmission investments is to ensure reliable connection of new loads, generation and energy storage. The authors provide a comprehensive case study on the effect of transmission tariffs on energy storage profitability, operation and investments. However, these papers do not consider regulatory framework or effect of uncertain renewable generation such as wind[5] or any other forms of uncertainty [6] .

In this paper we provide a study how energy storage will affect merchant-regulatory transmission investments in a system with uncertain wind generation. We first analyze possible effects energy storage may have on merchant-regulatory transmission investments. We validate the obtained hypotheses by proposing a mathematical model which incorporates regulatory constraints into merchant-regulatory investment planning and by providing simulation results of a 6-node case study and the IEEE 118-node system.

The contributions of the paper consist of four main points:

- We show that application of the H-R-G-V incentive regulation will in theory lead to a social welfare maximum outcome of joint energy storage and transmission investments at all times.
- We formulate a mathematical model that can be used to investigate merchant-regulatory investments in transmission and energy storage. The proposed model is bilevel, stochastic and non-linear and it is shown how this problem can be converted into a tractable MILP problem. The proposed conversion consists of only algebraic transformation techniques which provide precise linear approximations of nonlinear terms. Thus, the proposed model provide reliable simulation results.
- We propose a methodology to evaluate value of energy storage investment and incentive regulation. The methodology accounts for the effect of incentive regulation on energy

[5]According to [22], hour-ahead wind generation forecast errors can reach up to 50 % of installed wind capacity.

[6]Transmission investment planning is subject to different types of uncertainties. Transmission operation planning has to take into account the operation of the whole system. Each participant in the electricity market is subject to its own uncertain parameters. Generators and loads may experience unexpected outages of their equipment. Wind and solar generation highly depend on weather conditions which are also hard to predict. Furthermore, various economic uncertainties such as fuel prices and maintenance costs will affect the operation of generators and other electricity market participants and consequently affect the operation of transmission lines. Therefore, all aforementioned uncertainties may impact the need for additional transmission capacity and influence the congestion in a power system. However, in this paper, we aim to analyze the impact from wind generation uncertainties and therefore isolate them from the remaining sources of uncertainty.

storage investments as well as the effect of energy storage on incentive regulation. The proposed methodology can be used as an analytical tool to compare incentive regulations to non-transmission investments such as investments in energy storage.

- We simulate investment planning of transmission and energy storage under the considered incentive regulations and apply the proposed model to two case studies of different size and composition. In addition, we apply the proposed methodology to calculate the value of energy storage investments and incentive regulation. The results show that incentive regulations and energy storage investments are complementing each other and increase social welfare. Moreover, the theoretical proof of the efficiency of H-R-G-V is confirmed by the case studies.

2. Transmission investments under incentive regulation

In this section we formulate the investment problem of a Transco considering the incentive regulations Cost-Plus incentive regulation, ISS incentive regulation and H-R-G-V incentive regulation. Moreover, we incorporate energy storage investments in the analysis.

We consider that generation, load and energy storage are owned by independent companies Genco, Load and ES, respectively. Genco, ES and Loads are operated under perfect competition. In addition, we assume a regulatory entity (Regulator) which can have access to all information available to the MO and set various incentive regulations. The process of joint merchant-regulatory transmission investments and energy storage investments and interaction of aforementioned actors are described in Fig. 2.

The Transco maximizes its profit by expanding its transmission network while considering a fixed fee calculated by the Regulator. The Transco communicates transmission investment decisions to the Regulator and MO. The MO dispatches the system and communicates the required information to the Regulator. The Regulator calculates the fixed fee based on the information provided by MO (i.e., nodal prices, dispatch of generation, load and energy storage and investment costs of energy storage)[7] and communicates the value to the Transco.

Mathematically this process can be formulated as

$$Maximize \ \sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{s,t}] + \Phi_t - \overline{C}^T_t) \tag{1a}$$

$$Subject\ to:$$

$$f(\Phi_t) = 0 \ \ \forall t \tag{1b}$$

$$Maximize \ \sum_t (\mathbb{E}[\pi^G_{s,t}] + \mathbb{E}[\pi^T_{s,t}] + \mathbb{E}[\pi^L_{s,t}] + \mathbb{E}[\pi^S_{s,t}] - \tilde{C}^S_t$$

$$Subject\ to: \text{system technical constraints.} \tag{1c}$$

[7] In this paper we assume that nodal prices, dispatch of generation, load and energy storage and investment costs of energy storage are the only necessary information to calculate social welfare surplus which is defined in (2)

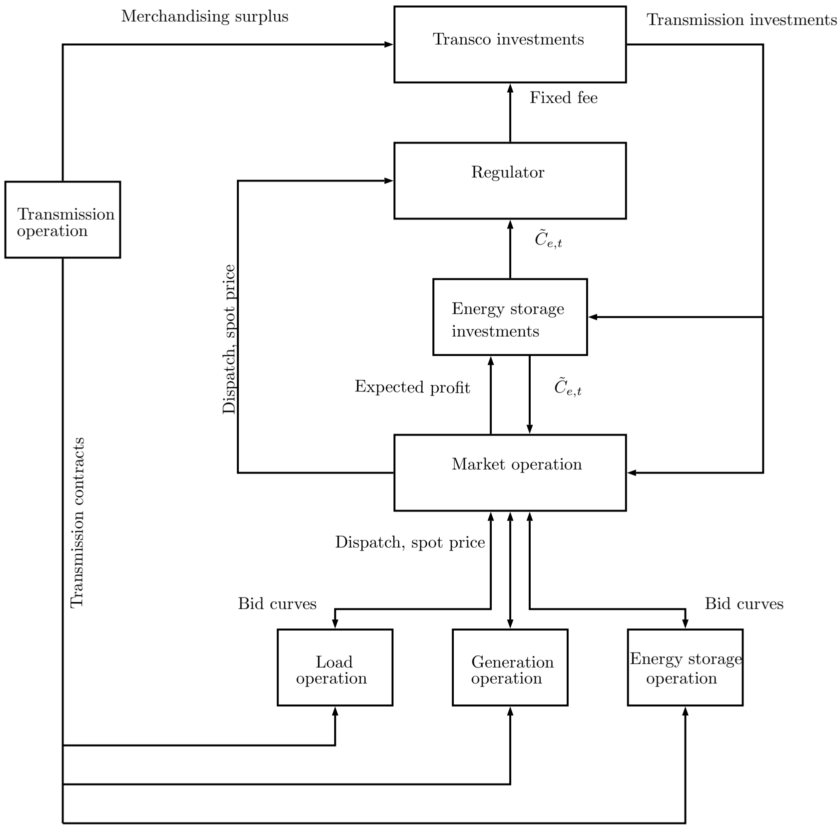

Figure 2: Incentive based regulation for transmission and energy storage expansion

We assume $\mathbb{E}[\pi^G_{s,t}]$, $\mathbb{E}[\pi^T_{s,t}]$, $\mathbb{E}[\pi^S_{s,t}]$ and $\mathbb{E}[\pi^L_{s,t}]$ as the total profit of generators, congestion rent earned by transmission company, profit of energy storage and the total net utility of loads in the spot market. $\tilde{C}^S_t$, $\overline{C}^T_t$ and Φ_t are the total energy storage investment cost, the total transmission investment cost and the fixed fee respectively. β_t is a discount rate of Transco and is assumed to be $0 < \beta_t < 1$. The function $f(\Phi_t) = 0$ represents a regulatory constraint and is used to calculate the fixed fee which depends on the choice of incentive based regulation and will be discussed below.

While the Transco and the Regulator are separate entities with different objectives mathematically the interaction between them can be simulated in one optimization problem. The objective function (1a) represents profit maximization of the Transco while the regulatory constraint represents the social welfare maximization objective of the Regulator. Social welfare surplus (SW_t) in the context of this paper is defined for each investment planning period as

$$SW_t = \sum_t (\mathbb{E}[\pi^G_{s,t}] + \mathbb{E}[\pi^T_{s,t}] + \mathbb{E}[\pi^L_{s,t}] + \mathbb{E}[\pi^S_{s,t}] - \tilde{C}^S_t - \overline{C}^T_t \qquad (2)$$

The profit of the Transco (1a) consists of its network merchandising surplus $\mathbb{E}[\pi^T_{s,t}]$ and the fixed fee collected from transmission network users (loads, energy storage and generators). In order to make a decision on new line investments and calculate expected merchandising surplus and a fixed fee the Transco has to take into account generation dispatch, electricity demand, spot prices and energy storage investment decisions which are the outputs of the problem of the welfare maximizing MO (1c). In order to provide expected dispatch of the system the MO collects the bids from Gencos, ES and Loads and investment decision on energy storage capacities. Under the assumption of perfect competition the interaction of MO, Gencos, ES and Loads can be modeled as cost minimization dispatch and energy storage investments of a power system. Thus, the regulated joint transmission and energy storage investments can be formulated as a bilevel problem with a regulatory constraint.

The function $f(\Phi_t) = 0$ varies based on the incentive regulation applied by the regulator. The fixed fee paid by the network users could be seen as a substitute to subsidy payments by the government or the regulator. In this paper we consider three different incentive regulations, Cost-Plus incentive regulation [9], ISS incentive regulation [7], H-R-G-V incentive regulation[16]. All these regulations can be effectively applied to a profit maximizing firm which operates under natural monopoly which is the case of the Transco. We compare these incentive regulations to the case without incentive regulation.

2.1. The case without incentive regulation

Consider problem (1) when the Regulator does not enforce any incentive regulation, i.e., $\Phi_t = 0$. The profit of the Transco is fully based on congestion rent and decisions on additional transmission capacity will be profitable only if any increase in overall congestion revenues from the system exceed the additional transmission capacity costs. Thus, the Transco may avoid investments in additional transmission capacity which may potentially reduce its profit and has no incentive to reduce congestion in the system [12].

2.2. The Cost-Plus incentive regulation

Cost-Plus incentive regulation is well described in [9]. Cost-Plus incentive regulation proposes to incentivize the Transco by gradually covering parts of transmission investment costs and providing trade off between reduced congestion rent and a fixed fee. When Cost-Plus incentive regulation is applied the regulator enforces the regulatory constraint as

$$\Phi_t = (1 + R_t)\overline{C}_t^T \tag{3}$$

where R_t is mark-up cost which is set by the regulator. In [9] the authors provide proof that Cost-Plus incentive regulation may lead to a social welfare maximum if R_t is chosen carefully.

The total profit of the Transco can be calculated as

$$\sum_t (1 + \beta_t)(\mathbb{E}[\pi_{s,t}^T] + R_t\overline{C}_t^T) \tag{4}$$

by rewriting the fixed fee according to regulatory constraint (3). The Tansco has a profit maximization objective. As a result of the reformulated objective function of the Transco in (4) we can observe that the Transco is likely to maximize the investment cost if transmission share of investment costs covered by the fixed fee is larger than the congestion rent. Thus, Cost-Plus incentive regulation may lead to over investment and may cause reduced social welfare. Moreover, Cost-Plus incentive regulation require the Regulator to have information about transmission investment costs in order to tune the value of R_t. Also, we can see that under Cost-Plus incentive regulation energy storage investments do not directly affect the investment decision of the Transco. However, the presence of energy storage may reduce congestion rents and as a result increase the possibility of overinvestment which should be discouraged by the Regulator.

2.3. The ISS incentive regulation

Similarly to the Cost-Plus incentive regulation the ISS incentive regulation provides a trade off for Transcos between profit from congestion rent and a fixed fee. However, unlike the Cost-Plus incentive regulation the ISS incentive regulation is based on change in social welfare surplus and does not require the Regulator to know the possible investment costs of the Transco. The ISS incentive regulation is described in details in [7] and can be formulated as a regulatory constraint for joint transmission and energy storage investments as

$$\Phi_t = \Delta\,\mathbb{E}[\pi_{s,t}^G] + \Delta\,\mathbb{E}[\pi_{s,t}^L] + \Delta\,\mathbb{E}[\pi_{s,t}^S] - \mathbb{E}[\pi_{s,t-1}^T] + \overline{C}_{t-1}^T - \Delta\tilde{C}_t^S \tag{5}$$

The regulatory constraint (5) of the ISS incentive regulation calculates the fixed fee Φ_t based on total changes in social welfare SW_t which is equivalent to the sum of changes in generation, load and energy storage profit minus investments in energy storage.

Incorporating regulatory constraint (5) to the objective function of the Trancos investment planning problem (1a) results in

$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{s,t}] + \Phi_t - \overline{C}^T_t) =$$
$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{s,t}] + \Delta\,\mathbb{E}[\pi^G_{s,t}] + \Delta\,\mathbb{E}[\pi^L_{s,t}] + \Delta\,\mathbb{E}[\pi^S_{s,t}] - \mathbb{E}[\pi^T_{s,t-1}] - \Delta\overline{C}^T_t - \Delta\tilde{C}^S_t) =$$
$$(1+\beta_{t=T})(\mathbb{E}[\pi^T_{s,t=T}] + \mathbb{E}[\pi^G_{s,t=T}] + \mathbb{E}[\pi^L_{s,t=T}] + \mathbb{E}[\pi^S_{s,t=T}]) + \sum_t (\beta_{t-1} - \beta_t)(\mathbb{E}[\pi^T_{s,t=T}] +$$
$$\mathbb{E}[\pi^G_{s,t=T}] + \mathbb{E}[\pi^L_{s,t=T}] + \mathbb{E}[\pi^S_{s,t=T}]) - (1+\beta_{t=1})(\mathbb{E}[\pi^T_{s,t=1}] - \mathbb{E}[\pi^G_{s,t=1}] - \mathbb{E}[\pi^L_{s,t=1}] - \mathbb{E}[\pi^S_{s,t=1}]) -$$
$$\overline{C}^T_{t=1} - \sum_t (\beta_{t-1} - \beta_t)\overline{C}^T_t - \overline{C}^T_{t=T} - \tilde{C}^S_{t=1} - \sum_t (\beta_{t-1} - \beta_t)\tilde{C}^S_t - \tilde{C}^S_{t=T} \tag{6}$$

Based on the reformulation provided in (6) we see that transmission investment planning under the ISS incentive regulation has the tendency to maximize social welfare. However, the objective of the Tranco highly depends on the discount rate β_t in each investment period. Moreover, ISS incentive regulation assumes that the Regulator does not have information on the discount rate of the Transco. While ISS incentive regulation leads to social welfare maximum the proof is dependent on the discount rate which is outside of the Regulators knowledge. Thus, some complications may arise. For example if the discount rate is small and does not vary over time the objective of the Transco is reduced to

$$(\mathbb{E}[\pi^T_{s,t=T}] + \mathbb{E}[\pi^G_{s,t=T}] + \mathbb{E}[\pi^L_{s,t=T}] + \mathbb{E}[\pi^S_{s,t=T}] - \mathbb{E}[\pi^T_{s,t=1}] - \mathbb{E}[\pi^G_{s,t=1}] - \mathbb{E}[\pi^L_{s,t=1}] - \mathbb{E}[\pi^S_{s,t=1}] +$$
$$\overline{C}^T_{t=1} - \overline{C}^T_{t=T} + \tilde{C}^S_{t=1} - \tilde{C}^S_{t=T}) \tag{7}$$

and at each investment period revenue of the Transco consists of the total welfare of the system calculated for that period minus a constant which is the sum of load, generation and energy storage welfare of the initial investment period.

When it comes to energy storage investment planning the ISS incentive regulation reflects the changes resulting from energy storage investments. The profit of the Transco under the ISS incentive regulation depends not only on congestion rent and marginal spot prices at different nodes but also on investment costs of energy storage. Thus, Transcos would have incentive to make investment which supports cheaper options for energy storage projects.

2.4. The H-R-G-V incentive regulation

The H-R-G-V incentive regulation follows similar approach as the ISS incentive regulation and calculates the fixed fee based on changes in social welfare surplus. The regulatory constraint for joint transmission and energy storage investments under the H-R-G-V incentive regulation can be formulated as in (8).

$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi^G_{s,t}] + \Delta\,\mathbb{E}[\pi^L_{s,t}] + \Delta\,\mathbb{E}[\pi^S_{s,t}] - \Delta\tilde{C}^S_t \tag{8}$$

This regulatory constraint links the maximum fixed fee to the nodal price differences that are derived by the MO and are based on the Transcos transmission network investments.

We reformulate the objective function (1a) considering the regulatory constraint:

$$\sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{s,t}] + \Phi_t - \overline{C}^T_t) = \sum_t (1+\beta_t)(\mathbb{E}[\pi^T_{s,t}] + \Delta\,\mathbb{E}[\pi^G_{s,t}] + \Delta\,\mathbb{E}[\pi^L_{s,t}] + \Delta\,\mathbb{E}[\pi^S_{s,t}] - \Delta\tilde{C}^S_t + \Phi_{t-1} - \overline{C}^T_t) \equiv \sum_t (1+\beta_t)(\mathbb{E}[\pi^G_{s,t}] + \mathbb{E}[\pi^T_{s,t}] + \mathbb{E}[\pi^L_{s,t}] + \mathbb{E}[\pi^S_{s,t}] - \tilde{C}^S_t - \overline{C}^T_t) \tag{9}$$

The reformulated objective function shows that the regulated objective function of the Transco is equivalent to the social welfare maximum objective. In each investment period t the Transco receives the total welfare of that period minus a constant which is equal to the sum of changes in load, generation and energy storage surplus. The changes in surplus relate to the benefits load, generation and energy storage receives from additional transmission capacity and should be large enough to cover the investment cost. Moreover, H-R-G-V regulation does not depend on the discount rate. Also, the H-R-G-V incentive regulation takes into account energy storage investments and promotes more efficient cost allocation of the investments (similar to ISS). The maximum fixed fee is closely related to the social surplus increase resulting from the network expansion. As a result the Transco's profit from the merchandising surplus and the fixed fee is itself closely related to social welfare and that feature induces the Transco to do efficient transmission investments that will result in welfare-optimal prices. Thus, the regulatory constraint and the fixed fee are parts of the H-R-G-V incentive regulation which combines rewards and penalties to achieve the objectives set by the regulator. Thus, the H-R-G-V incentive regulation combines a subsidy with a price cap.

3. Proposed Mathematical Models

This section presents models that can be used to simulate investments in transmission and energy storage under the incentive regulations discussed in section 2. The result is a stochastic non-linear bilevel optimization problem, which can be reformulated into a one-level equivalent MILP problem.

3.1. MO simulation

We first formulate the operation by the MO. The MO dispatches generation, load and energy storage while minimizing overall operation costs of the system. Energy storage investments are also included in the model and consist of two parts. First, investments into storage capacity $\tilde{S}_{e,t}$ which determines maximum storage capability of the storage unit. Second, investment in power capability of energy storage $\tilde{P}_{e,t}$ which determines maximum power output per operation period. The operation cost is discounted using the present value factor calculated as in (10).

$$p_t = \frac{(1+i)^t}{(1+d)^t} \tag{10}$$

where i is the annual inflation rate and d is a discount rate.

The term Ψ is used in the objective function to match short-term operating costs with long term investment planning and is equal to the number of operational periods in an investment period. The MO operation with energy storage investments is modeled as in (11). The symbols for the Lagrangian multipliers of each constraint are stated after the corresponding constraint separated by a colon.

$$\underset{\Omega_s}{Maximize} \sum_t p_t \langle \sum_{s,k} \pi_s \Psi (\sum_d \alpha_d d_{d,t,k,s} - \sum_g mc_g \; g_{g,t,k,s}) + \sum_e (\tilde{\alpha}_e \tilde{d}_{e,t,k,s} - \tilde{mc}_e \; \tilde{g}_{e,t,k,s}) - \sum_e \tilde{C}^{sr}_{e,t}(\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - \sum_e \tilde{C}^{pr}_{e,t}(\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) \rangle \quad (11a)$$

$$Subject\ to\ :$$

$$\tilde{S}_{e,t} - \tilde{S}_{e,t-1} \geq 0 \;\; : (\kappa_{e,t,k,s}) \; \forall e, t \quad (11b)$$

$$\tilde{P}_{e,t} - \tilde{P}_{e,t-1} \geq 0 \;\; : (\vartheta_{e,t,k,s}) \; \forall e, t \quad (11c)$$

$$\sum_g J_{n,g} g_{g,t,k,s} + \sum_w W_{n,w} \widehat{g}_{w,t,k,s} - \sum_d I_{n,d} d_{d,t,k,s} + \sum_e E_{n,e} \tilde{g}_{e,t,k,s} - \sum_e E_{n,e} \tilde{d}_{e,t,k,s} - \sum_l S_{n,l} f_{l,t,k,s} + \sum_l R_{n,l} f_{l,t,k,s} - \sum_m \overline{S}_{n,m} \widehat{f}_{m,t,k,s} + \sum_m \overline{R}_{n,m} \widehat{f}_{m,t,k,s} = 0 \;\; : (\lambda_{n,t,k,s}) \; \forall n, t, k, s \quad (11d)$$

$$-\frac{100}{X_l}(\sum_n S_{n,l}\theta_{n,t,k,s} - \sum_n R_{n,l}\theta_{n,t,k,s}) + f_{l,t,k,s} = 0 \;\; : (\sigma_{l,t,k,s}) \; \forall l, t, k, s \quad (11e)$$

$$-F_l \leq f_{l,t,k,s} \leq F_l \;\; : (\underline{\mu}_{l,t,k,s}, \overline{\mu}_{l,t,k,s}) \; \forall l, t, k, s \quad (11f)$$

$$\widehat{f}_{m,t,k,s} - \frac{100}{X_m}(\sum_n \overline{S}_{n,m}\theta_{n,t,k,s} - \sum_n \overline{R}_{n,m}\theta_{n,t,k,s}) \leq \Xi_m(1 - z_{m,t}) \;\; : (\overline{\sigma}_{m,t,k,s}) \; \forall m, t, k, s \quad (11g)$$

$$\widehat{f}_{m,t,k,s} - \frac{100}{X_m}(\sum_n \overline{S}_{n,m}\theta_{n,t,k,s} - \sum_n \overline{R}_{n,m}\theta_{n,t,k,s}) \geq -\Xi_m(1 - z_{m,t}) \;\; : (\underline{\sigma}_{m,t,k,s}) \; \forall m, t, k, s \quad (11h)$$

$$-z_{m,t}\Xi_m \leq \widehat{f}_{m,t,k,s} \leq z_{m,t}\Xi_m : (\underline{\zeta}_{m,t,k,s}, \overline{\zeta}_{m,t,k,s}) \;\; \forall m, t, k, s \quad (11i)$$

$$-\widehat{F}_m \leq \widehat{f}_{m,t,k,s} \leq \widehat{F}_m \;\; : (\underline{\gamma}_{m,t,k,s}, \overline{\gamma}_{m,t,k,s}) \; \forall m, t, k, s \quad (11j)$$

$$\tilde{s}_{e,t,k,s} = \tilde{s}_{e,t,k-1,s} - \tilde{g}_{e,t,k,s} + \tilde{d}_{e,t,k,s} \;\; : (\tau_{e,t,k,s}) \; \forall e, t, k, s \quad (11k)$$

$$0 \leq g_{g,t,k,s} \leq G_g \;\; : (\underline{\nu}_{g,t,k,s}, \overline{\nu}_{g,t,k,s}) \; \forall g, s, t, k \quad (11l)$$

$$0 \leq \widehat{g}_{w,t,k,s} \leq \widehat{G}_{w,t}\varrho_{w,t,k,s} \;\; : (\underline{\eta}_{w,t,k,s}, \overline{\eta}_{w,t,k,s}) \; \forall w, t, k, s \quad (11m)$$

$$0 \leq d_{d,t,k,s} \leq D_{d,t} \;\; : (\underline{\omega}_{d,t,k,s}, \overline{\omega}_{d,t,k,s}) \; \forall d, t, k, s \quad (11n)$$

$$0 \leq \tilde{g}_{e,t,k,s} \leq \tilde{P}_{e,t} \;\; : (\underline{\kappa}_{e,t,k,s}, \overline{\kappa}_{e,t,k,s}) \; \forall e, t, k, s \quad (11o)$$

$$0 \leq \tilde{d}_{e,t,k,s} \leq \tilde{P}_{e,t} \;\; : (\underline{\vartheta}_{e,t,k,s}, \overline{\vartheta}_{e,t,k,s}) \; \forall e, t, k, s \quad (11p)$$

$$0 \leq \tilde{s}_{e,t,k,s} \leq \tilde{S}_{e,t} \ : (\underline{\rho}_{e,t,k,s}, \overline{\rho}_{e,t,k,s}) \ \forall e,t,k,s \tag{11q}$$

$$\theta_{n=1,t,k,s} = 0 \ : (\xi_{t,k,s}) \ \forall t,k,s \tag{11r}$$

$$d_{d,t,k,s}, \tilde{d}_{e,t,k,s}, \tilde{g}_{e,t,k,s}, g_{g,t,k,s}, \widehat{g}_{w,t,k,s}, f_{l,t,k,s}, \widehat{f}_{m,t,k,s}, \theta_{n,t,k,s} \in \mathbb{R} \tag{11s}$$

Here $\Omega_s = \{d_{d,t,k,s}, \tilde{d}_{e,t,k,s}, \tilde{g}_{e,t,k,s}, g_{g,t,k,s}, \widehat{g}_{w,t,k,s}, f_{l,t,k,s}, \widehat{f}_{m,t,k,s}, \theta_{n,t,k,s}, \tilde{P}_{e,t}, \tilde{S}_{e,t}\}$ is the set of decision variables of the problem (11). The objective of the MO is to minimize overall system cost as shown in (11a). Constraints (11b) and (11c) ensure that the storage capacity and maximum power output are not decreasing. The operation of the MO is restricted by power balance constraints (11d) which ensure that total demand and generation is in balance at each node and at each operation period. Power flow constraints including upper and lower limits of existing lines are modeled through (11e)-(11f). The McCormick reformulation technique (also known as big-M reformulation) [23] is used to simulate the investment decisions in candidate transmission lines as in (11g)-(11i). If the disjunctive parameter is chosen carefully then the reformulated problem will be equivalent to the original non-linear disjunctive constraints of the investment decision. It should be noted that investment decisions in transmission $z_{m,t}$ are not decision variables of the MO operation problem and should be treated as parameters. Thermal generation, wind generation, load are limited by upper and lower values (11l)-(11n). Energy storage operation is modeled through energy balance constraints (11k) which keep track of the energy storage state of the charge $\tilde{s}_{e,t,k,s}$ while taking into account charging $\tilde{d}_{e,t,k,s}$ and discharging $\tilde{g}_{e,t,k,s}$. State of the charge of energy storage and charge and discharge variables are limited by upper and lower limit constraints in (11o)-(11q) which depend on investment decisions on energy storage ($\tilde{P}_{e,t}$ and $\tilde{S}_{e,t}$).

3.2. Merchant-regulatory transmission investment

The objective of the Transco is to maximize its expected profit over the investment planning period (t). The profit is the sum of the network merchandising surplus and a fixed fee imposed to consumers (Φ_t) minus the investment expenses ($\overline{C}_{m,t}$).

$$\underset{z_{m,t}, y_{m,t}, \Phi_t}{Maximize} \sum_t \langle \Phi_t + \sum_s (\sum_{n,d,k} I_{n,d} \lambda_{n,t,k,s} d_{d,t,k,s} + \sum_{n,e,k} E_{n,e} \lambda_{n,t,k,s} \tilde{d}_{e,t,k,s} - \sum_{n,g,k} J_{n,g} \lambda_{n,t,k,s} g_{g,t,k,s} - \sum_{n,w,k} W_{n,w} \lambda_{n,t,k,s} \widehat{g}_{w,t,k,s} - \sum_{n,e,k} E_{n,e} \lambda_{n,t,k,s} \tilde{g}_{e,t,k,s}) - p_t \sum_m \overline{C}_{m,t} y_{m,t} \rangle \tag{12a}$$

Subject to :

$$z_{m,t=1} = 0 \ \forall m \tag{12b}$$

$$z_{m,t} = \sum_{\widehat{t} \leq t} y_{m,\widehat{t}} \ \forall m, t \geq 2 \tag{12c}$$

$$\sum_t y_{m,t} \leq 1 \ \ \forall m,t \tag{12d}$$

$$\Phi_{t=1} = 0 \tag{12e}$$

$$f(\Phi_t) = 0 \tag{12f}$$

$$z_{m,t} \in \{0,1\} \tag{12g}$$

$$Where\ \left\{d_{d,t,k,s}, \tilde{d}_{e,t,k,s}, g_{g,t,k,s}, \widehat{g}_{w,t,k,s}\tilde{g}_{e,t,k,s}, \lambda_{n,t,k,s}\right\} \in$$

$$\arg \underset{\Omega_s}{Maximize} \sum_t p_t \langle \sum_{s,k} \pi_s \Psi (\sum_d \alpha_d d_{d,t,k,s} - \sum_g mc_g\ g_{g,t,k,s}) + \sum_e (\tilde{\alpha}_e \tilde{d}_{e,t,k,s} - \tilde{mc}_e\ \tilde{g}_{e,t,k,s}) -$$

$$\sum_e \tilde{C}^{sr}_{e,t}(\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - \sum_e \tilde{C}^{pr}_{e,t}(\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) \rangle$$

$$Subject\ to\ :\ (11b) - (11s) \tag{12h}$$

The optimization problem (11) simulates the MO operation decision and energy storage investments and operation for a given transmission investments decision ($z_{m,t}$). On the other hand, optimization problem (12) simulates the bilevel problem of the Transco under incentive regulation. Thus, the optimization problem (11) becomes the lower level of the optimization problem (12).

The profit-maximizing Transco faces a constraint on the fixed fee which is given by regulatory equality constraint (12f). The regulatory constraint depends on the incentive regulation and is formulated in (13) for no incentive regulation, (14) for Cost-Plus incentive regulation in (15) for ISS incentive regulation and in (16) for H-R-G-V incentive regulation.

$$\Phi_t = 0\ \ \forall t \tag{13}$$

$$\Phi_t = (1 + R_t \sum_m \overline{C}_{m,t} y_{m,t})\ \ \forall t \geq 2 \tag{14}$$

$$\Phi_t = \sum_s (\langle p_t \Psi \pi_s \sum_{d,k} (\alpha_d d_{d,t,k,s}) - \sum_{n,d,k} I_{n,d} \lambda_{n,t,k,s} d_{d,t,k,s} \rangle + \langle \sum_{n,g,k} J_{n,g} \lambda_{n,t,k,s} g_{g,t,k,s} -$$

$$p_t \Psi \pi_s \sum_{g,k} mc_g g_{g,t,k,s} \rangle + \sum_{n,w,k} W_{n,w} \lambda_{n,t,k,s} \widehat{g}_{w,t,k,s} + \langle \sum_{n,e,k} E_{n,e} \lambda_{n,t,k,s} (\tilde{g}_{e,t,k,s} - \tilde{d}_{e,t,k,s}) -$$

$$p_t \Psi \pi_s (\tilde{mc}_e \tilde{g}_{e,t,k,s} - \tilde{\alpha}_e \tilde{d}_{e,t,k,s} \rangle)) - \sum_s (\langle p_t \Psi \pi_s \sum_{d,k} \alpha_d d_{d,t-1,k,s} - \sum_{n,d,k} I_{n,d} \lambda_{n,t-1,k,s} d_{d,t-1,k,s} \rangle +$$

$$\sum_{n,w,k} W_{n,w} \lambda_{n,t-1,k,s} \widehat{g}_{w,t-1,k,s} + \langle \sum_{n,g,k} J_{n,g} \lambda_{n,t-1,k,s} g_{g,t-1,k,s} - p_t \Psi \pi_s \sum_{g,k} mc_g g_{g,t-1,k,s} \rangle +$$

$$\langle \sum_{n,e,k} E_{n,e} \lambda_{n,t-1,k,s} (\tilde{g}_{e,t-1,k,s} - \tilde{d}_{e,t-1,k,s}) - p_t \Psi \pi_s (\tilde{mc}_e \tilde{g}_{e,t-1,k,s} - \tilde{\alpha}_e \tilde{d}_{e,t-1,k,s} \rangle)) -$$

$$p_t \sum_e \tilde{C}^{sr}_{e,t}(\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - p_t \sum_e \tilde{C}^{pr}_{e,t}(\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) - (\sum_{n,d,k} I_{n,d} \lambda_{n,t-1,k,s} d_{d,t-1,k,s} +$$

$$\sum_{n,e} E_{n,e} \lambda_{n,t-1,k,s} \tilde{d}_{e,t-1,k,s} - \sum_{n,g,k} J_{n,g} \lambda_{n,t-1,k,s} g_{g,t-1,k,s} - \sum_{n,w} W_{n,w} \lambda_{n,t-1,k,s} \widehat{g}_{w,t-1,k,s} -$$

$$\sum_{n,e} E_{n,e}\lambda_{n,t-1,k,s}\tilde{g}_{e,t-1,k,s}) + p_t \sum_{m} \overline{C}_{m,t} y_{m,t-1} \; \forall t \geq 2 \tag{15}$$

$$\begin{aligned}
&\Phi_t - \sum_{s}(\langle p_t \Psi \pi_s \sum_{d,k}(\alpha_d d_{d,t,k,s}) - \sum_{n,d,k} I_{n,d}\lambda_{n,t,k,s} d_{d,t,k,s}\rangle + \langle \sum_{n,g,k} J_{n,g}\lambda_{n,t,k,s} g_{g,t,k,s} - \\
&p_t \Psi \pi_s \sum_{g,k} mc_g g_{g,t,k,s}\rangle + \sum_{n,w,k} W_{n,w}\lambda_{n,t,k,s}\widehat{g}_{w,t,k,s} + \langle \sum_{n,e,k} E_{n,e}\lambda_{n,t,k,s}(\tilde{g}_{e,t,k,s} - \tilde{d}_{e,t,k,s}) - \\
&p_t \Psi \pi_s (\tilde{mc}_e \tilde{g}_{e,t,k,s} - \tilde{\alpha}_e \tilde{d}_{e,t,k,s}\rangle)) = \\
&\Phi_{t-1} - \sum_{s}(\langle p_t \Psi \pi_s \sum_{d,k} \alpha_d d_{d,t-1,k,s} - \sum_{n,d,k} I_{n,d}\lambda_{n,t-1,k,s} d_{d,t-1,k,s}\rangle + \\
&\sum_{n,w,k} W_{n,w}\lambda_{n,t-1,k,s}\widehat{g}_{w,t-1,k,s} + \langle \sum_{n,g,k} J_{n,g}\lambda_{n,t-1,k,s} g_{g,t-1,k,s} - p_t \Psi \pi_s \sum_{g,s} mc_g g_{g,t-1,k,s}\rangle + \\
&\langle \sum_{n,e,k} E_{n,e}\lambda_{n,t-1,k,s}(\tilde{g}_{e,t-1,k,s} - \tilde{d}_{e,t-1,k,s}) - p_t \Psi \pi_s (\tilde{mc}_e \tilde{g}_{e,t-1,k,s} - \tilde{\alpha}_e \tilde{d}_{e,t-1,k,s}\rangle)) - \\
&p_t \sum_{e} \tilde{C}^{sr}_{e,t}(\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - p_t \sum_{e} \tilde{C}^{pr}_{e,t}(\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) \; \forall t \geq 2
\end{aligned} \tag{16}$$

3.3. Reformulation using KKT conditions and strong duality

The optimization problem (12) is a bilevel stochastic nonlinear mixed integer program. The lower level is a linear program, for which the Karush-Kuhn-Tucker (KKT) optimality conditions are necessary and sufficient [24]. Thus, the lower-level problem can be equivalently described by its KKT conditions. The KKT conditions consist of the original equality and inequality constraints, stationary conditions and complementary slackness conditions. The reformulated problem through the KKT conditions becomes a non-linear set of constraints which must be fulfilled by the global optimal solution of the original problem. The non-linearity is due to the complementary slackness conditions. In addition, complementary slackness conditions significantly increase the size of the problem which may complicate computational tractability. Complementary slackness conditions can be avoided by replacing them with the strong duality condition [25].

The reformulation is illustrated in Figure 3. Iteration 1 shows the original bilevel formulation. The lower level is a linear problem and therefore could be equivalently represented by the KKT optimality conditions. The result of replacing the lower level problem by its KKT conditions is shown in Iteration 2. However, the optimization problem in Iteration 2 is non-linear and therefore the complementary slackness conditions are replaced by the strong duality condition which implies that $f_{UL} = f_{UL}^{dual}$. The final reformulated problem is shown in Iteration 3.

Figure 3: One-level equivalent reformulation steps.

Iteration 1		*Iteration 2*		*Iteration 3*
$\underset{x,y}{Minimize}: f_{UL}$		$\underset{x,y}{Minimize}: f_{UL}$		$\underset{x,y}{Minimize}: f_{UL}$
S.t:		S.t:		S.t:
$h_{UL}(x,y)=0$		$h_{UL}(x,y)=0$		$h_{UL}(x,y)=0$
$g_{UL}(x,y)\leq 0$		$g_{UL}(x,y)\leq 0$		$g_{UL}(x,y)\leq 0$
$Where\ \{y\}\in$	$\equiv$	$KKTconditions:$	$\equiv$	$KKTconditions:$
$\arg \underset{y}{Min} f_{LL}$		$h_{LL}(y)=0$		$h_{LL}(y)=0$
S.t:		$g_{LL}(y)\leq 0$		$g_{LL}(y)\leq 0$
$h_{LL}(y)=0\ :(\lambda)$		$\{Stationary\ \ conditions\}:$		$\{Stationary\ \ conditions\}$
$g_{LL}(y)\leq 0\ :(\mu)$		$\bigtriangledown f_{LL}(y)+\lambda\bigtriangledown g_{LL}(y)+\mu\bigtriangledown h_{LL}(y)=0$		$\bigtriangledown f_{LL}(y)+\lambda\bigtriangledown g_{LL}(y)+\mu\bigtriangledown h_{LL}(y)=0$
		$\{Complimentary\ \ slackness\ \ conditions\}$		$\{Strong\ \ duality\ \ condition\}$
		$\mu g_{LL}(y)=0$		$f_{LL}=f_{LL}^{dual}$
		$\mu\geq 0$		$\mu\geq 0$

The stationary conditions of the KKT conditions are derived from the Lagrangian function by taking the first order derivative of all primal variables and setting the result equal to zero. For the lower level problem (11), i.e., the MO operation problem, the stationary conditions are derived as follows:

$$p_t\Psi\pi_s\alpha_d-\sum_n I_{n,d}\lambda_{n,t,k,s}+\underline{\omega}_{d,t,k,s}-\overline{\omega}_{d,t,k,s}=0\ \ \forall d,t,k,s \tag{17a}$$

$$-p_t\Psi\pi_s mc_g+\sum_n J_{n,g}\lambda_{n,t,k,s}+\underline{\nu}_{g,t,k,s}-\overline{\nu}_{g,t,k,s}=0\ \ \forall g,t,k,s \tag{17b}$$

$$\sum_n W_{n,w}\lambda_{n,t,k,s}+\underline{\eta}_{w,t,k,s}-\overline{\eta}_{w,t,k,s}=0\ \ \forall w,t,k,s \tag{17c}$$

$$p_t\Psi\pi_s\tilde{\alpha}_e-\sum_n E_{n,e}\lambda_{n,t,k,s}+\tau_{e,t,k,s}+\underline{\vartheta}_{e,t,k,s}-\overline{\vartheta}_{e,t,k,s}=0\ \ \forall e,t,k,s \tag{17d}$$

$$-p_t\Psi\pi_s\tilde{mc}_e+\sum_n E_{n,e}\lambda_{n,t,k,s}-\tau_{e,t,k,s}+\underline{\kappa}_{e,t,k,s}-\overline{\kappa}_{e,t,k,s}=0\ \ \forall e,t,k,s \tag{17e}$$

$$-\tau_{e,t,k,s}+\tau_{e,t,k+1,s}+\underline{\rho}_{e,t,k,s}-\overline{\rho}_{e,t,k,s}=0\ \ \forall e,t,k,s \tag{17f}$$

$$-p_t\tilde{C}_{e,t}^{sr}+\kappa_{e,t,k,s}-\kappa_{e,t+1,k,s}+\sum_{k,s}\overline{\rho}_{e,t,k,s}=0\ \ \forall e,t \tag{17g}$$

$$-p_t\tilde{C}_{e,t}^{pr}+\vartheta_{e,t,k,s}-\vartheta_{e,t+1,k,s}+\sum_{k,p}\overline{\kappa}_{e,t,k,s}+\sum_{k,p}\overline{\vartheta}_{e,t,k,s}=0\ \ \forall e,t \tag{17h}$$

$$-\sum_n S_{n,l}\lambda_{n,t,k,s} + \sum_n R_{n,l}\lambda_{n,t,k,s} + \sigma_{l,t,k,s} + \underline{\mu}_{l,t,k,s} - \overline{\mu}_{l,t,k,s} = 0 \ \ \forall l,t,k,s \tag{17i}$$

$$-\sum_n \overline{S}_{n,m}\lambda_{n,t,k,s} + \sum_n \overline{R}_{n,m}\lambda_{n,t,k,s} + \underline{\sigma}_{m,t,k,s} - \overline{\sigma}_{m,t,k,s} + \underline{\gamma}_{m,t,k,s} - \overline{\gamma}_{m,t,k,s} +$$
$$\underline{\zeta}_{m,t,k,s} - \overline{\zeta}_{m,t,k,s} = 0 \ \ \forall m,t,k,s \tag{17j}$$

$$-\frac{100}{X_l}\sum_l S_{n,l}\sigma_{l,t,k,s} + \frac{100}{X_l}\sum_l R_{n,l}\sigma_{l,t,k,s} + \xi_{t,k,s}\Upsilon(n=1) -$$
$$\frac{100}{X_m}\sum_m \overline{S}_{n,m}\underline{\sigma}_{m,t,k,s} + \frac{100}{X_m}\sum_m \overline{R}_{n,m}\underline{\sigma}_{m,t,k,s} + \frac{100}{X_m}\sum_m \overline{S}_{n,m}\overline{\sigma}_{m,t,k,s} -$$
$$\frac{100}{X_m}\sum_m \overline{R}_{n,m}\overline{\sigma}_{m,t,k,s} = 0 \ \ \forall n,t,k,p \tag{17k}$$

3.4. Strong duality condition

The complementary slackness conditions of the KKT conditions state that a constraint in the original problem must either be binding, i.e., $g_{LL}(y) = 0$, or the Lagrange multiplier must be equal to zero. Such a condition is however non-linear and is therefore replaced by a requirement that the value of the objective functions for the primal and dual problems should be equal for the optimal solution [26]. The strong duality conditions of the lower level problem (11), i.e., the MO operation problem and energy storage investment and operation are then given by

$$\sum_t p_t \langle \sum_{s,k} \pi_s \Psi(\sum_d \alpha_d d_{d,t,k,s} - \sum_g mc_g \ g_{g,t,k,s}) + \sum_e (\tilde{\alpha}_e \tilde{d}_{e,t,k,s} - \tilde{mc}_e \ \tilde{g}_{e,t,k,s}) -$$
$$\sum_e \tilde{C}^{sr}_{e,t}(\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - \sum_e \tilde{C}^{pr}_{e,t}(\tilde{P}_{e,t} - \tilde{P}_{e,t-1})\rangle = \sum_t \langle \sum_d D_{d,t}\overline{\omega}_{d,t,k,s} + \sum_g G_g \overline{\nu}_{g,t,k,s} +$$
$$\sum_w \widehat{G}_{w,t}\varrho_{w,t,k,s}\overline{\eta}_{w,t,k,s} + \sum_l F_l(\underline{\mu}_{l,t,k,s} + \overline{\mu}_{l,t,k,s}) + \sum_m \widehat{F}_m(\underline{\gamma}_{m,t,k,s} + \overline{\gamma}_{m,t,k,s}) +$$
$$\sum_m \underbrace{z_{m,t}\Xi_m(\underline{\zeta}_{m,t,k,s} + \overline{\zeta}_{m,t,k,s})}_{T1} + \sum_m \underbrace{\Xi_m(1-z_{m,t})(\overline{\sigma}_{m,t,k,s} + \underline{\sigma}_{m,t,k,s})}_{T2}\rangle \tag{18}$$

The terms T1 and T2 in the objective function of the dual problem which include the disjunctive parameters Ξ_m used to formulate power flow constraints of candidate transmission lines (11g)-(11i) are complicated because they include variables both from the upper and lower level problems and are thus non-linear. However, it can be shown that each of these terms are always equal to zero if the problem is solved to optimality (i.e., KKT conditions are satisfied). If the disjunctive parameters are tuned properly, i.e., large enough that they do not limit power flows on accepted candidate lines but small enough to avoid poorly conditioned matrices, then the constraints (11i) will never be binding. Thus, if $z_{m,t}$ is equal to zero then the Lagrangian multipliers $\overline{\sigma}_{m,t,k,s}$ and $\underline{\sigma}_{m,t,k,s}$ are equal to zero due to the complementary slackness condition, resulting in both expression T1 and T2 to be equal to zero. By analogy when $z_{m,t}$ is equal to one then $(1 - z_{m,t})$ is equal to zero and using complimentary slackness $\underline{\zeta}_{m,t,k,s}$ and $\overline{\zeta}_{m,t,k,s}$ leading to T1 and T2 equal to zero. Thus, we can extract non-linear terms T1 and T2 from the final formulation and add additional constraints which enforce T1=0 and T2=0 as in (20).

$$if z_{m,t} = 0 \Rightarrow \overline{\sigma}_{m,t,k,s} + \underline{\sigma}_{m,t,k,s} = 0 \Rightarrow T1 = 0, T2 = 0 \tag{19a}$$

$$if z_{m,t} = 1 \Rightarrow \overline{\zeta}_{m,t,k,s} + \underline{\zeta}_{m,t,k,s} = 0 \Rightarrow T1 = 0, T2 = 0 \tag{19b}$$

$$-\Xi_m z_{m,t} \leq \overline{\sigma}_{m,t,k,s} + \underline{\sigma}_{m,t,k,s} \leq \Xi_m z_{m,t} \tag{20a}$$

$$-\Xi_m (1 - z_{m,t}) \leq \overline{\zeta}_{m,t,k,s} + \underline{\zeta}_{m,t,k,s} \leq \Xi_m (1 - z_{m,t}) \tag{20b}$$

3.5. Linearization

The Transco profit function (12a) and the regulatory constraints of H-R-G-V (16) and ISS incentive regulation (15) are bilinear, because they include terms with multiplication of variables from both the upper and lower level problems:

$$\sum_{n,d} I_{n,d}\lambda_{n,t,k,s} d_{d,t,k,s} + \sum_{n,e} E_{n,e}\lambda_{n,t,k,s}(\tilde{d}_{e,t,k,s} - \tilde{g}_{e,t,k,s}) - \sum_{n,g} J_{n,g}\lambda_{n,t,k,s} g_{g,t,k,s} - \sum_{n,w} W_{n,w}\lambda_{n,t,k,s}\widehat{g}_{w,t,k,s} \tag{21}$$

The nodal prices can be extracted from these terms, i.e.,

$$\sum_{n} \lambda_{n,t,k,s} \underbrace{(\sum_{d} I_{n,d} d_{d,t,k,s} + \sum_{n,e} E_{n,e}(\tilde{d}_{e,t,k,s} - \tilde{g}_{e,t,k,s}) - \sum_{g} J_{n,g} g_{g,t,k,s} - \sum_{w} W_{n,w}\widehat{g}_{w,t,k,s})}_{L1} \tag{22}$$

The term L1 also appears in the power flow constraint (11d) and can thus be replaced by the sum of the power flows:

$$\sum_{l} \lambda_{n,t,k,s}(-\sum_{n} S_{n,l} f_{l,t,k,s} + \sum_{n} R_{n,l} f_{l,t,k,s}) + \sum_{m} \lambda_{n,t,k,s}(-\sum_{n} \overline{S}_{n,m}\widehat{f}_{m,t,k,s} + \sum_{n} \overline{R}_{n,m}\widehat{f}_{m,t,k,s}) = \sum_{l} f_{l,t,k,s} \underbrace{(-\sum_{n} S_{n,l}\lambda_{n,t,k,s} + \sum_{n} R_{n,l}\lambda_{n,t,k,s})}_{L2} + \sum_{m} \widehat{f}_{m,t,k,s} \underbrace{(-\sum_{n} \overline{S}_{n,m}\lambda_{n,t,k,s} + \sum_{n} \overline{R}_{n,m}\lambda_{n,t,k,s})}_{L3} \tag{23}$$

Terms L2 and L3 are parts of stationary condition constraints (17i) and (17j) respectively. Thus L2 and L3 equivalently can be represented as a linear combination of dual variables from constraints (17i) and (17j):

$$\sum_{l} f_{l,t,k,s}(\overline{\mu}_{l,t,k,s} - \underline{\mu}_{l,t,k,s} - \sigma_{l,t,k,s}) + \sum_{m} \widehat{f}_{m,t,k,s}(\underline{\sigma}_{m,t,k,s} - \overline{\sigma}_{m,t,k,s} + \underline{\gamma}_{m,t,k,s} - \overline{\gamma}_{m,t,k,s} + \underline{\zeta}_{m,t,k,s} - \overline{\zeta}_{m,t,k,s}) \tag{24}$$

Complementary slackness conditions for constraints (11f), (11j) and (11i) can be formulated as:

$$\begin{aligned}
f_{l,t,k,s}\overline{\mu}_{l,t,k,s} &= F_l\overline{\mu}_{l,t,k,s}\\
f_{l,t,k,s}\underline{\mu}_{l,t,k,s} &= F_l\underline{\mu}_{l,t,k,s}\\
\widehat{f}_{m,t,k,s}\overline{\gamma}_{m,t,k,s} &= \widehat{F}_m\overline{\gamma}_{m,t,k,s}\\
\widehat{f}_{m,t,k,s}\underline{\gamma}_{m,t,k,s} &= \widehat{F}_m\underline{\gamma}_{m,t,k,s}\\
\widehat{f}_{m,t,k,s}\underline{\zeta}_{m,t,k,s} &= z_{m,t}\Xi_m\underline{\zeta}_{m,t,k,s}\\
\widehat{f}_{m,t,k,s}\overline{\zeta}_{m,t,k,s} &= z_{m,t}\Xi_m\overline{\zeta}_{m,t,k,s}
\end{aligned} \tag{25}$$

Thus, constraint (24) can be reformulated as:

$$\sum_l F_l(\overline{\mu}_{l,t,k,s} + \underline{\mu}_{l,t,k,s}) + \sum_m \widehat{F}_m(\overline{\gamma}_{m,t,k,s} + \underline{\gamma}_{m,t,k,s}) + T1 + T2 \tag{26}$$

Following explanation provided in (19) and constraints (20) we can state that T1 and T2 are always equal to zero. Thus, we can reformulate (26) without terms T1 and T2. The final reformulation of $\sum_{n,d} I_{n,d}\lambda_{n,t,k,s}d_{d,t,k,s}+\sum_{n,e} E_{n,e}\lambda_{n,t,k,s}(\tilde{d}_{e,t,k,s}-\tilde{g}_{e,t,k,s})-\sum_{n,g} J_{n,g}\lambda_{n,t,k,s}g_{g,t,k,s}-\sum_{n,w} W_{n,w}\lambda_{n,t,k,s}\widehat{g}_{w,t,k,s}$ then can be written as combination of linear terms:

$$\sum_l F_l(\overline{\mu}_{l,t,k,s} + \underline{\mu}_{l,t,k,s}) + \sum_m \widehat{F}_m(\overline{\gamma}_{m,t,k,s} + \underline{\gamma}_{m,t,k,s}) \tag{27}$$

3.6. Reformulated MILP

After reformulation as a single level problem (section 3.3), elimination of some bilinear terms (section 3.4) and linearization of the remaining bilinear terms (section 3.5), the bilevel Transco-MO problem can be expressed as a MILP problem. The complete formulation is given below.

$$\underset{z_{m,t},y_{m,t},\Omega_s}{Maximize} \sum_t \langle \sum_s (\sum_l F_l(\overline{\mu}_{l,t,k,s} + \underline{\mu}_{l,t,k,s}) + \sum_m \widehat{F}_m(\overline{\gamma}_{m,t,k,s} + \underline{\mu}_{l,t,k,s})) + \Phi_t - p_t \sum_m \overline{C}_{m,t}y_{m,t}\rangle \tag{28a}$$

Subject to :

$$z_{m,t=1} = 0 \ \forall m \tag{28b}$$

$$z_{m,t} = \sum_{\widehat{t}\leq t} y_{m,\widehat{t}} \ \forall m, \forall t \geq 2 \tag{28c}$$

$$\sum_t y_{m,t} \leq 1 \ \forall m, \forall t \tag{28d}$$

$$\Phi_{t=1} = 0 \tag{28e}$$

$$f(\Phi_t) = 0 \; \forall t \geq 2 \tag{28f}$$

$$(11b) - (11s), \; (17a) - (17k), (20) \tag{28g}$$

$$\sum_t \langle \sum_d D_{d,t} \overline{\omega}_{d,t,k,s} + \sum_g G_g \overline{\nu}_{g,t,k,s} - \sum_l F_l (\overline{\mu}_{l,t,k,s} + \underline{\mu}_{l,t,k,s}) +$$
$$\sum_m \widehat{F}_m (\overline{\gamma}_{m,t,k,s} + \underline{\gamma}_{m,t,k,s}) + \sum_w \widehat{G}_{w,t} \varrho_{w,t,k,s} \overline{\eta}_{w,t,k,s} \rangle = \sum_t p_t \langle \Psi \sum_{s,k} \pi_s (\sum_d \alpha_d d_{d,t,k,s} -$$
$$\sum_g mc_g g_{g,t,k,s} + \sum_e (\tilde{\alpha}_e \tilde{d}_{e,t,k,s} - \tilde{mc}_e \; \tilde{g}_{e,t,k,s})) - \sum_e \tilde{C}^{sr}_{e,t} (\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) -$$
$$\sum_e \tilde{C}^{pr}_{e,t} (\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) \rangle \tag{28h}$$

$$\underline{\omega}_{d,t,k,s}, \overline{\omega}_{d,t,k,s}, \underline{\nu}_{g,t,k,s}, \overline{\nu}_{g,t,k,s}, \underline{\eta}_{w,t,k,s}, \overline{\eta}_{w,t,k,s}, \sigma_{l,t,k,s}, \underline{\mu}_{l,t,k,s}, \overline{\mu}_{l,t,k,s}, \overline{\gamma}_{m,t,k,s}, \underline{\gamma}_{m,t,k,s},$$
$$\Phi_t, \overline{\sigma}_{m,t,k,s}, \underline{\sigma}_{m,t,k,s}, \underline{\zeta}_{m,t,k,s}, \overline{\zeta}_{m,t,k,s} \geq 0 \tag{28i}$$

$$z_{m,t}, y_{m,t} \in \{0, 1\} \tag{28j}$$

The regulatory constraint (28f), $f(\Phi_t) = 0$, needs to be adjusted to the incentive regulation which is applied. Linearized regulatory constraints are presented in (29),(30),(31) and (32) for case without incentive regulation, Cost-Plus incentive regulation, ISS incentive regulation and H-R-G-V incentive regulation, respectively.

- without incentive regulation:

$$\Phi_t = 0 \;\; \forall t \tag{29}$$

- Cost-Plus incentive regulation

$$\Phi_t = (1 + R_t \sum_m \overline{C}_{m,t} y_{m,t}) \;\; \forall t \geq 2 \tag{30}$$

- ISS incentive regulation

$$\Phi_t = \sum_s (p_t \pi_s \Psi (\sum_{d,k} (\alpha_d d_{d,t,k,s} - \sum_{g,k} mc_g g_{g,t,k,s} - \sum_e (\tilde{mc}_e \tilde{g}_{e,t,k,s} + \tilde{\alpha}_e \tilde{d}_{e,t,k,s})) -$$
$$\sum_l F_l (\overline{\mu}_{l,t,k,s} + \underline{\mu}_{l,t,k,s}) - \sum_m \widehat{F}_m (\overline{\gamma}_{m,t,k,s} + \overline{\mu}_{l,t,k,s})) -$$
$$\sum_s \pi_s p_t \Psi (\sum_{d,k} (\alpha_d d_{d,t-1,k,s} - \sum_{g,k} mc_g g_{g,t-1,k,s} - \sum_e (\tilde{mc}_e \tilde{g}_{e,t-1,k,s} + \tilde{\alpha}_e \tilde{d}_{e,t-1,k,s})) +$$
$$p_t \sum_m \overline{C}_{m,t} y_{m,t-1} - p_t \sum_e \tilde{C}^{sr}_{e,t} (\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - p_t \sum_e \tilde{C}^{pr}_{e,t} (\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) \; \forall t \geq 2 \tag{31}$$

- H-R-G-V incentive regulation

$$\Phi_t - \sum_s (p_t \pi_s \Psi(\sum_{d,k}(\alpha_d d_{d,t,k,s} - \sum_{g,k} mc_g g_{g,t,k,s} - \sum_e (\tilde{mc}_e \tilde{g}_{e,t,k,s} + \tilde{\alpha}_e \tilde{d}_{e,t,k,s})) +$$
$$\sum_l F_l(\overline{\mu}_{l,t,k,s} + \underline{\mu}_{l,t,k,s}) - \sum_m \widehat{F}_m(\overline{\gamma}_{m,t,k,s} + \overline{\mu}_{l,t,k,s})) =$$
$$\Phi_{t-1} - \sum_s (\pi_s p_t \Psi(\sum_{d,k}(\alpha_d d_{d,t-1,k,s} - \sum_{g,k} mc_g g_{g,t-1,k,s} - \sum_e (\tilde{mc}_e \tilde{g}_{e,t-1,k,s} + \tilde{\alpha}_e \tilde{d}_{e,t-1,k,s})) -$$
$$\sum_l F_l(\overline{\mu}_{l,t-1,k,s} + \underline{\mu}_{l,t-1,k,s}) - \sum_m \widehat{F}_m(\overline{\gamma}_{m,t-1,k,s} + \underline{\gamma}_{m,t-1,k,s})) -$$
$$p_t \sum_e \tilde{C}^{sr}_{e,t}(\tilde{S}_{e,t} - \tilde{S}_{e,t-1}) - p_t \sum_e \tilde{C}^{pr}_{e,t}(\tilde{P}_{e,t} - \tilde{P}_{e,t-1}) \; \forall t \geq 2 \tag{32}$$

Here $\Omega_p = \Omega_s \cup \{\Phi_t, \underline{\omega}_{d,t,k,s}, \overline{\omega}_{d,t,k,s}, \underline{\nu}_{g,t,k,s}, \overline{\nu}_{g,t,k,s}, \underline{\eta}_{w,t,k,s}, \overline{\eta}_{w,t,k,s}, \sigma_{l,t,k,s}, \overline{\mu}_{l,t,k,s}, \underline{\mu}_{l,t,k,s}, \overline{\sigma}_{m,t,k,s}, \underline{\sigma}_{m,t,k,s}, \overline{\gamma}_{m,t,k,s}, \underline{\gamma}_{m,t,k,s}, \lambda_{n,t,k,s}, \xi_{t,k,s}, \underline{\zeta}_{m,t,k,s}, \overline{\zeta}_{m,t,k,s}\}$ is the set of decision variables of the problem (28).

4. Value of energy storage and incentive regulation

The value of energy storage investments and incentive regulation can be estimated by the corresponding change in social welfare. Incentive regulation may affect energy storage investments as well as the value of energy storage. Thus, to determine the effect of incentive regulation on the value of energy storage it should be estimated considering incentive regulations and compared to the case without incentive regulation. Similarly, energy storage investments may effect the value of incentive regulation. Thus, value of regulation with and without energy storage investments should be estimated. Assume social welfare of a system without incentive regulation and without energy storage investments is SW1. Then, energy storage investments are added which leads to new social welfare calculations denoted as SW2. By calculating the difference between SW1 and SW2 we obtain the value of energy storage without incentive regulation (ESV), (33).

$$ESV = SW2 - SW1 \tag{33}$$

Now, assume SW3 is a social welfare obtained when incentive regulation (Cost-Plus incentive regulation, ISS incentive regulation or H-R-G-V incentive regulation) is applied but energy storage investments are not enabled. Finally, SW4 corresponds to social welfare with incentive regulation and energy storage investments. By comparing SW3 and SW4 we calculate value of energy storage while accounting for incentive regulation (ESVR) as in (34).

$$ESVR = SW4 - SW3 \tag{34}$$

Similarly. value of regulation without accounting for energy storage (RV) is estimated by comparing SW1 and SW3 as in (35).

$$RV = SW3 - SW1 \tag{35}$$

While value of regulation considering energy storage investments is calculated by comparing SW4 and SW2 as in (36)

$$RV = SW4 - SW2 \tag{36}$$

The methodology of calculating energy storage value and incentive regulation value is illustrated in Fig. 4 and can be used as an analytical tool to compare incentive regulations to non-transmission asset investments such as investments in energy storage.

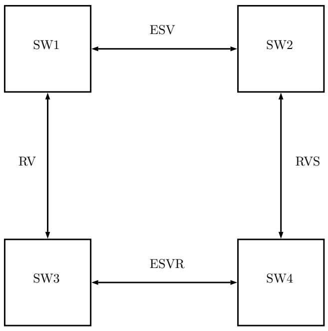

Figure 4: Estimation of value of energy storage and incentive regulation

5. Case studies

Two case studies will be presented here to illustrate how different incentive regulations influence transmission and storage investments. First, the proposed model will be applied to a small 6-node system to demonstrate the principles of the relation between transmission and energy storage investment decisions under incentive regulations. Then, the model is applied to the IEEE 118-node system to validate that the model is computationally applicable to larger systems. The simulation of each case study is performed for four planning periods which correspond to a year of operation. In order to estimate the value of energy storage under different incentive regulations we evaluate social welfare value[8] of each set-up as presented in Table 1. The methodology to evaluate energy storage investments (Section 4) is then applied.

[8]The social welfare is calculated based on the formula provided in (2)

Case study	Description
C1	Transmission investments without incentive regulation
C2	Transmission investments under H-R-G-V
C3	Transmission investments under Cost-P
C4	Transmission investments under ISS
C5	Transmission and ESS investments without incentive regulation
C6	Transmission and ESS investments under H-R-G-V
C7	Transmission and ESS investments under Cost-P
C8	Transmission and ESS investments under ISS

Table 1: Case study descriptions

5.1. 6-node example

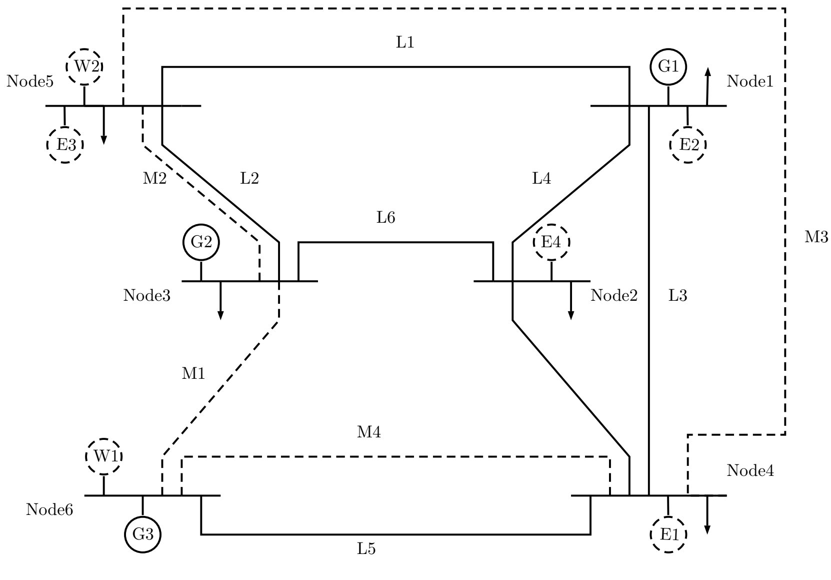

Figure 5: Single line diagram of 6-node system

A 6-node illustrative case study based on Garver's 6-node system was designed and the proposed model (28) was applied. A single-line diagram is presented in Fig. 5 where dashed lines represent candidate lines and dashed circles are candidate energy storage investment sites. The load, generation and energy storage are evenly distributed among the nodes of the system; hence there is no large congestion in the system. Nodes for candidate energy storage investments are chosen to cover possible benefits of energy storage for wind generation, load and thermal generator respectively.

The input data for transmission lines, loads, thermal and wind generators and energy storage are presented in Table 2, Table 3, Table 4 and Table 5 respectively. The MILP model was applied under four incentive regulation set-ups: without incentive regulation, Cost-Plus incentive regulation, ISS incentive regulation and H-R-G-V incentive regulation. The results are presented in Table 6, Table 7, Table 8 and Table 9 respectively. All four regulatory set-ups are then compared to a social welfare maximizing problem, where one single entity is simultaneously making all investment and operation decisions. The result of the social welfare maximization is given in Table 10. Values of energy storage and incentive regulations are estimated according to the proposed methodology in Section 4 and are presented in Fig. 6, Fig. 7 and Fig. 8 for Cost-Plus incentive regulation, for ISS incentive regulation and H-R-G-V incentive regulation, respectively.

Table 2: Data of transmission lines in the 6-node system

Line	Nodes (from,to)	Reactance (p.u.)	Capacity	Investment Cost (M$/Cct.)
Existing lines:				
L1	(1,5)	0.4	100	-
L2	(5,3)	0.6	100	-
L3	(1,4)	0.2	100	-
L4	(1,2)	0.2	100	-
L5	(4,6)	0.4	100	-
L6	(2,3)	0.2	100	-
Candidate lines:				
M1	(6,3)	0.2	100	10000
M2	(5,3)	0.48	100	10000
M3	(5,4)	0.63	100	40000
M4	(6,4)	0.3	100	50000

Table 3: Data of loads in the 6-node system

Load	Node	Capacity (MW) at $t = 1$	Short-run Marginal Utility ($/MWh)
D1	Node 1	250	95
D2	Node 2	245	75
D3	Node 3	235	82
D4	Node 4	730	105
D5	Node 5	225	55

Table 4: Data of generators in the 6-node system

Generator	Node	Capacity (MW)	Short-run Marginal Cost ($/MWh)
Thermal generation:			
G1	Node 1	600	60
G2	Node 3	500	50
G3	Node 6	1000	40
Wind generation:			
W1	Node 6	50	0
W2	Node 5	50	0

Table 5: Data of energy storage in the 6-node system

ES	Node	Short-run Marginal Cost ($/MWh)	Expansion cost ($/MWh)	Power electronics cost ($/MW)
E1	Node 1	60	2000	1000
E2	Node 3	50	3000	4000
E3	Node 3	50	1000	2000
E4	Node 6	40	5000	3000

Table 6: Investment results in the 6-node system without incentive regulation. Tran: Transmission; Inv: Investment.

	t1	t2	t3	t4	t5
M1	0	**1**	**1**	**1**	**1**
M2	0	0	0	0	0
M3	0	**1**	**1**	**1**	**1**
M4	0	0	0	0	0
M5	0	0	0	0	0
E1 (MWh)	0	0	0	0	0
E2 (MWh)	0	0	0	0	0
E3 (MWh)	0	41	41	41	41
E4 (MWh)	0	0	0	0	0
Congestion Rent (M$)	31.49	39.41	34.87	33.21	2.86
Load Surplus (M$)	2.08	2.93	2.11	2.81	1.01
Generation Surplus (M$)	13.82	15.18	14.01	14.04	15.91
ES Inv. Cost (M$)	0	0.006	0	0	0
Tran. Inv. Cost (M$)	0	3.10	0	0	0

Table 7: Investment results in the 6-node system under Cost-Plus incentive regulation. Tran: Transmission; Inv: Investment.

	t1	t2	t3	t4	t5
M1	0	**1**	**1**	**1**	**1**
M2	0	**1**	**1**	**1**	**1**
M3	0	**1**	**1**	**1**	**1**
M4	0	**1**	**1**	**1**	**1**
M5	0	0	0	0	0
E1 (MWh)	0	0	0	0	0
E2 (MWh)	0	0	0	0	0
E3 (MWh)	0	166	166	166	166
E4 (MWh)	0	0	0	0	0
Fixed Fee (M$)	0	7.98	7.98	7.98	7.98
Congestion Rent (M$)	31.49	7.23	34.87	33.21	2.86
Load Surplus (M$)	2.08	2.73	2.27	2.34	1.8
Generation Surplus (M$)	13.82	12.60	12.54	11.94	11.93
ES Inv. Cost (M$)	0	0.049	0	0	0
Tran. Inv. Cost (M$)	0	6.14	0	0	0

Table 8: Investment results in the 6-node system under ISS incentive regulation. Tran: Transmission; Inv: Investment.

M1	0	**1**	**1**	**1**	**1**
M2	0	0	0	0	0
M3	0	**1**	**1**	**1**	**1**
M4	0	**1**	**1**	**1**	**1**
M5	0	0	0	0	0
E1 (MWh)	0	0	0	0	0
E2 (MWh)	0	0	0	0	0
E3 (MWh)	0	90	90	90	90
E4 (MWh)	0	0	0	0	0
Fixed Fee (M$)	0	31.48	15.28	36.27	4.82
Congestion Rent (M$)	31.49	38.07	3.29	23.21	2.98
Load Surplus (M$)	2.08	3.81	2.83	2.33	1.79
Generation Surplus (M$)	13.82	11.59	11.99	11.93	11.99
ES Inv. Cost (M$)	0	0.013	0	0	0
Tran. Inv. Cost (M$)	0	5.62	0	0	0

Table 9: Investment results in the 6-node system under H-R-G-V incentive regulation. Tran: Transmission; Inv: Investment.

	t1	t2	t3	t4	t5
M1	0	**1**	**1**	**1**	**1**
M2	0	0	0	0	0
M3	0	**1**	**1**	**1**	**1**
M4	0	**1**	**1**	**1**	**1**
M5	0	0	0	0	0
E1 (MWh)	0	0	0	0	0
E2 (MWh)	0	0	0	0	0
E3 (MWh)	0	90	90	90	90
E4 (MWh)	0	0	0	0	0
Fixed Fee (M$)	0	0	32.96	11.32	29.89
Congestion Rent (M$)	31.49	38.07	3.29	23.21	2.98
Load Surplus (M$)	2.08	3.81	2.83	2.33	1.79
Generation Surplus (M$)	13.82	11.59	11.99	11.93	11.99
ES Inv. Cost (M$)	0	0.013	0	0	0
Tran. Inv. Cost (M$)	0	5.62	0	0	0

Table 10: Investment results in the 6-node system under welfare maximum objective. Tran: Transmission; Inv: Investment.

	t1	t2	t3	t4	t5
M1	0	**1**	**1**	**1**	**1**
M2	0	0	0	0	0
M3	0	**1**	**1**	**1**	**1**
M4	0	**1**	**1**	**1**	**1**
M5	0	0	0	0	0
E1 (MWh)	0	0	0	0	0
E2 (MWh)	0	0	0	0	0
E3 (MWh)	0	90	90	90	90
E4 (MWh)	0	0	0	0	0
ES Inv. Cost (M$)	0	0.013	0	0	0
Tran. Inv. Cost (M$)	0	5.62	0	0	0

The results of the 6-node system show that incentive regulations increase the social welfare. All incentive regulations provide a higher value of the social welfare compared to the set-up with no incentive regulations (see Fig. 9). The H-R-G-V incentive regulation and ISS incentive regulation actually result in the social welfare maximum, whereas the result of Cost-Plus incentive regulation is slightly lower, but much better than without incentive regulation. Without any incentive regulation only two candidate lines are accepted (see Table 6), whereas Cost-Plus incentive regulation is causing over investment as candidate line M2 is accepted (see Table 7).

Moreover, energy storage is also increasing the social welfare. Similar observations can be made for energy storage investments under different incentive regulations. Availability of additional transmission lines (Cost-Plus incentive regulation) leads to significantly higher investment in energy storage, however social welfare is still lower than under H-R-G-V incentive regulation and ISS incentive regulation.

It should be noted that the benefits of incentive regulations and energy storage investments are not in conflict; conversely, the value of energy storage is much higher with an appropriate incentive regulation. At the same time, the value of introducing an incentive regulation is higher when there is energy storage in the system. For example, the social welfare is increasing by 7.53 M$ when comparing no incentive regulation and no storage (set-up C1) to H-R-G-V and ISS incentive regulation (set-ups C2 or C3). With storage, the difference between no incentive (C5) and H-R-G-V as well as ISS incentive regulation (C6 and C8) is 12.81 M$.

It can also be noted that the value of adding energy storage without any incentive regulation, i.e., comparing C1 and C5, is lower than the value of adding an incentive regulation without storage, i.e., comparing C1 and C2-C4 (see Fig. 6 for Cost-Plus incentive regulation, Fig. 7 for ISS incentive regulation and Fig. 8 for H-R-G-V for incentive regulation).

Finally, Fig. 10 shows the profit of the Transco for the eight set-ups. It can be seen that the profit does not depend much on whether energy storage is present or not, but mostly depend on the incentive regulation. The Transco benefits most from H-R-G-V incentive regulation and ISS incentive regulation, which also maximize social welfare. However, it can be seen that the increase in profit for the Transco is much larger than the increase of the social welfare (280 M$ profit increase for H-R-G-V incentive regulation and 181 M$ for ISS incentive regulation compared to an increase of social welfare equal to 7.53 M$ without storage or 12.81 M$ with storage. Hence, the incentive regulation is increasing social welfare, but also efficiently transferring profit from the other players to the Transco).

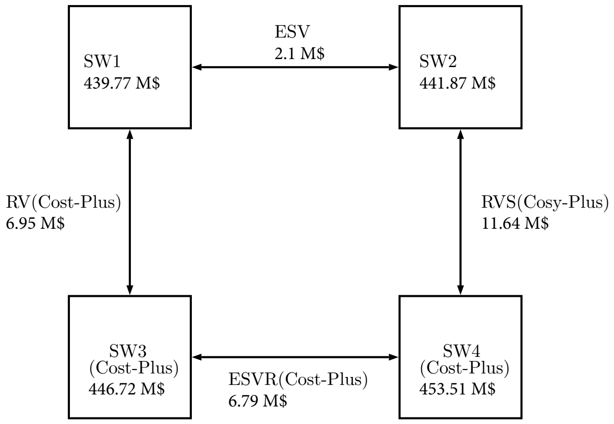

Figure 6: Calculation of the value of energy storage depending on the presence or absence of a regulatory scheme and calculation of the value of the regulation depending on the presence or absence of energy storage for the 6-node system under the Cost-Plus incentive regulation

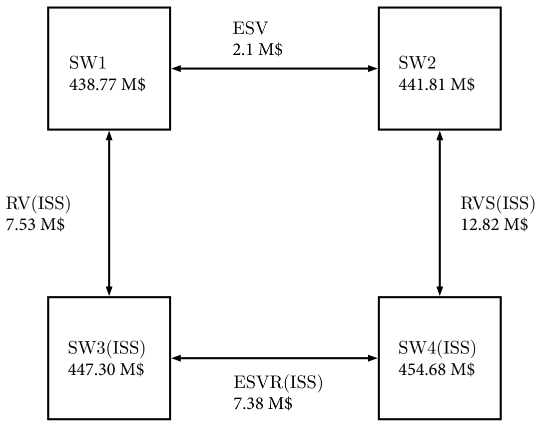

Figure 7: Calculation of the value of energy storage depending on the presence or absence of a regulatory scheme and calculation of the value of the regulation depending on the presence or absence of energy storage for the 6-node system under ISS incentive regulation

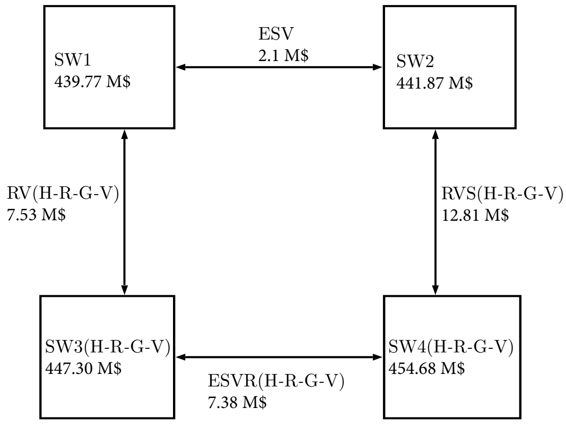

Figure 8: Calculation of the value of energy storage depending on the presence or absence of a regulatory scheme and calculation of the value of the regulation depending on the presence or absence of energy storage for the 6-node system under H-R-G-V incentive regulation

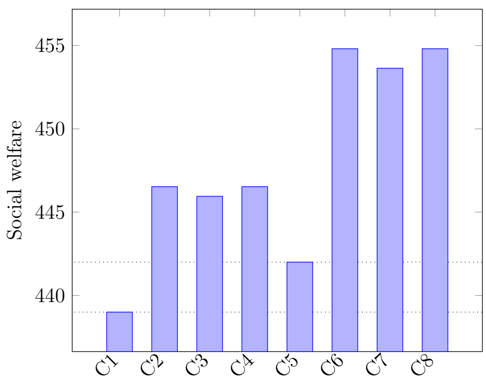

Figure 9: Social welfare results of set-ups C1-C8 for the 6-node system

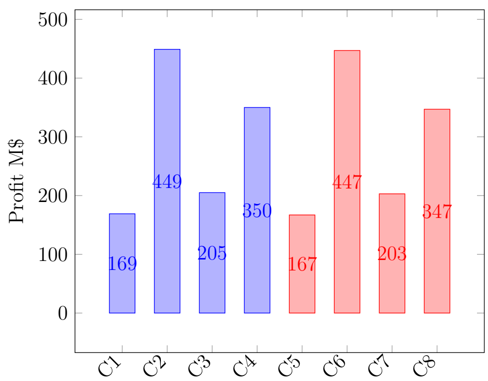

Figure 10: Profit of Transco for each case study C1-C8 for the 6-node system

5.2. IEEE 118-node example

The MILP model proposed in (28) is further verified on large case study based on the IEEE 118-node model. The simulations are run on a computer with two processors of 2.3 GHz and 128GB of RAM. All data for the IEEE test systems are taken from data files of the Matpower software [27]. The maximum demand at each node was increased by 50% . Data for candidate transmission lines and energy storage technologies are presented in Table 12 and Table 11, respectively. The results of the simulations are presented in Table 13 - Table 15 for H-R-G-V incentive regulation, Cost-Plus incentive regulation and ISS incentive regulation respectively. Similar to the 6-node case study the results of the simulation of the 118-node case study show that H-R-G-V incentive regulation and ISS incentive regulation considerably outperform Cost-Plus incentive regulation. At the same time, energy storage investments add considerable value to regulation and positively impact social welfare (See Fig. 11 and Fig. 12).

Table 11: Data of candidate energy storage systems in IEEE 118-node test system based on calculations provided in [28]

ESS	Node	Efficiency	Power electronics Cost (k$/MW)	Capacity Investment Cost (k$/MWh.)
E1	5	0.75	100	400
E2	10	0.66	100	380
E3	12	0.85	100	60
E4	12	0.95	100	2000
E5	14	0.75	100	40
E6	15	0.85	100	380
E7	25	0.75	100	60
E8	63	0.95	100	200
E9	75	0.85	100	400
E10	81	0.63	100	38
E11	83	0.85	100	400
E12	89	0.95	100	380
E13	102	0.6	100	60
E14	103	0.85	100	200
E15	116	0.75	100	400
E16	116	0.85	100	38
E17	117	0.95	100	60

Table 12: Data of candidate transmission lines in IEEE 118-node test system

Line	Nodes (from,to)	Reactance (p.u.)	Capacity	Investment Cost (k$/Cct.)
E1	(19,20)	0.4	100	4,000
E2	(19,82)	0.6	100	38,000
E3	(90,27)	0.2	100	6,000
E4	(39,91)	0.2	100	20,000
E5	(43,38)	0.4	100	4,000
E6	(52,38)	0.2	100	38,000
E7	(86,28)	0.3	100	6,000
E8	(87,25)	0.2	100	20,000
E9	(91,22)	0.48	100	40,000
E10	(41,21)	0.63	100	38,000
E11	(36,92)	0.3	100	4,000
E12	(5,23)	0.4	100	38,000
E13	(19,20)	0.6	100	6,000
E14	(45,7)	0.2	100	20,000
E15	(15,5)	0.2	100	4,000
E16	(15,25)	0.4	100	38,000
E17	(1,20)	0.2	100	6,000
E18	(12,39)	0.3	100	20,000
E19	(37,38)	0.2	100	4,000
E20	(80,50)	0.48	100	38,000
E21	(73,51)	0.3	100	20,000
E22	(56,90)	0.4	100	4,000
E23	(80,11)	0.6	100	6,000
E24	(11,15)	0.2	100	20,000
E25	(13,21)	0.2	100	4,000
E26	(24,27)	0.4	100	38,000
E27	(48,52)	0.2	100	6,000
E28	(67,19)	0.3	100	20,000
E29	(79,30)	0.48	100	4,000
E30	(51,45)	0.48	100	38,000

Table 13: Investment results in the IEEE 118-node system under H-R-G-V incentive regulation. Tran: Transmission; Inv: Investment.

	t1	t2	t3	t4	t5
Fixed Fee (M$)	0	493.77	472.92	447.59	414.10
Congestion Rent (M$)	386.70	1366.4	1417.9	1478.2	1460.5
Load Surplus (M$)	851.01	365.02	292.74	207.12	191.31
Generation Surplus (M$)	9691.01	1311.01	1134.23	1543.23	1591.12
ES Inv. Cost (M$)	0	11.09	18.05	0	0
Tran. Inv. Cost (M$)	0	26.8	4.2	4.4	3.8

Table 14: Investment results in the IEEE 118-node system under Cost-Plus incentive regulation. Tran: Transmission; Inv: Investment.

	t1	t2	t3	t4	t5
Fixed Fee (M$)	0	493.77	472.92	447.59	414.10
Congestion Rent (M$)	386.70	1366.4	1417.9	1478.2	1460.5
Load Surplus (M$)	851.01	365.02	292.74	207.12	191.31
Generation Surplus (M$)	9691.01	1311.01	1134.23	1543.23	1591.12
ES Inv. Cost (M$)	0	11.09	23.71	0	0
Tran. Inv. Cost (M$) 0	26.8	18.4	0	0	0

Table 15: Investment results in the IEEE 118-node system under ISS incentive regulation. Tran: Transmission; Inv: Investment.

Fixed Fee (M$)	0	326.56	361.15	321.98	311.05
Congestion Rent (M$)	386.70	1366.4	1417.9	1478.2	1460.5
Load Surplus (M$)	851.01	365.02	292.74	207.12	191.31
Generation Surplus (M$)	9691.01	1311.01	1134.23	1543.23	1591.12
ES Inv. Cost (M$)	0	11.09	18.05	0	0
Tran. Inv. Cost (M$) 0	26.8	4.2	4.2	4.4	3.8

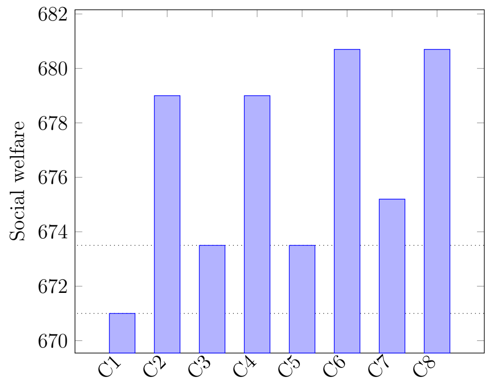

Figure 11: Social welfare results of set-ups C1-C8 for IEEE 118-node system

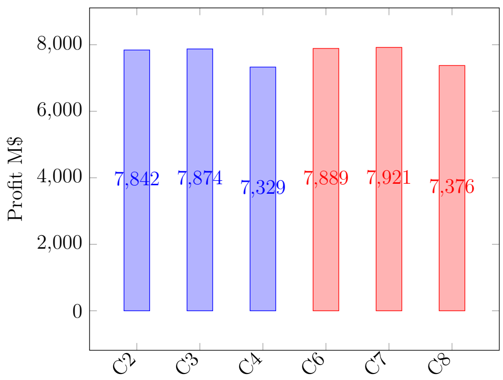

Figure 12: Profit of Transco for each case study C2-C4 and C6-C8 for IEEE 118-node system

6. Conclusion

In this paper we present an overview of incentive regulations which can be applied to merchant-regulatory transmission investments. The incentive regulations considered include Cost-Plus incentive regulation, ISS incentive regulation and H-R-G-V incentive regulation. The literature has shown that the aforementioned incentive regulations can be applied to merchant-regulatory transmission investment planning. However, the literature does not include the effect of energy storage systems which can be used as a substitute or a complement to transmission. In this paper we provide an analysis of the possible influence of energy storage investments on regulated transmission investments. We show that under Cost-Plus incentive regulation energy storage may have a negative impact on transmission investments and cause more severe over investment in transmission compared to the case without energy storage investments. Conversely, the ISS incentive regulation and H-R-G-V incentive regulation can be more beneficial for both joint and separate investment planning of transmission and energy storage.

The paper proposes a mathematical model where the incentive regulation applies regulatory constraints. In addition, the paper provides a methodology to estimate the value of energy storage and incentive regulation. We test the proposed model and the methodology on a 6-node illustrative example and the IEEE 118-node system. The results show that energy storage adds a significant value to social welfare with or without regulation. However, the value of joint transmission and energy storage investments is much higher than the value of each of them separately. Thus, the Regulator should ensure through incentive regulations or other means that independent transmission investments considers non-transmission assets in order to achieve the most favourable outcome.

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Nomenclature

Binary Variables

$z_{m,t}$ Transmission investment decision variable;

$y_{m,t}$ Transmission investment decision variable;

Dual Variables

$\underline{\vartheta}_{e,t,k,s}$ Lagrange multipliers of charge lower limit constraints;

$\overline{\vartheta}_{e,t,k,s}$ Lagrange multipliers of charge upper limit constraints;

$\underline{\omega}_{d,t,k,s}$ Lagrange multipliers of demand lower limit constraints;

$\overline{\omega}_{d,t,k,s}$ Lagrange multipliers of demand upper limit constraints;

$\underline{\kappa}_{e,t,k,s}$ Lagrange multipliers of discharge lower limit constraints;

$\overline{\kappa}_{e,t,k,s}$ Lagrange multipliers of discharge upper limit constraints;

$\sigma_{l,t,k,s}$ Lagrange multipliers of power flow equality constraints;

$\underline{\mu}_{l,t,k,s}$ Lagrange multipliers of power flow lower limit constraints;

$\overline{\mu}_{l,t,k,s}$ Lagrange multipliers of power flow upper limit constraints;

$\underline{\nu}_{g,t,k,s}$ Lagrange multipliers of generation lower limit constraints;

$\overline{\nu}_{g,t,k,s}$ Lagrange multipliers of generation upper limit constraints;

$\vartheta_{e,t,k,s}$ Lagrange multipliers of energy storage power capability constraints;

$\kappa_{e,t,k,s}$ Lagrange multipliers of energy storage capacity constraints;

$\underline{\sigma}_{m,t,k,s}$ Lagrange multipliers of disjunctive linearization constraints;

$\underline{\zeta}_{m,t,k,s}$ Lagrange multipliers of disjunctive linearization constraints;

$\overline{\zeta}_{m,t,k,s}$ Lagrange multipliers of disjunctive linearization constraints;

$\overline{\sigma}_{m,t,k,s}$ Lagrange multipliers of disjunctive linearization constraints;

$\underline{\gamma}_{m,t,k,s}$ Lagrange multipliers of power flow lower limit constraints;

$\overline{\gamma}_{m,t,k,s}$ Lagrange multiplier of power flow upper limit constraint;

$\tau_{e,t,k,s}$ Lagrange multipliers of energy balance of energy storage constraint;

$\underline{\rho}_{e,t,k,s}$ Lagrange multipliers of state of the charge lower limit constraints;

$\overline{\rho}_{e,t,k,s}$ Lagrange multipliers of state of the charge upper limit constraints;

$\xi_{t,k,s}$ Lagrange multipliers of voltage equality constraints for $n = 1$;

$\underline{\eta}_{w,t,k,s}$ Lagrange multipliers of wind generation lower limit constraints;

$\overline{\eta}_{w,t,k,s}$ Lagrange multipliers of wind generation upper limit constraint;

Incidence matrices

$S_{n,l}$ Incidence matrix for sending nodes n and existing lines l;

$\overline{S}_{n,m}$ Incidence matrix sending nodes n and candidate lines m;

$J_{n,g}$ Incidence matrix for generators g and nodes n;

$I_{n,d}$ Incidence matrix for loads d and nodes n;

$E_{n,e}$ Incidence matrix for energy storage e and nodes n;

$R_{n,l}$ Incidence matrix for receiving nodes n and existing lines l;

$\overline{R}_{n,m}$ Incidence matrix receiving nodes n and candidate lines m;

$W_{n,w}$ Incidence matrix for wind generators w and nodes n;

Parameters

Ξ_m Large number used for disjunctive reformulation;

d Discount rate;

$\tilde{C}^{sr}_{e,t}$ Investment costs of energy capacity of energy storage e;

$\tilde{mc}_e$ Degradation costs of energy storage e;

$\tilde{C}^{pr}_{e,t}$ Investment costs of power capability of energy storage e;

$\tilde{\alpha}_e$ Degradation costs of energy storage e;

mc_g Marginal cost of generator g

i Inflation rate;

$\overline{C}_{m,t}$ Investment costs of transmission line m;

α_d Load d utility functions;

$D_{d,t}$ Maximum capacity of load d;

F_l Maximum capacity of transmission line l;

G_g Maximum capacity of generator g;

$\widehat{F}_m$ Maximum capacity of transmission line m;

$\widehat{G}_{w,t}$ Maximum capacity of wind generator w;

Ψ Number of operational periods in investment planning period;

p_t Present worth factor;

π_s Probability of scenario s;

X_l Reactance of transmission line l;

X_m Reactance of transmission line m;

$\Upsilon(*)$ True or False parameter which is equal 1 if $*$ is true and 0 otherwise;

$\varrho_{w,t,k,s}$ Stochastic output of wind generator w;

Sets

d Load;

g Generation;

t Investment periods;

l Existing lines;

m Candidate lines;

n Nodes;

k Operation periods;

s Scenarios;

e Energy storage;

w Wind generators;

Variables

$\tilde{d}_{e,t,k,s}$ Charge of energy storage e at period t,k for scenario s;

$d_{d,t,k,s}$ Demand of load d at period t,k for scenario s;

$\tilde{g}_{e,t,k,s}$ Discharge of energy storage e at period t,k for scenario s;

$f_{l,t,k,s}$ Flow of line l at period t,k for scenario s;

$g_{g,t,k,s}$ Dispatched generation of generator g at period t,k for scenario s;

$\tilde{P}_{e,t}$ Invested energy storage power capability of energy storage e at period t;

$\tilde{S}_{e,t}$ Invested energy storage capacity of energy storage e at period t;

$\widehat{f}_{m,t,k,s}$ Flow of invested candidate line m at period t,k for scenario s;

$\tilde{s}_{e,t,k,s}$ State of charge of energy storage e at period t,k for scenario s;

$\theta_{n,t,k,s}$ Voltage at node n at period t,k for scenario s;

$\widehat{g}_{w,t,k,s}$ Dispatched wind generation of generator w at period t,k for scenario s;

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Transmission Network Investment Using Incentive Regulation: A Disjunctive Programming Approach.

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I. Vogelsang · J. Rosellón.

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Abstract A well-planned electric transmission infrastructure is the foundation of a reliable and efficient power system, especially in the presence of large scale renewable generation. However, the current electricity market designs lack incentive mechanisms which can guarantee optimal transmission investments and ensure reliable integration of renewable generation such as wind. This paper first proposes a stochastic bilevel disjunctive program for optimal transmission investment based on the newly proposed theoretical H-R-G-V incentive mechanism. The upper level is a profit-maximization problem of an independent transmission company (Transco), while the lower level is a welfare maximization problem. The revenue of the Transco is bounded by a regulatory constraint set by the regulator in order to induce socially optimal investments. The application of the H-R-G-V mechanism allows the regulator to ensure social maximum transmission investments and helps to reduce transmission congestion and wind power spillage. The transmission investment under the H-R-G-V mechanism is modeled as a stochastic bilevel disjunctive program. To solve the developed mathematical model we first propose a series of linearization and reformulation techniques to recast the original model as a stochastic mixed integer linear problem (MILP). We exploit the disjunctive nature of the reformulated stochastic MILP model and further propose a Bean decomposition algorithm to efficiently solve the stochastic MILP model. The proposed decomposition algorithm is also modified and accelerated to improve the computational performance. The computational performance of our MILP modeling approach and modified and accelerated Bean decomposition algorithm is studied through several examples in detail. The simulation results confirm a promising performance of both the modeling approach and its solution algorithm.

Keywords Transmission network investments · Incentive regulation · Bean decomposition algorithm · Disjunctive programming.

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1 Introduction

Optimal investment in transmission networks is a major concern in electricity markets around the world, largely due to growing electricity demand and increasing penetration of variable renewable generation. While the generation and retail sectors are effectively managed through competitive market rules, the transmission sector remains a natural monopoly and in many states is managed through independent profit-maximizing transmission companies (Transco). A Transco is responsible for the transmission lines' maintenance and the investments in additional transmission capacity. The reimbursement of transmission investment costs depends on the regulation and the incentive mechanisms adopted by the regulatory entity of the state. Currently the transmission sector is experiencing a lack of investment incentives (Rosellón et al 2018), (Hesamzadeh et al 2018). With the growth of renewables the absence of adequate incentive mechanisms will result in increased transmission congestion costs which will negatively affect social welfare (European Commission 2003), (Dyer 2003).

Various incentive mechanisms were proposed to tackle the incentive problem. They can be divided into two major groups, subsidy mechanisms and constraint mechanisms. Subsidy mechanisms were initially introduced by (Loeb and Magat 1979) and further developed by (Sappington and Sibley 1988) where an incremental surplus subsidy scheme (ISS) was proposed. The mechanism then was applied to transmission pricing and investments in (Gans and King 2000). On the other hand, constraint mechanisms were proposed by (Vogelsang 2001) and (Tanaka 2007), who use price-cap constraints to incentivize optimal transmission investment by a Transco. Under certain conditions, these mechanisms lead to transmission investment decisions which maximize social welfare (Hogan et al 2010). (Joskow and Tirole 2002) propose a reward/penalty mechanism. In this mechanism, the regulator rewards the Transco when the transmission network is expanded and the merchandising surplus as well as network congestion are decreased. (Léautier 2000) proposes an out-turn mechanism. The out-turn is defined as the difference between actual electricity prices and prices without transmission congestion. The Transco is responsible for total out-turn cost and any transmission losses. Variations of such incentive mechanisms were widely applied on energy infrastructure investments (Neumann et al 2015). More recently, an alternative incentive mechanism for transmission investments has been proposed by (Hesamzadeh et al 2018) following the incentive mechanisms in (Sappington and Sibley 1988) and (Hogan et al 2010). The H-R-G-V (Hesamzadeh-Rosellon-Gabriel-Vogelsang) mechanism envisages a dynamic interaction between a profit-maximizing Transco, the regulator and an Independent System Operator (ISO). The H-R-G-V mechanism combines the price cap approach with the ISS scheme. A regulatory entity (regulator) sets a charge for transmission network users (generators and loads) with variable fees corresponding to nodal price differences that are related to the merchandising surplus. In addition, generators and loads are charged with a fixed fee. This mechanism induces social welfare maximizing investments and efficient nodal prices for all planning periods. The comparison of advantages of aforementioned inventive mechanisms is presented in Table 1.

Theoretical justifications that the H-R-G-V mechanism can be effectively used for transmission investments have been presented in (Vogelsang 2018). Mathematically, the transmission investment problem under the H-R-G-V incentive mecha-

Table 1 Comparison of different incentive mechanisms.

Advantages:	Cost-Plus	ISS	H-R-V	H-R-G-V
Does not involve subsidies	yes	no	yes	**yes**
Guarantees socially optimal investments	no	yes	no	**yes**
Based on market information	no	yes	yes	**yes**
Promotes competitive behavior	no	no	yes	**yes**
Simple to model	yes	yes	no	**yes**
Convergence to global solution is guaranteed	yes	yes	no	**yes**

nism is formulated as a non-linear disjunctive program. The mathematical formulation and the solution algorithm previously proposed for modeling the H-R-G-V regulation are applied only to a small example system and they are not practical for real-size applications (Hesamzadeh et al 2018). Moreover, the application of the H-R-G-V mechanism in (Hesamzadeh et al 2018) and in (Vogelsang 2018) was considered only under deterministic input parameters. The growth of variable renewable generation will result in increased stochasticity in the system which should be taken into account in transmission investments as well. Thus, in this paper we extend the application of the mechanism to a stochastic framework and propose a solution algorithm which will mathematically guarantee a globally optimal solution.

The resulting initial model is the deterministic equivalent of a stochastic bilevel disjunctive program with integer variables. The solution of the formulated problem is complicated through several non-linear terms and disjunctive constraints. Thus, through a series of proposed linearization techniques, the initial bilevel program is transformed into a mixed-integer linear program (MILP) with disjunctive constraints. The disjunctive constraints are also complicating the solution process so that state-of the art solvers cannot be applied directly with a guarantee of finding a global solution.

A disjunctive program can be reformulated into a mixed-integer program using several existing techniques including the convex hull, cutting planes and disjunctive constraint linearization techniques[1]. All these techniques provide a reformulation of the original feasible sets and there are limitations specific for each technique. Convex hull methods are proved to provide a tight reformulation. Nevertheless, the approach requires additional variables and constraints which considerably increase the size of the problem for transmission investment models. On the other hand, the disjunctive constraint linearization technique does not affect the size of the problem. However, the disjunctive parameters involved in the reformulation create computational issues for the solver. A disjunctive parameter that is not tuned affects the convergence of the problem (Hooker 2011). The literature provides several methodologies for tuning the disjunctive parameter. The methodologies for tuning the disjunctive parameter can be found in (Trespalacios and Grossmann 2015) and (Hooker 2011). These methodologies are proved to provide good approximations of the disjunctive parameters under certain conditions but additional large scale optimization problems need to be solved for each case and optimality of the outcome still cannot be guaranteed. The problem of the disjunc-

[1] The disjunctive constraint linearization technique is also called the big-M reformulation techniques in some literature. Please see references (Hooker 2011) and (Trespalacios and Grossmann 2015)

tive parameter tuning becomes especially hard when the reformulation involves variables without physical upper or lower bounds which is the case in our proposed model.

Various solution algorithms can be considered to solve the reformulated disjunctive program. In (Garces et al 2009) and (Maurovich-Horvat et al 2015) state-of-the-art solvers such as CPLEX are used to solve the transmission investment model. Such methodology guarantees convergence to an optimal solution, however the application to our proposed stochastic MILP will require additional tuning of the disjunctive parameter. In addition, the tractability of the solution is low for large-scale problems (Bertsimas et al 2018). In the large-scale problems, the number of variables and constraints might exceed the level which can be handled by state-of-the-art solvers such as CPLEX. Accordingly, solvers such as CPLEX might not be able to find the optimal solution efficiently (tractability issue). In these cases, it is suggested to decompose the large optimization problem into smaller ones with reduced number of variables and constraints. In this way, the optimal solution can be found more efficiently (improved tractability). One of the most widely used decomposition algorithms is Benders decomposition algorithm. In (Conejo et al 2006) and (McCusker and Hobbs 2003), the Benders decomposition algorithm is used to improve computational tractability considering the uncertainty in the system. The Benders decomposition algorithm proves to be an effective tool and it reduces the computational complexity substantially. While the Benders decomposition algorithm is proved to be effective and can be applied to transmission investment models it does not solve the complications arising from incorporating the incentive mechanism into the transmission investment model. Moreover, the presence of a hard-to-tune disjunctive parameter will prevent a direct application of the Benders decomposition algorithm to our proposed MILP. A sub-optimally tuned disjunctive parameter will result in weak Benders cuts and will cause reduced tractability of the problem (Hooker 2011),(Codato and Fischetti 2004).Additional Gomory cuts were proposed to tackle the problem of disjunctive parameters in (Binato et al 2001), however the proposed approach achieves only an approximate disjunctive parameter without guaranteeing that it was tuned to optimality. Thus, the application of the Benders decomposition algorithm to disjunctive problems has challenges associated with disjunctive parameters.

Employing the disjunctive nature of our reformulated MILP model, we propose an algorithm based on the Bean decomposition algorithm. The Bean decomposition algorithm follows the Benders decomposition algorithm and these two algorithms can be directly compared. The Bean decomposition algorithm directly exploits the disjunctive nature of our proposed MILP model and it has a better computational tractability than Benders decomposition algorithm. We also modify the Bean decomposition algorithm such that disjunctive parameters are completely removed from solution algorithm. Accordingly, they are not needed to be optimally tuned. Moreover the modified Bean decomposition algorithm is accelerated by using some additional constraints. The benefits of our proposed algorithm in comparison to existing solution methodologies are presented in Table 2.

Accordingly, the main contributions of the current paper can be highlighted through the following points:

Table 2 Comparison of solution methodologies. Disj.: Disjunctive

	Global solution	Tuning of disj. parameter is required	Disj. parameter optimality guaranteed	Improved tractability
Direct application of state-of-the-art solvers	yes	yes	no	no
Standard Benders decomposition algorithm	yes	yes	no	no
Benders decomposition with disjunctive parameter tuning	yes	no	no	no
Standard Bean decomposition algorithm	yes	yes	no	no
Our proposed decomposition algorithm	**yes**	**no**	**yes**	**yes**

– The current paper presents an extension of the theoretical H-R-G-V incentive mechanism to the stochastic modeling framework. Wind generation uncertainty is considered in the proposed stochastic framework. The resulting model is a stochastic bilevel disjunctive program which is hard to solve. Accordingly, a series of reformulation and linearization techniques are proposed to recast the original model into an easier-to-solve stochastic MILP with disjunctive constraints.
– The paper then proposes a specialized decomposition algorithm based on the Bean decomposition algorithm to solve the derived MILP model. The proposed decomposition algorithm is aimed at guaranteeing the convergence to the globally optimal solution with good computational tractability and to avoid tuning of the disjunctive parameters. Moreover, it is accelerated by using some additional constraints.
– Several case studies of different size are presented to illustrate the performance of the incentive mechanism and solution methodology. We have demonstrated that the H-R-G-V incentive mechanism can be effectively used for transmission investment. The numerical results show that the proposed decomposition algorithm outperforms the standard Benders decomposition algorithm and it can be used effectively to obtain a globally optimal solution with better computational tractability.

The current paper is organized as follows. Section II describes the incentive-based regulated transmission investment mechanism and formulates the mathematical model. Section III then introduces a stochastic bilevel disjunctive program for the transmission investment planning problem based on the H-R-G-V mechanism. In Section IV the stochastic MILP reformulation of the proposed model is presented. Section V contains a short description of the standard Benders decomposition algorithm followed by our proposed decomposition algorithm. An illustrative example, case studies and the results are presented in Section VI. Section VII provides conclusions. Finally, a short discussion of reliability issues as well as a description of scenario generation methodology are presented in Appendix A.1 and Appendix A.2.

2 Incentive-based regulation: introduction to the H-R-G-V regulatory constraint

The incentive-based regulated transmission investment assumes that three independent organizations are involved in the investment planning and operation of a power system. The first organization is the welfare maximizing independent system operator (ISO) which operates dispatchable conventional and renewable generation assets and calculates the merchandizing surplus. The second organization is a regulated independent transmission company (Transco) which owns a transmission network and is responsible for transmission investment planning and for setting a fixed fee for loads and generators for transmission investments expenses. Finally, the third organization is a regulator which is responsible for providing proper regulatory mechanisms to ensure socially optimal investment decisions, meaning that the regulator has a social welfare maximizing objective. The interaction between ISO, regulator and Transco for transmission investments is illustrated in Figure 1.

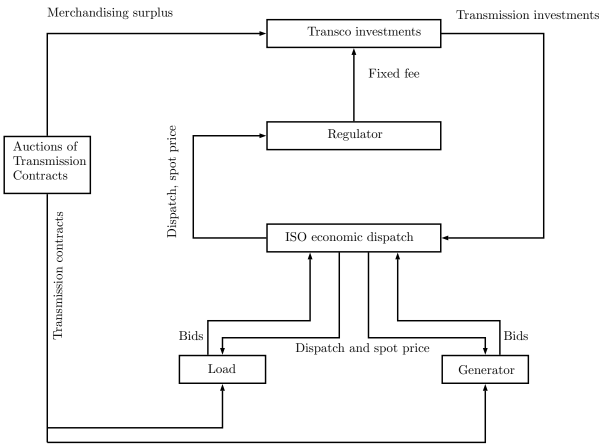


Fig. 1 Incentive-based regulation for transmission investments

The Transco maximizes its profit by expanding its transmission network while considering a fixed fee calculated by the regulator. The Transco communicates transmission investment decisions to the ISO. The ISO dispatches the system and communicates the required information to the regulator. The regulator calculates the fixed fee and communicates the fixed fee to the Transco. The Trasco also receives the merchandising surplus through auctioning transmission contracts.

Under H-R-G-V incentive mechanism the regulatory constraint links the fixed fee to the generator surplus and load surplus. These generator and load surplus are influenced by transmission investment decisions of Transco. The fixed fee is closely related to the social welfare increase resulting from the network investments. The fixed fee paid by the network users could be seen as a substitute to subsidy payments by the government or the regulator. In order to make a decision on new line investments and transmission tariffs, the Transco has to take into account expected generation dispatch, electricity demand and nodal prices which are the outputs of the problem of the welfare maximizing ISO. In order to provide the expected dispatch of the system, the ISO collects the bids from generators and loads. Under the assumption of perfect competition between generators and between loads the interaction of ISO, generators and loads can be modeled as cost-minimizing dispatch of a power system. Thus, the regulated transmission investments can be formulated as an interaction between ISO, Transco and regulator. From the modeling perspective, the simulation of the interaction between regulator and Transco can be merged. Under the H-R-G-V incentive mechanism the regulator can be represented effectively through the regulatory constraint applied to the operation and investment planning of the Transco. This will lead us to bilevel formulation of the regulated transmission investment problem.

In the upper-level problem, the Transco maximizes its profit which consists of the sum of its network merchandising surplus and a fixed fee to transmission network users (which is limited by the regulatory constraint) minus total investment costs. In the lower-level problem, the ISO takes into account the investment decisions made by the Transco and dispatches generation and loads by maximizing social welfare. The optimal dispatch is used to calculate the merchandising surplus, load surplus and generation surplus. The interaction between upper-level problem and lower-level problem is illustrated in Figure (2).

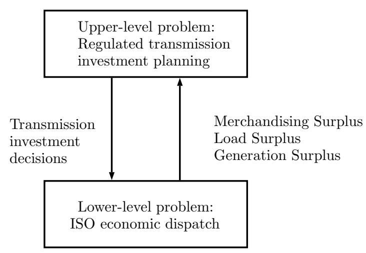


Fig. 2 Relation between upper-level problem and lower-level problem under H-R-G-V incentive regulation

The following assumptions are considered in this paper:

- The Transco and regulator have all information about economic dispatch model of the ISO. The fixed fee is calculated by the regulator and considered by the Transco. The transmission investment costs are only known by the Transco.
- We assume that the maximum demand is expected to grow by a certain percentage each of the following investment planning periods. Moreover, we assume

that demand is horizontal until it reaches a maximum. The maximum demand level is defined separately for each power system bus.

- Uncertainty comes only from wind generation and it is modeled using a moment-matching technique. The demand uncertainty is considered to be relatively low and negligible. A short discussion of incorporating additional uncertainties can be found in the Appendix A.2.
- We assume that the dispatch is made in a merit order. This means perfect competition in generation and load sector.
- The Transco is assumed to be a risk-neutral regulated profit-maximizing entity.
- The regulator has the power to affect the profit of the Transco by setting a limit on the fixed fee. The main objective of the regulator is to maximize social welfare.
- The transmission investment decision in a particular line corridor is performed only once throughout the planning horizon and the investment decision is not reversible (Xifan and McDonald 1994). The capacities of the candidate lines considered for investment are fixed and known in advance.

The H-R-G-V regulatory constraint is based on the overall change of generation and demand surplus and is formulated as:

$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi_t^G] + \Delta\,\mathbb{E}[\pi_t^L] \tag{1}$$

Where Φ_t is a fixed fee at investment period t to be set by the regulator and paid to the Transco and $\Delta\Phi_t = \Phi_t - \Phi_{t-1}$. $\mathbb{E}[\pi_t^G]$ and $\mathbb{E}[\pi_t^L]$ are the expected generation and demand surplus at investment period t while $\Delta\,\mathbb{E}[\pi_t^G] = \mathbb{E}[\pi_t^G] - \mathbb{E}[\pi_{t-1}^G]$ and $\Delta\,\mathbb{E}[\pi_t^L] = \mathbb{E}[\pi_t^L] - \mathbb{E}[\pi_{t-1}^L]$. Mathematically, the bilevel regulated transmission investment problem can be expressed as:

$$Maximize \sum_{t\in\mathcal{T}} (\mathbb{E}[\pi_t^T] + \Phi_t - \overline{C}_t^T) \tag{2a}$$

$$Subject\ to:$$

$$\text{Transmission investment decision constraint} \quad \forall t\in\{\mathcal{T}\setminus t1\} \tag{2b}$$

$$\Delta\Phi_t = \Delta\,\mathbb{E}[\pi_t^G] + \Delta\,\mathbb{E}[\pi_t^L] \quad \forall t\in\{\mathcal{T}\setminus t1\} \tag{2c}$$

$$\Phi_{t1} = 0 \tag{2d}$$

$$Maximize \sum_{t\in\mathcal{T}} (\mathbb{E}[\pi_t^G] + \mathbb{E}[\pi_t^T] + \mathbb{E}[\pi_t^L])$$

$$Subject\ to: \text{system's technical constraints.} \tag{2e}$$

Here $\mathbb{E}[\pi_t^T]$ is the merchandising surplus earned by the Transco in the spot market. $\overline{C}_t^T$ and Φ_t are the total transmission investment cost and the fixed fee respectively. In addition, we assume that the first investment planning period $t1$ is a status quo period with no investment decisions and no fixed fee.

Social Welfare (SW_t) in the context of this paper is defined for each investment planning period as

$$SW_t = \sum_{t\in\mathcal{T}} (\mathbb{E}[\pi_t^G] + \mathbb{E}[\pi_t^T] + \mathbb{E}[\pi_t^L] - \overline{C}_t^T) \tag{3}$$

If we reformulate the objective function (2a) by replacing the fixed fee with the regulatory constraint we obtain (Hesamzadeh et al 2018):

$$\sum_{t\in\mathcal{T}}(\mathbb{E}[\pi_t^T]+\Phi_t-\overline{C}_t^T)=\sum_{t\in\{\mathcal{T}\setminus t1\}}(\mathbb{E}[\pi_t^G]+\mathbb{E}[\pi_t^T]+\mathbb{E}[\pi_t^L]-\overline{C}_t^T)+\mathbb{E}[\pi_{t=t1}^T]+ \\ (|\mathcal{T}|-1)(\mathbb{E}[\pi_{t=t1}^G]+\mathbb{E}[\pi_{t=t1}^L]) \quad (4)$$

The reformulated objective function (4) shows that the regulated objective function of the Transco is equivalent to the social welfare objective (sum of generator, load and transmission surplus minus investment cost) at investment planning periods $t\in\{\mathcal{T}\setminus t1\}$. Transco does not perform investments in period $t1\in\mathcal{T}$ and the term $(|\mathcal{T}|-1)(\mathbb{E}[\pi_{t=t1}^G]+\mathbb{E}[\pi_{t=t1}^L])$ will not affect the investment results. Thus, the H-R-G-V mechanism promotes efficient cost allocation of the transmission investments and social maximizing investment decisions.
In (2) the ISO objective function is formulated as maximization of total generator, load and transmission surplus in the spot market. This maximization is equivalent to total load utility minus the total generation cost in the spot market. We assume perfect competition between generators and between loads. Thus, the mathematical formulation of regulated transmission investment with the H-R-G-V incentive mechanism can be presented in general terms as:

Maximize Merchandizing surplus + Fixed fee
- Total transmission investment cost (5a)
Subject to:
H-R-G-V regulatory constraint for each planning period (5b)
Linearized transmission investment constraints (5c)
Maximize (Total load utility - total generation cost) (5d)
Subject to: (5e)
Energy balance constraint (5f)
Power flow constraints (5g)
Upper and lower operation bounds (5h)

2.1 Nomenclature

Indices and Sets

$t, \widehat{t}\in\mathcal{T}$	Investment planning periods;
$k\in\mathcal{K}$	Operation sub-periods;
$n\in\mathcal{N}$	Buses ;
$i\in\mathcal{D}$	Demand;
$j\in\mathcal{G}$	Generation;
$w\in\mathcal{W}$	Wind generation;
$l\in\mathcal{L}$	Existing transmission lines;
$m\in\mathcal{M}$	Candidate transmission lines;
$s\in\mathcal{S}$	Wind power generation scenarios;

Parameters

$\Xi^{(m)}$	Disjunctive parameters used to linearize power flow constraints of candidate lines
$\Xi^{(T)}$	Disjunctive parameters used to linearize terms T1 and T2
$\overline{C}_{m,t}$	Investment cost of new line m (\$);
c_j	Marginal cost of generator j, (\$/MWh);
α_i	Intercept of linear utility i, (\$/MWh);
β	Expected annual price escalation rate;
γ	Expected periodic rate of return;
π_s	Probability of scenario s;
$I_{ni}^{(n)}$	Elements of incidence matrix I which shows the relation between set $\mathcal{N}$ and $\mathcal{D}$;
$J_{nj}^{(n)}$	Elements of incidence matrix J which shows the relation between set $\mathcal{N}$ and $\mathcal{G}$;
$W_{nw}^{(n)}$	Elements of incidence matrix W which shows the relation between set $\mathcal{N}$ and $\mathcal{W}$;
$S_{nl}^{(n)}, R_{nl}^{(n)}$	Elements of incident matrices S and $\overline{S}$ which shows the relation between set $\mathcal{N}$ and $\mathcal{L}$;
$R_{n,l}, \overline{R}_{n,m}$	Elements of incident matrices R and $\overline{R}$ which shows the relation between set $\mathcal{N}$ and $\mathcal{M}$;
F_l	Maximum capacity of line l, (MWh);
$\widehat{F}_m$	Maximum capacity of line m, (MWh);
X_l	Reactance of line l, ($p.u.$);
X_m	Reactance of line m, ($p.u.$);
G_j	Maximum production of generator j , (MWh);
$\widehat{G}_{wks}$	Maximum production of wind generator w in scenario s in operation sub-period k, (MWh);
D_{it}	Maximum demand i at planning period t, (MWh);
Θ	Voltage angle limits, ($p.u$);
Ψ	Number of operation sub-periods in one year;

Binary variables

z_{mt}, y_{mt}	Investment variables for line m at investment period t;

Continuous variables

d_{itks}	Consumption of demand i at investment period t, sub-period k and scenario s, (MWh);
g_{jtks}	Production of generator j at investment period t, sub-period k and scenario s, (MWh);
$\widehat{g}_{wtks}$	Production of wind generator w at investment period t, sub-period k and scenario s, (MWh);
f_{ltks}	Flow of line l at investment period t, sub-period k and scenario s, (MWh);
$\widehat{f}_{mtks}$	Flow of line m at investment period t, sub-period k and scenario s, (MWh);
θ_{ntks}	Voltage angle at bus n, investment period t, sub-period k and scenario s, ($p.u.$);
Φ_t	Fixed fee of Transco at investment period t, (\$);

2.2 The welfare-maximizing ISO

The ISO performs economic dispatch by maximizing the total load utility minus the generation cost given the available transmission lines. The power system consists of buses, which represent demand or generation or both. The buses are connected through existing (l) or newly built (m) transmission lines. Incident matrices $S, R, \overline{S}$ and $\overline{R}$ are used to link sending and receiving buses to existing and candidate lines. The elements of the matrices $S_{nl}^{(n)}, R_{nl}^{(n)}, \overline{R}_{nm}^{(n)}$ and $\overline{S}_{nm}^{(n)}$ will be equal to one if bus n is a sending or receiving bus for line l or m. By analogy incident matrices I, J and W with elements $I_{ni}^{(n)}, J_{nj}^{(n)}$ and $W_{nw}^{(n)}$ are used to map generators and loads to buses of the power system. The economic dispatch problem is presented by a linear optimization problem described in (6) that models the dispatch for a given investment planning period t, an operation sub-period k and a scenario realization s. The assumed scenarios are the result of fluctuating wind power generation which is modeled using a moment-matching scenario generation technique (see Appendix A.2). The detailed description of power system modeling approaches can be found in (Leuthold et al 2012).

The objective of the optimization problem (6) is to maximize the utility of demand minus the cost of generation. $\Omega_s = \{d_{itks}, g_{jtks}, \widehat{g}_{wtks}, f_{ltks}, \widehat{f}_{mtks}, \theta_{ntks}\}$ is the set of decision variables of (6).

$$\underset{\Omega_s}{Maximize} \sum_{i \in \mathcal{D}} \alpha_i d_{itks} - \sum_{j \in \mathcal{G}} c_j \; g_{jtks} \tag{6a}$$

$Subject\ to$:

$$\sum_{j \in \mathcal{G}} J_{nj}^{(n)} g_{jtks} + \sum_{w \in \mathcal{W}} W_{nw}^{(n)} \widehat{g}_{wtks} - \sum_{i \in \mathcal{D}} I_{ni}^{(n)} d_{itks} - \sum_{l \in \mathcal{L}} S_{nl}^{(n)} f_{ltks} + \sum_{l \in \mathcal{L}} R_{nl}^{(n)} f_{ltks} -$$

$$\sum_{m \in \mathcal{M}} \overline{S}_{nm}^{(n)} \widehat{f}_{mtks} + \sum_{m \in \mathcal{M}} \overline{R}_{nm}^{(n)} \widehat{f}_{mtks} = 0 \; {\scriptstyle \forall n \in \mathcal{N}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6b}$$

$$-\frac{100}{X_l}\left(\sum_{n \in \mathcal{N}} S_{nl}^{(n)} \theta_{ntks} - \sum_{n \in \mathcal{N}} R_{nl}^{(n)} \theta_{ntks}\right) + f_{ltks} = 0 \; {\scriptstyle \forall l \in \mathcal{L}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6c}$$

$$\begin{bmatrix} \widehat{f}_{mtks} = 0 \\ z_{mt} = 0 \end{bmatrix} \vee \begin{bmatrix} \widehat{f}_{mtks} - \frac{100}{X_m}\left(\sum_{n \in \mathcal{N}} \overline{S}_{nm}^{(n)} \theta_{ntks} - \sum_{n \in \mathcal{N}} \overline{R}_{nm}^{(n)} \theta_{ntks}\right) = 0 \\ z_{mt} = 1 \end{bmatrix}$$

$${\scriptstyle \forall m \in \mathcal{M}, t \in \mathcal{T}} \tag{6d}$$

$$-\widehat{F}_m \leq \widehat{f}_{mtks} \leq \widehat{F}_m \; {\scriptstyle \forall m \in \mathcal{M}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6e}$$

$$-F_l \leq f_{ltks} \leq F_l \; {\scriptstyle \forall l \in \mathcal{L}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6f}$$

$$0 \leq g_{jtks} \leq G_j \; {\scriptstyle \forall j \in \mathcal{G}, s \in \mathcal{S}, t \in \mathcal{T}, k} \tag{6g}$$

$$0 \leq \widehat{g}_{wtks} \leq \widehat{G}_{wks} \; {\scriptstyle \forall w \in \mathcal{W}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6h}$$

$$0 \leq d_{itks} \leq D_{it} \; {\scriptstyle \forall i \in \mathcal{D}, t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6i}$$

$$\theta_{n=n_1 tks} = 0 \; {\scriptstyle \forall t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S}} \tag{6j}$$

$$d_{itks}, g_{jtks}, \widehat{g}_{wtks}, f_{ltks}, \widehat{f}_{mtks}, \theta_{ntks} \in \mathbb{R} \tag{6k}$$

Following the general formulation in (5) the energy balance constraints (5f) at each bus are formulated in (6b). Power flows constraints (5g) are modeled as in (6c) for existing transmission lines and through disjunctive constraints (6d) for candidate lines. Integer variables z_{mt} in optimization problem (6) are considered to be parameters and are decision variables of the upper-level problem which will be discussed in the following subsection. Thermal limits of the lines are set in (6f) and (6e). Finally, upper and lower limits on generation, demand and voltage angles are enforced through (6g)-(**??**). The maximum demand is assumed to change for each investment planning period to reflect the growing trend of the demand over the years. The maximum wind generation is assumed to be a stochastic parameter and varies for each investment planning period t, operation sub-period k and scenario realization s. Constraint (6j) sets bus $n = n1$ as the reference bus.

2.3 The profit-maximizing Transco

The profit maximization model of the Transco is presented through the stochastic bilevel disjunctive program in (7) .

$$\underset{z_{mt},y_{mt},\Phi_t}{Maximize} \sum_{t\in\mathcal{T}} \frac{(1+\beta)^t}{(1+\gamma)^t} \langle \Phi_t + \Psi \sum_s \pi_s (\sum_{n,i,k} I^{(n)}_{ni} \lambda_{ntks} d_{itks} - \sum_{n,j,k} J^{(n)}_{nj} \lambda_{ntks} g_{jtks} - \sum_{n\in\mathcal{N},w\in\mathcal{W}} W^{(n)}_{nw} \lambda_{ntks} \widehat{g}_{wtks}) - \sum_{m\in\mathcal{M}} \overline{C}_{m,t} y_{mt} \rangle \tag{7a}$$

Subject to :

$$z_{m,t=t1} = 0 \ \forall m\in\mathcal{M} \tag{7b}$$

$$z_{mt} = \sum_{\widehat{t}\in\{t1,..t\}} y_{m,\widehat{t}} \ \forall m\in\mathcal{M}, t\in\mathcal{T} \tag{7c}$$

$$\sum_{t\in\mathcal{T}} y_{mt} \le 1 \ \forall m\in\mathcal{M}, t\in\mathcal{T} \tag{7d}$$

$$\Phi_{t=1} = 0 \tag{7e}$$

$$\mathbb{E}[\pi^L_t] = \sum_s \pi_s (\sum_{i,k} \alpha_i d_{itks} - \sum_{n,i,k} I^{(n)}_{ni} \lambda_{ntks} d_{itks}) \ \forall t\in\mathcal{T} \tag{7f}$$

$$\mathbb{E}[\pi^G_t] = \sum_s \pi_s (\sum_{n,j,k} (J^{(n)}_{nj} \lambda_{ntks} g_{jtks} - \sum_{j,k} c_j g_{jtks}) + \sum_{n,w,k} W^{(n)}_{nw} \lambda_{ntks} \widehat{g}_{wtks}) \ \forall t\in\mathcal{T} \tag{7g}$$

$$\Phi_t - \Phi_{t-1} = \Psi(\mathbb{E}[\pi^L_t] - \mathbb{E}[\pi^L_{s,t-1}] + \mathbb{E}[\pi^G_t] - \mathbb{E}[\pi^G_{s,t-1}]) \ \forall t\ge t2\in\mathcal{T} \tag{7h}$$

$$z_{mt} \in \{0,1\} \tag{7i}$$

$$Where\ \{d_{itks}, g_{jtks}, \widehat{g}_{wtks}, \lambda_{ntks}\} \in$$

$$\{\arg \underset{\Omega_s}{Maximize} \sum_{i\in\mathcal{D}} \alpha_i d_{itks} - \sum_{j\in\mathcal{G}} c_j\ g_{jtks} \tag{7j}$$

Subject to :

$$(6b) - (6k)\} \quad \forall t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{7k}$$

Optimization problem (7) simulates the bilevel program of the Transco under the H-R-G-V incentive mechanism. The optimization problem (6) is the lower-level program of the optimization problem (7). The objective of the Transco (7a) is to maximize its expected profit over the investment planning period (t). The expected revenue of the Transco is the expected merchandising surplus. The profit of the Transco is modeled as an expected value due to the stochasticity of wind generation and consequently the stochasticity of ISO economic dispatch. Each investment period (t) consists of operation sub-periods (k) which take into account representative hours of each year. In order to reflect the time value of the investment decision the total profit of the Transco for each investment planning period t is discounted using the present value factor calculated as $\frac{(1+\beta)^t}{(1+\gamma)^t}$. The present value factor is based on the expected rate of price escalation between investment periods β and the expected periodic rate of return γ. The parameter (ψ) is used to match short-term operation costs incurred in each operation sub-period k with long term investment costs incurred in each investment planning period t. For daily operation sub-periods ($\mathcal{K} = \{k1, ...k24\}$) and yearly investment periods, the parameter Ψ will be set to 365 while for hourly operation and yearly investment periods parameter Ψ will be set to 3870. The total Transco profit is the sum of the network merchandising surplus and a fixed fee to loads and generators (Φ_t) minus the investment costs ($\sum_{m\in\mathcal{M}} \overline{C}_{m,t} y_{mt}$). The fixed fee ($\Phi_t$) is set by the regulatory constraint (7h) which is modeled according to the formulation provided in (1). Generation surplus is calculated as a difference in generation revenue from operating in the spot market and generation operating costs as (7g). Similarly, demand surplus is calculated as a difference between the total benefit of consumption calculated using a linear utility function and the cost of energy purchased in the spot market. Generation surplus and demand surplus are affected by the stochastic nature of wind generation and thus should be included as expected values to consider different possible scenarios of economic dispatch. Earlier we have assumed that the first investment planning period $t1$ is a status quo period with neither investments nor a fixed fee. Thus, additional constraints are introduced to set the investment decision y_{mt} and Φ_t to zero at the initial investment planning period $t1$. We assume linear investment costs. The investment decision is taken through binary variable y_{mt} which is equal to 1 if an investment at period t is made and 0 otherwise. Constraint (7d) ensures that the decision to invest in line m is taken only once and it is irreversible. At the same time an additional variable z_{mt} is introduced to capture whether or not a candidate line m exists in any given planning period t. The variable z_{mt} is introduced to simplify the formulation of the bilevel problem and avoids the need to use $\sum_{t\in\mathcal{T}} y_{mt}$ in the lower-level program which may potentially complicate the solution process. The investment decision problem of the Transco as well as the regulatory constraint are subject to the solution of the lower-level programs which are modeled based on formulation (6). It represents the spot market clearance by the ISO in the considered power system. The lower-level program is a set of ISO economic dispatch models (6) which are solved simultaneously for each investment planning period t, operation sub-period k and scenario s.

The proposed transmission investment model is a stochastic bilevel disjunctive program. In the following section we present steps which will lead to an equivalent single-level stochastic MILP formulation with disjunctive constraints.

2.4 The linearization of disjunctive constraints (6d)

Disjunctive constraints can be linearized using a set of disjunctive parameters. This type of reformulation (also known as big-M technique) was well studied in (Lee and Grossmann 2000) and (Trespalacios and Grossmann 2015). The choice of disjunctive parameters is critical for linear reformulation of disjunctive constraints. The parameters should be chosen big enough that the original feasibility set does not change and not too big that the reformulated constraints are as tight as possible. If the disjunctive parameter is chosen carefully then the reformulated problem will be equivalent to the original one. Using this technique, the disjunctive constraints (6d) in the lower-level program of the Transco's problem (7) can be reformulated as linear constraints in (8).

$$\widehat{f}_{mtks} - \frac{100}{X_m}\Big(\sum_{n\in\mathcal{N}} \overline{S}^{(n)}_{nm}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}^{(n)}_{nm}\theta_{ntks}\Big) \leq$$
$$\Xi^{(m)}(1-z_{mt}) \ : (\overline{\sigma}_{mtks}) \ \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{8a}$$
$$\widehat{f}_{mtks} - \frac{100}{X_m}\Big(\sum_{n\in\mathcal{N}} \overline{S}^{(n)}_{nm}\theta_{ntks} - \sum_{n\in\mathcal{N}} \overline{R}^{(n)}_{nm}\theta_{ntks}\Big) \geq$$
$$-\,\Xi^{(m)}(1-z_{mt}) \ : (\underline{\sigma}_{mtks}) \ \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{8b}$$
$$-\,z_{mt}\Xi^{(m)} \leq \widehat{f}_{mtks} \leq z_{mt}\Xi^{(m)} : (\underline{\zeta}_{mtks}, \overline{\zeta}_{mtks}) \ \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{8c}$$

2.5 Reformulation using LP duality theorem

The optimization problem (7) after performing the reformulation described in subsection 2.4 becomes a bilevel mixed integer program. The lower-level problem is a linear program, for which LP duality theorem can be applied (Bertsekas 1999). Thus, the lower-level program can be equivalently described by its primal and dual lower level variables which satisfy primal and dual feasibility constraints and strong duality condition. The dual lower level feasibility constraints and strong duality conditions are derived in (9) and (10), respectively.

2.6 Nomenclature

Lagrange multiplier variables of (7)

λ_{ntks}	Price at bus n, investment period t, sub-period k and scenario s, ($\$/MWh$); sub-period k and scenario s, ($\$/p.u$);
$\overline{\mu}_{ltks}, \underline{\mu}_{ltks}$	Lagrange multipliers for line l upper and lower limit constraints (6f) at investment period t, sub-period k and scenario s, ($\$/MWh$);
σ_{ltks}	Lagrange multipliers for power flow constraints of line l constraints (6c) at investment period t, sub-period k and scenario s, ($\$/MWh$);

$\overline{\gamma}_{mtks}, \underline{\gamma}_{mtks}$	Lagrange multipliers for line m upper and lower limit constraints (6e) at investment period t, sub-period k and scenario s, ($\$/MWh$)
$\overline{\sigma}_{mtks}, \underline{\sigma}_{mtks}$	Lagrange multipliers for line m disjunctive relaxation constraints (8a)-(8b) at investment period t, sub-period k and scenario s, ($\$/MWh$)
$\overline{\zeta}_{mtks}, \underline{\zeta}_{mtks}$	Lagrange multipliers for line m disjunctive relaxation constraints (8c) at investment period t, sub-period k and scenario s, ($\$/MWh$);

2.6.1 Dual constraints

Dual constraints of the linear program (6) are derived as in (9).

$$\alpha_i - \sum_{n\in\mathcal{N}} I_{ni}^{(n)}\lambda_{ntks} + \underline{\omega}_{itks} - \overline{\omega}_{itks} = 0 \quad \forall i\in\mathcal{D}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{9a}$$

$$-c_j + \sum_{n\in\mathcal{N}} J_{nj}^{(n)}\lambda_{ntks} + \underline{\nu}_{jtks} - \overline{\nu}_{jtks} = 0 \quad \forall j\in\mathcal{G}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{9b}$$

$$\sum_{n\in\mathcal{N}} W_{nw}^{(n)}\lambda_{ntks} + \underline{\eta}_{wtks} - \overline{\eta}_{wtks} = 0 \quad \forall w\in\mathcal{W}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{9c}$$

$$-\sum_{n\in\mathcal{N}} S_{nl}^{(n)}\lambda_{ntks} + \sum_{n\in\mathcal{N}} R_{nl}^{(n)}\lambda_{ntks} + \sigma_{ltks} + \underline{\mu}_{ltks} - \overline{\mu}_{ltks} = 0 \quad \forall l\in\mathcal{L}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{9d}$$

$$-\sum_{n\in\mathcal{N}} \overline{S}_{nm}^{(n)}\lambda_{ntks} + \sum_{n\in\mathcal{N}} \overline{R}_{nm}^{(n)}\lambda_{ntks} + \underline{\sigma}_{mtks} - \overline{\sigma}_{mtks} + \underline{\gamma}_{mtks} - \overline{\gamma}_{mtks} +$$
$$\underline{\zeta}_{mtks} - \overline{\zeta}_{mtks} = 0 \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{9e}$$

$$-\frac{100}{X_l}\sum_{l\in\mathcal{L}} S_{nl}^{(n)}\sigma_{ltks} + \frac{100}{X_l}\sum_{l} R_{nl}^{(n)}\sigma_{ltks} + \xi_{tks} if(n = n1) -$$
$$\frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{S}_{nm}^{(n)}\underline{\sigma}_{mtks} + \frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{R}_{nm}^{(n)}\underline{\sigma}_{mtks} + \frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{S}_{nm}^{(n)}\overline{\sigma}_{mtks} -$$
$$\frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{R}_{nm}^{(n)}\overline{\sigma}_{mtks} = 0 \quad \forall n\in\mathcal{N}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{9f}$$

2.6.2 Strong duality condition

The strong duality condition of linear program (7) is formulated as in (10).

$$\sum_{i\in\mathcal{D}} \alpha_i d_{itks} - \sum_{j\in\mathcal{G}} c_j\ g_{jtks} = \sum_{t\in\mathcal{T}} \langle \sum_{i\in\mathcal{D}} D_{it}\overline{\omega}_{itks} + \sum_{j\in\mathcal{G}} G_j\overline{\nu}_{jtks} +$$
$$\sum_{l\in\mathcal{L}} F_l(\underline{\mu}_{ltks} + \overline{\mu}_{ltks}) + \sum_{m\in\mathcal{M}} \widehat{F}_m(\underline{\gamma}_{mtks} + \overline{\gamma}_{mtks}) +$$
$$\sum_{m\in\mathcal{M}} \underbrace{z_{mt}\varXi^{(m)}(\underline{\zeta}_{mtks} + \overline{\zeta}_{mtks})}_{T1} +$$

$$\sum_{m\in\mathcal{M}} \underbrace{\Xi^{(m)}(1-z_{mt})(\overline{\sigma}_{mtks}+\underline{\sigma}_{mtks})}_{T2}\rangle \;\; \forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{10}$$

Lemma 1 shows that terms T1 and T2 are zero at optimal solution.

Lemma 1 *If the disjunctive parameter $\Xi^{(m)}$ is tuned properly and optimization problem (6) is solved to optimality, then terms T1 and T2 in (10) are always equal to zero. Thus, we can reformulate the strong duality constraint as a combination of the strong duality constraint without terms T1 and T2 and the enforcing constraints T1=0 and T2=0, separately.*

Proof *For term T1, if $z_{mt}=0$ then $T1=0$. For the case where $z_{mt}=1$, since the disjunctive parameter $\Xi^{(m)}$ is tuned properly and we solve the problem to optimality, then the complimentary conditions are satisfied and constraints (8c) are not active. This, means $(\overline{\zeta}_{mtks}+\underline{\zeta}_{mtks})=0$ or $T1=0$. By analogy we can show that T2 is also always equal to zero when the KarushKuhnTucker (KKT) conditions are satisfied: i.e an optimal solution is reached.*
By ensuring constraints T1=0 and T2=0, we can drop T1 and T2 from (10) and rewrite the strong duality condition as:

$$\sum_{i\in\mathcal{D}}\alpha_i d_{itks}-\sum_{j\in\mathcal{G}}c_j\, g_{jtks}=$$
$$\sum_{t\in\mathcal{T}}\langle\sum_{i\in\mathcal{D}}D_{it}\overline{\omega}_{itks}+\sum_{j\in\mathcal{G}}G_j\overline{\nu}_{jtks}+\sum_{l\in\mathcal{L}}F_l(\underline{\mu}_{ltks}+\overline{\mu}_{ltks})+$$
$$\sum_{m\in\mathcal{M}}\widehat{F}_m(\underline{\gamma}_{mtks}+\overline{\gamma}_{mtks}) \;\; \forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{11a}$$
$$\sum_{m\in\mathcal{M}} z_{mt}\Xi^{(m)}(\underline{\zeta}_{mtks}+\overline{\zeta}_{mtks}) \;\; \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{11b}$$
$$\sum_{m\in\mathcal{M}} \Xi^{(m)}(1-z_{mt})(\overline{\sigma}_{mtks}+\underline{\sigma}_{mtks}) \;\; \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{11c}$$

The terms T1 and T2 in (11) are complicated terms due to their non-linear structure. Those terms can be linearized as in (12).

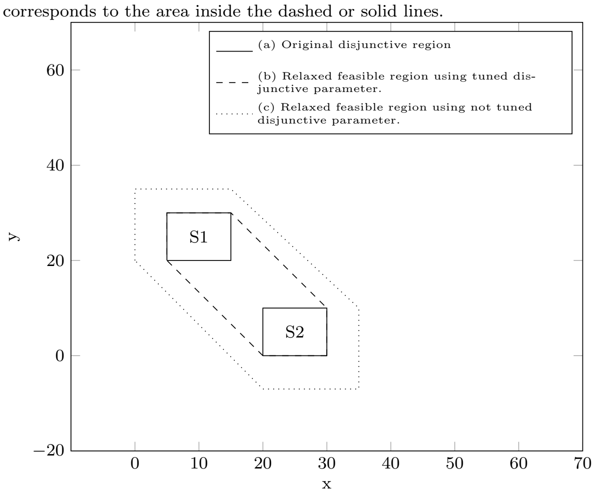
$$-\Xi^{(T)}(1-z_{mt})\le\overline{\sigma}_{mtks}+\underline{\sigma}_{mtks}\le\Xi^{(T)}(1-z_{mt}) \;\; \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{12a}$$
$$-\Xi^{(T)}z_{mt}\le\overline{\zeta}_{mtks}+\underline{\zeta}_{mtks}\le\Xi^{(T)}z_{mt} \;\; \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{12b}$$

2.6.3 The problem of tuning the disjunctive parameter

The disjunctive parameters $\Xi^{(m)}$ and $\Xi^{(T)}$ used in constraints (8) and (12) typically create some problems in the solution process (Hooker 2011) and (Trespalacios and Grossmann 2015).

First of all, a too large or a too small disjunctive parameter creates numerical errors and rounding errors for the optimizer. Thus, referring to constraints, the parameter $\Xi^{(m)}$ should be chosen small enough not to create numerical complications but big enough to guarantee that the constraints (8) are not binding when $z_{mt}=0$ and the original feasibility set does not change. Such disjunctive parameter can be found by analyzing the power flow limits of the candidate lines and voltage angle limits. However, when it comes to the second disjunctive parameter, $\Xi^{(T)}$, used in (12) the same methodology cannot be applied. Constraints in (12) contain Lagrange multipliers which do not have natural upper bounds (in case of non-negative Lagrange multipliers). Thus, it will be hard to guarantee the optimality of the tuned disjunctive parameter. Most of the existing methodologies designed to tune the disjunctive parameter focus on models with constraints similar to (8), which have a natural upper bound and thus can be tuned effectively. However, no methodology can guarantee the optimal choice of the disjunctive parameter for constraints without natural bounds as in (12).

Fig. 3 The impact of disjunctive parameter tuning on the relaxed feasible region. The region corresponds to the area inside the dashed or solid lines.



The impact of disjunctive parameter tuning on the relaxed feasible region is conceptually illustrated in Figure 3. The $S1$ and $S2$ are original feasible regions with disjunctive property (either $S1$ or $S2$ is the feasible region). Relaxed feasible regions using optimally tuned disjunctive parameters and the case when disjunctive parameters are not optimally tuned are demonstrated as region (b) and region (c), respectively. As we can see region (b) is a tighter relaxation.

2.7 Linearization

The bilinear terms $\lambda_{ntks}d_{itks}$, $\lambda_{ntks}g_{jtks}$ and $\lambda_{ntks}\widehat{g}_{wtks}$ in the Transco profit function and in the H-R-G-V regulatory constraint can be linearized as in (13) and (14).

$$\sum_{n\in\mathcal{N},i\in\mathcal{D}} I_{ni}^{(n)}\lambda_{ntks}d_{itks} - \sum_{n\in\mathcal{N},j\in\mathcal{G}} J_{nj}^{(n)}\lambda_{ntks}g_{jtks} - \sum_{n\in\mathcal{N},w\in\mathcal{W}} W_{nw}^{(n)}\lambda_{ntks}\widehat{g}_{wtks} =$$

$$\sum_{n\in\mathcal{N}}\lambda_{ntks}(\sum_{i\in\mathcal{D}}I_{ni}^{(n)}d_{itks}-\sum_{j\in\mathcal{G}}J_{nj}^{(n)}g_{jtks}-\sum_{w}W_{nw}^{(n)}\widehat{g}_{wtks})\overset{(6b)}{=}$$
$$\sum_{l\in\mathcal{L}}f_{ltks}(-\sum_{n\in\mathcal{N}}S_{nl}^{(n)}\lambda_{ntks}+\sum_{n\in\mathcal{N}}R_{nl}^{(n)}\lambda_{ntks})+\sum_{m\in\mathcal{M}}\widehat{f}_{mtks}(-\sum_{n\in\mathcal{N}}\overline{S}_{nm}^{(n)}\lambda_{ntks}+$$
$$\sum_{n}\overline{R}_{nm}^{(n)}\lambda_{ntks})\overset{(9d),(9e)}{=}\sum_{l\in\mathcal{L}}f_{ltks}(-\sigma_{ltks}-\underline{\mu}_{ltks}+\overline{\mu}_{ltks})+$$
$$\sum_{m\in\mathcal{M}}\widehat{f}_{mtks}(-\underline{\sigma}_{mtks}-+\overline{\sigma}_{mtks}-\underline{\gamma}_{mtks}+\overline{\gamma}_{mtks}-\underline{\zeta}_{mtks}+\overline{\zeta}_{mtks})\overset{(*)}{=}$$
$$\sum_{l\in\mathcal{L}}F_l(\overline{\mu}_{ltks}+\underline{\mu}_{ltks})+\sum_{m\in\mathcal{M}}\widehat{F}_m(\overline{\gamma}_{mtks}+\underline{\gamma}_{mtks})+T1+T2\overset{Lemma(1)}{=}$$
$$\sum_{l\in\mathcal{L}}F_l(\overline{\mu}_{ltks}+\underline{\mu}_{ltks})+\sum_{m\in\mathcal{M}}\widehat{F}_m(\overline{\gamma}_{mtks}+\underline{\gamma}_{mtks})\quad\forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}\tag{13}$$

Where $(*)$ comes from complementary slackness conditions for equations (6f), (6e) and (8a),(8b),(8c).

For bilinear terms in H-R-G-V regulatory constraint we have:

$$\langle\sum_{i\in\mathcal{D}}\alpha_i d_{itks}-\sum_{n\in\mathcal{N},i\in\mathcal{D}}I_{ni}^{(n)}\lambda_{ntks}d_{itks}\rangle+\langle\sum_{n\in\mathcal{N},j\in\mathcal{G}}J_{nj}^{(n)}\lambda_{ntks}g_{jtks}-\sum_{j\in\mathcal{G}}c_j g_{jtks}\rangle+$$
$$\sum_{w}W_{nw}^{(n)}\lambda_{ntks}\widehat{g}_{wtks}\overset{(9a)-(9c)}{=}\sum_{i\in\mathcal{D}}d_{itks}(\underline{\omega}_{itks}-\overline{\omega}_{itks})+$$
$$\sum_{j\in\mathcal{G}}g_{jtks}(\underline{\nu}_{jtks}-\overline{\nu}_{jtks})+\sum_{w}\widehat{g}_{wtks}(\underline{\eta}_{wtks}-\overline{\eta}_{wtks})\overset{(**)}{=}$$
$$\sum_{i\in\mathcal{D}}D_{it}\,\overline{\omega}_{itks}+\sum_{j\in\mathcal{G}}G_j\overline{\nu}_{jtks}+\sum_{w}\widehat{G}_{wks}\overline{\eta}_{wtks}\quad\forall t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S}\tag{14}$$

Where $(**)$ results from complementary slackness conditions for (6g),(6h) and (6i).

2.8 The reformulated stochastic MILP with linearized disjunctive constraints

The resulting model after performed linearizations and reformulations is presented in (15).

$$\underset{z_{mt},y_{mt},\Omega_p}{Maximize}:\sum_{t\in\mathcal{T}}\frac{(1+\beta)^t}{(1+\gamma)^t}\langle\sum_{s}\pi_s\psi(\sum_{l,k}F_l(\overline{\mu}_{ltks}+\underline{\mu}_{ltks})+\sum_{m,k}\widehat{F}_m(\overline{\mu}_{ltks}+\underline{\mu}_{ltks})+$$
$$\Phi_t-\sum_{m\in\mathcal{M}}\overline{C}_{m,t}y_{mt}\rangle\tag{15a}$$

$Subject\ to:$

$$(7b)-(7e)\tag{15b}$$

$$\Phi_t-\Psi\sum_{s}\pi_s(\sum_{i,k}D_{it}\overline{\omega}_{itks}+\sum_{j,k}G_j\overline{\nu}_{jtks}+\sum_{w,k}\widehat{G}_{wks}\overline{\eta}_{wtks})=$$

$$\Phi_{t-1} - \Psi \sum_{s} \pi_s (\sum_{i,k} D_{it-1}\, \overline{\omega}_{it-1ks} + \sum_{j,k} G_j \overline{\nu}_{jt-1ks} + \sum_{w,k} \widehat{G}_{wks} \overline{\eta}_{wt-1ks}) \;\; \forall t \in \{\mathcal{T} \setminus t1\} \tag{15c}$$

$$(6b) - (6f),\ (8a) - (8c),\ (6e) - (6k),\ (9a) - (9f),\ (12a) - (12b) \tag{15d}$$

$$\sum_{i \in \mathcal{D}} D_{it} \overline{\omega}_{itks} + \sum_{j \in \mathcal{G}} G_j \overline{\nu}_{jtks} + \sum_{l \in \mathcal{L}} F_l (\overline{\mu}_{ltks} + \underline{\mu}_{ltks}) +$$
$$\sum_{m} \widehat{f}_{mtks} (\overline{\gamma}_{mtks} + \underline{\gamma}_{mtks}) + \sum_{w} \widehat{G}_{wks} \overline{\eta}_{wtks} =$$
$$\sum_{i \in \mathcal{D}} \alpha_i d_{itks} - \sum_{j \in \mathcal{G}} c_j g_{jtks} \;\; \forall t \in \mathcal{T}, k \in \mathcal{K}, s \in \mathcal{S} \tag{15e}$$

$$\overline{\omega}_{itks}, \underline{\omega}_{itks}, \overline{\nu}_{jtks}, \underline{\nu}_{jtks}, \overline{\eta}_{wtks}, \underline{\eta}_{wtks}, \overline{\mu}_{ltks}, \underline{\mu}_{ltks}, \sigma_{ltks}, \Phi_t, \overline{\gamma}_{mtks}, \underline{\gamma}_{mtks}, \overline{\sigma}_{mtks},$$
$$\underline{\sigma}_{mtks}, \overline{\zeta}_{mtks}, \underline{\zeta}_{mtks} \geq 0 \tag{15f}$$

$$z_{mt}, y_{mt} \in \{0, 1\} \tag{15g}$$

Here $\Omega_p = \Omega_s \cup \{\Phi_t,\ f_{ltks},\ \widehat{f}_{mtks},\ \theta_{ntks}\ ,\ d_{itks},\ g_{jtks},\ \widehat{g}_{wtks},\ \overline{\omega}_{itks},\ \underline{\omega}_{itks},\ \overline{\nu}_{jtks},\ \underline{\nu}_{jtks},\ \overline{\eta}_{wtks},\ \underline{\eta}_{wtks},\ \overline{\mu}_{ltks},\ \underline{\mu}_{ltks},\ \sigma_{ltks},\ \overline{\gamma}_{mtks},\ \underline{\gamma}_{mtks},\ \overline{\sigma}_{mtks},\ \underline{\sigma}_{mtks},\ \overline{\zeta}_{mtks},\ \underline{\zeta}_{mtks}\}$ is the set of decision variables of optimization problem (15).

3 The proposed decomposition algorithm

The stochastic MILP model (15) has a special decomposing structure. Such structure allows us to decompose the problem into a number of independent optimization problems by separating the variables into two vectors. The first vector consists of continuous variables and the second one consist of integer variables. One of the decomposition algorithms for such types of problems is the Benders decomposition algorithm (Lumbreras and Ramos 2013). However, the Benders decomposition algorithm might be ineffective for disjunctive programs, especially when variables in the disjunctive constraint do not have natural upper bounds and the disjunctive parameter cannot be tuned optimally. When the disjunctive parameter is not optimal, the Benders cuts are proved to be weak and the convergence of the Benders decomposition algorithm cannot be guaranteed (Hooker 2011). This is the case for our proposed stochastic MILP model (15). Thus, we propose a specialized decomposition algorithm based on the Bean decomposition algorithm proposed in (Bean et al 1992). In (Bean et al 1992), the authors propose the cuts which are identical to Benders cuts, however, they allow one to eliminate the disjunctive parameter by exploiting the properties of the extreme points. Moreover Bean's cuts are especially applicable for the problems with similar decomposable properties as the proposed problem (15): i.e. for problems that can be decomposed over integer variables which appear in bilinear terms and were linearized using the big-M reformulation. Also, the master problem formulated using Bean's cuts has similar properties as sets partitioning problems and it further improves the tractability of the solution.

The Bean decomposition algorithm is an iterative solution algorithm and has two separate steps at each iteration. First, duality theory is used to determine upper bounds through fixing complicating integer variables (assuming a minimization program). The second step is to find a lower bound by solving the relaxed problem. The iteration between upper- and lower-bound programs is performed until the upper and lower bounds are close enough and the optimal solution is found. The special structure of the Bean decomposition algorithm allows one to create a tighter lower bound and a computationally more tractable master problem.

3.1 Nomenclature

To present the Bean decomposition algorithm the followings are defined.

Indices and Sets	
$a,\ a' \in \mathcal{A}$	Bean decomposition iterations;
$\Omega^{(1)}_{sa},\ \Omega^{(2)}_{sa}$	Sets of extreme points;
Binary variables	
u_a, u_0	Auxiliary variables;
Parameters	
K_a	Optimal objective value of subproblem;
L_a	Upper-bound constant for a step size;
Υ_a	A penalty factor;
H	Suitably large constants;
$\widehat{z}^a_{mt}, \widehat{y}^a_{mt}$	Fixed investment decisions of line m at period t;
Variables of the subproblem	
$\widehat{\lambda}^{(9a)}_{itks}$	Lagrange multipliers for dual constraints(9a),(MWh);
$\widehat{\lambda}^{(9b)}_{jtks}$	Lagrange multipliers for dual constraints(9b),(MWh);
$\widehat{\lambda}^{(9c)}_{wtks}$	Lagrange multipliers for dual constraints (9c), (MWh);
$\widehat{\lambda}^{(9d)}_{ltks}$	Lagrange multipliers for dual constraints (9d), (MWh);
$\widehat{\lambda}^{(9e)}_{mtks}$	Lagrange multipliers for dual constraints (9e), (MWh);
$\widehat{\lambda}^{(9f)}_{ntks}$	Lagrange multipliers for dual constraints (9f), ($p.u$);
$\widehat{\lambda}^{(15e)}_{tks}$	Lagrange multipliers for strong duality conditions (15e);
$\widehat{\lambda}^{(15c)}_{t}$	Lagrange multipliers for regulatory constraint (15c);
$\widehat{\lambda}_{ntks}$	Lagrange multipliers for energy balance constraints (6b) at bus n in period t,k for scenario s, ($\$/MWh$);
$\overline{\mu}^{(6f)}_{ltks}, \underline{\mu}^{(6f)}_{ltks}$	Lagrange multipliers for line l upper and lower limit constraints (6f), ($\$/MWh$);
$\sigma^{(6c)}_{ltks}$	Lagrange multipliers for power flow constraints of line l constraints (6c), ($\$/MWh$);
$\overline{\gamma}^{(6e)}_{mtks}, \underline{\gamma}^{(6e)}_{mtks}$	Lagrange multipliers for line m upper and lower limit constraints (6e), ($\$/MWh$)
$\overline{\sigma}^{(8a)}_{mtks}, \underline{\sigma}^{(8b)}_{mtks}$	Lagrange multipliers for line m disjunctive relaxation constraints (8a)-(8b), ($\$/MWh$)

$\overline{\zeta}_{mtks}^{(8c)}, \underline{\zeta}_{mtks}^{(8c)}$	Lagrange multipliers for line m disjunctive relaxation constraints (8c), ($\$/MWh$);
$\underline{\vartheta}_{mtks}^{(12a)}, \overline{\vartheta}_{mtks}^{(12a)}$	Lagrange multipliers for T1 and T2 linearization constraints (12a), (MWh);
$\underline{\kappa}_{mtks}^{(12b)}, \overline{\kappa}_{mtks}^{(12b)}$	Lagrange multipliers for T1 and T2 linearization constraints (12b), (MWh);

3.2 The Bean decomposition algorithm

The Bean decomposition algorithm includes a master problem and a sub-problem and can be applied to two-stage stochastic programs with disjunctive constraints. The stochastic master problem is formulated as in (16) while a stochastic sub-problem is formulated as in (17). The sets $\Omega_{sa}^{(1)}$ and $\Omega_{sa}^{(2)}$ represent index sets of extreme points and correspond to Lagrange multipliers of disjunctive constraints (8) and (12). The set $\Omega_{sa}^{(1)}$ corresponds to extreme points of constraints (8a),(8b) and (12a) while the set $\Omega_{sa}^{(2)}$ corresponds to extreme points of constraints (8c) and (12b). The Bean decomposition algorithm iteratevely solves master problem and sub-problem. At each iteration the master problem is updated with additional feasibility cut. Iterations are indexed using $a \in \mathcal{A}$. The set $\mathcal{A}$ becomes larger after each iteration if the algorithm does not satisfy the stopping criterion.

The master problem of the standard Bean decomposition algorithm is formulated as in (16).

$$\underset{u_a, z_{mt}, y_{mt}}{Maximize} \sum_{a \in \mathcal{A}} K_a u_a + H u_0 \tag{16a}$$

$$Subject\ to\ :$$

$$\sum_{mts \in \Omega_{sa}^{(1)}} z_{mt} + \sum_{mts \in \Omega_{sa}^{(2)}} (1 - z_{mt}) \leq |\Omega_{sa}^{(1)}| + |\Omega_{sa}^{(2)}| - 1 + \sum_{a' if (K_{a'} \geq K_a)} u_{a'} \ {\scriptstyle \forall a \in \mathcal{A}} \tag{16b}$$

$$\sum_{a} u_a = 1 \tag{16c}$$

$$z_{mt} = \sum_{\widehat{t} \in \{t1, .. t\}} y_{m\widehat{t}} \ {\scriptstyle \forall m \in \mathcal{M}, t \in \mathcal{T}} \tag{16d}$$

$$\sum_{t \in \mathcal{T}} y_{mt} \leq 1 \ \ {\scriptstyle \forall m \in \mathcal{M}} \tag{16e}$$

$$z_{mt}, y_{mt} \in \{0, 1\} \tag{16f}$$

The master problem (16) is a stochastic mixed-integer linear program with sets partitioning characteristics. All the constraints of the master problem contain only binary variables. Variables u_a are introduced for each iteration of the decomposition algorithm and are used to activate the decomposition cuts corresponding to the solution of the sub-problem. Variables z_{mt} and y_{mt} are the transmission investment variables. Variable u_0 is an auxiliary variable used to prevent the formulation to be unbounded from above. The objective function of the master problem consists of the objective function values of the sub-problems K_a at each iteration multiplied by the corresponding auxiliary variables u_a. The objective function also includes auxiliary variable u_0 multiplied by a large enough parameter H which sets the upper boundary for the master problem and this prevents the master problem from being unbounded. Feasibility cuts based on Bean's cuts are introduced in (16b) and they are based on extreme point sets of the subproblems. The extreme point sets are used to determine whether to include integer variables z_{mt} or not. The cut is activated using auxiliary variables u_a. The cuts in (16b) are equivalent to Benders cuts with optimal disjunctive parameter but the cuts in (16b) do not contain any disjunctive parameter in the formulation (Bean 1992). An additional constraint is introduced in (16c) to ensure that only one cut is activated at each iteration. The rest of constraints (16d)-(16f) are introduced to ensure that the solution of the master problem satisfies line investment constraints (7b)-(7d). Once the master problem is solved, the solution of the investment decision variables z_{mt} and y_{mt} are used to formulate the sub-problem

In order to formulate the sub-problem of the standard Bean decomposition algorithm, we first fix line investment decision variables z_{mt} and y_{mt} in problem (15) and treat them as constants. The investment decision parameters used in the sub-problem are modeled through $\widehat{z}^a_{mt}$ and $\widehat{y}^a_{mt}$. Once the integer variables are fixed and treated as parameters the problem (15) becomes a linear program. The sub-problem is the dual of the optimization problem (15a),(15c)-(15g) where investment decisions are fixed to the values obtained from master problem. The sub-problem of the standard Bean decomposition algorithm is formulated as in (17).

$$\begin{aligned} \underset{\Omega^d_p}{Minimize} : & \sum_{t\in\mathcal{T}} \langle \sum_{i\in\mathcal{D}} D_{it}\overline{\omega}^{(6i)}_{itks} + \sum_{l\in\mathcal{L}} F_l(\overline{\mu}^{(6f)}_{ltks} + \underline{\mu}^{(6f)}_{ltks}) + \sum_{j\in\mathcal{G}} G_j \overline{\nu}^{(6g)}_{jtks} + \\ & \sum_{m\in\mathcal{M}} \widehat{F}_m(\overline{\gamma}^{(6e)}_{mtks} + \underline{\gamma}^{(6e)}_{mtks}) + \sum_{w} \widehat{G}_{wks}\overline{\eta}^{(6h)}_{wtks} + \\ & \alpha_i \widehat{\lambda}^{(9a)}_{itks} - c_j \widehat{\lambda}^{(9b)}_{jtks} + \sum_{m\in\mathcal{M}} \underbrace{\widehat{z}^a_{mt}\Xi^{(m)}(\overline{\sigma}^{(8a)}_{mtks} + \underline{\sigma}^{(8b)}_{mtks})}_{T5} + \\ & \sum_{m\in\mathcal{M}} \underbrace{(1-\widehat{z}^a_{mt})\Xi^{(m)}(\overline{\zeta}^{(8c)}_{mtks} + \underline{\zeta}^{(8c)}_{mtks})}_{T6} + \sum_{m\in\mathcal{M}} \underbrace{\Xi^{(T)}\widehat{z}^a_{mt}(\overline{\vartheta}^{(12a)}_{mtks} + \underline{\vartheta}^{(12a)}_{mtks})}_{T7} + \\ & \sum_{m\in\mathcal{M}} \underbrace{\Xi^{(T)}(1-\widehat{z}^a_{mt})(\overline{\kappa}^{(12b)}_{mtks} + \underline{\kappa}^{(12b)}_{mtks})}_{T8} \rangle \end{aligned} \tag{17a}$$

Subject to :

$$\alpha_i \widehat{\lambda}^{(15e)}_{tks} - \sum_{n\in\mathcal{N}} I^{(n)}_{ni}\widehat{\lambda}_{ntks} + \underline{\omega}^{(6i)}_{itks} - \overline{\omega}^{(6i)}_{itks} = 0 \quad \forall i\in\mathcal{D}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17b}$$

$$-c_j \widehat{\lambda}^{(15e)}_{tks} + \sum_{n\in\mathcal{N}} J^{(n)}_{nj}\widehat{\lambda}_{ntks} + \underline{\nu}^{(6g)}_{jtks} - \overline{\nu}^{(6g)}_{jtks} = 0 \quad \forall j\in\mathcal{G}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17c}$$

$$\sum_{n\in\mathcal{N}} W^{(n)}_{nw}\widehat{\lambda}_{ntks} + \underline{\eta}^{(6h)}_{wtks} - \overline{\eta}^{(6h)}_{wtks} = 0 \quad \forall w\in\mathcal{W}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17d}$$

$$\sum_{n\in\mathcal{N}} R^{(n)}_{nl}\widehat{\lambda}_{ntks} - \sum_{n\in\mathcal{N}} S^{(n)}_{nl}\widehat{\lambda}_{ntks} + \sigma^{(6c)}_{ltks} + \underline{\mu}^{(6f)}_{ltks} - \overline{\mu}^{(6f)}_{ltks} = 0 \quad \forall l\in\mathcal{L}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17e}$$

$$\sum_{n\in\mathcal{N}} \overline{R}^{(n)}_{nm}\widehat{\lambda}_{ntks} - \sum_{n\in\mathcal{N}} \overline{S}^{(n)}_{nm}\widehat{\lambda}_{ntks} + \underline{\gamma}^{(6e)}_{mtks} - \overline{\gamma}^{(6e)}_{mtks} + \underline{\sigma}_{mtks} - \overline{\sigma}^{(8a)}_{mtks} + \underline{\zeta}^{(8c)}_{mtks} -$$

$$\overline{\zeta}^{(8c)}_{mtks} = 0 \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17f}$$

$$-\frac{100}{X_l}\sum_{l\in\mathcal{L}} S^{(n)}_{nl}\sigma^{(6c)}_{ltks} + \frac{100}{X_l}\sum_{l\in\mathcal{L}} R^{(n)}_{nl}\sigma^{(6c)}_{ltks} + \xi^{(6j)}_{ntks} if(n=n1) -$$

$$\frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{S}^{(n)}_{nm}\underline{\sigma}^{(8b)}_{mtks} + \frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{R}^{(n)}_{nm}\underline{\sigma}^{(8b)}_{mtks} + \frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{S}^{(n)}_{nm}\overline{\sigma}^{(8a)}_{mtks}$$

$$-\frac{100}{X_m}\sum_{m\in\mathcal{M}} \overline{R}^{(n)}_{nm}\overline{\sigma}^{(8a)}_{mtks} = 0 \quad \forall n\in\mathcal{N}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17g}$$

$$\frac{(1+\beta)^t}{(1+\gamma)^t} + \widehat{\lambda}^{(15c)}_t - \widehat{\lambda}^{(15d)}_{t+1} = 0 \forall t\in\mathcal{T} \tag{17h}$$

$$-\sum_{i\in\mathcal{D}} I^{(n)}_{ni}\widehat{\lambda}^{(9a)}_{itks} + \sum_{j\in\mathcal{G}} J^{(n)}_{nj}\widehat{\lambda}^{(9b)}_{jtks} + \sum_{w} W^{(n)}_{nw}\widehat{\lambda}^{(9c)}_{wtks} - \sum_{l\in\mathcal{L}} S^{(n)}_{nl}\widehat{\lambda}^{(9d)}_{ltks} +$$

$$\sum_{l\in\mathcal{L}} R^{(n)}_{nl}\widehat{\lambda}^{(9d)}_{ltks} - \sum_{m\in\mathcal{M}} \overline{R}^{(n)}_{nm}\widehat{\lambda}^{(9e)}_{mtks} + \sum_{m\in\mathcal{M}} \overline{R}^{(n)}_{nm}\widehat{\lambda}^{(9e)}_{mtks} = 0 \forall n\in\mathcal{N}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17i}$$

$$\widehat{\lambda}^{(9a)}_{itks} \le 0 \quad \forall i\in\mathcal{D}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17j}$$

$$-D_{it}\widehat{\lambda}^{(15e)}_{tks} - \Psi\pi_s(D_{it}\widehat{\lambda}^{(15c)}_t + D_{it-1}\widehat{\lambda}^{(15d)}_{t+1}) - \widehat{\lambda}^{(9a)}_{itks} \le 0 \quad \forall i\in\mathcal{D}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17k}$$

$$\widehat{\lambda}^{(9b)}_{jtks} \le 0 \forall j\in\mathcal{G}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17l}$$

$$-G_j\widehat{\lambda}^{(15e)}_{tks} - \Psi\pi_s(G_j\widehat{\lambda}^{(15c)}_t + G_j\widehat{\lambda}^{(15d)}_{t+1}) - \widehat{\lambda}^{(9b)}_{jtks} \le 0 \ \forall j\in\mathcal{G}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17m}$$

$$\widehat{\lambda}^{(9c)}_{wtks} \le 0 \quad \forall w\in\mathcal{W}, t, k, s \tag{17n}$$

$$-\widehat{G}_{wks}\widehat{\lambda}^{(15e)}_{tks} - \Psi\pi_s(\widehat{G}_{wks}\widehat{\lambda}^{(15c)}_t + \widehat{G}_{wks}\widehat{\lambda}^{(15d)}_{t+1}) - \widehat{\lambda}^{(9c)}_{wtks} \le 0 \quad \forall w\in\mathcal{W}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17o}$$

$$\widehat{\lambda}^{(9d)}_{ltks} - \frac{100}{X_l}\sum_{n\in\mathcal{N}} S^{(n)}_{nl}\widehat{\lambda}^{(9f)}_{ntks} + \frac{100}{X_l}\sum_{n\in\mathcal{N}} R^{(n)}_{nl}\widehat{\lambda}^{(9f)}_{ntks} = 0 \quad \forall l\in\mathcal{L}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17p}$$

$$\frac{(1+\beta)^t}{(1+\gamma)^t}\pi_s\Psi F_l - F_l\widehat{\lambda}^{(15e)}_{tks} + \widehat{\lambda}^{(9d)}_{ltks} \le 0 \quad \forall l\in\mathcal{L}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17q}$$

$$\frac{(1+\beta)^t}{(1+\gamma)^t}\pi_s\Psi F_l - F_l\widehat{\lambda}^{(15e)}_{tks} - \widehat{\lambda}^{(9d)}_{ltks} \le 0 \quad \forall l\in\mathcal{L}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17r}$$

$$\frac{(1+\beta)^t}{(1+\gamma)^t}\pi_s\Psi \widehat{F}_m - \widehat{F}_m\widehat{\lambda}^{(15e)}_{tks} + \widehat{\lambda}^{(9e)}_{mtks} \le 0 \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17s}$$

$$\frac{(1+\beta)^t}{(1+\gamma)^t}\pi_s\Psi \widehat{F}_m - \widehat{F}_m\widehat{\lambda}^{(15e)}_{tks} - \widehat{\lambda}^{(9e)}_{mtks} \le 0 \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17t}$$

$$\widehat{\lambda}^{(9e)}_{mtks} + \underline{\vartheta}^{(12a)}_{mtks} - \overline{\vartheta}^{(12a)}_{mtks} - \frac{100}{X_m}\sum_{n\in\mathcal{N}} \overline{S}^{(n)}_{nm}\widehat{\lambda}^{(9f)}_{ntks} +$$

$$\frac{100}{X_m}\sum_{n\in\mathcal{N}} \overline{R}^{(n)}_{nm}\widehat{\lambda}^{(9f)}_{ntks} \le 0 \quad \forall m\in\mathcal{M}, t\in\mathcal{T}, k\in\mathcal{K}, s\in\mathcal{S} \tag{17u}$$

$$-\widehat{\lambda}^{(9e)}_{mtks} + \underline{\vartheta}^{(12a)}_{mtks} - \overline{\vartheta}^{(12a)}_{mtks} + \frac{100}{X_m}\sum_{n\in\mathcal{N}} \overline{S}^{(n)}_{nm}\widehat{\lambda}^{(9f)}_{ntks} -$$

$$\frac{100}{X_m}\sum_{n\in\mathcal{N}}\overline{R}^{(n)}_{nm}\widehat{\lambda}^{(9f)}_{ntks}\leq 0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{17v}$$

$$\widehat{\lambda}^{(9e)}_{mtks}+\underline{\kappa}^{(12b)}_{mtks}-\overline{\kappa}^{(12b)}_{mtks}\leq 0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{17w}$$

$$-\widehat{\lambda}^{(9e)}_{mtks}+\underline{\kappa}^{(12b)}_{mtks}-\overline{\kappa}^{(12b)}_{mtks}\leq 0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{17x}$$

$$\widehat{\lambda}^{(9f)}_{ntks}=0 \quad \forall n\in\mathcal{N},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{17y}$$

$$\overline{\mu}^{(6f)}_{ltks},\underline{\mu}^{(6f)}_{ltks},\overline{\gamma}^{(6e)}_{mtks},\underline{\gamma}^{(6e)}_{mtks},\overline{\sigma}^{(8a)}_{mtks},\underline{\sigma}^{(8b)}_{mtks},\overline{\zeta}^{(8c)}_{mtks},\underline{\zeta}^{(8c)}_{mtks}\underline{\vartheta}^{(12a)}_{mtks},\overline{\vartheta}^{(12a)}_{mtks},$$
$$\underline{\kappa}^{(12b)}_{mtks},\overline{\kappa}^{(12b)}_{mtks}\geq 0 \tag{17z}$$

Where $\Omega^d_p=\{\widehat{\lambda}^{(9a)}_{itks},\ \widehat{\lambda}^{(9b)}_{jtks},\ \widehat{\lambda}^{(9c)}_{wtks},\ \widehat{\lambda}^{(9d)}_{ltks},\ \widehat{\lambda}^{(9e)}_{mtks},\ \widehat{\lambda}^{(9f)}_{ntks},\ \widehat{\lambda}^{(15e)}_{tks},\ \widehat{\lambda}^{(15c)}_{t},\ \widehat{\lambda}_{ntks},\ \overline{\mu}^{(6f)}_{ltks},\ \underline{\mu}^{(6f)}_{ltks},\ \overline{\gamma}^{(6e)}_{mtks},\ \underline{\gamma}^{(6e)}_{mtks},\ \overline{\sigma}^{(8a)}_{mtks},\ \underline{\sigma}^{(8b)}_{mtks},\ \overline{\zeta}^{(8c)}_{mtks},\ \underline{\zeta}^{(8c)}_{mtks},\ \underline{\vartheta}^{(12a)}_{mtks},\ \overline{\vartheta}^{(12a)}_{mtks},\ \underline{\kappa}^{(12b)}_{mtks},\ \overline{\kappa}^{(12b)}_{mtks}\}$ is the set of decision variables of the problem (17).

4 Modification and acceleration

The sub-problem (17) contains the disjunctive parameters. These disjunctive parameters are the terms $T5$ to $T8$ of the sub-problem. However, using Lemma 2 one can show that these terms will be equal to zero at the optimal solution.

Lemma 2 *If problem (17) is solved to optimality and disjunctive parameters are chosen optimally, then terms T5 to T8 in (17a) are always equal to zero. Thus, we can reformulate the objective function as a combination of the objective function without terms T5 to T8 as in (18a) and with additional constraints (18c)-(18f) which ensure that T5 to T8 are equal to zero*

Proof The proof is by analogy to Lemma 1. Terms T5 to T8 in dual problem (17) correspond to complementary slackness conditions of the primal problem (15a),(15c)-(15g). If the optimal solution is reached then the complementary slackness conditions are satisfied and T5=0, T6=0, T7=0 and T8=0

Therefore, the sub-problem (17) can be reformulated as (18) without any disjunctive parameter.

$$\begin{aligned}\underset{\Omega^d_p}{Minimize}\sum_{t\in\mathcal{T}}\langle\sum_{i\in\mathcal{D}}D_{it}\overline{\omega}^{(6i)}_{itks}+\sum_{j\in\mathcal{G}}G_j\overline{\nu}^{(6g)}_{jtks}+\sum_{w}\widehat{G}_{wks}\overline{\eta}^{(6h)}_{wtks}+\\ \sum_{l\in\mathcal{L}}F_l(\overline{\mu}^{(6f)}_{ltks}+\underline{\mu}^{(6f)}_{ltks})+\sum_{m\in\mathcal{M}}\widehat{F}_m(\overline{\gamma}^{(6e)}_{mtks}+\underline{\gamma}^{(6e)}_{mtks})+\\ +\alpha_i\widehat{\lambda}^{(9a)}_{itks}-c_j\widehat{\lambda}^{(9b)}_{jtks}\end{aligned} \tag{18a}$$

$$(17b)-(17z) \tag{18b}$$

$$\widehat{z}^a_{mt}(\overline{\sigma}^{(8a)}_{mtks}+\underline{\sigma}^{(8b)}_{mtks})=0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{18c}$$

$$\widehat{z}^a_{mt}(\overline{\vartheta}^{(12a)}_{mtks}+\underline{\vartheta}^{(12a)}_{mtks})=0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{18d}$$

$$(1-\widehat{z}^a_{mt})(\overline{\zeta}^{(8c)}_{mtks}+\underline{\zeta}^{(8c)}_{mtks})=0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{18e}$$

$$(1-\widehat{z}^a_{mt})(\overline{\kappa}^{(12b)}_{mtks}+\underline{\kappa}^{(12b)}_{mtks})=0 \quad \forall m\in\mathcal{M},t\in\mathcal{T},k\in\mathcal{K},s\in\mathcal{S} \tag{18f}$$

The Bean master problem (16) is formulated such that each feasibility cut takes into account all scenarios. In order to create tighter cuts we can reformulate the master problem (16) and replace the feasibility cut (16b) with feasibility cuts for each scenario separately as it is shown in (19). The convergence improvement is shown in (Santoso et al 2005).

$$\sum_{mt\in\Omega_{sa}^{(1)}} z_{mt} + \sum_{mt\in\Omega_{sa}^{(2)}} (1-z_{mt}) \leq |\Omega_{sa}^{(1)}| + |\Omega_{sa}^{(2)}| - 1 + \sum_{a'\, if(K_{a'}\geq K_a)} u_{a'} \ \forall a\in\mathcal{A}, s\in\mathcal{S} \tag{19}$$

Furthermore, authors in (Santoso et al 2005) propose a technique to strengthen Benders cuts. We apply a similar procedure to the Bean decomposition algorithm which results in the additional constraint (20) in the master problem formulation (16)

$$\sum_{mt\ \ if(\widehat{z}_{mt}^a=1)} (1-z_{mt}) + \sum_{mt\ \ if(\widehat{z}_{mt}^a=0)} z_{mt} \leq L_a \ \forall a\in\mathcal{A} \tag{20}$$

The intuition behind (20) is based on the need to prevent wide steps between different iterations of the master problem. At the initial iterations of the decomposition algorithm, the solution space of the master problem is vast which means at each iteration the master problem may provide a solution that is very different from the previous iteration solution. By introducing constraint (20), we can prevent the solution from changing too much between different itarations and thereby reduce the necessary number of iterations. The constraint (20) improves the convergence of the Bean decomposition algorithm. However, the parameter L_a depends on the starting point and on the iteration number, and it is hard to identify. The parameter L_a should be manually tuned for each case study. We propose to penalize large steps at each iteration in objective function using a penalty factor Υ_a. The resulting modified Bean master problem is shown in (21).

$$\underset{u_a, z_{mt}, y_{mt}}{Maximize} \sum_a K_a u_a + Hu_0 - \Upsilon_a\Big(\sum_{mt\ if(\widehat{z}_{mt}^a=1)} (1-z_{mt}) + \sum_{mt\ if(\widehat{z}_{mt}^a=0)} z_{mt}\Big) \tag{21a}$$

Subject to :

$$\sum_{mts\in\Omega_{sa}^{(1)}} z_{mt} + \sum_{mts\in\Omega_{sa}^{(2)}} (1-z_{mt}) \leq |\Omega_{sa}^{(1)}| + |\Omega_{sa}^{(2)}| - 1 + \sum_{a'\, if(K_{a'}\geq K_a)} u_{a'} \ \forall a\in\mathcal{A} \tag{21b}$$

$$\sum_a u_a = 1 \tag{21c}$$

$$z_{mt} = \sum_{\widehat{t}\in\{t1,..,t\}} y_{m\widehat{t}} \ \forall m\in\mathcal{M}, t\in\mathcal{T} \tag{21d}$$

$$\sum_{t\in\mathcal{T}} y_{mt} \leq 1 \ \ \forall m\in\mathcal{M} \tag{21e}$$

$$z_{mt}, y_{mt} \in \{0,1\} \tag{21f}$$

Our proposed solution algorithm solves the modified sub-problem (18) and the modified master problem (21) while increasing the number of iterations until the

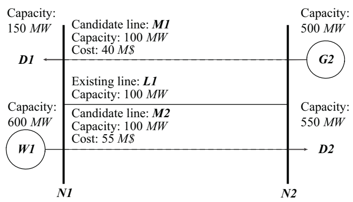


Fig. 4 The single-line diagram of the two-bus system.

optimality gap is satisfied. The proposed decomposition algorithm is presented in Algorithm 1. By using this algorithm the numerical instability problem caused by the disjunctive parameters is removed and whole solution procedure is accelerated.

Algorithm 1 Modified and accelerated Bean decomposition algorithm

```
procedure BEAN DECOMPOSITION
    z_mt =initial feasible solution;  UB=∞; LB=−∞
    while UP>LB do
            Solve subproblem (18)
            Update Ω_sa^(1) and Ω_sa^(2)
            Append constraints (21b) and solve master problem (21)
    end while
    return Optimal solution z_mt and y_mt
end procedure
```

5 Illustrative examples

As an illustrative example, the two-bus system presented in Figure 4 is studied in detail. The system contains wind generation which is solely located in bus $N1$. The initial transmission system is congested. We assume five planning periods for transmission investment ($|\mathcal{T}|$=5). Each investment planning period represents one year and includes 8760 hours of operation assuming one representative hour for each investment planning period (ψ=8760, $|\mathcal{K}|$=1). The Transco can build additional transmission lines $M1$ and $M2$. The maximum demand for the first period is set as 550 MW with a 10% rate of increase for each next planning year. Wind is also considered as a dispatchable source of energy with zero marginal cost. The present worth factor is calculated using an annual price escalation rate (β) equal to 2% and expected rate of return (γ) of 10%. When the H-R-G-V incentive mechanism is used, the Transco invests in $M1$ and $M2$ and sets a fixed fee of 4.76 M\$ at $t2$ which then further decreases in each of the next periods. At the same time demand reaches 550 MW at bus $N2$ and 150 MW at bus $N1$ which corresponds to their maximum values. When the H-R-G-V incentive mechanism is not used, the Transco will invest only in one line, $M1$, and the merchandising surplus will rise by 33% in comparison with H-R-G-V case. Moreover, demand will not reach the maximum value for $t4$ and $t5$ and the system is still congested. The

Table 3 Investment results in the 2-bus system. Tran. Inv: Transmission Investment. IR: H-R-G-V regulation applied. NR: No regulation applied. $^{(*)}$Wind spillage= $\frac{\widehat{G}_{wks}-\widehat{g}_{wtks}}{\widehat{G}_{wks}}$

Approach	Line label [from,to]	*t*1	*t*2	*t*3	*t*4	*t*5
IR	M1 [1,2]	0	**1**	**1**	**1**	**1**
	M2 [1,2]	0	**1**	**1**	**1**	**1**
NR	M1 [1,2]	0	**1**	**1**	**1**	**1**
	M2 [1,2]	0	0	0	0	0
IR	Fixed Fee (M$)	0	4.76	4.38	4.015	3.67
NR	Fixed Fee (M$)	-	-	-	-	-
IR	Merchandising surplus (M$)	4.69	6.19	5.90	5.62	5.35
NR	Merchandising surplus (M$)	4.69	8.19	7.60	7.05	6.54
Difference		**0**	**-2**	**-1.50**	**-1.43**	**-1.19**
IR	Generator and Load Surplus (M$)	3.25	8.01	7.63	7.27	6.92
NR	Generator and Load Surplus (M$)	3.25	3.41	3.54	3.65	3.75
Difference		**0**	**4.6**	**4.09**	**3.62**	**3.17**
IR	Average price N1($)	27.22	98.01	98.01	98.01	98.01
	Average price N2($)	179.68	179.68	179.68	179.68	179.68
NR	Average price N1($)	27.22	54.45	54.45	54.45	54.45
	Average price N2($)	179.68	179.68	179.68	179.68	179.68
IR	Wind spillage (%)$^{(*)}$	10	0	0	0	0
NR	Wind spillage (%)$^{(*)}$	10	2	2	2	2
Difference		**0**	**-2**	**-2**	**-2**	**-2**
IR	Tran. Inv. Cost (M$)	0	1.571	0	0	0
NR	Tran. Inv. Cost (M$)	0	0.762	0	0	0
Difference		**0**	**0.809**	**0**	**0**	**0**

introduction of the H-R-G-V incentive mechanism results in optimal investments in transmission lines. This in turn leads to much lower merchandising surplus and lower overall transmission congestion. The results for the two-bus system are presented in Table 3. They were also compared to welfare-maximizing transmission investment which has served as a benchmark. The results support the conclusions obtained in (Hesamzadeh et al 2018). The H-R-G-V mechanism provides sufficient incentives to the profit maximizing Transco to expand the transmission network such that social welfare is maximized and the congestion in the transmission lines and the wind power spillage are reduced.

As another illustrative example a five-bus system studied. The initial input data for the 5-bus system can be found in Table 4, Table 5 and Table 6. The introduction of the incentive mechanism results in optimal investments in transmission lines which leads to less wind spillage and less transmission congestion. The results for both, two-bus and five-bus case systems are presented in Table 3 and in Table 7, respectively.

6 Numerical results for large test systems

We apply the proposed stochastic MILP formulation presented in (15) to the IEEE 30-bus, 118-bus and 300-bus test systems. Data for the IEEE test systems are taken from data files of Matpower software, (Zimmerman et al 2011). The additional data used for simulations can be found in Table 8. We solve optimization

Table 4 Data of loads in the 5-bus system

Load	Short-run Marginal Utility ($/MWh)	Capacity (MW) at $t1$
d1	300	191
d2	300	196
d3	400	156

Table 5 Data of generators in the 5-bus system

Generator	Bus	Short-run Marginal Utility ($/MWh)	Capacity (MW)
g1	n1	14	40
g2	n1	15	170
g3	n3	30	520
g4	n4	40	200
g5	n5	10	600

Table 6 Data of transmission lines in the 5-bus system

Line label	[from,to]	Reactance (p.u.)	Capacity (MW)	Investment Cost ($/Cct.)
l1	[1,2]	0.4	100	-
l2	[1,4]	0.6	100	-
l3	[1,5]	0.2	100	-
l4	[2,3]	0.2	100	-
l5	[3,4]	0.4	100	-
l6	[4,5]	0.2	100	-
m1	[1,2]	0.2	100	200,000
m2	[3,5]	0.48	100	400,000
m3	[1,4]	0.63	100	310,000
m4	[5,2]	0.3	100	300,000
m5	[3,1]	0.3	100	380,000

problem (15) using the Benders decomposition algorithm, a commercially available state-of-the-art CPLEX solver[2] and our proposed decomposition algorithm. Both decomposition algorithm were implemented in GAMS software.The CPLEX solver is used to solve the MILP master problem and the sub-problem of each decomposition algorithm with the relative gap parameter set to zero. [3] The simulations are run on a computer with two processors and 128 GB of RAM. Wind power scenarios were simulated using the moment-matching technique explained in the Appendix A.2 of this paper (Rubasheuski et al 2014).

The performance of our proposed decomposition algorithm as compared to the Benders decomposition algorithm and the CPLEX solver is presented in Table

[2] The disjunctive parameters included in the formulation which is solved by the CPLEX solver are tuned using an iterative method where disjunctive parameters were increased till the point where the further change in the disjunctive parameters did not affect the solution of the problem. It should be noted that we cannot guarantee that disjunctive parameters were tuned to optimality. We are not aware of any methodology which allows one to tune the disjunctive parameters without known upper bound to optimality.

[3] This setting can be relaxed to allow for a small relative gap for both Bean and Benders decomposition algorithms. However, one should keep in mind that the strength of the cuts might be compromised. This is especially the case for Benders decomposition algorithm.

Table 7 Investment results in the 5-bus system.Tran. Inv: Transmission Investment. IR: H-R-G-V regulation applied. NR: No regulation applied. $^{(*)}$Wind spillage= $\frac{\widehat{G}_{wks}-\widehat{g}_{wtks}}{\widehat{G}_{wks}}$

Approach	Line label [from,to]	$t1$	$t2$	$t3$	$t4$	$t5$
IR	m1 [1,2]	0	**1**	**1**	**1**	**1**
	m2 [3,5]	0	**1**	**1**	**1**	**1**
	m3 [1,4]	0	**1**	**1**	**1**	**1**
	m4 [5,2]	0	**1**	**1**	**1**	**1**
	m5 [3,1]	0	0	0	0	0
NR	m1 [1,2]	0	**1**	**1**	**1**	**1**
	m2 [3,5]	0	0	0	0	0
	m3 [1,4]	0	**1**	**1**	**1**	**1**
	m4 [5,2]	0	**1**	**1**	**1**	**1**
	m5 [3,1]	0	0	0	0	0
IR	Fixed Fee (M$)	0	13.53	15.10	17.13	10.70
NR	Fixed Fee (M$)	-	-	-	-	-
IR	Merchandising surplus (M$)	46.52	38.71	38.14	36.44	42.01
NR	Merchandising surplus (M$)	46.52	51.74	52.69	53.37	53.06
Difference		**0**	**-13.03**	**-14.55**	**-16.93**	**-11.05**
IR	Generator and Load Surplus (M$)	85.64	99.17	100.74	102.77	96.36
NR	Generator and Load Surplus (M$)	85.64	86.03	86.09	85.75	85.22
Difference		**0**	**13.14**	**14.65**	**17.02**	**11.13**
IR	Wind spillage (%)$^{(*)}$	7	0	0	0	0
NR	Wind spillage (%)$^{(*)}$	7	1.43	1.43	1.43	1.43
Difference		**0**	**-1.43**	**-1.43**	**-1.43**	**-1.43**
IReg	Tran. Inv. Cost (k$)	0	11523.8	0	0	0
NReg	Tran. Inv. Cost (k$)	0	7714.3	0	0	0
Difference		**0**	**3809**	**0**	**0**	**0**

Table 8 Input data for case studies.

	IEEE 30-bus	IEEE 118-bus	IEEE 300-bus
Number of candidate lines	20	30	60
Number of existing lines	30	175	411
Conventional Generation,(MWh)	335	4300	20678
Wind Generation, (MWh)	450	2500	12000
Scenarios, (N)	20	20	20
Operation subperiods, (N)	24	105	72
Maximum Load, (MWh)	600	4242	23526
Number of periods	10	10	15

Table 9 Results for IEEE 30-bus case study.

	Number of New Lines	Objective Function, ($)	Computation Time, (h)	Iterations
CPLEX solver	4	145.15	0.485	-
Benders decomposition algorithm	4	145.15	1.48	584
Proposed decomposition algorithm	4	145.15	0.456	152

Table 10 Results for IEEE 118-bus case study. "$*$": no solution after 21 hours of simulation.

	Number of New Lines	Objective Function, (\$)	Computation Time, (h)	iterations
CPLEX solver	$*$	$*$	$*$	$*$
Benders decomposition algorithm	$*$	$*$	$*$	$*$
Proposed decomposition algorithm	23	3859	10.14	2510

Table 11 Results for IEEE 300-bus case study. "$*$": no solution after 21 hours of simulation

	Number of New Lines	Objective Function, (\$)	Computation Time, (h)	iterations
CPLEX solver	$*$	$*$	$*$	$*$
Benders decomposition algorithm	$*$	$*$	$*$	$*$
Proposed decomposition algorithm	15	10159	14.75	3192

9, Table 10 and Table 11. It should be noted that both the standard Benders decomposition algorithm and the CPLEX solver could not find an optimal solution after 21 hours of simulation.

7 Conclusion

This paper presents a stochastic bilevel disjunctive program for transmission investment planning. The Transco is subject to a proposed H-R-G-V regulatory constraint set by the regulator. The model takes into account uncertain wind generation using a moment matching technique. First, the stochastic bilevel disjunctive program is transformed to a stochastic MILP with linearized disjunctive constraints. A series of linearizations and reformulation techniques are introduced to arrive at the final stochastic MILP with linearized disjunctive constraints. To solve the reformulated MILP model, a specialized decomposition algorithm is developed employing the disjunctive nature of optimization problem. The proposed decomposition algorithm is based on the Bean decomposition algorithm. The scenario-separated feasability cuts and a penalization technique are used. Besides, we show that the proposed decomposition algorithm does not require any tuning of disjunctive parameters.

The stochastic MILP reformulation and proposed decomposition algorithm were applied to case studies of different size. In each case, the proposed H-R-G-V mechanism effectively dealt with congested power systems with integrated stochastic wind generation. The H-R-G-V mechanism incentivizes the Transco to produce welfare-maximum outcomes resulting in much lower congestion cost in comparison to the case where no regulation is present. Welfare-maximum transmission investments not only reduce the congestion cost but also support renewable generation and result in reduced wind power spillage. The computational performance of the proposed decomposition algorithm was tested further on IEEE 30-bus, 118-bus and 300-bus test systems with stochastic wind generation. The numerical results show that the proposed decomposition algorithm helps us to avoid the effect of the disjunctive parameter on finding the optimal solution and to improve the computational tractability of the problem. Therefore, the proposed H-R-G-V incentive mechanism, which is reformulated as MILP model, and proposed decomposition algorithm may be used as an efficient tool for transmission investment in electric power systems with wind generation.

This work could be extended by including reliability criteria and other sources of uncertainties in the transmission investment model under the H-R-G-V mechanism.

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A Appendix

A.1 Discussion of reliability issues and of economic risks for transmission investment planning

Transmission investment planning is subject to various uncertainties. Renewable generation and load uncertainties can congest the transmission system, especially, when the penetration is high. Furthermore, outages and other malfunctions of the equipment are hard to predict and therefore can affect the reliable operation of a power system. Therefore, these uncertainties have to be taken into account while the decisions on the transmission lines investments are made. In this section we provide a brief discussion of reliability criteria and risks related to the economic uncertainties.

Reliability standards vary for each system and are customarily adapted based on changing characteristics of the system such as, for example, the generation mix. The reliability standards can be incorporated in any transmission planning by enforcing additional technical constraints on transmission operation and planning. Under centralized planning, the reliability standards can be seen as the main criteria for the investments. However, under market based transmission planning the objective of a transmission investor is aimed at profit maximization. Yet, the reliability criteria can be still enforced by a regulator or a system operator (ISO). This applies to transmission investment planning under the H-R-G-V mechanism as well. The H-R-G-V incentive mechanism promotes socially optimal investments and it is aimed at reducing the congestion cost of the system. Reduced congestion, itself, will result in more reliable operation of a power system. Moreover, based on the mathematical models presented in (6) and (7) the system operator can still enforce additional technical reliability constraints which have to be met for the secure operation of the system. For example, the N-1 criterion can be modeled as an extra constraint in the lower-level program. This approach will lead to socially optimal investments while reliability criteria are satisfied. Under a different approach the regulator could promote reliability criteria by assigning monetary value to each criterion. Thus, the reliability of the power system will become a part of the reward structure of the Transco (Vogelsang 2018).

Apart from having to fulfill reliability criteria, the Transco can be subject to additional economic risks. In this paper, we assume that the Transco is a risk neutral entity. However, this assumption can be easily dropped and additional constraints on the risk tolerance of the Transco can be added to the model. However, the complexity of the problem should be reconsidered and therefore additional research is required to properly address the risk attitude of the Transco.

Other uncertainties such as changes in demand, solar power generation and any other renewable generation uncertainties can be incorporated to the proposed model using the same, moment-matching technique, presented in this paper. The description of the moment-matching scenario generation technique can be found in Appendix A.2.

A.2 The moment-matching method for generating wind scenarios

The moment-matching scenario generation technique is based on historical data. The method does not require any knowledge of the distribution of uncertain parameters, instead, it exploits statistical properties of the sampled historical data such as the mean (M_n), standard deviation (SD_n), skewness (SK_n), kurtosis (KRT_n) and correlation ($Corr_{n,m}$). These measurements are also known as moments. In (22) we present the equations used to calculate each of the aforementioned statistical property. Once the moments of the historical sampled data are known, we can generate a number of scenarios with the matching properties. The generation of the scenarios is performed using the mathematical model presented in (23) by minimizing the mismatch for each moment.

$$M_n = \frac{1}{K}\sum_k n_k \tag{22a}$$

$$SD_n = \sqrt{\frac{1}{K}\sum_k (M_n - n_k)^2} \tag{22b}$$

$$SK_n = \frac{1}{K}\frac{\sum_k (M_n - n_k)^3}{SD_n^3} \tag{22c}$$

$$KRT_n = \frac{1}{K}\frac{\sum_k (M_n - n_k)^4}{SD_n^4} \tag{22d}$$

$$Corr_{n,m} = \frac{\sum_k (M_n - n_k)(M_m - m_k)}{\sqrt{\sum_k (M_n - n_k)^2 \sum_k (M_m - m_k)^2}} \tag{22e}$$

Where n and m are the sets of uncertain parameters and k is the considered historical data set with total of K elements.

$$\begin{aligned} &\underset{p_s}{Minimize}: \sum_n ((f^M(n,p) - M_n)^2 + (f^{SD}(n,p) - SD_n)^2 + (f^{SK}(n,p) - SK_n)^2 \\ &+ (f^{KRT}(n,p) - KRT_n)^2) + \sum_{n,m} (f^{Corr}(n,m,p) - Corr_{n,m})^2 \end{aligned} \tag{23a}$$

$$Subject\ to:$$

$$f^M(n,p) = \sum_s n_s p_s \tag{23b}$$

$$f^{SD}(n,p) = \sum_s (f^M(n,p) - n_s)^2 p_s \tag{23c}$$

$$f^{SK}(n,p) = \sum_s \frac{(f^M(n,p) - n_s)^3 p_s}{(f^{SD}(n,p))_n^3} \tag{23d}$$

$$f^{KRT}(n,p) = \sum_s \frac{(f^M(n,p) - n_s)^4 p_s}{(f^{SD}(n,p))^4} \tag{23e}$$

$$\begin{aligned} &f^{Corr}(n,m,p) = \\ &\sum_s \frac{(f^M(n,p) - n_s)(f^M(m,p) - m_s)p_s}{\sqrt{(f^M(n,p) - n_s)^2 (f^M(m,p) - m_k)^2}} \end{aligned} \tag{23f}$$

$$\sum_s p_s = 1 \tag{23g}$$

Where in (23), s is the index for scenarios and p_s is the probability corresponding to each scenario.

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Merchant-Regulatory Coordination of Transmission Investment with Optimal Battery-Storage Capacity

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***Abstract*—This paper proposes a merchant-regulatory approach for forward-looking transmission investment. The transmission company (Transco) is a profit-maximizing company covering its transmission investment cost through collecting the congestion rent and a regulated fixed-fee to network users. The Transco takes into account the optimal battery-storage capacity coordinated with renewable-energy developments in its transmission investment decisions. The proposed approach of transmission investment is modeled as a mixed-integer nonlinear bilevel program. Then through a proposed Lemma and a series of linearization techniques, the whole problem is recast as an equivalent mixed-integer linear program (MILP). To further improve the computational tractability of the reformulated MILP model, the disjunctive nature of the MILP is fully exploited through a proposed disjunctive-based decomposition (DBD) algorithm. Interestingly, the proposed DBD algorithm does not need optimal tuning of the disjunctive parameters (known as big-M in relevant literature) which further makes it attractive. The utility and performance of the whole MILP modeling and DBD algorithm have been successfully tested through several numerical examples.**

***Index Terms*—Forward-looking transmission investment, Battery-storage system, Incentive regulation.**

NOMENCLATURE

Binary Variables

a_{btks} Battery storage charge/discharge indicator;
z_{mt},y_{mt} Transmission investment decision variables;

Incidence matrices

$I_n^{(i)}$ Incidence matrix element of load i, node n;
$J_n^{(j)}$ Incidence matrix element of generator j, node n;
$R_n^{(l)}$ Incidence matrix element of receiving node n, line l;
$\overline{R}_n^{(m)}$ Incidence matrix element of receiving node n, line m;
$S_n^{(l)}$ Incidence matrix element of sending node n, line l;
$\overline{S}_n^{(m)}$ Incidence matrix element of sending node n, line m;
$W_n^{(w)}$ Incidence matrix element of generator w, node n;

Parameters

A_i Load i marginal utility;
$C_b^{(ch)}$ Cycling cost of charging battery storage unit b;
$C_b^{(dh)}$ Cycling cost of discharging battery storage unit b;
$C_{bt}^{(E)}$ Investment cost of battery storage energy capacity for candidate unit b at period t;
C_j Marginal cost of generator unit j;
$C_{bt}^{(P)}$ Investment cost of battery storage power capacity for candidate unit b at period t;
$C_{mt}^{(T)}$ Investment cost of transmission line m at period t;
$C_{wt}^{(W)}$ Investment cost of renewable unit w at period t;

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D_{it} Maximum capacity of load i at period t;
F_l Maximum capacity of existing transmission line l;
$\widehat{F}_m$ Maximum capacity of candidate transmission line m;
G_j Maximum capacity of generator j;
$\widehat{G}_w$ Maximum capacity of renewable generator w;
P_s Probability of scenario s;
Ψ Number of operational periods in an investment period;
r Interest rate;
Θ Maximum voltage angle;
ϱ_{wtks} Stochastic output of renewable generator w at period t, k, scenario s;
Ξ_m, Ξ Sufficiently large constants;
X_l Reactance of existing transmission line l;
X_m Reactance of candidate transmission line m;

Indices and Sets

$b \in \mathcal{E}$ Battery storages;
$i \in \mathcal{D}$ Loads;
$j \in \mathcal{G}$ Generators;
$k \in \mathcal{K}$ Operation periods;
$l \in \mathcal{L}$ Existing lines;
$m \in \mathcal{M}$ Candidate lines;
$n \in \mathcal{N}$ Nodes;
$s \in \mathcal{S}$ Scenarios;
$t \in \mathcal{T}$ Investment periods;
$w \in \mathcal{W}$ Renewable-energy generators;

Variables

$\tilde{d}_{btks}$ Charge of battery storage b at period t, k, scenario s;
d_{itks} Demand of load i at period t, k, scenario s;
e_{bt} Energy capacity of battery storage b at period t;
f_{ltks} Flow of line l at period t, k, scenario s;
$\widehat{f}_{mtks}$ Flow of line m at period t, k,scenario s;
$\tilde{g}_{btks}$ Discharge of battery b at period t, k, scenario s;
g_{jtks} Generation of generator j at period t, k, scenario s;
$\widehat{g}_{wtks}$ Renewable output of unit w at period t, k, scenario s;
p_{bt} Power capacity of battery storage b at period t;
Φ_t Fixed fee at period t;
q_{btks} State of charge of battery b at period t, k, scenario s;
θ_{ntks} Voltage angle at node n at period t, k, scenario s;
u_{wt} Investment level in renewable generator w at period t;

I. INTRODUCTION

BATTERY storage system (BSS) refers to a system of storage technologies which convert the surplus electrical energy to another form which can be then converted to electrical energy when needed. The faster-than-expected cost declines of different storage technologies and integration-rate of the renewable generation are expected to lead to a BSS with size of over 400 GWh by 2030 in the world's energy system [1]. Battery storage technology is considered as one of the most advanced low-carbon technologies. In Europe €200 million are being invested into battery research and innovation. This means by 2030 we will see a real shift to low- and zero-emission vehicles including electric cars in Europe further expanding the BSS capacity. At the same time, in the next five years, it is expected that one-fifth of the global energy demand is supplied by renewable energies. During the period 2017 to 2023, global renewable generation is forecast to meet more than 70% of electricity generation growth [2]. The energy storage system and in particular batteries play a vital role in the transition of the electricity industry to a carbon-free electricity system. The proper utilization of the BSS can smooth the variable and intermittent renewable generation and reduce the intermittent cost of the variable renewable generation. Accordingly, investment in the battery-storage capacity needs to be coordinated with the investment in the renewable-energy capacity. This investment coordination is expected to achieve through market-based investments driven by competitive spot-market prices. However, the economic benefit of the coordinated investment in battery-storage and renewable-energy capacity is not fully realized if it is carried out in isolation from transmission capacity investment. A forward-looking transmission investment coordinated with joint battery-storage and renewable-energy investment can significantly increase the economic benefit that electricity consumers realize [3], [4].

A. Review and classification of the relevant literature

Optimal investment in transmission network, BSS and renewable generation capacities requires a coordination mechanism. This is partly due to the fact that the transmission investment is a (merchant-) regulatory process while the battery-storage and renewable-generation capacities are developed through market-driven processes and they are carried out by profit-maximizing companies. The investment coordination is not a new problem in liberalized electricity markets and proactive and reactive solutions are proposed to address this issue in [5] and [6]. The concept of investment coordination is further discussed in [7] and [8]. Authors in [9] and [10] propose game theoretic models for proactive and reactive coordination. All these papers support the proactive view for efficient coordination [11]. More recently, reference [3] discusses the issue of investment coordination considering the investment in renewable-generation capacities. The forward-looking transmission investment is proposed where the transmission investment is carried out first taking into account the renewable-generation investments. Although we can rely on market prices to deliver the optimal investment in the battery-storage and the renewable-generation capacities, the market-driven transmission investment is still in theoretical literature[1]. This means that the transmission investment needs a proper regulatory mechanism to incentivize the optimal investment in transmission capacity which in turn supports the optimal investment in the battery-storage and the renewable-generation capacities. References [13] and [14] propose price-cap regulatory mechanisms to incentivize transmission investment. Under certain conditions, these regulatory mechanisms lead to a transmission expansion plan which maximizes social welfare [15]. Reference [16] proposes a reward/penalty regulatory mechanism. In this regulatory mechanism, the regulator rewards the transmission investor when the transmission is expanded and the congestion rents are decreased. Reference [17] proposes an out-turn regulatory mechanism. The out-turn is defined as the difference between the actual electricity prices and the prices without transmission congestion. The transmission investor is responsible for total out-turn cost and any transmission losses. References [15] and [18] extend the work in [13] and propose an incentive-based mechanism for transmission investment. In this incentive-based regulatory mechanism, the transmission investor maximizes its profit (sum of merchandising surplus and a fixed charge) subject to the price-cap constraint introduced in [13]. The authors in [19] propose a simple regulatory incentive mechanism which is applicable to electricity transmission investment. The proposed mechanism can incentivize a regulated transmission company (Transco) to invest in the transmission network such that the social-welfare is maximized [20]. Reference [21] proposes an incremental surplus subsidy (ISS) mechanism for regulating a firm when the regulator does not have cost information of the regulated firm. In other words, when a monopolist carries out a relevant regulatory activity, the ISS awards the monopolist the gain from the social-welfare increase. The ISS mechanism has a number of attractive features which makes it applicable for transmission investment. *Gangs* and *King* noticed this point in [22] and proposed the ISS mechanism for transmission network investment in Australia. Aforementioned literature shows that implementing the ISS mechanism can result in maximizing social-welfare investment in the Australian transmission network. In this paper, we show that the ISS regulatory mechanism can efficiently coordinate the BSS, wind generation, and transmission investments. Table I compares the contributions of the key existing literature with the ones in our paper. The lack of a comprehensive paper addressing engineering, regulatory economics and computational aspects of the transmission investment coordination is clear from Table I.

Table I
THE COMPARATIVE LITERATURE REVIEW

Papers	IM[i]	IC[ii]	SA[iii]	SM[iv]	MM[v]	CA[vi]
[13], [14], [15], [18]	✓	×	×	×	×	×
[19], [21], [22]	✓	×	×	✓	×	×
[3], [5], [7], [9]	×	✓	×	×	✓	✓
[23], [24]	✓	✓	×	×	✓	×
Our paper	✓	✓	✓	✓	✓	✓

i: Incentive Mechanism proposed, ii: Can be applied to Investment Coordination, iii: Supports coordinated investment in more than two assets (System Approach), iv: Social-welfare Maximum is guaranteed, v: Comprehensive Mathematical Model is proposed, vi: Solution methodology and Computational Aspects are addressed

B. Contributions

The current paper contributes to the relevant literature as follows: (a) It proposes a merchant-regulatory mechanism for forward-looking transmission investment coordinated with

[1]Merchant transmission investment where the investor relies on inter-locational price differences (congestion rent) has a tendency to deliver sub-optimal investment both in theory and in practice [12].

the optimal investment in joint battery-storage and renewable-energy capacity. (b) The proposed optimal investment framework is modeled as a mixed-integer nonlinear bilevel program which is then transformed to a more computationally tractable MILP model. (c) a disjunctive-based decomposition (DBD) algorithm is proposed and carefully studied to employ the disjunctive properties of the proposed model. Rest of this paper is organized as follows. Section II explains the proposed merchant-regulatory mechanism and its mathematical model. The DBD algorithm is proposed in Section III. Section IV gives an illustrative example numerical results. Section V concludes the paper.

II. Proposed mechanism for transmission investment

We assume a profit-maximizing Transco investing in transmission network. The Transo covers its investment costs by collecting the congestion rent and receiving a regulated fixed-fee from the regulator. The forward-looking Transco forecasts and considers the future investments in battery-storage and renewable-generation capacities in its optimal transmission investment decision. The forward-looking investment decision of the Transco is modeled through an stochastic bilevel program in (1).

$$\underset{z_{mt},y_{mt}}{\text{Maximize}} \sum_t \frac{\Phi_t+\pi_t^T-\sum_m C_{mt}^{(T)} y_{mt}}{(1+r)^{t-1}} \tag{1a}$$

Subject to:

$$z_{mt}=\sum_{\widehat{t}\leq t} y_{m,\widehat{t}}\ \forall m,t\geq 2 \tag{1b}$$

$$\sum_t y_{mt}\leq 1\ \ \forall m,t \tag{1c}$$

$$z_{mt}=0\ \forall m,t{=}1 \tag{1d}$$

$$z_{mt},y_{mt}\in\{0,1\} \tag{1e}$$

$$\text{Where } \Phi_t\in SOL\{(2)\} \text{ and } \pi_t^T\in SOL\{(3)\} \tag{1f}$$

In optimization problem (1), $\pi_t^T = \sum_{snk}\lambda_{ntks} (\sum_{ik} I_n^{(i)} d_{itks} + \sum_{nb} E_n^{(b)}\lambda_{ntks}(\tilde{d}_{btks}-\tilde{g}_{btks}) - \sum_{jk} J_n^{(j)} g_{jtks} - \sum_{wk} W_n^{(w)}\widehat{g}_{wtks})$ is total expected congestion rent of the Transco. Objective function of the Transco is modeled in (1a) as total expected congestion rent π_t^T plus fixed fee Φ_t minus total investment cost. Investment in transmission lines is modeled through variable y_{mt}. The investment decision is irreversible and ensured through an auxiliary variable z_{mt} and investment constraint (1c) . Fixed fee Φ_t is decided by the regulator which decision process can be described through (2) while congested rent π_t^T depends on the battery-storage and renewable-energy capacity investments and hourly dispatch of the system which is simulated through (3). $SOL\{(2)\}$ and $SOL\{(3)\}$ refer to solutions of the mathematical models (2) and (3), respectively. The regulator decision problem is presented in (2).

$$\text{Find } \Phi_t \tag{2a}$$

Such that:

$$\Phi_{(t=1)}=0 \tag{2b}$$

$$\Phi_t=\Delta\pi_t^L+\Delta\pi_t^G+\Delta\pi_t^W+\Delta\pi_t^E-\pi_{t-1}^T+ \frac{1}{(1+r)^{t-1}}(\sum_m C_{mt}^{(T)} y_{m(t-1)}-\sum_w C_{wt}^{(W)}(u_{wt}-u_{w(t-1)})- \sum_b C_{bt}^{(E)}(e_{bt}-e_{b(t-1)})-\sum_b C_{bt}^{(P)}(p_{bt}-p_{b(t-1)}))\ \forall t\geq 2 \tag{2c}$$

$$\text{Where } \pi_t^T\in SOL\{(3)\} \tag{2d}$$

In the regulatory equation (2c), $\pi_t^L = \sum_{sik}(\Psi A_i d_{itks} - \sum_n I_n^{(i)}\lambda_{ntks} d_{itks})$, $\pi_t^G = \sum_{sjk}(\sum_n J_n^{(j)}\lambda_{ntks} g_{jtks} - \Psi C_j g_{jtks})$, $\pi_t^W = \sum_{snwk} W_n^{(w)}\lambda_{ntks}\widehat{g}_{wtks}$, and $\pi_t^E = \sum_{snbk}(E_n^{(b)}\lambda_{ntks}(\tilde{g}_{btks}-\tilde{d}_{btks})+\Psi(C_b^{(dh)}\tilde{d}_{btks}-C_b^{(ch)}\ \tilde{g}_{btks}))$ are expected load surplus, generation surplus, renewable-generation surplus and battery-storage surplus in the spot market. Here two separate time indices t and k are used for investment periods (in years) and operation periods (in hours) respectively. The regulatory constraint is modeled in (2c) which is not in place for the first planning period $t=1$ ($\Phi_{(t=1)}=0$ in (2b)) .

Since the fixed fee Φ_t can be calculated through set of equations and the objective function of the regulator and Transco do not contradict with each other; the regulators decision problem (2) can be merged with transmission investment decision of Transco (1) and solved simultaneously. On the other hand, the battery-storage and renewable-energy capacity investment can be modeled as a maximization problem in (3). Lagrange multiplier associated with each constraint is presented in parentheses.

$$\underset{\Omega}{\text{Maximize}} \sum_t \frac{\Psi}{(1+r)^{t-1}}\Big(\sum_{sk} P_s(\sum_i A_i d_{itks}-\sum_j C_j\, g_{jtks})- \sum_b (C_b^{(dh)}\tilde{d}_{btks}+C_b^{(ch)}\ \tilde{g}_{btks})-(\sum_b C_{bt}^{(E)}(e_{bt}-e_{b(t-1)})- \sum_b C_{bt}^{(P)}(p_{bt}-p_{b(t-1)})-\sum_w C_{wt}^{(W)}(u_{wt}-u_{w(t-1)})\Big) \tag{3a}$$

Subject to:

$$u_{wt}-u_{w(t-1)}\geq 0\ \ :(\eta_{wt})\ \forall w,t \tag{3b}$$

$$e_{bt}-e_{b(t-1)}\geq 0\ \ :(\kappa_{bt})\ \forall b,t \tag{3c}$$

$$p_{bt}-p_{b(t-1)}\geq 0\ \ :(\vartheta_{bt})\ \forall b,t \tag{3d}$$

$$\sum_j J_n^{(j)} g_{jtks}+\sum_w W_n^{(w)}\widehat{g}_{wtks}-\sum_i I_n^{(i)} d_{itks}+\sum_b E_n^{(b)}\tilde{g}_{btks}- \sum_b E_n^{(b)}\tilde{d}_{btks}-\sum_l S_n^{(l)} f_{ltks}+\sum_l R_n^{(l)} f_{ltks}-\sum_m \overline{S}_n^{(m)}\widehat{f}_{mtks}+ \sum_m \overline{R}_n^{(m)}\widehat{f}_{mtks}=0\ \ :(\lambda_{ntks})\ \forall n,t,k,s \tag{3e}$$

$$-\frac{100}{X_l}(\sum_n S_n^{(l)}\theta_{ntks}-\sum_n R_n^{(l)}\theta_{ntks})+f_{ltks}=0\ \ :(\sigma_{ltks}) \tag{3f}$$

$$\widehat{f}_{mtks}-\frac{100}{X_m}(\sum_n \overline{S}_n^{(m)}\theta_{ntks}-\sum_n \overline{R}_n^{(m)}\theta_{ntks})\leq \Xi_m(1-z_{mt}):(\overline{\sigma}_{mtks})\ \forall m,t,k,s \tag{3g}$$

$$\widehat{f}_{mtks}-\frac{100}{X_m}(\sum_n \overline{S}_n^{(m)}\theta_{ntks}-\sum_n \overline{R}_n^{(m)}\theta_{ntks})\geq -\Xi_m(1-z_{mt})\ \ :(\underline{\sigma}_{mtks})\ \forall m,t,k,s \tag{3h}$$

$$-z_{mt}\Xi_m\leq\widehat{f}_{mtks}\leq z_{mt}\Xi_m:(\underline{\zeta}_{mtks},\overline{\zeta}_{mtks})\ \forall m,t,k,s \tag{3i}$$

$$q_{btks}=q_{bt(k-1)s}-\tilde{g}_{btks}+\tilde{d}_{btks}\ \ :(\tau_{btks})\ \forall b,t,k,s \tag{3j}$$

$$-\widehat{F}_m\leq\widehat{f}_{mtks}\leq\widehat{F}_m\ \ :(\underline{\gamma}_{mtks},\overline{\gamma}_{mtks})\ \forall m,t,k,s \tag{3k}$$

$$-F_l \leq f_{ltks} \leq F_l \ : (\underline{\mu}_{ltks}, \overline{\mu}_{ltks}) \ \forall l,t,k,s \quad (3l)$$

$$0 \leq g_{jtks} \leq G_j \ : (\underline{\nu}_{jtks}, \overline{\nu}_{jtks}) \ \forall j,s,t,k \quad (3m)$$

$$0 \leq \widehat{g}_{wtks} \leq (\widehat{G}_w + u_{wt}) \varrho_{wtks} : (\underline{\eta}_{wtks}, \overline{\eta}_{wtks}) \ \forall w,t,k,s \quad (3n)$$

$$0 \leq \tilde{g}_{btks} \leq p_{bt} a_{btks} \ : (\underline{\kappa}_{btks}, \overline{\kappa}_{btks}) \ \forall b,t,k,s \quad (3o)$$

$$0 \leq \tilde{d}_{btks} \leq p_{bt}(1 - a_{btks}) \ : (\underline{\vartheta}_{btks}, \overline{\vartheta}_{btks}) \ \forall b,t,k,s \quad (3p)$$

$$0 \leq q_{btks} \leq e_{bt} \ : (\underline{\rho}_{btks}, \overline{\rho}_{btks}) \ \forall b,t,k,s \quad (3q)$$

$$0 \leq d_{itks} \leq D_{it} \ : (\underline{\omega}_{itks}, \overline{\omega}_{itks}) \ \forall i,t,k,s \quad (3r)$$

$$\theta_{ntks} = 0 \ : (\xi_{ntks}) \ \forall t,k,s,n = 1 \quad (3s)$$

$$a_{btks} \in \{0,1\} \quad (3t)$$

$$d_{itks}, \tilde{d}_{btks}, \tilde{g}_{btks}, q_{btks}, g_{jtks}, \widehat{g}_{wtks}, f_{ltks}, \widehat{f}_{mtks}, p_{bt}, e_{bt}, \theta_{ntks}, u_{wt} \in \Re \quad (3u)$$

Nodal prices, dispatched demand, generation and energy storage charge and discharge as well as battery-storage and renewable-generation investments are calculated in (3). Non-decreasing properties of renewable-generation invested capacities and battery-storage invested capacities are modeled in (3b)-(3d). Investments in renewable-generation and battery-storage are modeled as continuous variables and are not reversible. Investments in batteries can be divided into two separate investments: energy capacity e_{bt} and power capacity p_{bt}. Energy capacity determines the maximum limit of the state of charge while power capacity sets the limits on charge and discharge rates. Active power balance constraint for node n is written in (3e). Active power flow constraints for existing lines are formulated in (3f). Similarly (3g) and (3h) are used for candidate lines. Here the active power flow constraint will be enforced only when we invest in the corresponding candidate line m ($z_{mt}=1$). Flow of the candidate line m forced to be zero when we did not invest in this line using constraint (3i). Energy balance constraint for battery storage b is modeled in (3j) to keep track on the state of charge of an energy storage and available energy capacity. Upper and lower bound of generation, demand, energy storage and thermal limits of existing and candidate transmission lines are modeled in (3k)-(3r). Simultaneous charge and discharge in batteries is not possible due to technical limitation of power electronics. Thus, following traditional battery operation model in [25] and [26] an auxiliary integer variable a_{btks} is introduced into upper and lower limit constraints of energy storage (3o)-(3p) to prevent simultaneous charge and discharge during operation. This variable a_{btks} is equal to 1 if the energy storage is discharging and is 0 otherwise. Constraint (3s) sets node 1 as the reference node with zero voltage angle. $\Omega = \{u_{wt}, e_{bt}, p_{bt}, \tilde{d}_{btks}, \tilde{g}_{btks}, q_{btks}, d_{itks}, g_{jtks}, \widehat{g}_{wtks}, f_{ltks}, \widehat{f}_{mtks}, \theta_{ntks}\}$ is the set of decision variables of the lower-level model. Lagrange multipliers are assigned to each constraint and presented in parentheses separated by colon. $\Re$ in (3u) is set of real numbers. The optimization problem (1)-(3) is a mixed-integer nonlinear bilevel program and accordingly computationally expensive. We proposed the following reformulation techniques to convert it to a single-level MILP model.

A. The linear programming (LP) equivalent

We have the following Lemma for battery-storage and renewable-energy capacity investment optimization model (3).

Lemma 1. *The binary variables in the MILP model (3) can be dropped without simultaneous charge and discharge operation of the battery-storage system. Meaning relaxed LP formulation of (3) without charge and discharge binary variables is equivalent to the MILP formulation.*

Proof. Assume that the binary variables are not in place (the problem (3) is formulated as an LP problem) and charge and discharge happen simultaneously, i.e. $\tilde{d}_{btks} > 0$ and $\tilde{g}_{btks} > 0$. This implies that we can derive KKT optimality conditions for relaxed LP formulation of (3) and Lagrangian multipliers of constraints (3o) and (3p) will be equal to zero, $\underline{\kappa}_{btks} = 0$ and $\underline{\vartheta}_{btks} = 0$. Using stationary conditions (4a) and (4b) of the relaxed LP model of (3):

$$\frac{-\Psi}{(1+r)^{t-1}} P_s C_b^{(ch)} - \sum_n E_n^{(b)} \lambda_{ntks} + \tau_{btks} + \underline{\vartheta}_{btks} - \overline{\vartheta}_{btks} = 0 \quad (4a)$$

$$\frac{-\Psi}{(1+r)^{t-1}} P_s C_b^{(dh)} + \sum_n E_n^{(b)} \lambda_{ntks} - \tau_{btks} + \underline{\kappa}_{btks} - \overline{\kappa}_{btks} = 0 \quad (4b)$$

we can derive

$$\sum_n E_n^{(b)} \lambda_{ntks} \overset{(4a)}{=} -\frac{\Psi}{(1+r)^{t-1}} P_s C_b^{(ch)} + \tau_{btks} + \underline{\vartheta}_{btks} - \overline{\vartheta}_{btks}$$

$$\overset{(4b)}{=} \frac{\Psi}{(1+r)^{t-1}} P_s C_b^{(dh)} + \tau_{btks} - \underline{\kappa}_{btks} + \overline{\kappa}_{btks} \ \ \forall b,t,k,s. \quad (5a)$$

Previously we assumed that $\tilde{d}_{btks} > 0$ and $\tilde{g}_{btks} > 0$ which leads to (5b).

$$-\frac{\Psi P_s}{(1+r)^{t-1}} (C_b^{(dh)} + C_b^{(ch)}) = \overline{\vartheta}_{btks} + \overline{\kappa}_{btks} \ \forall b,t,k,s \quad (5b)$$

Under the assumption $\tilde{d}_{btks} > 0$ and $\tilde{g}_{btks} > 0$ the sum of $\overline{\vartheta}_{btks} + \overline{\kappa}_{btks}$ on the right-hand side of the equation (5b) will be either 0 or a strictly positive while the expression $-P_t \Psi P_s C_b^{(dh)} - P_t \Psi P_s C_b^{(ch)}$ on the left-hand side is strictly negative. This leads us to contradiction and to the conclusion that the assumption $\tilde{d}_{btks} > 0$ and $\tilde{g}_{btks} > 0$ does not hold. Thus, battery storage will not charge and discharge at the same time and at least one of the variables $\tilde{d}_{btks}$ or $\tilde{g}_{btks}$ should be equal to zero in the optimal solution. Furthermore, LP equivalent reformulation is a relaxation of the original MILP, meaning the solution of the LP equivalent ($SW_{LP}(\boldsymbol{y}^*)$) is greater than or equal to the original MILP solution ($SW_{MILP}(\boldsymbol{x}^*)$), where $\boldsymbol{y}^*$ and $\boldsymbol{x}^*$ are optimal solution vectors of the original MILP and the LP equivalent. On the other hand, since we have proved that the disjunctive property of constraints (3o) and (3p) are maintained in $\boldsymbol{y}^*$, we have $SW_{MILP}(\boldsymbol{y}^*) \leq SW_{MILP}(\boldsymbol{x}^*)$). Therefore, $SW_{MILP}(\boldsymbol{y}^*) \leq SW_{MILP}(\boldsymbol{x}^*) \leq SW_{LP}(\boldsymbol{y}^*)$). Moreover, since the SW_{MILP} and SW_{LP} are linear functions, $SW_{MILP}(\boldsymbol{x}^*) = SW_{LP}(\boldsymbol{y}^*)$ and $\boldsymbol{x}^* = \boldsymbol{y}^*$. □

Using Lemma 1, the lower-level MILP model is transformed to an equivalent LP model. which can then be replaced by the primal feasibility conditions, dual feasibility conditions and the strong-duality conditions [27], [28].

B. The linear reformulation of the nonlinear terms

The Transco profit function and the regulatory constraint contain the bilinear terms $\lambda_{ntks} d_{itks}$, $\lambda_{ntks} g_{jtks}$ and $\lambda_{ntks} \widehat{g}_{wtks}$. The bilinear terms include multiplication of variables from both the upper-level and lower-level problems and they appear in the objective function as well as in the regulatory constraint.

These bilinear terms can be grouped together as $L_{tks} = \sum_{ni} I_n^{(i)} \lambda_{ntks} d_{itks} - \sum_{nj} J_n^{(j)} \lambda_{ntks} g_{jtks} + \sum_{nb} E_n^{(b)} \lambda_{ntks} (\tilde{d}_{btks} - \tilde{g}_{btks}) - \sum_{nw} W_n^{(w)} \lambda_{ntks} \widehat{g}_{wtks}$. The term L_{tks} can be then reformulated as a combination of linear terms in (6).

$$\sum_l F_l(\overline{\mu}_{ltks} + \underline{\mu}_{ltks}) + \sum_m \widehat{F}_m(\overline{\gamma}_{mtks} + \underline{\gamma}_{mtks}) \quad (6)$$

The strong-duality condition of the lower-level problem is derived using linearized bilinear terms as set out in (7).

$$\sum_t \frac{\Psi}{(1+r)^{t-1}} \Big(\sum_{s,k} P_s (\sum_i A_i d_{itks} - \sum_j C_j \; g_{jtks}) - \sum_b (C_b^{(dh)} \tilde{d}_{btks} + C_b^{(ch)} \; \tilde{g}_{btks}) - (\sum_b C_{bt}^{(E)} (e_{bt} - e_{b(t-1)}) - \sum_b C_{bt}^{(P)} (p_{bt} - p_{b(t-1)}) - \sum_w C_{wt}^{(W)} (u_{wt} - u_{w(t-1)}) \Big) = \sum_t \Big(\sum_i D_{it} \overline{\omega}_{itks} + \sum_j G_j \overline{\nu}_{jtks} + \sum_l F_l(\underline{\mu}_{ltks} + \overline{\mu}_{ltks}) + \sum_m \widehat{F}_m(\overline{\gamma}_{mtks}) \Big) \quad (7a)$$

$$-\Xi_m z_{mt} \le \overline{\sigma}_{mtks} + \underline{\sigma}_{mtks} \le \Xi_m z_{mt} \quad (7b)$$

$$-\Xi_m (1 - z_{mt}) \le \overline{\zeta}_{mtks} + \underline{\zeta}_{mtks} \le \Xi_m (1 - z_{mt}) \quad (7c)$$

The initial mixed-integer nonlinear bilevel model (1)-(3) is transformed into an MILP model (8). Where Ω' is the set of all primal and dual continuous variables of (8).

$$\underset{z_{mt}, y_{mt}, \Omega'}{\text{Maximize}} \sum_t \langle \sum_s (\sum_l F_l(\overline{\mu}_{ltks} + \underline{\mu}_{ltks}) + \sum_m \widehat{F}_m(\overline{\gamma}_{mtks} + \underline{\mu}_{ltks}) + \Phi_t - \frac{1}{(1+r)^{t-1}} \sum_m C_{mt}^{(T)} y_{mt} \rangle \quad (8a)$$

Subject to:

$$z_{m,(t=1)} = 0 \; \forall m \quad (8b)$$

$$z_{mt} = \sum_{\widehat{t} \le t} y_{m,\widehat{t}} \; \forall m, \forall t \ge 2 \quad (8c)$$

$$\sum_t y_{mt} \le 1 \; \forall m, t \quad (8d)$$

$$\Phi_t = \sum_s P_s \sum_k (\frac{\Psi}{(1+r)^{t-1}} ((\sum_i A_i d_{itks} - \sum_j C_j g_{jtks} + \sum_b (C_b^{(ch)} \tilde{g}_{btks} + C_b^{(dh)} \tilde{d}_{btks}) - \sum_k (\sum_i (A_i d_{i(t-1)ks} - \sum_j C_j g_{j(t-1)ks}) + \sum_{b,k} (C_b^{(ch)} \tilde{g}_{b(t-1)ks} + C_b^{(dh)} \tilde{d}_{b(t-1)ks})) - \sum_l F_l(\overline{\mu}_{ltks} + \underline{\mu}_{ltks}) - \sum_m \widehat{F}_m(\overline{\gamma}_{mtks} + \overline{\mu}_{ltks})) + \frac{1}{(1+r)^{t-1}} (\sum_m C_{mt}^{(T)} y_{m(t-1)} - \sum_w C_{wt}^{(W)} (u_{wt} - u_{w(t-1)}) - \sum_b C_{bt}^{(E)} (e_{bt} - e_{b(t-1)}) - \sum_b C_{bt}^{(P)} (p_{bt} - p_{b(t-1)})) \; \forall t \ge 2 \quad (8e)$$

$$(2b), (3b)-(3n), (3q)-(3u), (4), (7) \quad (8f)$$

$$0 \le \tilde{g}_{btks} \le p_{bt} \;\; : (\underline{\kappa}_{btks}, \overline{\kappa}_{btks}) \; \forall b, t, k, s \quad (8g)$$

$$0 \le \tilde{d}_{btks} \le p_{bt} \;\; : (\underline{\vartheta}_{btks}, \overline{\vartheta}_{btks}) \; \forall b, t, k, s \quad (8h)$$

$$\underline{\omega}_{itks}, \overline{\omega}_{itks}, \underline{\nu}_{jtks}, \overline{\nu}_{jtks}, \underline{\eta}_{wtks}, \overline{\eta}_{wtks}, \sigma_{ltks}, \overline{\zeta}_{mtks} \ge 0 \quad (8i)$$

$$z_{mt}, y_{mt} \in \{0, 1\} \quad (8j)$$

III. Disjunctive-based decomposition (DBD)

Reformulated and linearized optimal investment model (8) is a linear disjunctive program. The disjunction properties occur in transmission investment constraints ((3g))-((3i)) since a subset of constraints are satisfied using the binary variables z_{mt} and y_{mt}. The disjunctive structure of the problem can be exploited to improve computational tractability of the problem using decomposition algorithm. In this section we propose a modified and accelerated decomposition algorithm based on initial decomposition framework presented in [29]. We show that proposed algorithm not only exploits disjunctive structure of the problem but removes the need in tuning any additional arbitrary parameters used in the disjunctive constraint formulation. For the sake of simplicity, a general form is used in this section to explain our porposed DBD algorithm. Generalized disjuctive program could be written as (9). Vectors of variables and proper parameter matrices are employed to state (8) in the general form as (9).

$$\underset{\boldsymbol{u}, \boldsymbol{y}}{\text{Maximize}} \quad R^\intercal \boldsymbol{u} \quad (9a)$$

Subject to:

$$A\boldsymbol{u} \le B \;\; : (\boldsymbol{\mu}) \quad (9b)$$

$$V\boldsymbol{u} \le C - \Xi(\mathcal{I} - \boldsymbol{y}) \;\; : (\boldsymbol{\nu}) \quad (9c)$$

$$E\mathbf{y} = Z \quad (9d)$$

$$\mathbf{u} \ge 0 \quad (9e)$$

$$\forall y \in \mathbf{y} : y \in \{0, 1\} \quad (9f)$$

Here $\mathbf{u} = [\underline{\omega}_{itks}, \overline{\omega}_{itks}, \underline{\nu}_{jtks}, \overline{\nu}_{jtks}, \underline{\eta}_{wtks}, \overline{\eta}_{wtks}, \sigma_{ltks}, \overline{\zeta}_{mtks}, \overline{\xi}_{ntks}, \underline{\xi}_{ntks}]$ is vector of positive continuous variables (9e) and $\mathbf{y} = [z_{mt}, y_{mt}]$ is vector of binary variables in (9f). Equality constraints are enforced using two inequality constraints. For instance, $\overline{\vartheta}_{btks} \le 0$ and $\overline{\vartheta}_{btks} \ge 0$ are used instead of $\overline{\vartheta}_{btks} = 0$ to be able to use constraint (9b) in the general formulation. The problem in (8) could be written in the general form in (9) using proper parameter matrices R, A, B, V, C, E, and Z. Also $\mathcal{I}$ is an square identity matrix. (9c) is employed to enforce $V\mathbf{u} \le C$ only when the coincide binary variable is equal to one and relaxed otherwise. $\Xi \in \Re$ is a sufficiently large constant that satisfies $V\mathbf{u} \le C - \Xi$ when $y \in \mathbf{y}$ is zero. Furthermore, $V\mathbf{u} \le C$ is enforced when corresponding $y \in \mathbf{y}$ is one. (9d) is used to enforce Z number of constraints in (9c). The disjunctive structure can be used to split the problem into a master problem and a subproblem. The subproblem is formulated based on dual of the original problem (9) by fixing complicating variables ($y \in \mathbf{y}$) as in (10). Initial values could be chosen arbitrarily for the first iteration.

$$\underset{\boldsymbol{\mu}, \boldsymbol{\nu}}{\text{Minimize}} \quad K_v = B^\intercal \boldsymbol{\mu} + C^\intercal \boldsymbol{\nu} + (-\Xi(\mathcal{I} - \boldsymbol{y}_v)^\intercal) \boldsymbol{\nu} \quad (10a)$$

Subject to:

$$A^\intercal \boldsymbol{\mu} + V^\intercal \boldsymbol{\nu} \ge R \;\; : (\mathbf{u}) \quad (10b)$$

$$\boldsymbol{\mu}, \boldsymbol{\nu} \ge 0 \quad (10c)$$

The subproblem (10) is derived using the duality theorem applied on a relaxed linear version of problem (9) where complicating variables ($y \in \mathbf{y}$) are treated as parameters.

The objective function of the subproblem (10) contains the disjunctive parameter in the term $(-\Xi(\mathcal{I}-\boldsymbol{y}_v)^\intercal)\boldsymbol{\nu}$. However, the complementary slackness conditions of constraints (9c) guarantee that the term $(\mathcal{I}-\boldsymbol{y}_v)^\intercal\boldsymbol{\nu}$ is equal to zero for the optimal solution. Therefore, $(-\Xi(\mathcal{I}-\boldsymbol{y}_v)^\intercal)\boldsymbol{\nu}$ could be removed from the objective function if additional constraint which represents complementary slackness condition is added to the formulation. Doing this, the subproblem (10) equivalently reformulated as (11) without disjunctive parameter.

$$\underset{\boldsymbol{\mu},\boldsymbol{\nu}}{\text{Minimize}}\ \ K_v = B^\intercal\boldsymbol{\mu} + C^\intercal\boldsymbol{\nu} \tag{11a}$$

Subject to:

$$A^\intercal\boldsymbol{\mu} + V^\intercal\boldsymbol{\nu} \geq R\ \ : \mathbf{u} \tag{11b}$$

$$\boldsymbol{\mu}, \boldsymbol{\nu} \geq 0 \tag{11c}$$

$$(\mathcal{I} - \boldsymbol{y}_v)^\intercal\boldsymbol{\nu} = 0 \tag{11d}$$

The Lagrange multipliers of the subproblem are used as input parameters to the master problem. In each iteration, $\boldsymbol{\nu}_v$ forms the new set Ω_v; this set is used to represent index sets for extreme points corresponding to the constraints with integer variables (9c). Using the set Ω_v obtained through solving the subproblem as well as the objective function value K_v, master problem is formulated as (12).

$$\underset{x_v,\boldsymbol{y}_v}{\text{Maximize}} \sum_v K_v x_v \tag{12a}$$

Subject to:

$$\sum_{m,t\in\Omega_v} y_{m,t} \leq |\Omega_v| - 1 + \sum_{v'\ni(K_{v'}\geq K_v)} x_{v'} \tag{12b}$$

$$\sum_v x_v = 1 \tag{12c}$$

$$E\mathbf{y} = Z \tag{12d}$$

$$y_{m,t} \in \{0,1\}\ \forall y_{m,t} \in \mathbf{y}_v \tag{12e}$$

Here $|\Omega_v|$ is cardinality of the set Ω_v. The constraint (12b) represents feasibility cuts modeled according to the presented approach in [30]. Variables x_v are used to activate the corresponding feasibility cut. Solution of the master problem derives a set of integer variables $y_{m,t} \in \mathbf{y}_v$ which are used to update fixed values of the complicating variables in the subproblem ($\boldsymbol{y}_v$). The master problem (12) forms cuts which are as tight or tighter than cuts of Benders decomposition [30]. However, the cuts in (12b) do not contain disjunctive parameters (unlike the original Benders cuts) and allow to skip tuning of the disjunctive parameters. The proposed DBD algorithm solves the subproblem (11) and the master problem (12) while increasing the number of iterations until the optimality gap is satisfied. Without the disjunctive parameter, the numerical stability problem is eliminated. The proposed DBD algorithm is detailed in Fig. 2. Here original Benders decomposition approach and our modified decomposition approaches are shown for two iterations. The master problem during the initial iterations might have multiple optimal solutions. At each iteration, these multiple solutions are found and then associated subproblems to these optimal solutions are solved in parallel.

IV. Case studies

The investment mechanism has been applied to a six-node system as well as to IEEE 118-node and 300-node systems.

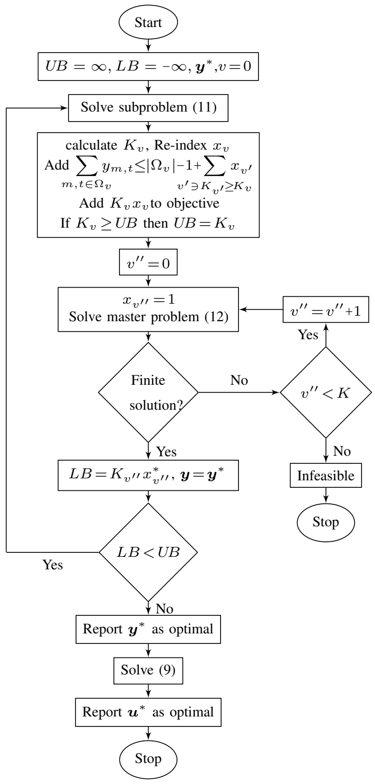

Figure 1. The proposed DBD algorithm

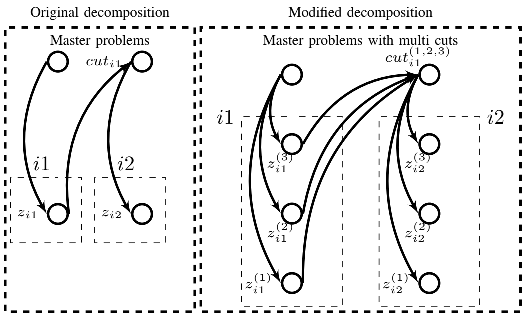

Figure 2. The multi-cut acceleration technqiue employed in DBD algorithm in Fig. 1

A. The six-node illustrative example

Single-line diagram of the six-node system is shown in Fig. 3. Two periods are considered where period 1 models the status quo case. The profit-maximizing Transco has four candidate transmission lines (6,3), (5,3), (5,4) and (6,4) where each pair (x, y) represents a line from node x to node y. Renewable-energy generators $W1$ and $W2$ are considering to invest in nodes 6 and 5 respectively. Outputs of the renewable-energy generators are stochastic and scenarios of wind generation output are made using a moment-matching technique proposed in [31]. Three sites are considered for battery-storage investments in nodes 4, 5, and 6. The system data are presented in Tables II and III.

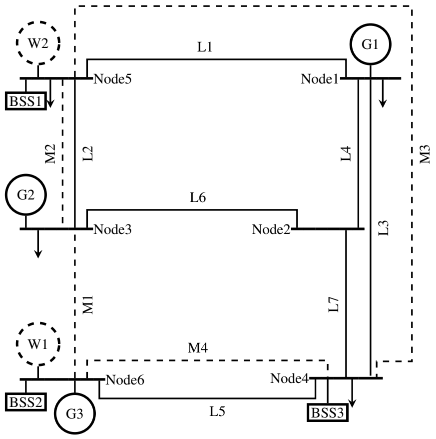

Figure 3. Single-line diagram of the six-node system

Table II
DATA OF LOADS IN THE SIX-NODE SYSTEM

Load	Node	Short-run Marginal Utility ($/MWh)	Capacity (MW) at $t=1$
D1	Node 1	250	95
D2	Node 2	245	75
D3	Node 3	235	82
D4	Node 4	730	105
D5	Node 5	225	55

Table III
DATA OF GENERATORS AND BSSS IN THE SIX-NODE SYSTEM

Generator	Node	Short-run marginal cost ($/MWh)	Capacity (MW)	Expansion cost
G1	Node 1	600	60	-
G2	Node 3	500	50	-
G3	Node 6	1,000	40	-
W1	Node 6	50	0	80,000
W2	Node 5	50	0	7,000
BSS1	Node 5	0	0	800/500
BSS2	Node 4	0	0	300/600
BSS3	Node 6	0	0	500/300

The results of the transmission investment under our proposed mechanism are reported in Table IV and compared to the case when no regulation is applied (which is simulated using the same model but setting the fixed fee equal to zero for all time periods) and the benchmark case which refers to the system investments under the social-welfare maximizing objective.

Under our proposed investment mechanism, the Transco invests in lines M1, M3 and M4 but never in line M2 which is identical to investment decisions in the benchmark case. In comparison, the investments under the no regulatory mechanism is completely different from the benchmark case. Therefore, they cannot deliver investments which are social-welfare maximizing. Our proposed mechanism also supports social-welfare maximizing investments by renewable-energy

Table IV
INVESTMENT RESULTS IN THE SIX-NODE SYSTEM

	MRM[i]	NRG[ii]	SWM[iii]
M1	**1**	0	**1**
M2	0	**1**	0
M3	**1**	**1**	**1**
M4	**1**	0	**1**
W1 (MW)	1,229	1,309	1,229
W2 (MW)	235	136	235
BSS1 (MW/MWh)	0/0	0/0	0/0
BSS2 (MW/MWh)	78/78	43/29	78/78
BSS3 (MW/MWh)	157/56	132/40	157/56
Wind spillage [viii] (%)	0.5%	3%	0.5%
Fixed Fee (M$)	4,830.84	-	-
Congestion Rent (M$)	661.9	759.5	-
Load Surplus (M$)	5,720.5	2,888.4	-
BSP[iv] Surplus (M$)	549.5	439.1	-
Generation Surplus (M$)	4,384	3,588	-
WGP[v] Surplus (M$)	1,610	2,108	-
Trans.[vi] Inv.[vii] Cost (M$)	48.5	5.8	-

i: our proposed merchant-regulatory mechanism, ii: No regulation, iii: Social-welfare maximising results, iv: BSS surplus, v: Wind generation surplus, vi: Transmission, vii: Investment
viii: wind spillage is calculated as $\frac{(\widehat{G}_w+u_{wt})\varrho_{wtks}-\widehat{g}_{wtks}}{(\widehat{G}_w+u_{wt})\varrho_{wtks}}$

Table V
INPUT DATA FOR CASE STUDIES

	IEEE 118-node	IEEE 300-node
Number of candidate lines	30	60
Number of existing lines	175	411
Conventional Generation (MW)	4,300	20,678
Wind Generation (MW)	2,500	1,2000
Battery storage (MWh)	100	100
Number of scenarios	20	20
Number of operation subperiods	105	72
Maximum Load (MW)	4,242	23,526
Number of periods	4	4

generators and battery-storage units. And as a consequence renewable-energy generation spillage is substantially reduced.

B. Performance of the proposed DBD algorithm

The proposed MILP model in (8) and the DBD algorithm are further verified on larger-scale case studies based on the IEEE 118- and 300-node systems. The simulations are run on a computer with two 2.3 GHz processors and 128 GB of Random Access Memory (RAM). All data for the IEEE test systems are taken from data files of the MATPOWER software [32]. The maximum demand at each node was increased by 50%. Scenarios of wind generation outputs are generated using a moment-matching technique proposed in [31]. As we can see in Table VI and Table VII, the DBD algorithm can find the optimal solution while the Benders decomposition algorithm and the off-the-shelf solver CPLEX fail to report any solution. This improvement of computational tractability is result of three major contributions of the proposed decomposition algorithm. First, the disjunctive nature of the the MILP model is fully exploited. Second, the algorithm does not have the disjunctive parameter in neither master problem nor subproblem. Thus, the adverse numerical effect of the disjunctive parameter was removed. Third, convergence of the algorithm was accelerated using parallel computation technique and multiple cut generation.

Table VI
RESULTS FOR IEEE 118-NODE CASE STUDY

	Objective Function ($)	Computation Time (h)	iterations
CPLEX solver	*	*	*
Benders decomposition	*	*	*
Proposed DBD	3,859	8.01	1,105

"*":No solution after 24 hours of simulation

Table VII
RESULTS FOR IEEE 300-NODE CASE STUDY

	Objective Function ($)	Computation Time (h)	Iterations
CPLEX solver	*	*	*
Benders decomposition	*	*	*
Proposed DBD	6,712	9.5	10,139

"*": No solution after 24 hours of simulation

V. CONCLUSIONS

This paper proposes a coordination mechanism for efficient investment in the battery storage, renewable-energy and transmission capacity. Under the proposed investment mechanism, the Transco moves first and invests in the transmission network over planning periods, collects the merchandising surplus and a fixed fee based on the ISS regulation. The Transco takes into account optimal capacity of the battery storage and the renewable generation in its investment decisions. The proposed investment mechanism results in the maximum social-welfare investments in the whole system. The mathematical model of the proposed investment mechanism is a large-scale mixed integer bilevel program and therefore it is hard to be solved. This bilevel program is converted into a one-level equivalent stochastic mixed integer linear program through a Lemma and a series of proposed linearization techniques. The resulting stochastic model is solved using a proposed DBD algorithm. The MILP reformulation and proposed DBD algorithm were applied to case studies of different sizes. The numerical results show utility of the proposed investment mechanism, its reformulated MILP model and its associated DBD algorithm for efficient coordinated investments.

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Publication P1

Short-term planning of hydro-thermal system with high wind energy penetration and energy storage

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***Abstract*—Wind based electricity generation is considered as one of the solutions for emission reduction. However, variability and uncertainty of wind speeds create challenges for balancing in power systems and in many cases require improvements in ramping capabilities of the system along with additional reserve generation capacity. Ramping capability as well as generation reserves could be provided by different technologies such as thermal and hydro generation and different types of energy storage. The last option is considered to be a possible solution for power systems with large wind generation. This paper provides a model for planning of energy storage units in a hydro-thermal power system with high wind energy penetration. The model is used to compare the effect of different generation mix and energy storage presence on the operation of the power system and balancing cost in particular.**

***Keywords*—Stochastic processes, Dynamic programming, Energy storage, Power system planning, Wind power generation.**

I. NOMENCLATURE

A. Indices

ees	Energy storage systems
gen	Generators
h	Hydro power stations
h^*	Hydro power stations located upstream
l	Transmission lines
n	Nodes of the system
s	Scenarios
t	Planning period
w	Wind based generation
tech	superset for sets gen and h

B. Variables

g_{ees}^{ch}	Charge of energy storage
g_{ees}^{dch}	Discharge of energy storage
g_{ees}	Output of energy storage
g_{ees}^*	Output of energy storage (stochastic)
g_{gen}	Output of conventional generation units
g_{gen}^*	Output of generation units (stochastic)
g_h	Output of hydro unit
g_h^*	Output of hydro unit
g_w	Consumed wind based generation
$\uparrow \Delta g_{gen}$	Expected balancing from thermal units
$\uparrow \Delta g_{ees}^{ch}$	Stochastic energy storage output
$\uparrow \Delta g_{ees}^{dch}$	Stochastic energy storage output
$\uparrow \Delta g_h^{up}$	Stochastic hydro generation output
$\downarrow \Delta g_{gen}$	Stochastic conventional generation output
$\downarrow \Delta g_{ees}^{ch}$	Stochastic energy storage output
$\downarrow \Delta g_{ees}^{dch}$	Stochastic energy storage output
$\downarrow \Delta g_h$	Stochastic hydro generation output
soc_{ees}	State of charge of energy storage
$spill$	Spillage of wind power generation
s_h	Spillage of water
u_h	Discharge of reservoir
vr_h	Reservoir content
v_n	voltage angle at the node

C. Parameters

cp_{gen}	balancing penalty cost for thermal units
cp_{ees}	balancing penalty cost for energy storage
d_n	Load at the node
FC	Future cost of electricity
fl_h	Constant inflow in water reservoirs
g_w^*	Wind power generation
G_{gen}^{max}	Maximum generation of thermal units
G_h^{max}	Maximum generation of hydro units
G_{gen}^{min}	Minimum generation thermal units
G_h^{min}	Minimum generation of hydro units
inf_h	Constant inflow
IR_l	Matrix of receiving end of transmission lines
IS_l	Matrix of sending end of transmission lines
I_{gen}	Incidence matrix for generation
I_h	Incidence matrix for hydro based generation
I_w	Incidence matrix for wind based generation
I_{ees}	Incidence matrix for energy storage units
mc_{ees}	Cost of operation of energy storage
$R1_g^{max}$	Ramping limit of conventional unit
$R2_g^{max}$	Ramping limit for reserves
SOC_{ees}^{max}	Storage capacity of energy storage
SOC_{ees}^{min}	Minimum state of charge of energy storage
T_l^{max}	Transmission line capacity
ϵ_{ees}	Energy conversion efficiency
ϕ_{ees}	Self discharge of energy storage
σ_h	Hydro power conversion rate

II. INTRODUCTION

Increasing energy demand along with the need to reduce emissions has resulted in a large expansion of wind power generation in the last decades, for example in Europe, USA and China. The variability and unpredictability of wind power increase the need for balancing, both including automatic services and load following. The variability of the wind speed requires that the system has enough ramping capability to follow the variations of the wind power generation in different time frames, ranging from seconds to hours. Additional uncertainties related to unpredictability will require larger reserves for the frequency control as well as better ramping capability.

Hydro-thermal power systems generally have good ramping capability and energy storage possibility in form of hydro reservoirs. However, for a large-scale expansion of wind power (or other variable generation such as solar) existing hydro flexibility might not be sufficient. The ramping capability of the system can then be improved by increasing the flexibility of existing power plants, adding additional fast-ramping generation capacity, demand response or energy storage capability.

Energy storage systems integrated with wind power are considered to be an efficient and serviceable solution due to the possibility to be used for both automatic services and load following. Pumped hydro and compressed air energy storage are the only bulk energy storage systems that are commercially available today [1]. However, some other technologies such as flywheels, sodium-sulfur batteries, lead-acid batteries has been successfully tested for providing services to the grid on TSO and utility levels [2].

There are different ways how energy storage systems could be used for balancing applications, especially in presence of large amount of variable, renewable generation [1]. A database with a list of existing energy storage projects around the world can be found in [3]. A review of modelling techniques for energy storage is provided in [4] and includes more than 150 papers on energy storage assessment subject. The papers and models analysed in [4] are used to investigate the value of adding energy storage to a thermal power system. However, for hydro-thermal power systems, there is a need for modelling the value of additional energy storage capability in relation to the existing flexibility and storage capacity of hydro units.

The aim of this paper is to present a model of the operation of energy storage in hydro-thermal power systems and apply the model to varying case studies with different generation mix. The model focuses on load-following on an hourly time-scale, but also considers the need for 15-minutes reserves. In order to incorporate the uncertainties in operation of a power system with large amounts of wind power, the stochastic programming framework is used. The model is applied to a test system with varying degrees of existing flexibility, and the value of adding energy storage is compared.

The suggested model is presented in section III. Case studies are presented and discussed in section IV and the conclusions are given in section V.

III. Short-term generation planing problem

A short-term generation planing model should be able to reflect stochastic nature of the wind power generation. Thus, two-stage stochastic programming technique is used as a framework for the model. The model assumes that no other stochastic process affect the generation planning except wind power generation.

The decision framework consist of two stages. First stage variables are the generation dispatch values scheduled prior the beginning of the planing period. Second stage variables are related to expected balancing cost associated with stochastic wind power generation.

Wind speed scenarios are modeled using Semi-Markov modeling technique presented in [5] and further used to constructs a scenario tree. Scenarios for wind speed are then used as an input for wind power generation scenarios which are calculated based on wind curve provided by [6].

Minimize:

$$\sum_t (C_g(t) + C_b(t)) + C_a \tag{1}$$

Where:

$$C_g(t) = \sum_{gen} mc_{gen} g_{gen}(t) + \sum_{ees} mc_{ees}(g^{ch}_{ees}(t) + g^{dch}_{ees}(t)) \tag{2}$$

$$\begin{aligned} C_b(t) = & \sum_s pi(s) * \\ & * [(mc_{gen}) \sum_{gen} (\uparrow \Delta g_{gen}(t,s) - \downarrow \Delta g_{gen}(t,s)) \\ & + (cp_{gen}) \sum_{gen} (\uparrow \Delta g_{gen}(t,s) + \downarrow \Delta g_{gen}(t,s)) \\ & + (mc_{ees} + cp_{ees}) \sum_{ees} (\uparrow \Delta g^{ch}_{ees}(t,s) + \downarrow \Delta g^{ch}_{ees}(t,s)] \end{aligned} \tag{3}$$

$$C_a = -\sum_{ees} soc_{ees}(T,s) FC - \sum_h h_v(T,s) FC \tag{4}$$

The objective function is to minimize the cost of the scheduled non stochastic day ahead generation dispatch $C_g(t)$ based on the marginal generation cost of thermal units mc_{ees} and expected balancing cost $C_b(t)$. The balancing cost appears only in presence of stochastic wind power generation and depends on marginal costs and additional penalty cost cp_{gen} connected to required rapid change in dispatch. In addition, the operation of hydro and energy storage units takes into account energy arbitrage opportunity cost C_a. Energy could be saved at the end of planing period T to be traded in the future.

This model does not include any binary variables or nonlinear constraint preventing energy storage from charging or discharging at the same time. However, in order to avoid such events a small penalty cost mc_{ees} was added to objective function for each MWh of energy storage operation.

For simplification of the constraints the following equation for substitution variables are used:

$$g^*_{tech}(t,s) = g_{tech}(t) + \uparrow \Delta g_{tech}(t,s) - \downarrow \Delta g_{tech}(t,s), \quad \forall t, s, tech. \tag{5}$$

$$g^{ch*}_{ees}(t,s) = g^{ch}_{ees}(t) + \uparrow \Delta g^{ch}_{ees}(t,s) - \downarrow \Delta g^{ch}_{ees}(t,s), \quad \forall t, s, ees. \tag{6}$$

$$g^{dch*}_{ees}(t,s) = g^{dch}_{ees}(t) + \uparrow \Delta g^{dch}_{ees}(t,s) - \downarrow \Delta g^{dch}_{ees}(t,s), \quad \forall t, s, ees. \tag{7}$$

$$u^*_h(t,s) = u_h(t) + \uparrow \Delta u_h(t,s) - \downarrow \Delta u_h(t,s), \ \forall t, s, h. \tag{8}$$

Subject to:

$$\begin{aligned} & I_{gen} g^*_{gen}(t,s) + I_{ees}(g^{*ch}_{ees}(t,s) + g^{*dch}_{ees}(t,s)) + I_h g^*_h(t,s) \\ & + I_w g_w(t,s) - d_n(t,s) + IR_l f(l,t,s) \\ & - IS_l f(l,t,s) = 0, \quad \forall t, s, n. \end{aligned} \tag{9}$$

Consumption and generation of electricity should be equal at each point of time. Thus, power balance equation (9) is used. The equation maintains the balance between power generation consumption as well as power inflow and outflow at each node for each planing time step. For simplicity this model assumes that all power flows are direct current (DC). Thus, voltage angles are not taken in consideration.

$$f(l,t,s) = (IS_l v(n,t,sc) - IR_l v(n,t,sc))/X(l),\ \forall t,s,l. \quad (10)$$

Power flows between connected nodes used in power balance equation could be determined for DC power system model through voltages on both ends and technical characteristics of transmission lines such as reactance (10).

The model includes different types of technologies apart from thermal generation such as hydro power and energy storage. Both of these technologies requite additional operation constraint to include storage possibilities.

$$vr_h(t,s) = vr_h(t-1,s) - u^*_h(t,s) - s_h(t,s) + fl_h + \sum_{h^*} u^*_{h^*}(t-\tau_{h^*},s) + \sum_{h^*} s_{h^*}(t-\tau_{h^*},s),\ \forall t,s,h. \quad (11)$$

Hydrological balance equation (11) controls the hourly reservoir water level including previous content, direct inflow fl_h, spillage s_h and outflow u^*_h used for power generation.

$$g^*_h(t,s) = \sigma_h u^*_h(t,s),\ \forall t,s,h. \quad (12)$$

Power generated by hydro units is determined through linear function (12). This means that the efficiency of the hydro unit is assumed to be constant. Another approach is to use piecewise linear function.

$$SOC_{ees}(t,s) = \phi_{ees} SOC_{ees}(t-1,s) + \epsilon_{ees} g^{ch}_{ees}(t,s) - 1/\epsilon_{ees} g^{dch}_{ees}(t,s),\ \forall t,s,ees. \quad (13)$$

The energy balance equation (13) controls the state of the charge of the energy storage unit. The dynamics of energy storage are very similar to hydro power. The main difference is that energy storage will convert surplus of electricity and store it in different form of energy or in form of electromagnetic field and then convert it back when it is demanded [7]. The conversion of electricity into another form of energy will cost some losses. These losses could be represented through efficiency coefficient ϵ_{ees} of energy storage. Also, most of energy storage has self discharge rate ϕ_{ees} which also cause the losses of energy.

$$g_w(t,s) = g^*_w(t,s) + spill_w(t,s)\ \forall t,s,w. \quad (14)$$

In this model wind based generation could be spilled when there are excess of generation or not enough ramping capability.Thus, equation (14) is used to determine actual consumed wind power $g_w(t,s)$.

Ramping constraints:

$$g^*_{gen}(t,s) - g^*_{gen}(t-1,s) \le R1^{max}_{gen},\ \forall t,s,gen. \quad (15)$$
$$g^*_{gen}(t-1,s) - g^*_{gen}(t,s) \le R1^{max}_{gen},\ \forall t,s,gen. \quad (16)$$
$$\uparrow \Delta g_{gen}(t,s) \le R2^{max}_{gen},\ \forall t,s,gen. \quad (17)$$
$$\downarrow \Delta g_{gen}(t,s) \le R2^{max}_{gen},\ \forall t,s,gen. \quad (18)$$

There are two different ramping limits in this model. First ramping limit is for change in power generation between each operating hour, $R1^{max}_{gen}$. Second ramping limit, $R2^{max}_{gen}$, is for balancing requirements and for reserves.

Maximum and minimum limit constraints:

$$G^{min}_{tech} \le g^*_{tech}(t,s) \le G^{max}_{tech},\ \forall t,s,tech. \quad (19)$$
$$G^{min}_{tech} \le g_{tech}(t) \le G^{max}_{tech},\ \forall t,tech. \quad (20)$$
$$G^{min}_{ess} \le g^{*ch}_{ees}(t,s) \le G^{max}_{ees},\ \forall t,s,ees. \quad (21)$$
$$G^{min}_{ess} \le g^{*dch}_{ees}(t,s) \le G^{max}_{ees},\ \forall t,s,ees. \quad (22)$$
$$G^{min}_{ess} \le g^{ch}_{ees}(t) \le G^{max}_{ees},\ \forall t,ees. \quad (23)$$
$$G^{min}_{ess} \le g^{dch}_{ees}(t) \le G^{max}_{ees},\ \forall t,ees. \quad (24)$$
$$SOC^{min}_{ees} \le SOC_{ees}(t,s) \le SOC^{max}_{ees},\ \forall t,s,ees. \quad (25)$$
$$-T^{max}_l \le lf(l,t,s) \le T^{max}_l,\ \forall t,s,l. \quad (26)$$
$$0 \le v_h(t,s) \le v^{max}_h,\ \forall t,s,h. \quad (27)$$
$$0 \le s_h(t,s) \le s^{max}_h,\ \forall t,s,h. \quad (28)$$
$$0 \le u_h(t,s) \le u^{max}_h,\ \forall t,s,h. \quad (29)$$

Reserve constraints:

$$\sum_h \uparrow res_h(t) + \sum_{gen} \uparrow res_{gen}(t) + \sum_{ees} \uparrow res_{ees}(t) \ge Res^{reg},\ \forall t. \quad (30)$$
$$\sum_h \downarrow res_h(t) + \sum_{gen} \downarrow res_{gen}(t) + \sum_{ees} \downarrow res_{ees}(t) \ge Res^{reg},\ \forall t. \quad (31)$$

$$g^*_{tech}(t,s) + \uparrow res_{tech}(t) \le G^{max}_{tech},\ \forall t,s,tech. \quad (32)$$
$$g_{tech}(t) + \uparrow res_{tech}(t) \le G^{max}_{tech},\ \forall t,tech. \quad (33)$$
$$g^*_{tech}(t,s) - \downarrow res_{tech}(t) \ge G^{min}_{tech},\ \forall t,s,tech. \quad (34)$$
$$g_{tech}(t) - \downarrow res_{tech}(t) \ge G^{max}_{tech},\ \forall t,tech. \quad (35)$$
$$G^{min}_{ess} \le \downarrow res_{ees}(t) \le G^{max}_{ees},\ \forall t,ees. \quad (36)$$
$$G^{min}_{ess} \le \uparrow res_{ees}(t) \le G^{max}_{ees},\ \forall t,ees. \quad (37)$$
$$SOC_{ees}(t,s) + \uparrow res_{ees}(t) \le SOC^{max}_{ees},\ \forall t,s,ees. \quad (38)$$
$$SOC_{ees}(t,s) - \downarrow res_{ees}(t) \ge SOC^{min}_{ees},\ \forall t,s,ees. \quad (39)$$
$$\uparrow \Delta res_{gen}(t) \le \uparrow R2^{max}_{gen},\ \forall t,gen. \quad (40)$$
$$\downarrow \Delta res_{gen}(t) \le \downarrow R2^{max}_{gen},\ \forall t,gen. \quad (41)$$

$$g^*_{tech}(t,s) + \uparrow res_{tech}(t) \le G^{max}_{tech},\ \forall t,s,tech. \quad (42)$$
$$g_{tech}(t) + \uparrow res_{tech}(t) \le G^{max}_{tech},\ \forall t,tech. \quad (43)$$
$$g^*_{tech}(t,s) - \downarrow res_{tech}(t) \ge G^{min}_{tech},\ \forall t,s,tech. \quad (44)$$
$$g_{tech}(t) - \downarrow res_{tech}(t) \ge G^{max}_{tech},\ \forall t,tech. \quad (45)$$
$$G^{min}_{ess} \le \downarrow res_{ees}(t) \le G^{max}_{ees},\ \forall t,ees. \quad (46)$$
$$G^{min}_{ess} \le \uparrow res_{ees}(t) \le G^{max}_{ees},\ \forall t,ees. \quad (47)$$
$$SOC_{ees}(t,s) + \uparrow res_{ees}(t) \le SOC^{max}_{ees},\ \forall t,s,ees. \quad (48)$$
$$SOC_{ees}(t,s) - \downarrow res_{ees}(t) \ge SOC^{min}_{ees},\ \forall t,s,ees. \quad (49)$$
$$\uparrow \Delta res_{gen}(t) \le \uparrow R2^{max}_{gen},\ \forall t,gen. \quad (50)$$
$$\downarrow \Delta res_{gen}(t) \le \downarrow R2^{max}_{gen},\ \forall t,gen. \quad (51)$$

The reserves are non-stochastic variables and could be provided by each generation of energy storage unit and the reserved capacity should be enough to cover the possible outage of biggest thermal or hydro generation unit.

IV. Case study

A. Input Data

Three different case studies are applied to two different power systems: thermal only and hydro-thermal. The operation of a hydro-thermal power system is then compared to the operation of a thermal only power system under each case study.

Case 1. First, operation of both systems was compared under assumption, when no wind based generation is present. The generation mix for Case 1 for both systems presented in tables I and II.

Case 2. Second case study is designed to capture differences in operation when very large amount of wind based generation is added. The generation mix for Case 2 for both systems is presented in tables IV and V.

Case 3. Finally, the third case studies operation of both systems when additional energy storage capacity is present.The generation mix for Case 3 is almost the same as for Case 2 and could be found in tables IV and V. The only difference is the energy storage presence. The energy storage size as well as power capability could be found in table III. Energy storage system assumed to be a large scale battery system with average parameters. The data used for energy storage model parameters is based on information provided in [8]. The parameters associated with energy conversion and storage presented in table III.

All three cases were applied to the 30 bus IEEE test system with planing horizon of 32 hours and one hour time resolution for generation dispatch and 15 min ramping limits for balancing and 10 minutes for reserves. Ramping capability of thermal units presented in table VI. Hydro and energy storage ramping capability is assumed to be very fast and are not a subject for additional ramping constrains.

The costs of operation of the conventional generation are based on information provided in [9]. The generation with faster ramping capability assumed to be more expensive.

The load dynamics is modeled based on historical Swedish load data and taken as the average load during 32 hours during autumn.

Two hydro power generators are present in the hydro-thermal system and it is assumed that hydro power plant with a higher index is located upstream and the released water from upstream reservoir will reach downstream power plant with the time delay of 2,6 hours.

TABLE I. Installed capacity by generation type for thermal power system. Case 1.

Generation type	Generation size (MW)	Nodes
Thermal 1	50	23
Thermal 2	60	13
Thermal 3	80	1
Thermal 4	80	2
Thermal 5	80	22
Thermal 6	80	27

TABLE III. Energy storage characteristics.

Energy storage capacity, SOC_{ees}^{max}	50 MWh
Power limit, G_{gen}^{max}	30 MW
Energy conversion efficiency, ε	0.80
Self discharge of energy storage, η	0.97
Initial state of charge	50%

TABLE II. Installed capacity by generation type for hydro-thermal power system. Case 1.

Generation type	Generation size (MW)	Nodes
Hydro 1	80	22
Hydro 2	80	27
Thermal 1	50	23
Thermal 2	60	13
Thermal 3	40	1
Thermal 4	60	2

TABLE IV. Installed capacity by generation type for thermal system. Case 2 and Case 3.

Generation type	Generation size (MW/MWh)	Nodes
Thermal 1	50	23
Thermal 2	60	13
Thermal 3	40	1
Thermal 4	60	2
Thermal 5	80	22
Thermal 6	80	27
Wind 1	80	1
Wind 2	80	2
Wind 3	80	15

TABLE V. Installed capacity by generation type for hydro-thermal system. Case 2 and Case 3.

Generation type	Generation size (MW/MWh)	Nodes
Hydro 1	80	22
Hydro 2	80	27
Thermal 1	50	23
Thermal 2	60	13
Thermal 3	40	1
Thermal 4	60	2
Wind 1	80	1
Wind 2	80	2
Wind 3	80	15

TABLE VI. Ramping capability of thermal generation units.

Generation Unit	Ramping capability
Thermal 1	1 %
Thermal 2	1 %
Thermal 3	2 %
Thermal 4	2 %
Thermal 5	1 %
Thermal 6	1 %

B. Results

The main results on cost of operation, spillage and future arbitrage value presented in table VII for thermal power system and in table VIII for hydro-thermal power system.

As it was expected, during the simulation of operation of Case 1 and Case 2 significant cost reduction in operation of both thermal and hydro-thermal after wind power integration was observed. However, in both cases significant spillage of wind power occurred: an average of 5 % for hydro-thermal system and 10.5 % for thermal only system. In addition, the cost of operation splits into two parts, non-stochastic operation cost of scheduled dispatch and stochastic expected balancing cost associated with variability and uncertainty of wind power generation. Another important aspect is the significant reduction in the arbitrage value for hydro power generation meaning that the required balancing of wind generation affected possible future profit of hydro-power generation. Thus, we can further study the benefits of adding energy storage unit under these three main possible contributions: cost reduction, additional arbitrage value and spillage reduction.

During the simulation of the third case, when energy storage capacity was integrated, further cost reduction was observed for both thermal and hydro-thermal systems. However, thermal system has much higher cost reduction than hydro-thermal. As it was expected hydro-thermal system has almost no change in balancing cost as well as in total operation cost due to presence of highly flexible hydro power units. Despite that additional energy storage capacity reduces spillage of the wind power and increases arbitrage value of total stored energy. Also with the increase in the benefit of the possible arbitrage energy storage use increases and partly replaces the balancing done with hydro power. Thus, energy storage can provide additional benefits even to highly flexible hydro-thermal system. The value of these benefits, however, varies based on the size and technical characteristics of the energy storage such as efficiency and self-discharge. Proposed model can be used to quantify the benefits for a specific system.

TABLE VII. OPERATION COST FOR THERMAL POWER SYSTEM.

	Case 1	Case 2	Case 3
Operation cost	185247 $	140612$	131099$
Expected balancing cost	-	9937$	9634$
Arbitrage value	-	-	18$
Average spillage	-	31 MWh	3 MWh

TABLE VIII. OPERATION COST FOR HYDRO-THERMAL POWER SYSTEM.

	Case 1	Case 2	Case 3
Operation cost	96767$	71133$	71101$
Expected balancing cost	-	2376$	2301$
Arbitrage value	1077$	117 $	223 $
Average spillage	-	15 MWh	2 MWh

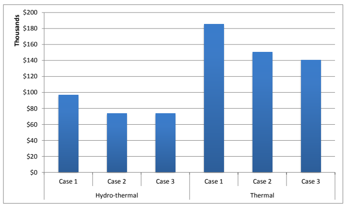

Fig. 1. Total cost of operation including scheduled dispatch cost and stochastic balancing cost, $.

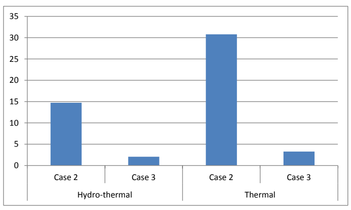

Fig. 2. Wind based energy generation spillage, average value of the scenario based spillage, MWh.

V. CONCLUSION

This paper presents a model for short-term planning of hydro-thermal and thermal only systems with wind power and energy storage. In addition, the paper describes a methodology to evaluate energy storage based on different generation mix of power system. The model has been applied to the IEEE 30-bus system and tested under different case studies.

The model helps to compare how system with a different energy mix can handle the balancing of the stochastic variable generation and how energy storage can be used for the balancing purposes. The benefits of energy storage is evaluated through three main contributions. First of all contribution to a balancing cost reduction. Second, contribution to an arbitrage possibility and finally, through contribution to a spillage reduction. Despite the lower need for additional balancing resources in presence of hydro power some of the challenges of a large scale wind generation integration are still present such as spillage of wind energy and possible high arbitrage cost for hydro power producer. These challenges could be successfully addressed through integration of an energy storage unit.

Presence of the large scale energy storage unit in the system results in significant cost reduction, especially for the thermal power system. The cost reduction is present not only in non-stochastic operation cost but more importantly in balancing cost. Moreover, another benefit of the energy storage is reduced amount of spilled wind energy. Thus, energy storage could be a very efficient solution for thermal-power systems with high penetration of wind based generation.

The proposed model and methodology can be used for other systems with different generation mix and different energy storage types. In addition, the model can be used as a basis for evaluation of the benefit of energy storage technology for transmission expansion deferral, the subject, however, was outside of scope of this paper. The case studies provided in this paper showed that performance and benefits of energy storage highly depends on existing flexibility of the system. The proposed model can be used to study the integration of energy storage under different levels of flexibility of the system. However, an additional study on comparison of the possible benefits of energy storage and the capital cost can be proposed for more comprehensive evaluation of energy storage technology.

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