

# NETWORK DESIGN PROBLEMS AND VALUE OF CONTROL MECHANISMS IN POWER SYSTEMS

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NETWORK DESIGN PROBLEMS AND VALUE OF CONTROL  
MECHANISMS IN POWER SYSTEMS

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May, 2019

We certify that we have read this dissertation and that in our opinion it is fully adequate, in scope and in quality, as a dissertation for the degree of Doctor of Philosophy.

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# ABSTRACT

## NETWORK DESIGN PROBLEMS AND VALUE OF CONTROL MECHANISMS IN POWER SYSTEMS

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Power systems planning and operations is one of the most challenging problems in energy field due to its complex, large-scale and nonlinear nature. Operating power systems with uncertainties and disturbances such as failure of system components increases complexity and causes difficulties in sustaining a supply-demand balance in power systems without jeopardizing grid reliability. To handle with the uncertainties and operate power systems without endangering grid reliability, utilities and system operators implement various control mechanisms such as energy storage, transmission switching, renewable energy curtailment and demand-side management. In this thesis, we first propose a multi-period mathematical programming model to discuss the effect of transmission switching decisions on power systems expansion planning problems. We then explore the value of control mechanisms for integrating renewable energy sources into power systems. We develop a two-stage stochastic programming model that co-optimizes investment decisions and transmission switching operations. Later, we analyze the effect of demand-side management programs on peak load management. We provide a conceptual framework for quantifying the incentives paid to the consumers to reshape their load profiles while taking hourly electrical power generation costs as reference points. Finally, we study reliability aspect of the power system planning and consider unexpected failures of components. We provide a two-stage stochastic programming model and discuss value of transmission switching on grid reliability.

*Keywords:* Generation and transmission expansion planning, Control mechanisms, Transmission switching, Reliability.

# ÖZET

## ELEKTRİK GÜÇ SİSTEMLERİNDE AĞ TASARIMI VE KONTROL MEKANİZMALARININ ÖNEMİ

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Güç sistemleri planlaması ve operasyonları; karmaşık, büyük ölçekli ve doğrusal olmayan doğası nedeniyle enerji alanındaki zor problemlerden biridir. Yenilenebilir üretimin belirsizliği, arz-talep tahmin hataları ve öngörülemeyen arızalar gibi nedenlerle elektrik güç sistemi operasyonları daha karmaşık hale gelmektedir. Bu durumlar, sistemlerin kararlılığını tehlikeye sokmakta ve arz-talep dengesinin sağlanmasını zorlaştırmaktadır. Bu olayların oluşmasını engellemek ya da etkilerini azaltmak için enerji depolama sistemleri, iletim hattı açma/kapama, yenilenebilir enerji üretiminin kısıtlanması ve talep tarafı katılımı gibi çeşitli kontrol mekanizmaları uygulanabilmektedir. Bu tezde ilk olarak iletim hattı açma/kapama kararlarının güç sistemleri genişleme planlama problemlerine etkisini incelemek amacıyla çok dönemli bir matematiksel programlama modeli önerilmiştir. Daha sonra, bahsedilen kontrol mekanizmalarının yenilenebilir enerji kaynaklarının elektrik enerjisi üretiminde kullanılmasındaki değeri araştırılmıştır. Bu amaçla, yeni yatırım ve iletim hattı açma/kapama kararlarını birlikte ele alan, diğer kontrol mekanizmalarıyla ilgili kısıtları da içeren iki-aşamalı bir stokastik programlama modeli geliştirilmiştir. Tezin bir sonraki bölümünde talep tarafı katılımı programlarının pik talep yönetimine etkisi incelenmiştir. Saatlik elektrik enerjisi üretim maliyetlerini referans noktası olarak, tüketicilerin yük profillerini değiştirmeleri için ödenecek teşvikleri belirlemek amacıyla kavramsal bir çerçeve sunulmuştur. Son bölümde, güç sistemlerindeki öngörülemeyen arızaları ele alan ve güvenilirlik kısıtlarını içeren güç sistemleri planlama problemi incelenmiştir. Bu problem için iki-aşamalı stokastik bir programlama modeli sunulmuş ve iletim hattı açma/kapama kontrol mekanizmasının şebeke güvenilirliği konusundaki değeri araştırılmıştır.

*Anahtar sözcükler:* Üretim ve iletim genişleme planlaması, Kontrol mekanizmaları, İletim hattı açma/kapama, Güvenilirlik.

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# Abbreviations and Acronyms

DC: Direct Current

CD-TS: Contingency-dependent Transmission Switching

DEP: Distribution Expansion Planning

DR: Demand Response

DSM: Demand-side Management

ESS: Energy Storage System

FOR: Forced Outage Rate

GEP: Generation Expansion Planning

GSTEP: Generation, Substation and Transmission Expansion Planning

GTEP: Generation and Transmission Expansion Planning

LS: Load-shedding

LSHF: Load-shifting

MILP: Mixed-integer Linear Programming

PSC-TS: Preventive Security Constrained Transmission Switching

R-GTEP: Reliability Constrained Generation and Transmission Expansion Planning

REC: Renewable Energy Curtailment

RES: Renewable Energy Source

SEP: Substation Expansion Planning

STEP: Substation and Transmission Expansion Planning

TEP: Transmission Expansion Planning

TS: Transmission Switching

# Chapter 1

## Introduction

Power system planning is a decision making process that determines locations and sizes of power system components and time of building them. The main aim of this process is to design systems to generate and transmit sufficient and continuous electrical power to the end-users in a cost-effective way. Designing power systems and determining power system operations are considered among the challenging problems in energy field due to its complex, large-scale and non-linear nature. Moreover, operating power systems with uncertainties and disturbances such as failure of components increases complexity and causes difficulties in sustaining a supply-demand balance in power systems without jeopardizing grid reliability. Thus, to withstand the uncertainties and maintain security of grids during disturbances, the power system is expected to be flexible enough.

To increase flexibility in the power systems and operate them without endangering reliability, utilities can implement various control mechanisms, such as energy storage systems (ESSes), demand-side management (DSM), renewable energy curtailment (REC) and transmission switching (TS). ESSes are the most effective solutions for cleaner energy sources in electricity generation [1]. These systems smooth the intermittency and variability of renewable energy sources (RES) by storing electrical energy generated at off-peak hours to use at peak

hours. These systems can increase utilization of RES, and thus a substantial decrease in generation from non-renewable energy sources can be achieved. Moreover, by storing energy at off-peak hours, ESSes reduce the need for peaking power plants that are generally used at peak hours and decrease the total operating cost to meet electricity demand of consumers and maintain supply-demand balance.

Demand-side management (DSM) refers to a group of activities to increase the overall efficiency of power systems including generation, transmission, distribution and consumption. Demand response (DR) is one of the main tools of DSM and reshapes consumers' electricity consumption or their load profiles by either load-shedding (LS) or load-shifting (LSHF) implementations. Figure 1.1a depicts an illustrative load profile. LS reduces energy consumption at peak periods (Figure 1.1b) whereas LSHF implementation shifts energy consumption from peak periods to off-peak periods (Figure 1.1c). The new load profiles after shedding and shifting consumption is presented by blue dotted lines. Efficient DSM activities can reduce operating costs in the systems, increase grid reliability and decrease greenhouse gas emissions. By rescheduling load profiles, DR programs can also reduce need for peaking power plants [2].

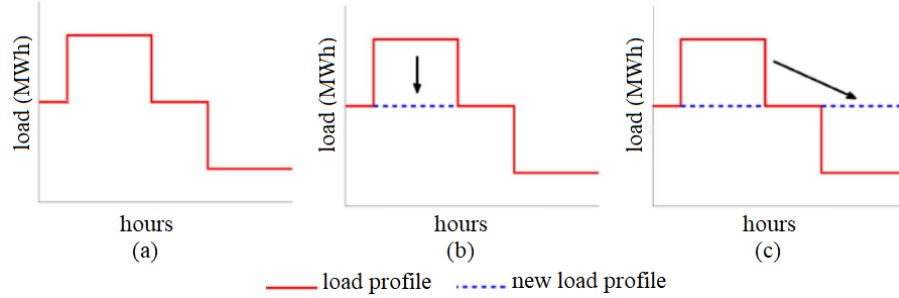


Figure 1.1: Illustration of demand response programs a) An illustrative load profile b) Effect of load-shedding c) Effect of load-shifting.

Renewable energy curtailment (REC) is one of the control mechanisms to maintain system energy balance and has been utilized since the beginning of the electric power industry [3]. REC is defined as reducing generation from renewable sources generally because of transmission congestion in the power systems or capacity of transmission lines. Curtailment generation from renewable sources

can also be used during low load periods or to satisfy technical and operational constraints such as maintaining system voltage level, frequency requirements or minimum generation requirements from thermal sources [4].

Transmission switching (TS) is another control mechanism and identifies the branches that should be taken out of service to increase the utilization of the network [5]. Although increasing efficiency of the grid by switching (or taking out of service) branches is a counter-intuitive phenomenon, which is one of the Braess's paradoxes seen in transportation networks [6], adding even a zero-cost line may increase congestion in the power systems, and thus reduces utilization of the grid.

In any power systems, flows on all lines should be in proportion to their electrical characteristics [7]. Equation (1.1) is a Direct current (DC) approximation of power flow model and should be satisfied for all existing lines,  $A$ , in the system.  $\varphi_{ij}$  is a parameter that shows the susceptance (one of the electrical characteristics) of line  $\{i, j\}$ ,  $f_{ij}$  and  $\theta_i$  represent the flow on the line  $\{i, j\}$  and voltage of the node  $i$ , respectively.

$$f_{ij} = \varphi_{ij}(\theta_i - \theta_j) \quad \forall \{i, j\} \in A \quad (1.1)$$

To illustrate the benefits of TS operations, we utilize a 3-node (or referred to as 3-bus) system with a 300 MW generation unit at node 1 and 300 MW load (or demand) at node 3 (Figure 1.2a). We assume that lines  $\{1,2\}$ ,  $\{2,3\}$  and  $\{1,3\}$  have the same electrical characteristics and capacities of them are 300 MW, 300 MW and 150 MW, respectively. To satisfy Equation (1.1), the solution should be as in Figure 1.2b. Since capacity of line  $\{1,3\}$  is less than 200 MW, the solution in Figure 1.2b is infeasible and the demand at node 3 cannot be met. Thus, in this case, the system operator should consider adding new lines and/or generation units to maintain supply-demand balance. However, if TS operation is utilized in this system and if line  $\{1,3\}$  is switched (or opened), then the solution turns out to be feasible and 300 MW can be transmitted as given in Figure 1.2c without requiring any new investments.

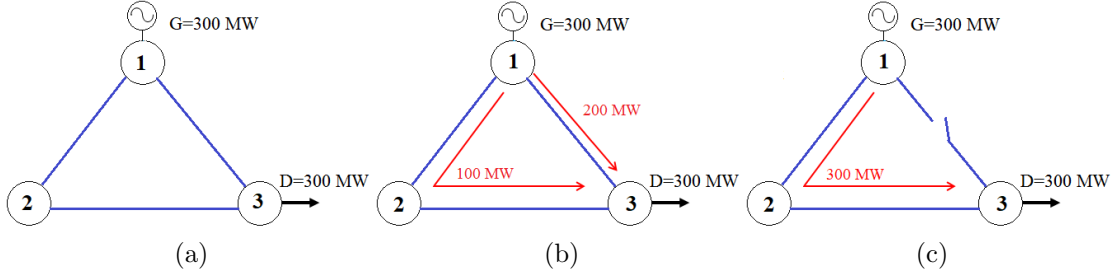


Figure 1.2: An illustrative example for transmission switching.

In this thesis, we consider challenging problems in energy field and use operations research techniques to explore the value of control mechanisms explained above in power system planning and operations. We particularly discuss the effects of control mechanisms on network design and value of them for dealing with difficulties in sustaining energy balance and grid reliability. Mathematical tools and operations research techniques for energy problems have been utilized in the literature (e.g. for generation plant location and for energy distribution such as heating, electricity demand [8]) and there is an ever-growing need for the application of operations research techniques to overcome these challenging problems since uncertainties and disturbances increase complexity of the problems. In this thesis, we define problems in energy field from operations research point of view. For the problems we discuss in the following chapters, we present non-linear mathematical programming formulations and use linearization techniques to provide linear versions of them. We also provide new solution approaches using operations research techniques and test both models and solution approaches on different datasets such as IEEE 6-bus (or 6-node), 24-bus (or 24-node) and 118-bus (or 118-node) power systems.

The rest of thesis is organized as follows. Chapter 2 provides general definitions and summarizes the related literature on power system expansion planning problems, control mechanisms and grid reliability.

Chapter 3 explores the value of co-optimizing subproblems of power system expansion planning such as generation, transmission and substation expansion planning problems for a long-term planning horizon. In the related literature,

investment cost of substations are either ignored or considered as part of the investment cost of generation units and/or transmission lines. In Chapter 3, we first show that considering investment cost of substations and determining location and size of them can considerably change the network design. We then propose a mixed integer linear programming model (MILP) for a multi-period power system planning problem considering transmission switching (TS) operations in order to find the least costly expansion plan. A solution methodology, in which we decompose our integrated multi-period problem into a set of single period problems as many as the number of expansion periods, is also presented to overcome the computational challenge of the proposed model. The results show that the proposed solution approach yields near optimal solutions in minutes.

In Chapter 4, we discuss value of control mechanisms to handle the variability of RES in a power system with a high renewable energy penetration for a target year. Since TS is a common practice in power systems to increase transfer capacity of the grids [9], the beneficial impact of TS is discussed in many studies (e.g. [9, 10]). However, to the best of our knowledge, there is no study that discusses value of TS on both storage siting and sizing decisions. In this chapter, we introduce a two-stage stochastic programming model that co-optimizes TS operations, and transmission and storage investments (i.e. storage locations and sizes) subject to limitations on load-shedding (LS) and renewable energy curtailment (REC) amounts. We discuss the effect of TS on the total investment and operational costs, siting and sizing decisions of ESSes, and LS and REC mechanisms. Using these analyses, we precisely characterize the joint benefits of TS and ESSes. The results obtained with different scenarios provide insights about the role of storage units for different limits of LS and REC control mechanisms.

In the literature, most studies include penalty costs (or can be considered as incentive payments) for demand response (DR) programs and/or REC policies to compensate for their impacts on quality of life and revenue losses from renewable energy generators. However, if these penalty costs are not well defined, operational and/or tactical plans may be affected. Thus, in Chapter 4, instead of using monetary values for LS and REC, we limit LS and REC amounts and examine the effects of these limits on the solutions.

Motivated from the explanation above related to the effect of penalty costs on the plans, in Chapter 5, we discuss DR programs and develop a conceptual framework in the macro level for quantifying the incentive paid to the consumers to reduce or shift their energy consumptions. A MILP model that considers load-shifting (LSHF) and load-shedding (LS) programs as an alternative to deploying generation from peaking power plants that generally have high operational costs is presented. The model minimizes total operating cost associated with deploying generation from peaking power plants and incentives paid to consumers for LSHF and LS programs for one year. An analysis has been performed to identify the break-even ratios between the costs of LSHF, LS and operating peaking power plants for the alternative DR policies while taking hourly costs of operating peaking power plants as reference points. In this chapter, we characterize break-even points for the incentives using a real data from the Turkish power system and analyze the effects of key parameters (e.g. maximum load that can be shifted in one day and different incentive payment policies) of our model on the solutions.

Chapter 6 discusses the reliability aspect of the power system expansion planning problem where reliability is defined as the ability to withstand disturbances arising from outage of generation units and/or transmission lines [11]. The problem determines the new investments to guarantee that the system remains feasible (whole system load can still be met) after outage of generation units or transmission lines for a target year. Related literature plans the new investments by considering only the feasibility of the power system after outage of the components and disregard the outcomes (e.g. operational costs) during these contingency states. In this chapter, we present a two-stage stochastic programming model for the problem that considers each outage of a line as single scenario with a certain probability of happening. We then include the operational costs for each contingency (or scenario) in the objective function in the expected form. Since the role of randomness in outages in the power system expansion planning can be more prominent especially when TS is considered, we introduce *contingency-dependent TS* as recourse actions of our two-stage stochastic model that calculates the expected operational cost in a more accurate manner. We also propose a solution methodology with a filtering technique that aggregates

scenarios and reduces number of scenarios in consideration. The results of the model and solution methodology show that the proposed solution method finds results in significantly shorter solution times compared to the solution times of the model.

In this chapter, we also introduce a real-world data set to the literature for the 380-kV Turkish transmission network, which is published in Mendeley Data<sup>1</sup> and present our results for this data set. This thesis concludes with final remarks, future research directions and discussion on possible extensions.

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<sup>1</sup>Peker, Meltem; Kocaman, Ayse Selin; Kara, Bahar (2018), "A real data set for a 116-node power transmission system", Mendeley Data, v1, <http://dx.doi.org/10.17632/dv3vjnwwf9.1>

## Chapter 2

# General Definitions and Related Literature

In this chapter, the following three sections provide detailed definitions of given concepts in Chapter 1, and summarize the literature on subproblems of power system expansion planning, control mechanisms and reliability criterion, respectively.

### 2.1 Subproblems of Power System Expansion Planning

For many years, power system expansion planning problems attract researchers mainly due to the challenge of their nonlinear and complex nature. Studies that focus on finding the least cost (or the best possible) solution for the problem differ from each other by the assumptions or the level of decomposition that they use in their solution approaches to ease the complexity of the problem. Dividing the power expansion planning problem into subproblems and trying to solve these easier subproblems sequentially is a widely used approach in the literature [7]. These subproblems include problems of generation expansion planning (GEP),

transmission expansion planning (TEP), distribution expansion planning (DEP) and substation expansion planning (SEP).

GEP deals with the expansion capacity of generation units while minimizing investment and operating cost to satisfy the load. TEP addresses the problem of determining the optimal configuration of the network in order to meet demand over the planning horizon while satisfying economical, technical and reliability constraints. DEP is similar to the TEP and it aims to find the optimal configuration of the network for the distribution phase of the electricity value chain. Lastly, SEP addresses the problem of optimal sizing, sitting and allocating new substations and expanding the capacity of existing substations. Depending on the level of decomposition, different types of substations, such as *generation (step-up)*, *transmission* and *distribution (step-down)* substations are also considered in the expansion planning problems [12] (Figure 2.1).

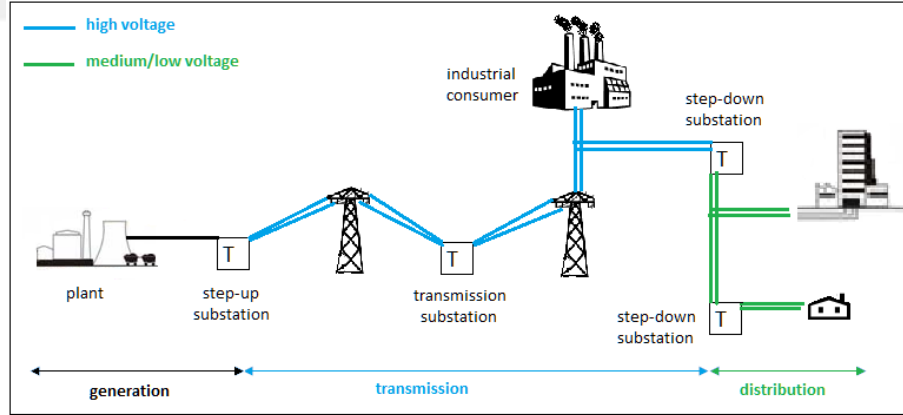


Figure 2.1: A schematic representation of electricity value chain.

Although there are some papers that only focus on GEP [13]-[18] and TEP [19]-[22] problems, in the literature, there are also studies which consider transmission and generation as inseparable components of the power systems [23]. Generation and transmission expansion planning (GTEP) problem simultaneously optimizes the decisions related to generation plants and transmission network. In [24] and [25], a single period GTEP problem and in [26], a multi-period GTEP problem are considered. Multi-period GTEP problem are discussed in many studies with different extensions such as including demand-side management [23], renewable

energy sources [27] and greenhouse gas emissions [28]. Since long-term power system expansion planning problems are complex, some researchers work on improving computational quality of the problem (e.g. [29]).

SEP problems are generally studied within the context of DEP problem once the generation requirements are known [30]. There are a limited number of papers that study substation and transmission expansion planning (STEP) problems simultaneously. In [31], a single period STEP problem is studied and the locations of substations, their connections to demand points as well as the lines between substations are determined. An algorithm that decomposes the problem into investment and feasibility-check subproblems is also proposed in [31]. In [32], a scenario-based stochastic STEP problem for a single period is discussed. The model in [32] finds new substations and transmission lines, and determines the generation amounts only at prescribed generation plants. Problems similar to SEP and STEP are also studied in DEP for determining locations of distribution substations and connection of demand nodes to the substations lines as in [33]-[36].

In the GTEP problems, decisions related to substation locations are not included. Similarly, in the STEP problems, generation expansion decisions (i.e. locations and sizes) are not included to the problem. To the best of our knowledge, there is no study that considers the expansion planning of substations in the GTEP problems. With the aim of filling this gap in the literature, in Chapter 3, we present an integrated generation, substation and transmission expansion planning problem (GSTEP) and show value of considering substation decisions explicitly in the power system expansion planning problem. We also note that in power system expansion planning problems, most studies focus on cost minimization as we do in Chapter 3. For real-life applications, there might be other considerations (e.g. social and environmental) that affect decisions of substation units' expansion planning and for more information about these factors, we refer the reader to [37]-[39].

## 2.2 Control Mechanisms

Increasing concerns about the environment and energy security reveal the necessity of using clean and sustainable energy resources in electricity generation. To encourage new investments in order to use more renewable energy sources (RES), utilities implement policies such as feed-in tariffs, carbon taxes and/or renewable portfolio standards [40], and as a result, a 19% share of RES in meeting world electricity demand in 2000 increased to 24% in 2016 [41]. Improvements such as this help reduce carbon emissions and dependence on fossil fuels. However, increased penetration of RES can lead to high variability and uncertainty in electricity generation as these sources are intermittent and dependent on atmospheric conditions and spatial locations. Low predictability and variability of electricity generation from RES can cause difficulties in sustaining a supply-demand balance and/or power frequency in a grid, and thus can impose new challenges around power system reliability and stability. To continue utilizing these clean sources without endangering power system reliability, utilities implement various control mechanisms such as energy storage systems (ESSes), transmission switching (TS), renewable energy curtailment (REC) and demand-side management (DSM). These control mechanisms are detailed in the following subsections.

### 2.2.1 Energy Storage Systems (ESS)

Energy storage systems are the most effective solutions for integrating RES in electricity generation. These systems store electrical energy generated at off-peak hours to use at peak hours. Thus, they smooth the intermittency of RES and increase generation from RES and decrease greenhouse gas emissions.

The value of ESSes has been increasingly discussed in the literature from different perspectives. Most studies focus on system operation and determine the ESS' state of charge for each time period [42]. In these studies, given the locations and sizes of the storage units, the aim is to maximize profit by bidding/selling operations in energy markets. However, these studies ignore the effect of ESS

locations and sizes (e.g. [43]). To address this deficiency, other studies consider ESS locations and operations simultaneously for multi-stage [44], robust [45] and long-term [46] planning problems. There are also a few papers that optimize only ESS sizes under demand and generation uncertainties [47].

To fully reveal the benefits of ESSes, their siting and sizing decisions should be considered simultaneously during the planning stage; however, only few papers focus on this co-optimization process. A three-stage heuristic algorithm to solve the co-optimized problem is proposed in [42]. Effect of different technology types, such as pumped storage hydro, compressed-air energy storage, lithium ion batteries and fly-wheel energy storage on sizing ESSes are analyzed in [48]. In [49], the effect of REC penalty costs and the capital costs of storage units on optimal ESS locations and sizes are discussed. In [50], the value of co-optimizing ESS and GTEP considering renewable portfolio standards is assessed. The effect of limiting budget for investing storages on ESS locations are discussed in [51]. A long-term planning problem considering battery lifetime and degradation are examined in [52].

### **2.2.2 Transmission Switching (TS)**

Transmission switching is another control mechanism that adds flexibility to the grid and a common practice in power systems to increase transfer capacity of the system [9]. Beneficial impacts of TS on power systems planning and operations has been demonstrated in academic studies as well as industrial applications such as for the California and New England independent system operators in [53] and for the PJM system in [54, 55]. The value of TS is also discussed for theoretical examples. The first mathematical programming model considering TS is provided in the context of TEP problem in [56]. Later, the effect of TS on GTEP problem is presented in [57] and by limiting number of switchable lines, the solutions for different cases are compared. The benefits of TS are also discussed in many studies from perspectives such as reliability [5, 9] and economic efficiency [10]. The value of TS in reliability will be detailed in Chapter 2.3.

There are a few studies that discuss the effect of TS on RES penetration. The value of TS on wind power penetration levels and line capacity expansion plans are discussed in [58]. The effect of TS on total system cost and utilization of wind power, considering the uncertainty of wind power generation are presented in [59]. In [60], a linearized Alternative Current (AC) model is developed to analyze benefits of TS operations on RES utilization. However, none of these studies includes storages. To the best of our knowledge, only a few papers simultaneously consider TS operations and ESS investment planning. In [61] and [62], TS and storage operations are considered simultaneously in a unit commitment problem without allowing new investments. In [63], a model for an investment planning problem including TS operations is proposed to find out the locations of new transmission lines and storages.

### **2.2.3 Renewable Energy Curtailment (REC)**

Renewable energy curtailment is also used to handle RES variability. With an increase in RES penetration, a significant amount of renewable energy could be curtailed due to technical and operational reasons to maintain system voltage and frequency levels or to satisfy minimum generation requirements from thermal sources [4]. However, by lowering RES supply, the benefits of using clean sources and revenues from renewable generators are reduced. Moreover, REC can be considered as a significant waste, especially for countries that have renewable energy targets (such as Australia, Turkey, Brazil and Ireland [64, 65]). Therefore, to promote new investments in sustainable energy, in some real markets, revenue losses from renewable energy generators are sometimes compensated for in some contracts/policies [66, 67]. For this compensation, in [45, 52, 60, 62] a penalty cost for curtailing generation from RES is considered. The effect of penalty cost for REC on the optimal location and size of storages are discussed in [49].

## 2.2.4 Demand-Side Management (DSM)

Demand-side management refers to a group of activities to increase the overall efficiency in the power system. Demand response (DR) is one of the main tools of DSM and increases demand flexibility in the system, and thus reduces capacity requirements. DR programs help utilities reduce demand at peak hours by either shifting or curtailing load [2]. Efficient implementation of DR may also reduce the need for peaking power plants and/or under-utilized electrical infrastructures, which can have high investment and operational costs. Since reducing demand intentionally by load-shifting (LSHF) and/or load-shedding (LS) programs affects quality of life, incentive payments, which is also referred to as penalty cost or value of loss load, are generally considered to compensate for the impact on life quality [1].

The value of DR applications has been discussed in the literature from different perspectives. Effect of DR on power systems for managing generation uncertainty and outages is analyzed in [68]. In [69], it is discussed that demand flexibility can increase prices in the systems with high wind power production. In [70], benefits of DR together with storage and distributed generation on capital investments are evaluated. Demand flexibility is analyzed in terms of decreasing wind curtailment in [71] and determining market clearing prices with multiple consumer groups in [72]. The effect of DR is also analyzed in different problems such as unit commitment [73] and expansion planning [74].

In the macro level, benefits of having flexible demands are analyzed for different power systems such as in the U.K [75], German [76] and China [77]. The potential economic impact of having flexible demand and renewable sources are presented for the Spanish electricity market in [78] and for the German power system in [79]. The existing programs at different independent system operators in the U.S. are summarized and limitations for participation of DR to these systems are explained in [80]. DR in the context of integrated strategic resource planning is discussed for the power system of China to reduce carbon emission and increase renewable energy utilization [81].

Although the value of DR programs has been demonstrated in both theoretical examples and real power systems, the success of DR programs highly depends on consumers' acceptance and willingness to participate in DR programs. Consumers' behaviors and perceptions on DR programs have also been discussed in the literature. Distrust of utility and seeing no need for the programs are reported as crucial factors for unwillingness to participate in DR programs [82]. Psychological factors that shape consumer behavior in regard to electricity prices are also examined in [83]. The authors note that insights from psychology and behavioural economics could be utilized to find appropriate DR programs.

In Chapter 4, we discuss value of co-optimizing TS operations, and transmission and storage investments (i.e. ESS locations and sizes) subject to limitations on LS and REC amounts. As presented in Table 2.1, except for our study, there is no paper that considers TS operations, transmission and ESS investments decisions simultaneously. In Chapter 4, we fill a gap in the literature by proposing a model and analyzing the value of TS on ESS siting and sizing decisions alike. We present that TS can be a more efficient and cheaper solution compared to building new lines or more expensive ESSes. Therefore, considering TS in power system strategic and/or operational planning leads to higher social welfare by decreasing overall costs, enhancing quality of life and utilizing cleaner sources in electricity generation.

As presented in Table 2.1, most papers include penalty costs for LS and/or REC policies to compensate for their impacts on quality of life and revenue losses from renewable energy generators. However, we note that operational and/or tactical plans may be affected if these penalty costs are not well defined. Moreover, the impact of the cost parameters might be more prominent if both are considered in the planning phase, as used in the problem discussed in Chapter 4. Therefore, instead of using monetary values for LS and REC, we limit LS and REC amounts and examine the effects of these limits on the solutions.

In Chapter 5, we analyze DR programs and develop a conceptual framework for quantifying the incentives payments for LSHF and LS applications. To the best of our knowledge, there is no study that identifies the break-even ratios

Table 2.1: Comparison of the literature

|                | ESS | TS | investment<br>costs | pen. cost<br>for LS | pen. cost<br>for REC | sizing |
|----------------|-----|----|---------------------|---------------------|----------------------|--------|
| [58]           | ✗   | ✓  | line                | ✗                   | ✗                    | ✗      |
| [42]           | ✓   | ✗  | ESS                 | ✗                   | ✗                    | ✓      |
| [43]           | ✓   | ✗  | ✗                   | ✗                   | ✗                    | ✗      |
| [44]           | ✓   | ✗  | line, ESS           | ✓                   | ✗                    | ✗      |
| [46]           | ✓   | ✗  | line, ESS           | ✗                   | ✗                    | ✗      |
| [45]           | ✓   | ✗  | line, ESS           | ✓                   | ✓                    | ✗      |
| [48]           | ✓   | ✗  | ESS                 | ✗                   | ✗                    | ✓      |
| [49]           | ✓   | ✗  | ESS                 | ✗                   | ✓                    | ✓      |
| [50]           | ✓   | ✗  | gen., line, ESS     | ✓                   | ✗*                   | ✓      |
| [51]           | ✓   | ✗  | ESS                 | ✓                   | ✗                    | ✓      |
| [52]           | ✓   | ✗  | line, ESS           | ✓                   | ✓                    | ✓      |
| [59]           | ✗   | ✓  | ✗                   | ✓                   | ✗                    | ✗      |
| [60]           | ✗   | ✓  | ✗                   | ✗                   | ✓                    | ✗      |
| [61]           | ✓   | ✓  | ✗                   | ✗                   | ✗                    | ✗      |
| [62]           | ✓   | ✓  | ✗                   | ✓                   | ✓                    | ✗      |
| [63]           | ✓   | ✓  | line, ESS           | ✓                   | ✗                    | ✗      |
| Our study [84] | ✓   | ✓  | line, ESS           | ✗*                  | ✗*                   | ✓      |

✗\* instead of using penalty cost, the values are limited by various upper bounds.

between the costs of LSHF, LS and operating peaking power plants that would result in alternative DR policies. In this direction, we propose a MILP model that considers DR programs as alternatives to using peaking power plants while considering hourly generation costs of peaking power plants as reference points. Using an extensive computational study, we assess incentive payments and find out break-even points using a real data from the Turkish power system. We also analyze effect of key parameters of the proposed model on the incentive payments.

## 2.3 Reliability Criterion

Reliability constrained generation and transmission expansion planning (R-GTEP), another problem commonly studied in literature, defines reliability as the ability to withstand disturbances arising from outage of generation units or transmission lines [11]. This problem determines the new investments to guarantee that the system remains feasible in case of component breakdowns. Most

of the studies that consider reliability criteria plan new investments based on only the feasibility of the power system after a line or generator contingency and ignore the outcomes during the contingency states [85]-[90]. As the probabilistic realizations of outages are customarily overlooked, the effect of randomness in contingencies on the investment plans and the cost of the expansion plans are usually disregarded. Some papers partially consider the probabilistic realization of outages by considering loss of load probability and/or expected energy not served [91]-[94] or risk-based decision-making process [95, 96]. Although these papers consider the effect of randomness in contingencies on the investment costs, they still overlook the effect of probabilistic nature of contingencies on the operational costs. Reliability of power system has been also discussed considering different sources of uncertainties such as uncertainty in generation or consumer behavior of electricity price [97]-[99]. However, these studies also do not explicitly include the operational costs during the contingency states.

Beneficial impact of TS on the reliability are demonstrated in [10, 100, 101]. In [10], the value of a seasonal transmission switching on the total cost and reliability level of the power system is discussed. In [100], TS and N-1 reliability criterion<sup>2</sup> are considered simultaneously. In [101], the effect of TS on the power system is analyzed and the monetary value of expected energy not served (EENS) for the solutions are calculated and the effect of TS on EENS is discussed. However, in these studies the status of transmission lines are determined before observing the contingencies and network topology is designed to satisfy the whole system load after any contingency without requiring operator control on generators. This approach is referred to as *preventive security constrained transmission switching* [101], and ignores the probabilistic nature of outages and the expected operational costs during the contingencies. Therefore, the overall costs of the investment planning projects are underestimated. Although having a single network topology for all time periods is extremely unlikely due to uncertainties [53], system operators have flexibility to monitor and change the status of the transmission lines after a contingency. For this purpose, we introduce a new transmission switching concept, *contingency-dependent TS*, which entails the

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<sup>2</sup>A power system that satisfies N-1 reliability criterion remains feasible after outage of a single line or generation unit.

definition of transmission switching decisions based on each contingency.

In Chapter 6, we propose a two-stage stochastic programming model for the R-GTEP problem that includes expected operational cost during the contingencies, an aspect that has been overlooked in the literature which can affect the investment plans. We calculate expected operational costs in a more accurate manner by utilizing the proposed contingency-dependent TS concept. To overcome computational burden of the R-GTEP problem different approaches such as determining a short list of the candidate lines [86, 87], line outage distribution factors method [88, 89], worst case analysis [90] and umbrella constraint discovery technique [102, 103] are used in the literature. In this chapter, we utilize a filtering approach to find the critical contingencies. Thus, by using the filtering approach, we reduce the computational challenge of the two-stage stochastic programming model and find the optimal or near-optimal solutions for the original problem that satisfies the N-1 reliability criterion.

## Chapter 3

# Substation Location and Transmission Network Expansion Problem for Power Systems

This chapter discusses subproblems of power system expansion planning and explores the value of co-optimizing these subproblems. We first demonstrate the economic value of incorporating substation decisions to the generation and transmission expansion planning problem for a long-term planning horizon. We then provide an integrated model including generation, substation and transmission components of the power system to find the least cost network by determining the locations and sizes of these components simultaneously. We also propose a solution methodology, in which we decompose the multi-period problem into several single-period problems that are solved sequentially to overcome the computational challenge of the proposed model. The model and solution method are tested on the IEEE 24-bus and 118-bus power systems.

The organization of this chapter is as follows: In Section 3.1 we explain our problem and present the value of adding substation decisions to the Generation and Transmission Expansion Planning (GTEP) problem on a small sized instance. Section 3.2 provides the mathematical model and solution approaches for the

problem. We show and discuss the results of the proposed model in Section 3.3. We also compare the results of the proposed solution approach with the solutions that are obtained by sequentially solving the subproblems. This chapter concludes with Section 3.4. The results of this chapter are currently under second revision in *Networks and Spatial Economics*.

### 3.1 Problem Definition and Motivation

In the literature, different types of substations are considered in the expansion planning problems depending on the level of decomposition of the problem, such as *generation (step-up)*, *transmission* and *distribution (step-down)* substations [12]. However, in GTEP problems, substation components, which can be used to increase/decrease the voltage of the power at critical locations or re-route the power flow, are not explicitly included. A central planner might consider investment cost of a step-up substation as a portion of the investment cost of a generation plant, since a generator is always connected to the grid through a step-up substation. Similarly, the planner might also consider the investment cost of transmission and step-down substations as a part of the investment cost of lines. However, with these approaches capacity planning of the substations might not be correctly determined as they are calculated independently from the rest of the grid. The substations' capacities might depend on the total generation amount of the plants that are connected to the substations or power flows sent through step-up and/or transmission substations. Thus, investment cost of the substations may not be included correctly to the expansion plan and might underestimate or overestimate the real cost in the power system. Moreover, without including decisions related to substations' locations and capacities to the GTEP problem, a different network configuration and a different expansion plan for the system components might be obtained.

An integrated model for the expansion planning is necessitated and we discuss an integrated generation, substation and transmission expansion planning (GSTEP) problem in this chapter. Given the demand of nodes and possible

generation amounts from different source types, the model finds optimal siting, sizing and timing of system components (generation plants, substation units and lines) in order to fulfill power demand in a multi-period planning horizon. The model minimizes total investment and operational costs and determines power generation amounts, power flows and flow directions on the transmission lines considering transmission switching option.

To motivate the problem and discuss the value of including substations decisions in GTEP problem, we first provide a real-life example for the North American power grid. We then present an example using a 6-bus network and compare the optimal results with and without substation decisions. In [12], the North American power grid which includes generation plants, major substations and transmission lines is explained. In the North American power grid, the authors identified 14,099 nodes as substations for the North American power system. Substations that have a single high-voltage transmission line are referred to as distribution substations, and that are located at a source of power are referred to as step-up substations. The remaining ones are classified as transmission substations. In [12], 1633 of 14,099 nodes are distinguished as step-up substations, 2179 nodes are referred to as distribution substations and the remaining ones are labeled as transmission substations. In such a large power system, ignoring investment costs of substations or considering as a part of investment cost of other components may underestimate or overestimate the total costs and may result with a different network structure. We note here that, in our problem setting, we utilize the same assumptions for the types of substations as in [12]. As we detail in Section 3.2, if a generation plant is built, then we require a step-up substation at the same node and if there is a node at an intersection point of more than two lines, then we also require a transmission substation at that node.

In the following example, we discuss the value of explicitly modeling substations in the problem by comparing the optimal solutions of GTEP and GSTEP obtained through a mathematical model presented in Section 3.2. We show that including substation decisions affects the network structure, changes the substations' locations and decreases the total cost on a 6-bus power system. Although the following is an example for a greenfield investment planning (i.e. there is

no existing infrastructure in the system), the same discussions are also valid for brownfield investments (i.e. there are existing generators, substations and lines) as presented later in Section 3.3.

For this example, demand of buses and candidate lines are adapted from [104] and provided in Appendix Tables A.1 and A.2. Load of buses is taken as 1/4 of the loads given in [104] and bus 6 is also considered as a demand node with 10 MW load. In addition to the transmission line type with 100 MW capacity given in [104], we include one more transmission line type with 50 MW capacity (Appendix, Table A.3). Three types of generation plants and five type of substations are considered for both step-up and transmission substations, and the characteristics of them are given in Appendix, Tables A.4 and A.5, respectively.

Figure 3.1a and Figure 3.1b present the optimal networks resulting from GTEP and GSTEP problems, respectively. In the GTEP output, one generation plant at node 2, and 5 transmission lines are built with the total cost of \$229.64M (Figure 3.1a). Thick lines have 100 MW capacity whereas the other lines have 50 MW capacity. Although it is not explicitly modeled in GTEP problem, there should be 3 substations: one for step-up substation at node 2 in order to connect generation plant to the grid and two for transmission substations at nodes 3 and 5, which are required to change the line type or to re-increase voltage of power in order to decrease power loss due to long distances between the nodes or to re-route power flow. We calculate the required capacities with respect to the generation amount and power flows on the lines. Using Table A.5 in Appendix, we then calculate the investment costs of substations and it is equal to \$31.44M. When the costs of substations are added to the optimal cost of the GTEP, which is \$229.64M, the overall cost turns out to be \$261.08M. In the GSTEP solution, with the same parameter setting, we obtain a star network solution (Figure 3.1b), i.e. power is directly sent to all the demand nodes from generation plant at node 2. In this case, we have only one substation at node 2 and 5 transmission lines, and the optimal cost of GSTEP is equal to \$247.82M. Hence, for this example, by including decisions related to substations, we decrease the total cost of the power system by \$13.26M and by 5.07%.

One can question the effect of the investment cost of substations to the network structure and to the total cost of the power system. In order to analyze this effect, we come up with a parametric analysis by multiplying investment cost of substations with a factor,  $\alpha$ . Figure 3.1c and Figure 3.1d present the optimal networks for GSTEP problem when investment cost of substations are multiplied by  $\alpha=0.05$ , 0.3, respectively. Table 3.1 shows the results of all instances with the cost distribution in terms of investment costs of generation, substation, lines, and operation and maintenance (O&M) cost for both GTEP and GSTEP problems for  $\alpha = 0.05$ , 0.3 and 1.0 where  $\alpha = 1.0$  corresponds to the original investment cost of substations. Under the columns *GTEP*, the values given in bold show the calculated substation cost depending on  $\alpha$ .

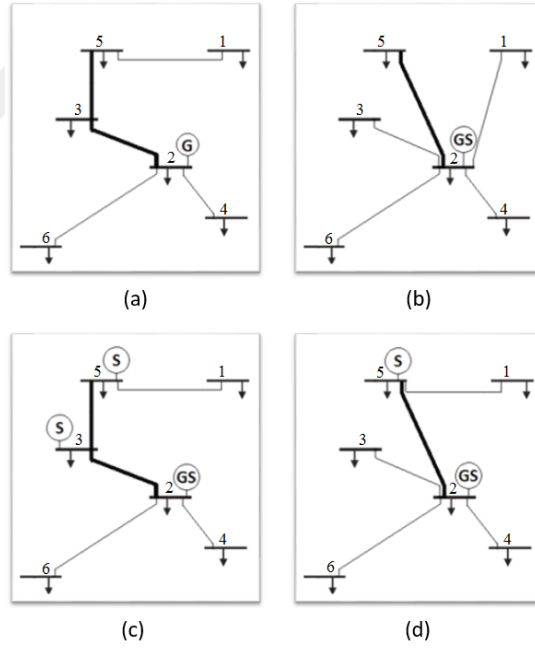


Figure 3.1: (a) Result of GTEP (b) Result of GSTEP (c) Result of GSTEP for  $\alpha = 0.05$  (d) Result of GSTEP for  $\alpha = 0.3$ .

When the investment cost of substations is small, (i.e.  $\alpha = 0.05$ ), the optimal solution of GSTEP is the same as GTEP (Figure 3.1a and Figure 3.1c). That is, the output of the formulation where investment cost of substations are ignored (GTEP) is the same with the one where they are explicitly considered (GSTEP). When  $\alpha = 0.3$ , in the optimal result, there exist only two substations at nodes 2 and 5, and 5 transmission lines with only one of them being 100 MW capacity

(Figure 3.1d). Thus, even when  $\alpha = 0.3$ , beside the locations of substations, the capacity of the components in the network also changes. For this case, the total cost of GTEP (after adding substation costs) is 0.86% higher than the total cost of GSTEP. When  $\alpha = 1.0$ , value of integrating substation to the problem is more obvious since total cost of GTEP is 5.35% higher than the total cost of GSTEP.

Table 3.1: Results of GTEP and GSTEP for different  $\alpha$  values

|                            | $\alpha=0.05$ |        | $\alpha=0.3$ |        | $\alpha=1.0$ |        |
|----------------------------|---------------|--------|--------------|--------|--------------|--------|
|                            | GTEP          | GSTEP  | GTEP         | GSTEP  | GTEP         | GSTEP  |
| total cost(M\$)            | 231.21        | 231.21 | 239.07       | 237.04 | 261.08       | 247.82 |
| generation inv. cost (M\$) | 180.00        | 180.00 | 180.00       | 180.00 | 180.00       | 180.00 |
| line inv. cost (M\$)       | 22.56         | 22.56  | 22.56        | 23.28  | 22.56        | 26.16  |
| O&M cost (M\$)             | 27.08         | 27.08  | 27.08        | 26.80  | 27.08        | 26.73  |
| substation inv. cost (M\$) | <b>1.57</b>   | 1.57   | <b>9.43</b>  | 6.95   | <b>31.44</b> | 14.92  |

A similar analysis is also made by multiplying the investment cost of transmission lines by 3.0 and Figure 3.2 presents the optimal networks resulting from GTEP and GSTEP problems for the original and adapted cost of transmission lines. The network obtained from GTEP remains the same when the investment cost of transmission lines is increased (Figure 3.2a). However, even in a small network, the network obtained from GSTEP changes significantly as the investment cost of the lines is increased. When cost of transmission lines are at their original values, there are one generation unit, one step-up substation and 5 transmission lines with only one of them being 100 MW capacity (Figure 3.2b). But, as the cost increases, the optimal solution of GSTEP changes and two generation units and two step-up substations are built at nodes 2 and 5 (Figure 3.2c). In this case, four transmission lines are built with 50 MW capacity.

From these examples, we can conclude that substation decisions should be included into the GTEP problem and, central planner should co-optimize generation, transmission and substation expansion planning problems since considering substation decisions may decrease the total cost in the power system (Table 3.1) and also change the network structure and expansion plans substantially (Fig 3.2). Hence, in this chapter, we aim to provide an integrated model including

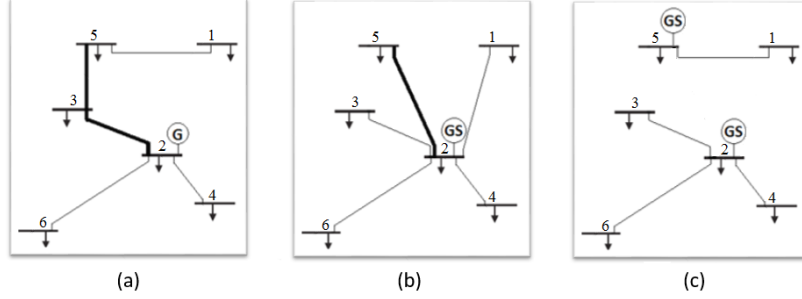


Figure 3.2: (a) Result of GTEP with adapted transmission line costs (b) Result of GSTEP with original transmission line costs (c) Result of GSTEP with adapted transmission line costs.

generation, substation and transmission components of the power system to find the least cost network by determining the locations and sizes of these components simultaneously. We can also get some insights about the changes in the optimal solutions with respect to the investment costs of substations. We can see that depending on the ratio between the substation cost and the costs of other system components, the optimal cost and optimal expansion plans of the systems can be highly different and our analysis can also help find these break-even ratios that would result in significant investment differences. We also note here that, in some cases, adding more equipment such as transformers to an existing substation site might be enough for expansion planning instead of building a new substation site. As shown in the examples above, central planner can consider alternative investment costs for upgrading the existing system and obtain an expansion plan with reinforcing the capacity of substations.

## 3.2 Problem Formulation and Solution Approaches

In this chapter, we consider Direct Current (DC) power flow model, an approximation of Alternative Current (AC) power model, and a single load scenario as in [23, 24, 26, 27, 105]. We determine a sufficient number of operating conditions and divide each time period into a set of load blocks to consider variability of

demand within the time period [57, 106]. As in [27], we also assume that a predetermined ratio of the transferred power is lost due to line resistance and the ratio depends on line types. As we explain in Section 3.1, a new generation plant is always connected to the grid through a step-up substation. Thus, we guarantee that there is an existing step-up substation or a new step-up substation built at the same node with the new plant. We also explain that there should be a transmission substation if there is a node at an intersection point of more than two lines to transmit power to other demand nodes or other substations. Hence, in our model we also guarantee that the nodes at an intersection point has a transmission substation in order to transform/re-increase the voltage level or reroute the power flow. For brevity, throughout this chapter, we refer a node that has just substations as *substation node*, a node that has substation and generation units as *generation node* and the remaining nodes (which have no generation and substation units) as *demand node*.

### 3.2.1 Mathematical Programming Model

We use the following notation for the mathematical programming model. Let  $G = (N, E)$  be a graph where  $N$  is the node set for demand nodes and candidate nodes for locating generation plants, substation units; and  $E$  is the candidate corridors for building transmission lines. We note that substations are only differentiated with respect to their capacities (as in Appendix, Table A.5). In this chapter, our planning horizon is for  $T$  periods and each time bucket has  $TI$  years. Since GSTEP problem is for a long-term planning horizon, this problem can be considered for strategic planning.

|                         |                                     |                     |                                                            |
|-------------------------|-------------------------------------|---------------------|------------------------------------------------------------|
| • <b>Sets (Indices)</b> |                                     | $C$                 | set of generation technologies ( $c$ )                     |
| $N$                     | set of all nodes ( $i$ and $j$ )    | $S$                 | set of substations ( $s$ )                                 |
| $E$                     | set of corridors ( $e = \{i, j\}$ ) | $B$                 | set of load blocks ( $b$ )                                 |
| $\Psi^+(e)$             | sending-end bus of corridor $e$     | $T$                 | set of periods ( $t$ )                                     |
| $\Psi^-(e)$             | receiving-end bus of corridor $e$   | • <b>Parameters</b> |                                                            |
| $A$                     | set of line types ( $a$ )           | $D_{ibt}$           | demand of node $i$ at load block $b$<br>at period $t$ (MW) |

|                |                                                                         |                                                                                                           |                                                                                       |
|----------------|-------------------------------------------------------------------------|-----------------------------------------------------------------------------------------------------------|---------------------------------------------------------------------------------------|
| $CapG_{ict}$   | generation capacity in node $i$ from source type $c$ at period $t$ (MW) | $dur_{bt}$                                                                                                | duration of load block $b$ at period $t$ (h)                                          |
| $CapL_a$       | capacity of transmission line type $a$ (MW)                             | <b>• Decision Variables</b><br>$X_{ict}$ 1 if source type $c$ is built at node $i$ at period $t$ , 0 o.w. |                                                                                       |
| $CapS_s$       | capacity of substation type $s$ (MVA)                                   | $G_{icbt}$                                                                                                | generation amount in node $i$ from source type $c$ at load block $b$ at period $t$    |
| $l_e$          | distance of corridor $e$ (km)                                           | $K_{ist}$                                                                                                 | 1 if substation type $s$ is built at node $i$ at period $t$ , 0 o.w.                  |
| $r$            | discount rate                                                           | $\bar{K}_{it}$                                                                                            | 1 if at least one substation exists at node $i$ at period $t$ , 0 o.w.                |
| $c_c^{inv}$    | investment cost of source type $c$ (\$)                                 | $\theta_{ibt}$                                                                                            | voltage angle of node $i$ at load block $b$ at period $t$                             |
| $c_c^{om}$     | operation&maintenance cost of source type $c$ (\$/MWh)                  | $L_{eat}$                                                                                                 | 1 if line type $a$ exists at corridor $e$ at period $t$ , 0 o.w.                      |
| $c_a^{line}$   | investment cost of transmission line type $a$ (\$/km)                   | $Z_{eabt}$                                                                                                | 1 if line type $a$ at corridor $e$ is closed at load block $b$ at period $t$ , 0 o.w. |
| $\varphi_{ea}$ | susceptance of line type $a$ of corridor $e$ (p.u.)                     | $f_{eabt}$                                                                                                | flow on line type $a$ at corridor $e$ at load block $b$ at period $t$                 |
| $TI$           | number of years in each period                                          |                                                                                                           |                                                                                       |
| $ef_a$         | transmission loss on the line type $a$ per unit flow                    |                                                                                                           |                                                                                       |
| $c_s^{sub}$    | investment cost of substation type $s$ (\$)                             |                                                                                                           |                                                                                       |

The proposed model for GSTEP is as follows. The objective function (3.1) minimizes net present value of total cost; the first three terms are for the investment costs of generation plants, substation units and transmission lines, respectively. The last term calculates the total operational cost during the planning horizon. The function  $\kappa(r, TI) = (1+r)(1 - (1+r)^{-TI})/r$  is to calculate the present value of annual cost that has  $TI$  years in each time period with interest rate  $r$  [107]. We remark here that, the cost of losses is not explicitly modeled in the objective function since total generation in the system is equal to total demand and power losses, and losses are inherently included within the operational cost ( $z_{om}$ ) through generation amounts.

$$\begin{aligned}
\min \quad & z_{inv} + z_{sub} + z_{line} + z_{om} \\
z_{inv} = & \sum_{t \in T} (1+r)^{-\text{TI}(t-1)} \sum_{i \in N} \sum_{c \in C} c_c^{inv} X_{ict} \\
z_{sub} = & \sum_{t \in T} (1+r)^{-\text{TI}(t-1)} \sum_{i \in N} \sum_{s \in S} c_s^{sub} K_{ist} \\
z_{line} = & \sum_{t \in T} (1+r)^{-\text{TI}(t-1)} \sum_{e \in E} \sum_{a \in A} c_a^{line} l_e (L_{eat} - L_{eat-1}) \\
z_{om} = & \sum_{t \in T} (1+r)^{-\text{TI}(t-1)} \kappa(r, \text{TI}) \sum_{i \in N} \sum_{c \in C} \sum_{b \in B} c_c^{om} dur_{bt} G_{icbt}
\end{aligned} \tag{3.1}$$

• *Power Balance Constraint:*

$$\sum_{c \in C} G_{icbt} + \sum_{e \in E | \Psi^-(e)=i} \sum_{a \in A} f_{eabt} - \sum_{e \in E | \Psi^+(e)=i} \sum_{a \in A} (1 + e f_a) f_{eabt} = D_{ibt} \quad \forall i \in N, b \in B, t \in T \tag{3.2}$$

Constraint (3.2) provides the power balance, that is equivalent to Kirchhoff's first law and implies conservation of the power at each node (after adding losses on the transmission lines for the transferred power) for each time period.

• *Generation Dispatch Constraints:*

$$G_{icbt} \leq \sum_{t' \in T: t' \leq t} Cap G_{ict'} X_{ict'} \quad \forall i \in N, c \in C, b \in B, t \in T \tag{3.3}$$

$$\sum_{i \in N} D_{ibt} \leq \sum_{i \in N} \sum_{c \in C} \sum_{t' \in T: t' \leq t} Cap G_{ict'} X_{ict'} \quad \forall b \in B, t \in T \tag{3.4}$$

Constraint (3.3) states that generation amount in node  $i$ , at load block  $b$ , at period  $t$  cannot exceed the possible generation amount that could be produced from all of the generation units located at node  $i$  until time period  $t$ . Constraint (3.4) guarantees that the total generation capacity is greater than the total demand in the power system for each load block and time period. We note that, Constraint (3.4) can be considered as a valid inequality and can be safely removed

from the model. However, we keep it in our model, as preliminary computational studies presented better computational quality with this constraint.

- *Substation-Related Constraints:*

$$\sum_{e \in E | \Psi^+(e)=i} \sum_{a \in A} (1 + ef_a) |f_{eabt}| \leq \sum_{s \in S} \sum_{t' \in T: t' \leq t} CapS_s K_{ist'} \quad \forall i \in N, b \in B, t \in T \quad (3.5)$$

$$\sum_{e \in E | \Psi^-(e)=i} \sum_{a \in A} |f_{eabt}| \leq \sum_{s \in S} \sum_{t' \in T: t' \leq t} CapS_s K_{ist'} + D_{ibt}(1 - \bar{K}_{it}) \quad \forall i \in N, b \in B, t \in T \quad (3.6)$$

$$X_{ict} \leq \bar{K}_{it} \quad \forall i \in N, c \in C, t \in T \quad (3.7)$$

$$\bar{K}_{it} \leq \sum_{s \in S} \sum_{t' \in T: t' \leq t} K_{ist'} \quad \forall i \in N, t \in T \quad (3.8)$$

$$K_{ist} \leq \bar{K}_{it} \quad \forall i \in N, s \in S, t \in T \quad (3.9)$$

$$\bar{K}_{it-1} \leq \bar{K}_{it} \quad \forall i \in N, t \in T \quad (3.10)$$

Constraints (3.5) and (3.6) limit the total flow leaving from and entering to the substation node or generation node  $i$  with the capacity of the substations located at that node, respectively. Constraints (3.7) and (3.8) satisfy that if a generation plant is built at node  $i$ , at least one step-up substation should also be built at the same node. Constraint (3.9) guarantees that  $\bar{K}_{it}$  should be 1 if there is at least one substation unit at node  $i$  at period  $t$ . Constraint (3.10) couples time units for substations.

- *Network Constraints:*

$$-CapL_a Z_{eabt} \leq (1 + ef_a) f_{eabt} \leq CapL_a Z_{eabt} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.11)$$

$$f_{eabt} = \varphi_{ea} Z_{eabt} (\theta_{ibt} - \theta_{jbt}) \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.12)$$

$$Z_{eabt} \leq L_{eat} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.13)$$

$$L_{eat-1} \leq L_{eat} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.14)$$

Constraint (3.11) is the capacity constraint for the transmission lines. Constraint (3.12) represents the power flow constraints based upon the Kirchhoff's

second law and it determines that the power flow on each line (if used) is equal to the susceptance of the line multiplied by the difference of the voltage angles of the nodes. Constraint (3.13) enforces that a line can be used at period  $t$ , only if the line is built. Constraint (3.14) couples time units for transmission lines.

• *Domain Constraints:*

$$-\pi \leq \theta_{ibt} \leq \pi \quad \forall i \in N, b \in B, t \in T \quad (3.15)$$

$$\theta_{1bt} = 0 \quad \forall b \in B, t \in T \quad (3.16)$$

$$\theta_{ibt} \text{ unrestricted} \quad \forall i \in N, b \in B, t \in T \quad (3.17)$$

$$X_{ict} \in \{0, 1\}, G_{icbt} \geq 0 \quad \forall i \in N, c \in C, b \in B, t \in T \quad (3.18)$$

$$L_{eat} \in \{0, 1\} \quad \forall e \in E, a \in A, t \in T \quad (3.19)$$

$$K_{ist} \in \{0, 1\} \quad \forall i \in N, s \in S, t \in T \quad (3.20)$$

$$\bar{K}_{it} \in \{0, 1\}, \quad \forall i \in N, t \in T \quad (3.21)$$

$$Z_{eabt} \in \{0, 1\}, f_{eabt} \text{ unrestricted} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.22)$$

Constraint (3.15) sets limits on the voltage angles at every node. Constraint (3.16) is the reference point for voltage profile of nodes, and without loss of generality, node 1 is selected as the reference point. Constraints (3.17)-(3.22) are the domain constraints.

We remark that, Constraints (3.5), (3.6) and (3.12) are nonlinear. Similar to the linearization techniques used in [20], we provide a linear formulation for the problem. In the linear model, the flow amount on each line is expressed as the difference of two nonnegative flow variables  $f_{eabt}^+$  and  $f_{eabt}^-$ :

$$f_{eabt} = f_{eabt}^+ - f_{eabt}^- \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.23)$$

and the difference of voltage angles are expressed as the difference of two non-negative variables  $\Delta\theta_{ebt}^+$  and  $\Delta\theta_{ebt}^-$  as follows:

$$\theta_{ibt} - \theta_{jbt} = \Delta\theta_{ebt}^+ - \Delta\theta_{ebt}^- \quad \forall e = \{i, j\} \in E, b \in B, t \in T \quad (3.24)$$

By using the above substitutions, Constraint (3.12) is linearized and replaced

with the following ones:

$$f_{eabt}^+ \leq \varphi_{ea} \Delta \theta_{ebt}^+ \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.25)$$

$$f_{eabt}^- \leq \varphi_{ea} \Delta \theta_{ebt}^- \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.26)$$

$$f_{eabt}^+ \geq \varphi_{ea} \Delta \theta_{ebt}^+ - M(1 - Z_{eabt}) \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.27)$$

$$f_{eabt}^- \geq \varphi_{ea} \Delta \theta_{ebt}^- - M(1 - Z_{eabt}) \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.28)$$

where  $M$  in (3.27) and (3.28) represents a sufficiently large number so that the new constraints does not cut any feasible solution if the line  $e$  is not in operation.

In order to linearize  $|f_{eabt}|$ , we utilize Equation (3.23) and a linear expression for the absolute value in Constraints (3.5) and (3.6) can be derived as follows:

$$|f_{eabt}| = f_{eabt}^+ + f_{eabt}^- \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.29)$$

Thus, a mixed integer linear model for GSTEP, referred to as *GSTEP-L*, is as follows:

$$\min \quad z_{inv} + z_{sub} + z_{line} + z_{om} \quad (3.1)$$

$$s.t \quad (3.3), (3.7) - (3.10), (3.13)-(3.21), (3.24)-(3.28)$$

$$\begin{aligned} & \sum_{c \in C} G_{icbt} + \sum_{e \in E | \Psi^-(e)=i} \sum_{a \in A} (f_{eabt}^+ - f_{eabt}^-) - \\ & \sum_{e \in E | \Psi^+(e)=i} \sum_{a \in A} (1 + e f_a) (f_{eabt}^+ - f_{eabt}^-) = D_{ibt} \quad \forall i \in N, b \in B, t \in T \end{aligned} \quad (3.2')$$

$$\begin{aligned} & \sum_{e \in E | \Psi^+(e)=i} \sum_{a \in A} (1 + e f_a) (f_{eabt}^+ + f_{eabt}^-) \leq \\ & \sum_{s \in S} \sum_{t' \in T: t' \leq t} CapS_s K_{ist'} \quad \forall i \in N, b \in B, t \in T \end{aligned} \quad (3.5')$$

$$\begin{aligned} & \sum_{e \in E | \Psi^-(e)=i} \sum_{a \in A} (f_{eabt}^+ + f_{eabt}^-) \leq \sum_{s \in S} \sum_{t' \in T: t' \leq t} CapS_s K_{ist'} + D_{ibt} (1 - \bar{K}_{it}) \\ & \quad \forall i \in N, b \in B, t \in T \end{aligned} \quad (3.6')$$

$$(1 + e f_a) f_{eabt}^+ \leq CapL_a Z_{eabt} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.11')$$

$$(1 + e f_a) f_{eabt}^- \leq CapL_a Z_{eabt} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.11'')$$

$$L_{eabt}, Z_{eabt} \in \{0, 1\}, f_{eabt}^+ \geq 0, f_{eabt}^- \geq 0 \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.22')$$

$$\Delta \theta_{ebt}^+ \geq 0, \Delta \theta_{ebt}^- \geq 0 \quad \forall e \in E, b \in B, t \in T \quad (3.30)$$

In our problem setting, we do not include constraints such as the start-up/shut-down status and ramping rates of plants or the voltage angle differences of transmission lines after switching on. As we only focus on the strategic decisions, we limit our discussion to the detail given above. However, these constraints can easily be included to the presented model.

### **3.2.2 Solution Approaches**

Power system expansion planning problems are highly complex and nonlinear problems. Thus, not to encounter with memory problems for large networks, dividing the original problem into subproblems and solving these subproblems sequentially utilizing the outputs/results of previous subproblems is a widely used approach in the literature. In the next section, we discuss this sequential solution approach for the integrated GSTEP problem. We first remark here that this approach solves the GSTEP problem heuristically since it requires decomposing and optimizing the subproblems of GSTEP individually and may not find the optimal solutions. In addition to this sequential approach, in this chapter, we also present another heuristic solution approach for the integrated GSTEP problem to be able to solve larger instances within reasonable solution times. The sequential solution approach and the proposed time-based solution approach are explained below.

#### **3.2.2.1 Sequential Approach**

In this approach, we decompose the GSTEP problem with respect to system components. We first temporarily ignore decisions related to substations and plan only the decisions related to generation units and transmission lines simultaneously. Thus, to make the decisions related to generation units and lines, we solve the GSTEP problem optimally. Then, based on the optimal solution obtained

after solving the GTEP problem, we determine the decisions related to substations (i.e. the required capacity and location of substations). We then add the decision related to substations to the optimal solution and calculate the cost of these substations and add these costs to the optimal result of GTEP problem. Thus, we obtain a feasible solution for the original GSTEP problem. Flow chart of the sequential solution approach is presented in Figure 3.3.

In order to obtain GTEP problem, we remove the following constraints that are related to substations from GSTEP-L: Constraints (3.5') and (3.6') which are related to capacity limitation of substations, Constraints (3.7)-(3.10) which are the relationship constraints between generation units and substations, and domain constraints ((3.20) and (3.21)). The remaining constraints of the GSTEP-L constitutes a model for the GTEP problem and the model is referred to as *GTEP-L*:

$$\begin{aligned}
\min \quad & z_{inv} + z_{line} + z_{om} \\
s.t \quad & (3.2'), (3.3), (3.11'), (3.11''), (3.13)-(3.17) \\
& (3.19), (3.22'), (3.24)-(3.28), (3.30)
\end{aligned} \tag{3.31}$$

We solve the presented model above optimally and the optimal solution value of the GTEP-L is denoted by  $\hat{z}^{GTEP}$  and the optimal values for the decision variables are denoted by  $\hat{X}$ ,  $\hat{L}$ ,  $\hat{G}$ ,  $\hat{f}^+$  and  $\hat{f}^-$ . Then, based on the output of these decision variables, we calculate the required capacity of substations at each node, and so,  $\hat{K}$  and  $\hat{\bar{K}}$  are determined. We also calculate total investment cost of substations ( $z_{sub}$ ) and denote by  $\hat{z}^{SUB}$ . Hence, at the end of this procedure, we obtain a solution for the original problem (GSTEP) using the sequential solution approach. The corresponding objective value for the solution is equal to  $\hat{z}^{GTEP} + \hat{z}^{SUB}$ .

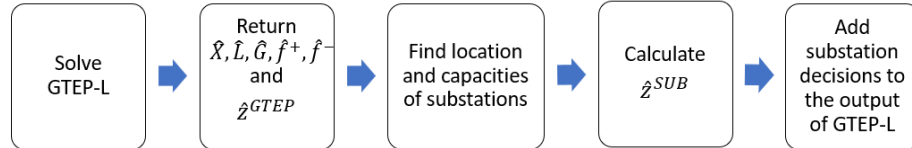


Figure 3.3: Flow chart of the sequential approach.

### 3.2.2.2 Time-based Approach

In this section, we present a time-based heuristic solution approach to efficiently solve the proposed GSTEP problem. Instead of decomposing the problem into subproblems with respect to the system components, in this approach, we decompose our multi-period problem into a set of single period problems as many as the number of expansion periods ( $|T|$ ) considered. All single-period expansion plans are solved iteratively by feeding the optimal results of a period as an existing infrastructure for the next time period in a nested way.

In this approach, we first obtain all single-period expansion planning problems and define a problem for each single time period  $t$ . We refer the problem *Single Period Expansion Problem* ( $SPEP_t$ ). In  $SPEP_1$ , we consider only the first period and solve  $SPEP_1$  to find the optimal solution. We then feed the optimal solution of  $SPEP_1$  as an existing network for the problem  $SPEP_2$  and find the optimal solution for the second time period. By applying the same procedure up to period  $t$ , we obtain all the investment decisions (generation units, substations and lines), generation amounts and power flows up to period  $t$ . We then fix these variables in  $SPEP_t$  and obtain the new investment decisions, generation amounts and power flows at period  $t$  by solving  $SPEP_t$  optimally. All the one-period expansion problems ( $SPEP_1, SPEP_2, \dots, SPEP_{|T|}$ ) are solved iteratively, and hence, after solving  $SPEP_{|T|}$ , we obtain a solution for the original GSTEP problem. Flow chart of the time-based solution approach is presented in Figure 3.3.

For time period  $t$ , the model of  $SPEP_t$  is given below.

$$\begin{aligned}
\min \quad & z_{inv} + z_{sub} + z_{line} + z_{om} \\
s.t \quad & (3.2'), (3.3), (3.5'), (3.6'), (3.11'), (3.11''), \\
& (3.7)-(3.10), (3.13)-(3.21), (3.22'), (3.24)-(3.28), (3.30) \\
& X_{ic1} \dots X_{ict-1}, G_{icb1} \dots G_{icbt-1} \text{ are fixed} & \forall i \in N, b \in B, c \in C \\
& K_{is1} \dots K_{ist-1} \text{ are fixed} & \forall i \in N, s \in S \\
& L_{ea1} \dots L_{eat-1} \text{ are fixed} & \forall e \in E, a \in A \\
& f_{eab1}^+ \dots f_{eat-1}^+, f_{eab1}^- \dots f_{eat-1}^- \text{ are fixed} & \forall e \in E, a \in A, b \in B
\end{aligned} \tag{1}$$

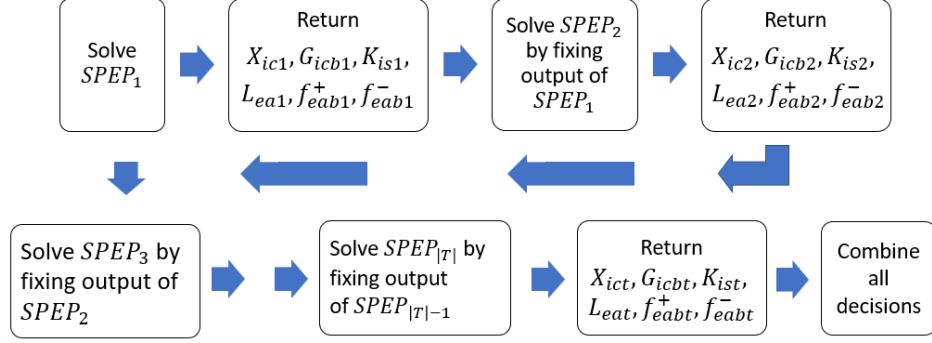


Figure 3.4: Flow chart of the time-based approach.

### 3.3 Computational Study

In this section, we first introduce the data sets and parameters that are used in the computational study. We then present the solution of the proposed model (GSTEP-L) for the IEEE 24-bus power system. In order to discuss the economic value of integrating subproblems, we compare the results of GSTEP-L along with the results of the sequential and time-based solution approaches. We, then, discuss the effect of transmission switching on the results. Lastly, we test the solution approaches on a larger network and present results of the sequential and time-based solution approaches for the IEEE 118-bus power system for different cases. For all instances, we report results obtained with the model and solution approaches once the reported gap by the solver is less than 1%. All computation results are obtained on a Linux environment with 2.4GHz Intel Xeon E5-2630 v3 CPU server with 64GB RAM. All the experiments of the model and heuristics are implemented using Java Platform, Standard Edition 8 Update 91 (Java SE 8u91) and Gurobi 6.5.1 in parallel mode using up to 32 threads.

### 3.3.1 IEEE 24-bus Power System

The proposed model has been applied to a modified version of IEEE 24-bus power system. IEEE 24-bus power system includes 24 nodes, 32 generation plants and 35 corridors for building transmission lines [108]. A 15-year planning horizon is considered and divided into three time periods of equal length,  $|T| = 3$ . Demand of nodes at the initial time period ( $t=0$ ) are the same as the original demand values given in [108] for 24 nodes. Annual demand growth rate is assumed to be 6% and the discount rate that includes inflation,  $r$ , is 5% [109]. In the computational study, four load blocks are considered for one year and load-duration curve is given in Figure 3.5. Percentage of the peak demand ( $p_b$ ) at each load block  $b$  and duration of each load block are obtained from [57]. Demand in each load block,  $D_{ibt}$ , is calculated with respect to given percentages.

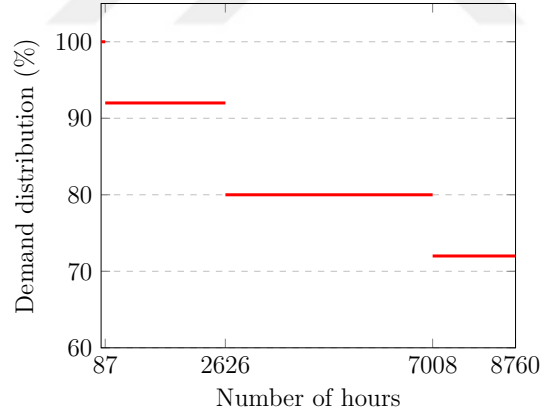


Figure 3.5: Load-duration curve.

For 24-bus, characteristics of the transmission lines (capacity, investment cost and reactance of the lines) are obtained from [110] and presented in Appendix Table A.6. Maximum three lines are allowed for each corridor and the lines in any corridor have the same characteristics with the existing ones. To allow new investment decisions, the maximum capacity of each line is set to the half of the capacity given in [110] and seven new corridors are also considered given in [111]. Instead of distance between the nodes, investment costs of the transmission lines ( $c_a^{line} l_e$ ) are given in [110]. Transmission loss parameter is equal to 2.5% of flow

amounts on all the lines [112].

Table A.4 in Appendix presents the characteristics of the new generation units. Permitted nodes for expanding generation capacities are 2, 3, 9, 13, 15 and 23 for the IEEE 24-bus power system. Existing generation plants are obtained from [108]. Table A.5 in Appendix shows alternatives for the substations and their associated costs. These costs are estimated using various sources [107, 113]. We permit all nodes to have substations, and we assume that substation costs are independent from their locations. However, for real-life applications, these costs might be dependent on geographical conditions and some of nodes might not be suitable for building substations.

Figure 3.6 illustrates the optimal expansion of the network for the IEEE 24-bus power system for the GSTEP problem. In Figure 3.6a, black lines and black circles represent existing transmission lines and generation units, respectively. The total cost of the optimum solution is equal to \$4266.30M and the cost distribution of the total cost is \$1048.06M for generation plants, \$395.53M for substations and \$73.15M for transmission lines. The total expanded capacity of generation, substation and transmission lines at the end of planning horizon are 3200 MV, 6900 MVA and 3075 MW, respectively. At time period 1, there are at least one substation at 16 nodes and 5 of them are transmission substations located at nodes 9, 10, 11, 12 and 17.

### **3.3.1.1 Computational Analysis of the Solution Approaches**

This section compares the results of our integrated model (GSTEP-L) with the sequential and time-based solution approaches. Table 3.2 presents the results of them for GSTEP problem under the columns titled with "GSTEP-TS". As well as providing total cost, the cost distribution in terms of investment costs of generation, substation and lines, and operation and maintenance (O&M) cost are reported. We again note that, sequential and time-based solution approaches solve GSTEP problem heuristically.

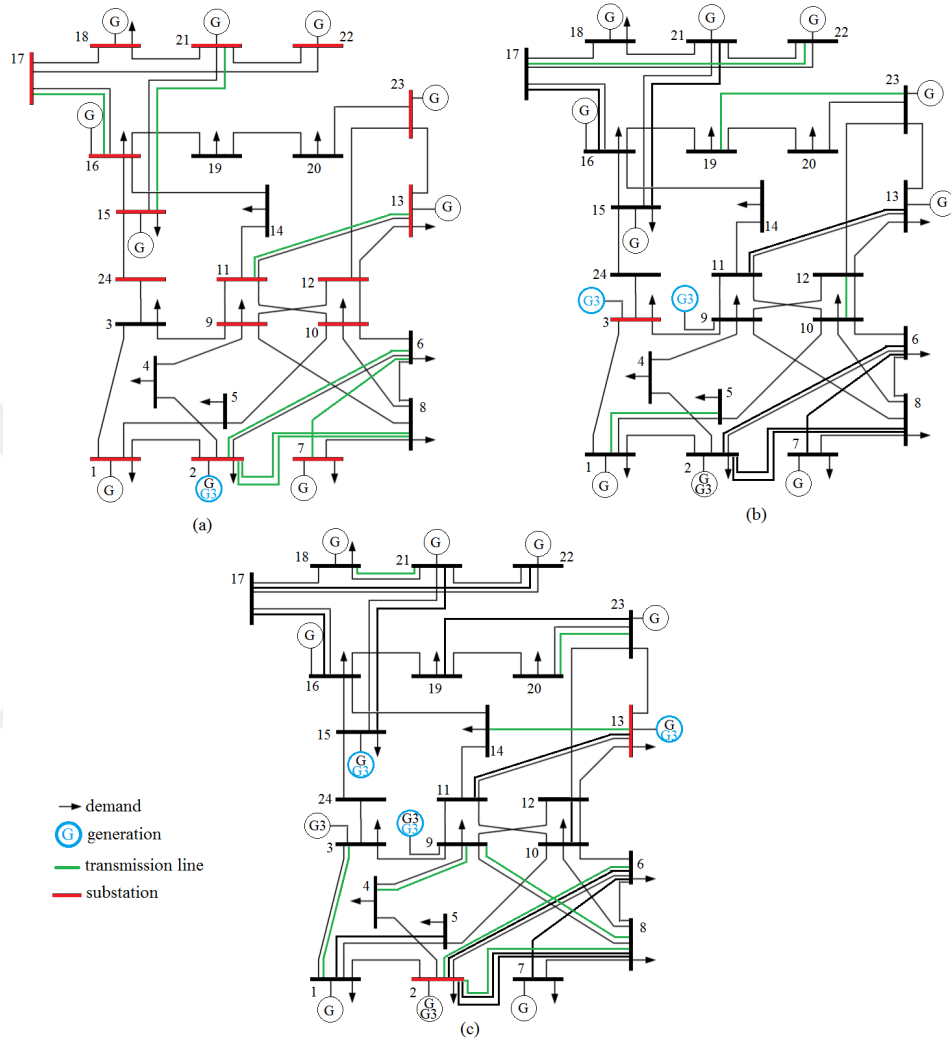


Figure 3.6: Optimum solution of the problem for the IEEE 24-bus power system (a) Time period 1 (b) Time period 2 (c) Time period 3.

We first compare the objective function values of the solutions obtained with sequential and time-based approaches. The proposed time-based approach finds a very good solution since the gap from the optimal solution is less than 1%. Moreover, the solution value of the sequential approach is higher than the solution value obtained with the time-based approach and the difference between the result of sequential approach and the optimum solution is 3.86%. The time-based approach also overcomes the model and sequential approach in terms of solution time. The optimum solution of the GSTEP problem is found in approximately 12 hours and sequential approach terminates in 1.8 hours, whereas time-based

approach finds the solutions in 2.3 minutes. Thus, in a very short time, the time-based approach finds a better solution than the solution obtained with sequential approach.

Using these analyses, we can also discuss the economic value of incorporating substation decisions to the expansion problem by comparing the solutions of sequential solution approach and our GSTEP model. When the substations are ignored while determining the expansion plans, the estimated cost of the power system (denoted by  $\hat{z}^{GTEP}$ ) would be equal to \$3847.11M, which corresponds to about 10% deviation from the real expansion planning cost. When the required capacities of the substations are determined after obtaining the solution of the GTEP, the calculated total cost is equal to \$4430.98M and 3.86% higher than the real cost. Thus, these findings are also consistent with our discussions explained in Section 3.1 and they show that generation, transmission and substation decisions should be optimized simultaneously.

### 3.3.1.2 Analysis of Transmission Switching

In this section, we discuss the additional benefit of allowing transmission switching (TS). Since in the original problem, GSTEP, all the lines are considered as switchable, we first need to revise the model in order to guarantee that line switching is not allowed. For this requirement, we add the following constraint to the model:

$$L_{eat} \leq Z_{eabt} \quad \forall e \in E, a \in A, b \in B, t \in T \quad (3.32)$$

Constraint (3.32) guarantees that, if a line is built at  $t$  (or existing), then the line should be used in the same period. With Constraint (3.14), this requirement holds for all time periods.

For analyzing effects of TS on the expansion plans, we again compare the solutions of the three approaches; namely, the optimization model, the sequential approach and the time-based approach. Table 3.2 presents the results for the case when TS is not allowed under the columns titled with "GSTEP-noTS". In

sequential approach, in order not to allow switching lines, Constraint (3.32) is also added to the GSTEP-L presented in Section 3.2. When TS is not allowed, we obtain similar results for the three solution methods; GSTEP-L has the lowest objective function value and the sequential solution approach has the largest objective value. The difference between the results of GSTEP-L and sequential approach is 2.30%, whereas the difference between the solutions of GSTEP-L and time-based approach is 1.22%. For this case, we report the best solution that is obtained within 12 hours for the GSTEP-L and the gap reported by the solver is 1.48% at the end of 12 hours. Interestingly, when TS is not allowed, the solution time of the sequential approach (20 seconds) is shorter than the solution time of the proposed approach (13 minutes). We note that, in both cases (with and without TS) time-based solution approach finds a better solution than the sequential approach in a reasonable solution time.

Table 3.2: Comparison of cases GSTEP-TS and GSTEP-noTS for three approaches on the IEEE 24-bus power system

|                  | GSTEP-TS |            |            | GSTEP-noTS |            |            |
|------------------|----------|------------|------------|------------|------------|------------|
|                  | GSTEP-L  | Sequential | Time-based | GSTEP-L    | Sequential | Time-based |
| sol. time (h)    | 12.00    | 1.80       | 0.04       | >12.00     | 0.01       | 0.22       |
| total cost (M\$) | 4266.30  | 4430.98    | 4306.14    | 4341.42    | 4441.45    | 4394.49    |
| $z_{inv}$ (M\$)  | 1048.06  | 1017.17    | 1017.17    | 1048.06    | 1048.06    | 1017.17    |
| $z_{sub}$ (M\$)  | 395.53   | 583.87     | 412.73     | 448.93     | 580.16     | 469.44     |
| $z_{line}$ (M\$) | 73.15    | 61.05      | 82.64      | 73.61      | 49.71      | 112.64     |
| $z_{om}$ (M\$)   | 2749.54  | 2768.88    | 2793.59    | 2770.81    | 2763.53    | 2795.23    |
| (gap%)           |          | 3.86%      | 0.93%      |            | 2.30%      | 1.22%      |

We also remark that, including substation decisions to the system increases the diversity of the system components in terms of line, substation and generator types. As TS can be considered as a tool to increase the utilization of the network, TS can change solutions in the GSTEP problem, as by definition it includes more decisions. As shown in Table 3.2, in sequential approach, TS decreases total cost by \$10.47M, whereas it decreases total cost by \$75.12M in GSTEP-L due to changes in the values of the investment planning decisions. Since more decisions of GSTEP-L are changed, the effect of TS is more pronounced for the GSTEP-L (0.17% vs. 0.02%) and this amplifies optimizing the substation location decisions.

Table 3.3 and Table 3.4 show the details of the optimum solutions of GSTEP problem for the cases when TS is allowed and not. These solutions also support the discussions above. Although total generation capacity is not affected, the locations and capacities of generation plants are changed. Moreover, the capacities and locations of substations are quite different from each other. When TS is not allowed (GSTEP-noTS), two and four more substations are built at  $t = 1$  and at  $t = 2$ , respectively and total capacities at the end of time horizon are 6900 and 8100 MVA, for the cases TS and no-TS, respectively. Although the total investment costs of transmission lines are almost the same for both cases, the networks at the end of planning horizon are significantly different from each other (Table 3.4). When TS is not allowed, total number of transmission lines is also increased; one and two more transmission lines are built at  $t = 1$ ,  $t = 2$ , respectively. Hence by adding more freedom in GSTEP, the expansion planning decisions and total cost can be affected significantly.

Table 3.3: Installed generation and substation units for GSTEP-TS and GSTEP-noTS on the IEEE 24-bus power system

| $t$ | GSTEP-TS                        |                           | GSTEP-noTS                      |                           |
|-----|---------------------------------|---------------------------|---------------------------------|---------------------------|
|     | bus number<br>(generation type) | # of added<br>subs. units | bus number<br>(generation type) | # of added<br>subs. units |
| 1   | 2(3)                            | 16                        | 9(3)                            | 18                        |
| 2   | 3(3), 9(3)                      | 1                         | 2(3), 3(3)                      | 5                         |
| 3   | 9(3), 13(3), 15(1)              | 2                         | 9(1), 13(3), 15(3)              | 2                         |

Table 3.4: Installed number of lines and corridors for GSTEP-TS and GSTEP-noTS on the IEEE 24-bus power system

| $t$ | GSTEP-TS            |                                                                | GSTEP-noTS          |                                                                       |
|-----|---------------------|----------------------------------------------------------------|---------------------|-----------------------------------------------------------------------|
|     | # of added<br>lines | transmission lines                                             | # of added<br>lines | transmission lines                                                    |
| 1   | 7                   | (2,6), (2,8), (2,8), (6,7)<br>(11,13), (15,21), (16,17)        | 8                   | (7,8), (8,9), (10,12), (12,23),<br>(15,21), (15,24), (16,17), (17,22) |
| 2   | 4                   | (1,5), (10,12)<br>(17,22), (19,23)                             | 7                   | (1,2), (1,5), (2,6), (2,8),<br>(2,8), (14,16), (20,23)                |
| 3   | 8                   | (1,3), (2,6), (2,8), (4,9)<br>(8,9), (13,14), (18,21), (20,23) | 8                   | (2,6), (2,8), (4,9), (8,9),<br>(13,14), (15,16), (18,21), (20,23)     |

### 3.3.2 IEEE 118-bus Power System

The proposed solution approach is also tested with a large network which includes 118 nodes, 54 generation units and 186 corridors for building transmission lines. The total load at the initial time period ( $t=0$ ) is equal to peak load of the power system and the load ratio of each demand node. Total demand at the initial time period is 6485 MW and the maximum generation capacity is equal to 7220 MW. Investment cost of transmission lines is taken as 144,000\$/km. Data about the demand, existing network and specification of transmission lines are taken from <http://motor.ece.iit.edu/data/>. The remaining parameters are the same with the parameters used in IEEE 24-bus power system. For the IEEE 118-bus power system, we generate three cases to test the proposed solution approach and for all the cases, we stopped computations once the reported gap by the solver is less than 1% or solution time is higher than 12 hours.

#### 3.3.2.1 Base Case

For the IEEE 118-bus power system, demand growth rate is assumed to be 3% per year and 32 nodes whose generation capacities in the current network are more than 100 MW are allowed for expanding generation capacities. The same 61 corridors in [114] are considered for expanding transmission network. Table 3.5 compares total costs of three solution approaches. We also report cost distributions in terms of investment costs of generation, substation, transmission lines and O&M costs.

For the IEEE 118-bus power system, we obtain the optimal solution within the time limit and GSTEP-L finds the optimum solution in approximately 9.3 hours whereas sequential and time-based solution approaches find the solutions in 65 seconds and 8 minutes, respectively.

The value of adding substation location decision to the GTEP problem can also easily be observed from Table 3.5. The investment cost of generation units in GSTEP-L is \$197.31M higher than the investment cost of generation units

in sequential approach whereas the investment cost of substations in GSTEP-L is \$565.49M less than the investment cost of substations in sequential approach. Hence, by adding substation location decisions to the problem, the objective value is decreased by 4.28%. Although the solution time of the sequential approach is less than the solution time of the proposed time-based solution approach, the proposed method finds a solution that has smaller objective value than solution of the sequential approach. The gap between the solution of the time-based approach and the best solution obtained at the end of time limit is 2.77%.

Table 3.5: Comparison of the three approaches on the IEEE 118-bus power system

|                  | GSTEP-TS |            |            |
|------------------|----------|------------|------------|
|                  | GSTEP-L  | Sequential | Time-based |
| sol. time (h)    | 9.3      | 0.02       | 0.13       |
| total cost (M\$) | 9143.89  | 9535.15    | 9397.45    |
| $z_{inv}$ (M\$)  | 921.03   | 723.72     | 662.70     |
| $z_{sub}$ (M\$)  | 999.36   | 1564.85    | 1044.50    |
| $z_{line}$ (M\$) | 2.56     | 0.43       | 7.81       |
| $z_{om}$ (M\$)   | 7220.85  | 7246.16    | 7682.44    |
| gap(%)           |          | 4.28%      | 2.77%      |

We remark that the benefit of incorporating substation decisions to the GTEP problem is more evident for the IEEE 118-bus power system. In addition to the cost difference between the solutions of GSTEP-L and sequential solution approach, the network design changes substantially. In GSTEP-L one more generation plant and two more transmission lines are built at  $t = 1$  compared to the solution of sequential approach. However, in the solution of GSTEP-L, 45 less substations are built through the time horizon that justifies the difference in the  $z_{sub}$  values of the both solution approaches.

### 3.3.2.2 Case A

In the base case, we only allow the same 61 corridors given in [114] for expanding the transmission lines. To impose more investment decisions and to increase the density of the network, we generate a different instance and in this case, the

maximum capacity of each line is set to the two thirds of the original capacities and all the existing corridors are allowed to be expanded.

Table 3.6 shows the results of three solution approaches. We report the best solution that is obtained within 12 hours for the GSTEP-L and the gap reported by the solver is 2.26% at the end of 12 hours. For this test instance, the proposed time-based solution approach outperforms the sequential solution approach both in terms of solution quality and solution time. The gap of time-based approach from the best solution obtained at the end of time limit is 1.33%, whereas the gap between the sequential approach and best solution is 3.70%. Although the solution times increase for all the approaches, the proposed solution approach finds a good solution in 0.53 hours whereas the sequential approach terminates after 0.75 hours.

### 3.3.2.3 Case B

For generating another test instance, in addition to allowing all corridors for expanding transmission lines (Case A), we increase the demand growth rate to 6% per year. All the 118 nodes in the system are also allowed for expanding generation capacities. In this case, the capacity of the transmission lines are set to their original values.

Table 3.6 presents the solutions of the three approaches and for the GSTEP-L. We report the best solution obtained within the time limit and the gap reported by the solver is equal to 2.85%. For this case, the solution time of the sequential approach is less than the solution time of the proposed time-based solution approach. However, time-based approach again finds better solution than the obtained with the sequential approach and the gap of time-based approach from the best solution obtained at the end of time limit is about 1% whereas the gap between the sequential approach and best solution is higher than 5%.

Table 3.6: Comparison of cases for the three approaches on modified versions of the IEEE 118-bus power system

|                  | Case A  |            |            | Case B   |            |            |
|------------------|---------|------------|------------|----------|------------|------------|
|                  | GSTEP-L | Sequential | Time-based | GSTEP-L  | Sequential | Time-based |
| sol. time (h)    | > 12.00 | 0.75       | 0.53       | > 12.00  | 0.29       | 3.02       |
| total cost (M\$) | 9295.75 | 9640.01    | 9419.80    | 11226.44 | 11814.66   | 11351.08   |
| $z_{inv}$ (M\$)  | 944.73  | 785.11     | 676.27     | 1710.38  | 1509.62    | 1499.87    |
| $z_{sub}$ (M\$)  | 1063.31 | 1583.55    | 1044.10    | 1185.44  | 1853.29    | 1139.90    |
| $z_{line}$ (M\$) | 23.09   | 8.00       | 18.51      | 14.47    | 6.02       | 16.84      |
| $z_{om}$ (M\$)   | 7264.64 | 7263.34    | 7680.93    | 8316.15  | 8445.72    | 8694.47    |
| gap(%)           |         | 3.70%      | 1.33%      |          | 5.24%      | 1.11%      |

### 3.4 Conclusion

In this chapter, we study a multi-period power expansion planning problem that includes decisions related to substations' locations and sizes. In the literature, substation decisions are not explicitly considered in the transmission network design problem and the investment costs of them are either ignored or considered as a part of investment costs of other components which may overestimate or underestimate the real cost in the system. In this chapter, we propose a mathematical programming model for the integrated problem that finds a minimum cost network and locations of substations and generation units. We also present a time-based solution approach in which we decompose the multi-period problem into single-period problems and proceed by fixing the output of the one period in the next time periods.

In the computational study, we first discuss the economic value of adding substation decisions to the problem on the IEEE 24-bus power system. We also analyze the effect of TS on the GSTEP problem and discuss the results of the model, sequential and time-based approaches when TS is not allowed. We then apply the solution approaches to a larger network, IEEE 118-bus power system, and discuss the value of incorporating substation decisions and their effect to the network design. We test the proposed solution approach for different cases and conclude that ignoring the investment costs of the substations and adding the

substations based on the solution of GTEP overestimates the real cost by 3%-5%. We can also deduct that improving network density increases the solution time of the model and for these cases the proposed time-based solution approach can be utilized since it finds near optimal solutions in shorter solution times.



## Chapter 4

# Benefits of Transmission Switching and Energy Storage in Power Systems with High Renewable Energy Penetration

This chapter discusses the control mechanisms explained in Chapter 2 in power systems expansion planning problems to handle variability of renewable energy sources (RES). We provide a two-stage stochastic programming model that optimizes transmission switching operations, transmission and storage investments subject to limitations on load-shedding (LS) and renewable energy curtailment (REC) amounts, simultaneously for a target year. We discuss the effect of transmission switching (TS) on total system cost, energy storage system (ESS) locations and sizes, LS and REC. An extensive computational study on the IEEE 24-bus power system with wind and solar as available renewable sources demonstrates that the total cost and total capacity of energy storage systems can be decreased by as much as 17% and 50%, respectively, when transmission switching is incorporated into the power system.

The outline of the chapter is as follows: In Section 4.1, we explain the problem

and provide the proposed mathematical model. In Section 4.2, we present the results of our extensive computational study and examine solutions around the value of TS. We conclude this chapter with some final remarks in Section 4.3. The results of this chapter is published in Applied Energy [84].

## 4.1 Problem Definition and Mathematical Formulation

In this section, we introduce our model, which co-optimizes new investments and operational decisions. As the aim of this chapter is to present the joint benefit of ESSes and TS, we assume that planning is done by a vertically integrated utility. A central planner that makes all investment and operation decisions can benefit from this co-optimization process, as planning for TS operations can potentially provide a cheaper solution for countries with renewable energy targets.

For accurate representation of ESSes, we consider both energy capacity and power ratings (ramp rates for charging/discharging) of ESSes. In our model, we ignore the cost for generating electricity from available RES. A Direct Current (DC) approximation of power flow constraints, as given in [7], is utilized in the proposed model, as also used in [46, 50, 63]. In this chapter, we consider a static planning approach and plan for a target year which has  $NS$  number of days with hourly time bucket. For the sake of computational tractability, we select representative days which are considered as scenarios of the problem. Each scenario  $s$  has a probability  $\sigma_s$ , which is proportional to the occurrence of similar days based on observations in the target year. Below, we provide an extensive form of a two-stage stochastic programming model for the problem. The decisions made in the first stage include investments of transmission lines and ESSes. The second stage involves recourse actions that are based on operational decisions such as power flows, generation amounts and transmission line status at each hour of the scenarios. We use the following notation for the mathematical programming model.

• **Sets (Indices)**

$B$  Set of buses  $(i, j)$

$C(C_R)$  Set of all (renewable) gen. units  $(g)$

$A(EA)$  Set of all (existing) lines  $(a)$

$AS_{ij}$  Set of lines between buses  $i$  and  $j$

$T$  Set of hours of a scenario  $(t)$

$S$  Set of scenarios  $(s)$

$\Psi^+(a)$  Sending-end bus of line  $a$

$\Psi^-(a)$  Receiving-end bus of line  $a$

• **Parameters**

$D_{its}$  Demand of bus  $i$  at hour  $t$  of scenario  $s$  (MW)

$\overline{F}_a$  Capacity of line  $a$  (MW)

$c_a^{line}$  Annualized investment cost of candidate line  $a$  (\$)

$\varphi_a$  Susceptance of line  $a$  (p.u.)

$\tau$  Maximum number of switchable lines

$\sigma_s$  Probability of scenario  $s$

$p^{ls}$  Ratio of load that can be shed to total load

$p^{rec}$  Ratio of renewable generation that can be curtailed to total generation

$c_g^{om}$  Operation cost of unit  $g$  (\$/MWh)

$\overline{G}_{igts}$  Maximum generation limits from unit  $g$  in bus  $i$  at hour  $t$  of scenario  $s$  (MW)

$\underline{G}_{igts}$  Minimum generation limits from unit  $g$  in bus  $i$  at hour  $t$  of scenario  $s$  (MW)

$R_g^{up}$  Ramp-up rate of unit  $g$

$R_g^{down}$  Ramp-down rate of unit  $g$

$\overline{E}(\underline{E})$  Maximum (Minimum) energy capacity of ESS (MWh)

$\overline{P}(\underline{P})$  Maximum (Minimum) power rating of ESS (MW)

$c^E$  Annualized investment cost of ESS for energy capacity (\$/MWh)

$c^P$  Annualized investment cost of ESS for power rating (\$/MW)

$c^d$  Discharging (or ageing) cost of ESS (\$/MW)

$\eta$  Charging/Discharging efficiency of ESS

$\alpha$  Energy-power ratio of ESS

$E_0$  Initial energy level of ESS

$NS$  Number of days in the target year

• **Decision Variables**

$L_a$  1 if candidate line  $a$  is built, 0 o.w.

$Y_i$  1 if ESS is built at bus  $i$ , 0 o.w.

$Y_i^E$  Energy capacity of ESS at bus  $i$

$Y_i^P$  Power rating of ESS at bus  $i$

$P_{its}^c$  Charging rate of ESS at bus  $i$  at hour  $t$  of scenario  $s$

$P_{its}^d$  Discharging rate of ESS at bus  $i$  at hour  $t$  of scenario  $s$

$X_{its}$  Status of ESS at bus  $i$  at hour  $t$  of scenario  $s$ , 1 is for charging/0 is for discharging

$E_{its}$  State of charge of ESS at bus  $i$  at hour  $t$  of scenario  $s$

$G_{igts}$  Power generation of unit  $g$  in bus  $i$  at hour  $t$  of scenario  $s$

$DS_{its}$  Load shedding amount at bus  $i$  at hour  $t$  of scenario  $s$

$f_{ats}$  Power flow on line  $a$  at hour  $t$  of scenario  $s$

$Z_{ats}$  1 if line  $a$  is closed at hour  $t$  of scenario  $s$ , 0 if it is open

$\theta_{its}$  Voltage angle of bus  $i$  at hour  $t$  of scenario  $s$

The objective function (4.1) minimizes the total annualized investment costs of new transmission lines ( $z_{line}$ ) and storage units ( $z_{storage}$ ), as well as the expected operational costs of conventional generators and ESSes ( $z_{om}$ ) for one year. In the objective function, we do not include charging cost of ESSes since we require daily energy balance for storages. Thus, total charging rate is equal to  $1/\eta^2$  times of total discharging rate for each representative day. The objective function is presented below and subject to the following constraints:

$$\begin{aligned}
\min \quad & z_{line} + z_{storage} + z_{om} \\
z_{line} = \quad & \sum_{a \in A \setminus EA} c_a^{line} L_a \\
z_{storage} = \quad & \sum_{i \in B} (c^E Y_i^E + c^P Y_i^P) \\
z_{om} = \quad & \sum_{s \in S} NS \sigma_s \sum_{i \in B} \sum_{t \in T} \left\{ \sum_{g \in C \setminus C_R} c_g^{om} G_{igts} + c^d P_{its}^d \right\}
\end{aligned} \tag{4.1}$$

• *Power Balance Constraint:*

$$\begin{aligned}
& \sum_{g \in C} G_{igts} + \sum_{a \in A \Psi^-(a)=i} f_{ats} - \sum_{a \in A \Psi^+(a)=i} f_{ats} - \\
& P_{its}^c + P_{its}^d = D_{its} - DS_{its} \quad \forall i \in B, t \in T, s \in S
\end{aligned} \tag{4.2}$$

Constraint (4.2) guarantees the power balance at node  $i$  at each time period, which includes generation from both conventional and renewable sources, incoming/outgoing flows, ESS charging and discharging rates and demand and load shedding amounts.

• *Generation Dispatch Constraints:*

$$G_{igts} \leq \bar{G}_{igts} \quad \forall i \in B, g \in C_R, t \in T, s \in S \tag{4.3}$$

$$\underline{G}_{igts} \leq G_{igts} \leq \bar{G}_{igts} \quad \forall i \in B, g \in C \setminus C_R, t \in T, s \in S \tag{4.4}$$

$$R_g^{down} \leq G_{igts} - G_{igt-1s} \leq R_g^{up} \quad \forall i \in B, g \in C \setminus C_R, t \in T, s \in S \tag{4.5}$$

Constraints (4.3) and (4.4) set lower and upper bounds for electricity generation from renewable and conventional sources, respectively. Constraint (4.5) limits the maximum allowable change of generation from conventional sources between consecutive time periods.

• *Network Constraints:*

$$-\bar{F}_a Z_{ats} \leq f_{ats} \leq \bar{F}_a Z_{ats} \quad \forall a \in A, t \in T, s \in S \quad (4.6)$$

$$f_{ats} = \varphi_a Z_{ats} (\theta_{its} - \theta_{jts}) \quad \forall a \in AS_{ij}, t \in T, s \in S \quad (4.7)$$

$$Z_{ats} \leq L_a \quad \forall a \in A, t \in T, s \in S \quad (4.8)$$

$$\sum_{a \in A} L_a \leq \sum_{a \in A} Z_{ats} + \tau \quad \forall t \in T, s \in S \quad (4.9)$$

Constraint (4.6) limits the flow on the closed lines and also enforces that there is no flow on the open lines [63]. Constraint (4.7) defines the power flow on the closed lines as a function of the buses' voltage angles, considering a DC approximation of power flow constraint. The constraint also guarantees that there cannot be any flow on lines that are switched off. Constraint (4.8) satisfies that a line is built if it is used (or closed) [63] and Constraint (4.9) limits the number of switchable lines with  $\tau$ .

• *ESS Constraints:*

$$E_{its} = E_{it-1s} + \Delta t (\eta P_{its}^c - \frac{1}{\eta} P_{its}^d) \quad \forall i \in B, t \in T, s \in S \quad (4.10)$$

$$\underline{E}Y_i \leq E_{its} \leq Y_i^E \quad \forall i \in B, t \in T, s \in S \quad (4.11)$$

$$\underline{E}Y_i \leq Y_i^E \leq \bar{E}Y_i \quad \forall i \in B, t \in T, s \in S \quad (4.12)$$

$$\underline{P}Y_i \leq Y_i^P \leq \bar{P}Y_i \quad \forall i \in B, t \in T, s \in S \quad (4.13)$$

$$P_{its}^c \leq Y_i^P \quad \forall i \in B, t \in T, s \in S \quad (4.14)$$

$$P_{its}^d \leq Y_i^P \quad \forall i \in B, t \in T, s \in S \quad (4.15)$$

$$P_{its}^c \leq \bar{P}X_{its} \quad \forall i \in B, t \in T, s \in S \quad (4.16)$$

$$P_{its}^d \leq \bar{P}(1 - X_{its}) \quad \forall i \in B, t \in T, s \in S \quad (4.17)$$

$$\alpha Y_i^P \leq Y_i^E \quad \forall i \in B, t \in T, s \in S \quad (4.18)$$

$$E_{i0s} = E_{iT_s} = E_0 Y_i \quad \forall i \in B, s \in S \quad (4.19)$$

Constraint (4.10) satisfies the energy balance between consecutive time periods. Constraint (4.11) limits storage units state of charge levels by their capacities, and Constraint (4.12) guarantees that storage capacity is between the predetermined lower and upper bounds. Constraint (4.13) also sets lower and upper bounds for storage units' power ratings. Constraints (4.14) and (4.15) are the ramp rate of the storage units and limit their charging and discharging rates by their power ratings. Constraints (4.16) and (4.17) prevent ESSes from simultaneously charging and discharging [50]. Constraint (4.18) relates energy capacity and power rating via a given ratio. A daily storage cycling constraint (4.19) is added to enforce the storage energy balance for each representative day, as in [46, 48, 50].

• *LS and REC Constraints:*

$$\sum_{i \in B} \sum_{t \in T} DS_{its} \leq p^{ls} \sum_{i \in B} \sum_{t \in T} D_{its} \quad \forall s \in S \quad (4.20)$$

$$\sum_{i \in B} \sum_{g \in C_R} \sum_{t \in T} G_{igts} \geq (1 - p^{rec}) \sum_{i \in B} \sum_{g \in C_R} \sum_{t \in T} \bar{G}_{igts} \quad \forall s \in S \quad (4.21)$$

As explained earlier, instead of using monetary values for LS and REC, we limit their amounts. Constraints (4.20) and (4.21) set upper bounds for the LS and REC amounts, respectively.

• *Domain Constraints:*

$$L_a = 1 \quad \forall a \in EA \quad (4.22)$$

$$\theta_{ref,ts} = 0 \quad \forall t \in T, s \in S \quad (4.23)$$

$$-\pi \leq \theta_{its} \leq \pi \quad \forall i \in B, t \in T, s \in S \quad (4.24)$$

$$G_{igts} \geq 0, \theta_{its} \text{ urs} \quad \forall i \in B, g \in C, t \in T, s \in S \quad (4.25)$$

$$P_{its}^d \geq 0, P_{its}^c \geq 0, X_{its} \geq 0, E_{its} \geq 0, DS_{its} \geq 0 \quad \forall i \in B, t \in T, s \in S \quad (4.26)$$

$$L_a \in \{0, 1\} \text{ f}_{ats} \text{ urs}, Z_{ats} \in \{0, 1\} \quad \forall a \in A, t \in T, s \in S \quad (4.27)$$

$$Y_i \in \{0, 1\}, Y_i^E \geq 0, Y_i^P \geq 0 \quad \forall i \in B \quad (4.28)$$

Constraints (4.22)-(4.28) are for the domain restrictions of the decision variables. Constraint (4.22) is for the existing lines and Constraint (4.23) is the reference point for the buses' voltage angles. The remaining constraints are the nonnegativity and binary constraints for the decision variables.

#### 4.1.1 Linearization of the Model

We note that the model is nonlinear due to the multiplication of decision variables in Constraint (4.7). Here, we linearize the model by utilizing the Big-M type of linearization technique. Two nonnegative flow variables,  $f_{ats}^+$  and  $f_{ats}^-$ , each one representing flow on the same line in one direction, express  $f_{ats}$  as follows:

$$f_{ats} = f_{ats}^+ - f_{ats}^- \quad \forall a \in A, t \in T, s \in S \quad (4.29)$$

Similarly, two nonnegative variables,  $\Delta\theta_{ats}^+$  and  $\Delta\theta_{ats}^-$ , express the voltage angle difference between buses  $i$  and  $j$  as follows:

$$\theta_{its} - \theta_{jts} = \Delta\theta_{ats}^+ - \Delta\theta_{ats}^- \quad \forall a \in AS_{ij}, t \in T, s \in S \quad (4.30)$$

By using Equations (4.29) and (4.30), Constraint (4.7) is linearized and replaced with the following constraints:

$$f_{ats}^+ \leq \varphi_a \Delta\theta_{ats}^+ \quad \forall a \in AS_{ij}, t \in T, s \in S \quad (4.31)$$

$$f_{ats}^- \leq \varphi_a \Delta\theta_{ats}^- \quad \forall a \in AS_{ij}, t \in T, s \in S \quad (4.32)$$

$$f_{ats}^+ \geq \varphi_a \Delta\theta_{ats}^+ - M_a(1 - Z_{ats}) \quad \forall a \in AS_{ij}, t \in T, s \in S \quad (4.33)$$

$$f_{ats}^- \geq \varphi_a \Delta\theta_{ats}^- - M_a(1 - Z_{ats}) \quad \forall a \in AS_{ij}, t \in T, s \in S \quad (4.34)$$

Constraints (4.31)-(4.34) correctly linearize Constraint (4.7) for a sufficiently large positive number,  $M_a$ , in (4.33) and (4.34). If line  $a$  is open (i.e.  $Z_{ats} = 0$ ), Constraints (4.33) and (4.34) become redundant as  $f_{ats}^+$  and  $f_{ats}^-$  are already larger than or equal to zero. For this case, Constraints (4.31) and (4.32) are also

redundant, as  $f_{ats} = 0$  from Constraint (4.6). When  $Z_{ats} = 1$ , Constraints (4.31) and (4.33) reduce to  $f_{ats}^+ = \varphi_a \Delta \theta_{ats}^+$  and Constraints (4.32) and (4.34) reduce to  $f_{ats}^- = \varphi_a \Delta \theta_{ats}^-$ . By using the equalities in (4.29) and (4.30), we obtain  $f_{ats} = \varphi_a(\theta_{its} - \theta_{jts})$ , which is the same equation obtained from Constraint (4.7) with  $Z_{ats} = 1$ . Thus, adding Constraints (4.29)-(4.34) and removing Constraint (4.7) linearize the proposed model, and we obtain a mixed integer linear programming (MILP) model for the extensive form of the two-stage stochastic programming model given above.

In our model, we do not include features such as the start-up/shut-down status of conventional plants or the voltage angle differences of transmission lines after closing the lines. A model including these features leads to a problem that requires more computational power. In this chapter, as our aim is to discuss the value of ESSes and TS, we limit our discussion to the detail given above.

## 4.2 Computational Study

This section analyzes the benefits from co-optimizing transmission switching and other control mechanisms, such as energy storage systems, renewable energy curtailment and load shedding as a policy of demand-side management. The effect of TS on total system cost, LS and REC, as well as the locations and sizes of ESS are discussed in detail. The model is applied to the IEEE Reliability test system for varying limitations on LS and REC amounts.

### 4.2.1 Data

As shown in Figure 4.1, the IEEE Reliability test system includes 24 buses, 32 generation plants located at 10 buses and 34 corridors for transmission lines. In the original network, the total installed capacity and total peak demand are 3405 MW and 2805 MW, respectively [115]. To induce congestion in the system and observe the value of TS in a power system with a high level of renewable energy

penetration, we reduce the transmission line capacities by 50% and the installed capacity of thermal sources by 75%. Following [50], we allow wind and solar sources at six buses; solar generation units are available at buses 3, 5 and 7, and wind generation units are available at buses 16, 21 and 23. The installed capacities of new generation units, cost of transmission lines and ESS characteristics (e.g. round-trip efficiency, capital and discharging costs) are also obtained from [50]. We limit ESS capacity to 1,000 MWh/bus, select an energy-power ratio of six hours and a round-trip efficiency of 81%. Annualized investment costs of energy capacity and power rating of ESS are \$4,000/MWh and \$80,000/MW, respectively, and the discharging cost of ESS is \$5/MW [50]. We also limit the installed capacity of solar and wind generation units to 1,500MW/bus and 1,000 MW/bus, respectively.

The planning horizon is one year (365 days) and the duration of each time period is set to one hour. Hourly wind and solar profiles for 365 days are obtained using wind speed and solar radiation values from [116] and hourly demand profiles of nodes are obtained from [115]. To observe the joint effect of TS and ESSes, different profiles are used for each wind and solar generation units. Thus, we have hourly profiles in seven-dimensional space (one for load, three for wind generation units and three for solar generation units) for the target year. Since all profiles are independent from each other, we use a *K-means algorithm* in seven dimensional space to cluster days based on their similarity. We use the Euclidean distance as measurement and select five days that represents one year. The profiles, which are the centers of the clusters (or the closest profile to the center), are selected as the representative days. Using the cardinality of each cluster (i.e. occurrence of the similar days), we determine the probabilities of the representative days.

#### 4.2.2 Computational Analysis

In this section, we first compare the results obtained from the model when neither ESSes nor TS is used (*Base case*) with the version that only includes ESSes (*ESS case*). We further analyze the results obtained from the ESS case with the model

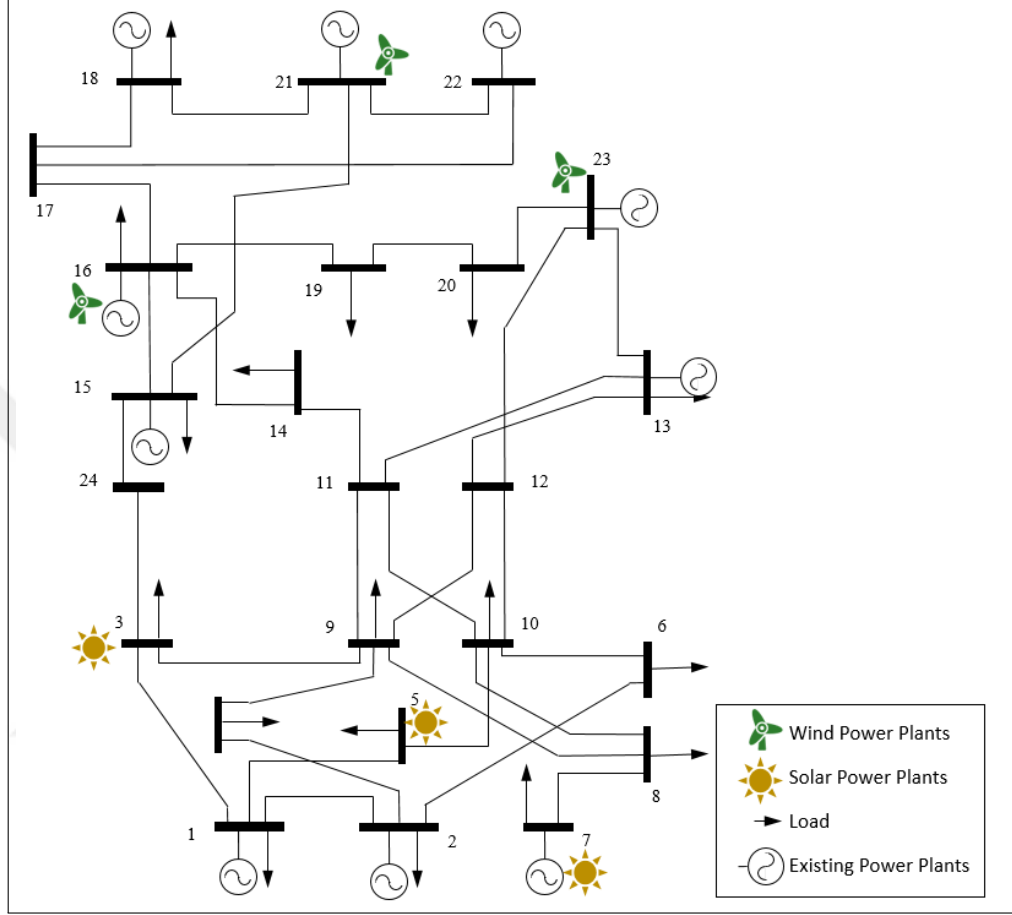


Figure 4.1: Modified IEEE 24-bus power system.

that includes both ESSes and TS (*ESS-TS case*) to observe the value of TS. For these analyses, instead of using penalty costs for LS and REC policies, we vary the limits for the maximum allowable LS and REC amounts. Starting from the instance where there are no restrictions on meeting demand ( $p^{ls} = 1$ ) and using RES in generated electricity ( $p^{rec} = 1$ ), we gradually tighten these limits and report the minimum cost, locations and sizes of ESSes for each combination of  $p^{ls}$  and  $p^{rec}$ . Unless otherwise stated, in all experiments for the ESS-TS case, we limit the number of switchable lines to five and report the solutions with a 1% optimality gap. Experiments are implemented in Java platform using Cplex 12.7.1 on a Linux OS environment with Dual Intel Xeon E5-2690 v4 14 Core 2.6GHz processors with 128 GB of RAM. The optimal solutions for the Base and ESS cases are obtained within five minutes and six hours, respectively. However,

the solution times increase up to 35 hours for the ESS-TS case, as the model optimizes TS operations and ESS siting and sizing simultaneously. We also note that in all three cases, solution times increase as  $p^{ls}$  and/or  $p^{rec}$  decrease.

#### 4.2.2.1 Effect of TS on the Total System Cost and Value of ESSes

Figure 4.2 shows the optimal costs of the three cases for different combinations of  $p^{ls}$  and  $p^{rec}$ . As we have the minimum generation requirement from conventional sources (i.e. not to shut-down them), in all cases the solutions obtained with the most relaxed instance,  $(p^{ls}, p^{rec})=(1.0, 1.0)$ , are also equal to the solutions obtained with  $(p^{ls}, p^{rec})=(0.4, 0.5)$ . Thus, relaxing the limits only for  $p^{ls}$  or only for  $p^{rec}$  beyond this point (i.e.  $p^{ls} > 0.4$  and  $p^{rec} > 0.5$ ) does not change the optimal solutions. Therefore, we ignore those regions and focus only on the solutions obtained with  $p^{ls} \leq 0.4$  and  $p^{rec} \leq 0.5$ . We first note that reducing the ratios generally increases the optimal costs, as more investments are necessary to either meet the predetermined ratio of the total load or generate more electricity from RES. However, guaranteeing the required generation from RES needs more investments compared to the required investments for meeting the predetermined ratio of the load because the highest total system costs are obtained from the solutions with  $p^{rec} \leq 0.2$ .

Figure 4.2 also represents the value of ESSes and the joint benefit of ESSes and TS in a power system with a high level of renewable energy penetration. For the Base case, we cannot obtain any feasible solutions for the instances with  $p^{ls} \leq 0.1$  or  $p^{rec} \leq 0.4$  (Figures 4.2a and 4.2d). However, by adding storage units to the same power system, we obtain solutions for these instances (Figures 4.2b and 4.2e). Further, by also integrating TS, we find better solutions (Figures 4.2c and 4.2f) than those obtained only with ESSes.

To observe the value of TS, we compare the optimal solutions of the ESS and ESS-TS cases. Table 4.1 presents the percentage improvements in total system cost for different values of  $p^{ls}$  and  $p^{rec}$  after incorporating TS operations, and Figure 4.3 visualizes these improvements. Transmission switching decreases

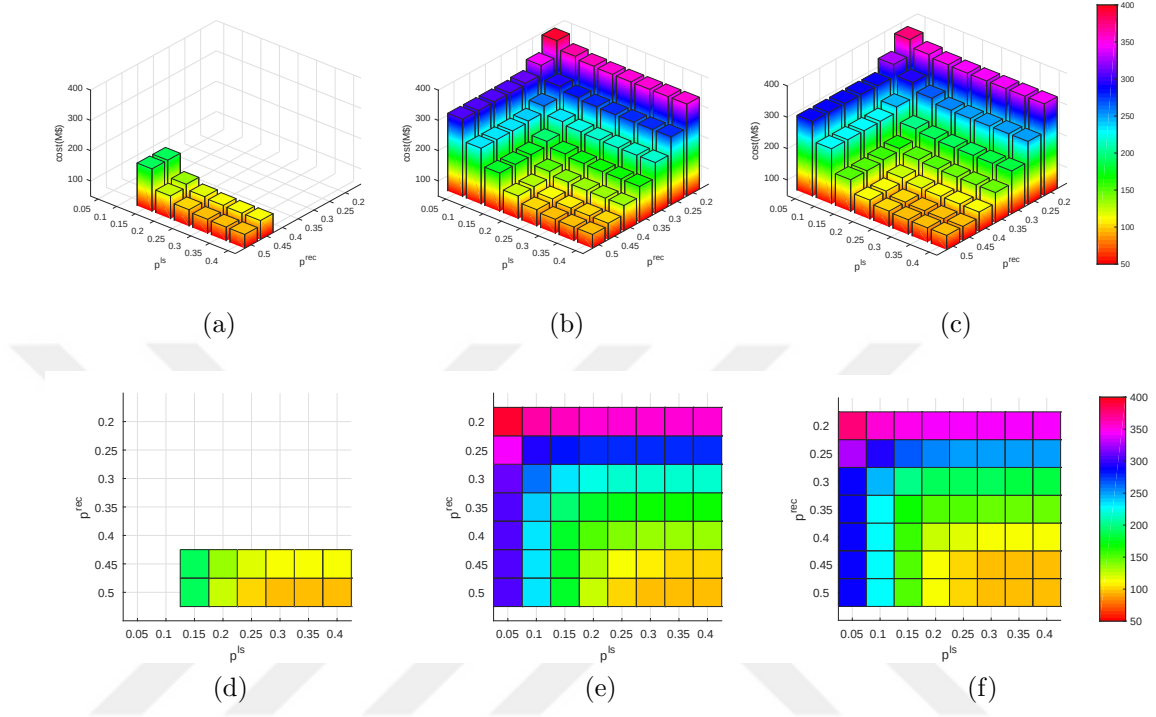


Figure 4.2: Total system cost a) Base case b) ESS case c) ESS-TS case and Top Views for d) Base case e) ESS case f) ESS-TS case.

the total cost in all instances, and on the average, the saving is about 8.5%. Although the effect of TS is not significant for low  $p^{ls}$  or low  $p^{rec}$  values, TS substantially reduces the total costs for the remaining  $p^{ls}$  ( $0.15 \leq p^{ls} \leq 0.4$ ) and medium  $p^{rec}$  ( $0.3 \leq p^{rec} \leq 0.4$ ) values. Therefore, if there are no TS operations, system operators must build new ESSes and/or lines and use more conventional power plants for electricity generation. However, by using TS operations, system operators require fewer investments to satisfy the same limits. Our results show that total cost can be reduced up to 16.27% when TS operations are incorporated into a power system.

According to the savings obtained by different  $p^{ls}$  and  $p^{rec}$  limits, it is possible to partition the results in Table 4.1 into four zones to observe the underlying reasons behind the shape presented in Figure 4.3. For this analysis, we also detail the optimal solutions of the ESS and ESS-TS cases, and Figure 4.4 demonstrates the differences between the objective functions of the two cases in monetary values, in terms of  $z_{storage}$ ,  $z_{om}$  and  $z_{line}$ . When  $p^{ls} \leq 0.1$  (*Zone A*), in response to

Table 4.1: Effect of TS on the total system cost (%)

|  |      | $p^{rec}$ |      |       |       |       |       |       | $p^{ls}$ |
|--|------|-----------|------|-------|-------|-------|-------|-------|----------|
|  |      | 0.20      | 0.25 | 0.30  | 0.35  | 0.40  | 0.45  | 0.50  |          |
|  | 0.05 | 3.94      | 3.96 | 7.16  | 6.05  | 6.05  | 6.05  | 6.05  |          |
|  | 0.10 | 3.18      | 0.43 | 5.48  | 4.58  | 3.49  | 3.49  | 3.49  |          |
|  | 0.15 | 3.20      | 5.10 | 13.93 | 15.46 | 12.25 | 14.29 | 14.29 |          |
|  | 0.20 | 3.20      | 8.22 | 13.99 | 13.85 | 16.27 | 13.12 | 11.64 |          |
|  | 0.25 | 3.17      | 8.22 | 14.34 | 12.86 | 15.99 | 10.19 | 4.20  |          |
|  | 0.30 | 3.17      | 8.14 | 14.19 | 12.75 | 15.45 | 7.81  | 0.21  |          |
|  | 0.35 | 3.17      | 8.14 | 14.61 | 13.00 | 15.08 | 7.95  | 0.16  |          |
|  | 0.40 | 3.17      | 8.14 | 14.61 | 13.00 | 15.91 | 7.86  | 0.00  |          |

Zone A

Zone B

Zone C

Zone D

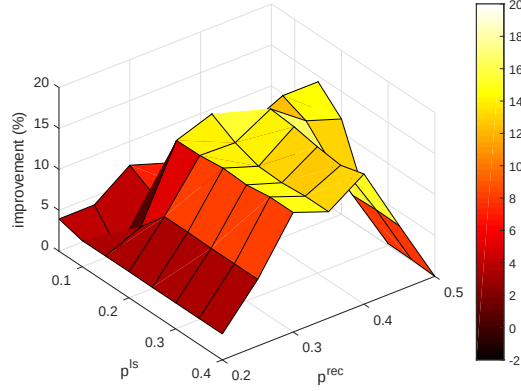


Figure 4.3: Visual representation of the effect of TS on the total system cost (%).

the reduction in ESS investment costs and hourly operations, the same or more lines are required in the ESS-TS case, except for in one instance, where savings from using TS are limited due to increases in  $z_{line}$ . When  $p^{ls}$  is higher ( $p^{ls} \geq 0.2$ ) and  $p^{rec} \leq 0.25$  (Zone B), TS decreases the optimal value of  $z_{line}$  and/or  $z_{storage}$ . However, savings from TS are also limited because investments for lines and for ESSes are needed in the ESS-TS case in order to meet the generation requirement. For these instances, we also observe that electricity generation from conventional sources are at their minimum levels in both cases.

When both  $p^{ls}$  and  $p^{rec}$  are high (i.e.  $p^{ls} \geq 0.2$  and  $p^{rec} \geq 0.45$ ) (Zone D), there is no need in either case to build new lines. Thus, TS decreases only the operational and storage investment costs in most instances. We also note that the reductions in the total system cost in the last column of Table 4.1 are only due to savings from operational costs because neither ESSes nor transmission

lines are built for these cases. In our experiment setting, the highest savings are obtained when  $p^{ls} \geq 0.2$  and  $0.3 \leq p^{rec} \leq 0.4$  (*Zone C*). Although the decreases in operational costs are small, the required investment costs of transmission lines and/or ESSes are significantly reduced. We refer to instances with  $p^{ls} = 0.15$  as *transition zones* because some of the solutions are similar to the solutions in Zone A and some of them are similar to the solutions in Zones B, C or D.

We also analyze the solutions in each row in Zones B through D. Transmission switching operations first yield to savings from ESS investment costs and then transmission line investment costs. Further relaxing the renewable generation requirement increases the savings in both assets, as in Zone C. Passing from Zone C to Zone D decreases savings from the assets because transmission lines and ESSes are not needed in the ESS or ESS-TS case. However, in Zone D, decreases in operational costs become significant. We also note that we do not obtain smooth transitions or trends within or between the zones mainly due to the discrete sets that we have for  $p^{ls}$  and  $p^{rec}$  values as well as the capacity of system components.

#### 4.2.2.2 Effect of TS on Siting and Sizing of ESSes

As observed earlier, changing transmission line status decreases the total system cost, and one of the potential reasons for this decrease is because other components in the system are being used more efficiently. Therefore, TS operations can affect the number, sizes (i.e. energy capacity and power rating) and locations of storage units.

To observe the value of TS on ESS decisions, we compare the optimal results obtained with the ESS and ESS-TS cases. Table 4.2 presents the number of storage units, and they generally increase for both cases as we tighten  $p^{ls}$  and  $p^{rec}$  limits. We also observe that the number of storage units are highly dependent on  $p^{rec}$  values. Although varying only  $p^{ls}$  for any  $p^{rec}$  value does not change the number of ESSes in many instances, varying only  $p^{rec}$  for any  $p^{ls} \geq 0.2$  changes the number of ESSes from 11 to 0. Therefore, depending on renewable energy

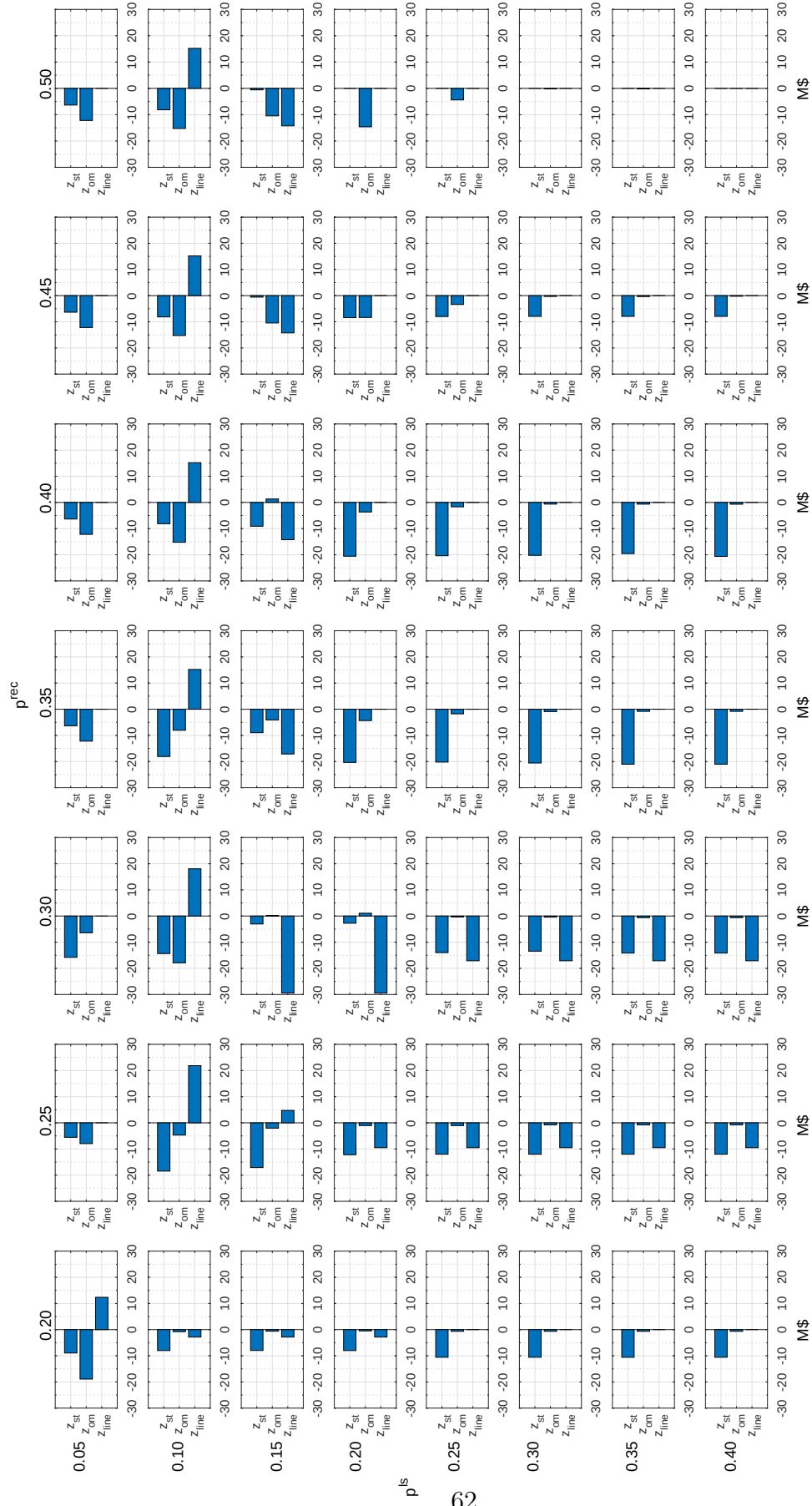


Figure 4.4: Cost difference in the objective function components for the ESS-TS case.

targets, ESSes can play an important role.

Our results also demonstrate that increasing the efficiency of the system with TS operations generally leads to fewer storage units needed for the same limits. We also note that ESS locations are similar in both cases, and that ESSes are generally located close to renewable generation units or large conventional power plants (Figure 4.1) to add flexibility to the grid to use the stored energy as required. More details about ESS locations can be found in Appendix Figures B1-B4.

Table 4.2: Number of storage units for the ESS case and the ESS-TS case

|          |      | ESS case  |      |      |      |      |      |      | ESS-TS case |      |      |      |      |      |      |
|----------|------|-----------|------|------|------|------|------|------|-------------|------|------|------|------|------|------|
|          |      | $p^{rec}$ |      |      |      |      |      |      | $p^{rec}$   |      |      |      |      |      |      |
|          |      | 0.20      | 0.25 | 0.30 | 0.35 | 0.40 | 0.45 | 0.50 | 0.20        | 0.25 | 0.30 | 0.35 | 0.40 | 0.45 | 0.50 |
| $p^{ls}$ | 0.05 | 11        | 8    | 7    | 6    | 6    | 6    | 6    | 11          | 8    | 6    | 6    | 6    | 6    | 6    |
|          | 0.10 | 11        | 9    | 6    | 5    | 4    | 4    | 4    | 10          | 8    | 6    | 4    | 4    | 4    | 4    |
|          | 0.15 | 11        | 9    | 6    | 5    | 3    | 1    | 1    | 10          | 8    | 6    | 5    | 2    | 1    | 1    |
|          | 0.20 | 11        | 9    | 6    | 5    | 3    | 1    | —    | 10          | 8    | 6    | 5    | 2    | —    | —    |
|          | 0.25 | 11        | 9    | 7    | 5    | 3    | 1    | —    | 10          | 8    | 6    | 5    | 2    | —    | —    |
|          | 0.30 | 11        | 9    | 7    | 5    | 3    | 1    | —    | 10          | 8    | 6    | 5    | 2    | —    | —    |
|          | 0.35 | 11        | 9    | 7    | 5    | 3    | 1    | —    | 10          | 8    | 6    | 4    | 2    | —    | —    |
|          | 0.40 | 11        | 9    | 7    | 5    | 3    | 1    | —    | 10          | 8    | 6    | 4    | 2    | —    | —    |

Table 4.3 presents the savings in the total energy capacity and power rating of ESSes when TS operations are used in the power system. The value of TS is significant for instances when  $p^{ls} \geq 0.1$  and  $0.35 \leq p^{rec} \leq 0.4$ ; up to 50.69% savings on the total energy capacity and 57.52% savings on the total power rating are obtained. As discussed above, savings decrease when  $p^{ls}$  or  $p^{rec}$  is low because investments are also required in the ESS-TS case. Moreover, in five instances, when  $p^{rec}$  is equal to 0.45, the storage units built in the ESS case are not needed in the ESS-TS case. Thus, 100% savings are obtained in these instances. Details on the energy capacity and power rating of ESSes can be found in Appendix Figures B1-B4.

We now detail the locations and sizes of storage units for the highlighted row and columns in Table 4.3. In the following tables and figures, the row and the column are represented by  $(p^{ls}, p^{rec}) = (0.2, :)$  and  $(p^{ls}, p^{rec}) = (:, 0.4)$ , respectively. Figures 4.5 and 4.6 demonstrate the total energy capacity and power rating of storage units for the ESS and ESS-TS cases with  $(p^{ls}, p^{rec}) = (0.2, :)$  and  $(p^{ls}, p^{rec}) = (:, 0.4)$ , respectively. When we relax RES generation requirements

Table 4.3: Savings in ESS sizes due to TS (%)

|          |      | Savings in energy capacity (%) |       |       |       |       |        |       | Savings in power rating (%) |       |       |       |       |        |       |
|----------|------|--------------------------------|-------|-------|-------|-------|--------|-------|-----------------------------|-------|-------|-------|-------|--------|-------|
|          |      | $p^{rec}$                      |       |       |       |       |        |       | $p^{rec}$                   |       |       |       |       |        |       |
|          |      | 0.20                           | 0.25  | 0.30  | 0.35  | 0.40  | 0.45   | 0.50  | 0.20                        | 0.25  | 0.30  | 0.35  | 0.40  | 0.45   | 0.50  |
| $p^{ls}$ | 0.05 | 3.06                           | 5.08  | 13.33 | 5.43  | 5.43  | 5.43   | 5.43  | 6.53                        | 4.77  | 17.55 | 8.27  | 8.27  | 8.27   | 8.27  |
|          | 0.10 | 2.30                           | 11.47 | 17.42 | 33.10 | 20.43 | 20.43  | 20.43 | 6.00                        | 15.88 | 15.26 | 27.70 | 16.70 | 16.70  | 16.70 |
|          | 0.15 | 2.25                           | 10.55 | 2.29  | 16.21 | 30.84 | 3.86   | 3.86  | 5.99                        | 14.89 | 3.89  | 15.10 | 27.26 | 4.28   | 4.28  |
|          | 0.20 | 2.27                           | 7.32  | 2.59  | 25.28 | 50.02 | 100.00 | —     | 6.01                        | 10.67 | 3.34  | 30.68 | 57.52 | 100.00 | —     |
|          | 0.25 | 3.17                           | 7.19  | 14.82 | 24.51 | 50.69 | 100.00 | —     | 7.73                        | 10.52 | 13.94 | 30.72 | 56.80 | 100.00 | —     |
|          | 0.30 | 3.17                           | 7.20  | 13.77 | 25.15 | 50.35 | 100.00 | —     | 7.73                        | 10.52 | 13.58 | 31.18 | 56.38 | 100.00 | —     |
|          | 0.35 | 3.17                           | 7.19  | 14.52 | 26.90 | 48.61 | 100.00 | —     | 7.73                        | 10.52 | 14.30 | 31.44 | 54.56 | 100.00 | —     |
|          | 0.40 | 3.17                           | 7.19  | 14.52 | 26.90 | 51.40 | 100.00 | —     | 7.73                        | 10.52 | 14.30 | 31.44 | 57.55 | 100.00 | —     |

(or increase  $p^{rec}$ ) for the instances with  $p^{ls} = 0.2$  (Figure 4.5), the total energy capacity and power rating of ESSes gradually decrease in both cases. On the other hand, Figure 4.6 shows that relaxing  $p^{ls}$  up to 0.15 for the instances with  $p^{rec} = 0.4$  reduces the energy capacity and power rating. Thus, we conclude that while energy storage is a very effective component of the system for meeting the various  $p^{rec}$  limits, the role of storage is limited to only very small  $p^{ls}$  values, and the effect of TS on this role of the storage becomes more prominent as the constraints on REC and LS are relaxed.

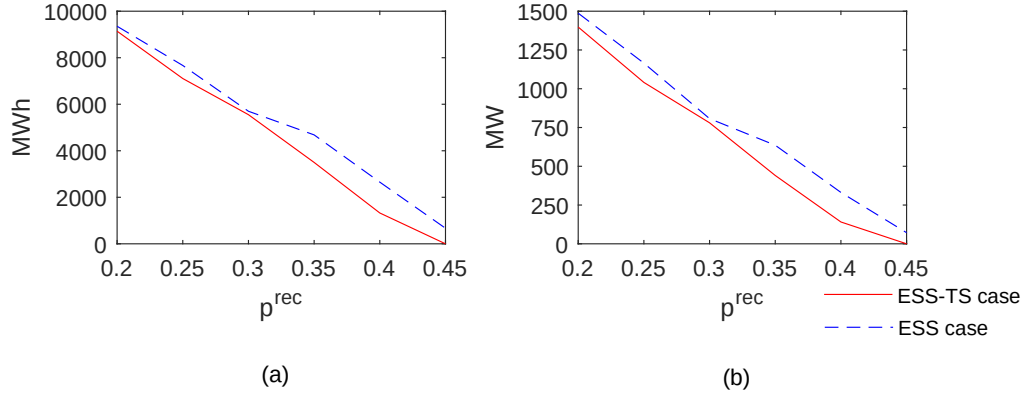


Figure 4.5: Effect of TS on ESS sizing with  $(p^{ls}, p^{rec}) = (0.2, :)$  a) energy capacity (in MWh) and b) power rating (in MW).

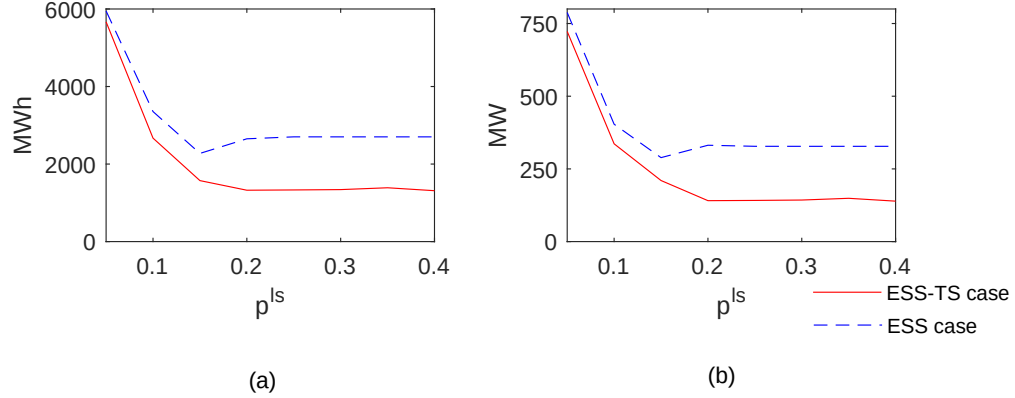


Figure 4.6: Effect of TS on ESS sizing with  $(p^{ls}, p^{rec})=(\cdot, 0.4)$  a) energy capacity (in MWh) and b) power rating (in MW).

For the results obtained with  $(p^{ls}, p^{rec})=(0.2, \cdot)$  and  $(p^{ls}, p^{rec})=(\cdot, 0.4)$ , Figures 4.7-4.10 detail the results of ESS by presenting the changes in their locations and sizes when TS is incorporated into the power system. In the figures, we only focus on the differences, and do not present storage units built at the same bus with the maximum allowable energy capacity or power rating in the ESS and ESS-TS cases. One can find the storage units with the maximum sizes in both cases in Appendix Tables B.1 and B.2. So far, we have presented that TS can decrease the total number of storage units (Table 4.2) and/or the total energy capacity and power rating (Table 4.3). These conclusions can also be observed in Figures 4.7-4.10. For example, in the solution obtained with  $(p^{ls}, p^{rec})=(0.15, 0.4)$ , in both the ESS and ESS-TS cases, the size of the storage units located at buses 5 and 21 are almost the same. In the ESS-TS case, by not needing to build the storage at bus 7 that is located in the ESS case, the number of storage units in the system decreases by one. Even when the number and locations of storage units are the same, TS can decrease the total storage size, as in  $(p^{ls}, p^{rec})=(0.2, 0.35)$ .

Transmission switching can also affect the locations of storage units in the system. For instance, as in the solution obtained with  $(p^{ls}, p^{rec})=(0.1, 0.4)$ , in the ESS-TS case, new storage is built at bus 22 instead of at bus 3 in the ESS case to increase utilization of wind generation units (Figures 4.9 and 4.10). Therefore, not only for short-term operational decisions, but also for medium- to long-term

planning decisions, as discussed in [63] without considering ESS sizing, the effect of TS can be significant depending on load targets and/or RES utilization levels.

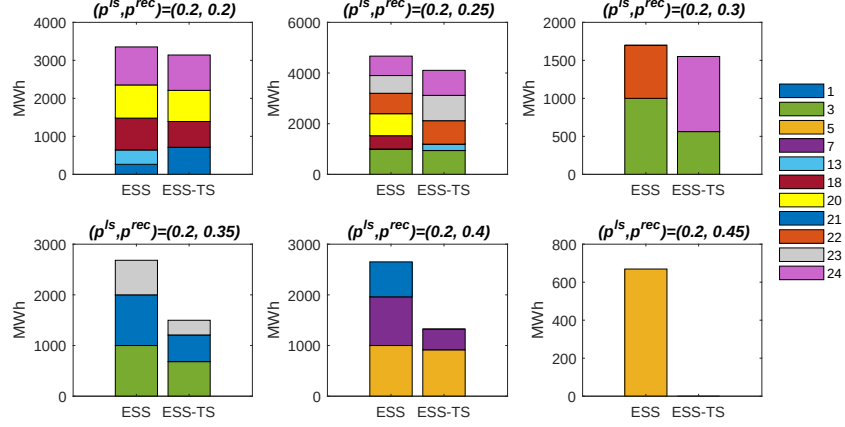


Figure 4.7: Effect of TS on ESS siting and energy capacity (in MWh) for  $(p^{ls}, p^{rec}) = (0.2, :)$ .

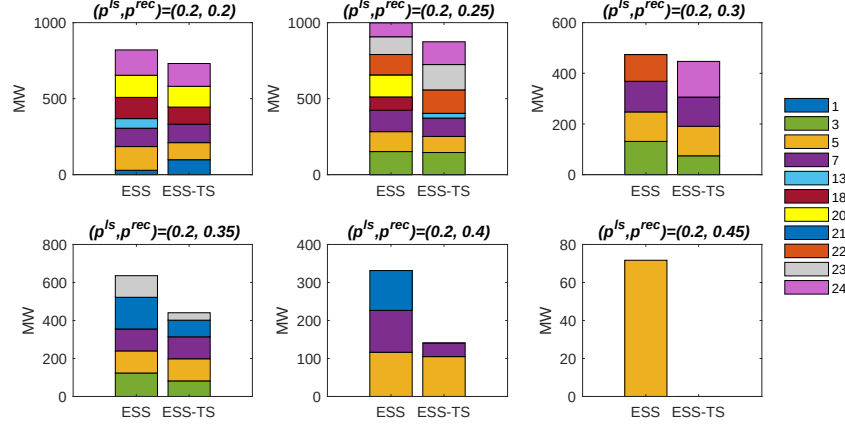


Figure 4.8: Effect of TS on ESS siting and power rating (in MW) for  $(p^{ls}, p^{rec}) = (0.2, :)$ .

#### 4.2.2.3 Effect of TS on REC and LS

Previous sections discuss the effect of TS on the total system cost and on ESS locations and sizes. We show that TS adds flexibility to the grid, increases component efficiency and generates more electricity from RES to meet demand. Therefore, in addition to reducing the total system cost and storage sizes, TS inherently increases the share of RES in the total supply.

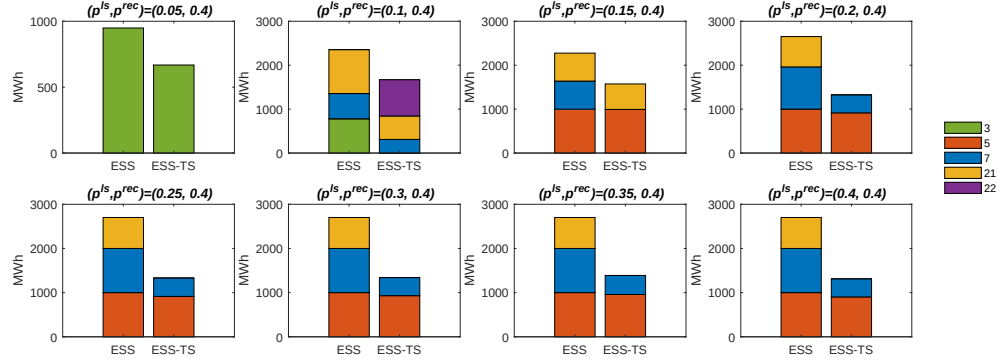


Figure 4.9: Effect of TS on ESS siting and energy capacity (in MWh) for  $(p^{ls}, p^{rec}) = (:, 0.4)$ .

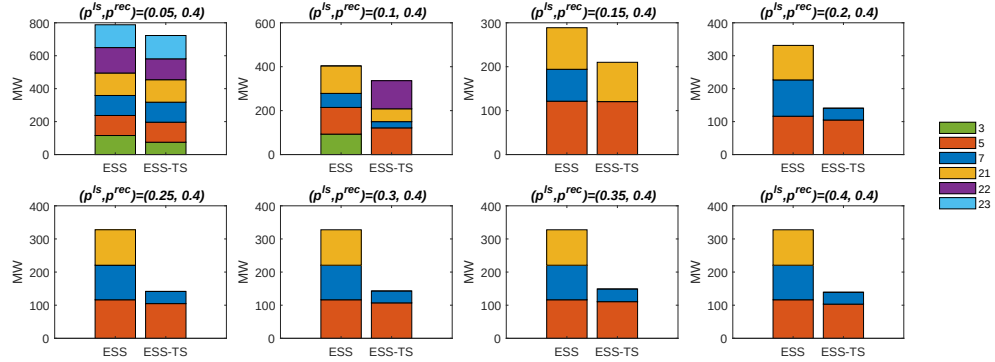


Figure 4.10: Effect of TS on ESS siting and power rating (in MW) for  $(p^{ls}, p^{rec}) = (:, 0.4)$ .

Although the benefit of TS on decreasing curtailment of RES is obvious in some instances, such as  $(p^{ls}, p^{rec}) = (0.2, 0.5)$ , where the total system cost decreases due to an increase in generation from RES, the effect of TS on LS control mechanism is not obvious due to the discretization of  $p^{ls}$  and  $p^{rec}$ . In order to handle this deficiency and examine the effect of TS on LS, we modify the proposed model from Section 4.1. We provide the following multi-objective mathematical programming model that minimizes  $p^{ls}$  and  $p^{rec}$  as two conflicting objectives:

$$\min \quad \bar{p}^{ls} \quad (4.35)$$

$$\min \quad \bar{p}^{rec} \quad (4.36)$$

$$s.t \quad (4.2) - (4.5), (4.8) - (4.28)$$

$$\sum_{i \in B} \sum_{t \in T} DS_{its} \leq \bar{p}^{ls} \sum_{i \in B} \sum_{t \in T} D_{its} \quad \forall s \in S \quad (4.20')$$

$$\sum_{i \in B} \sum_{g \in C_R} \sum_{t \in T} G_{igts} \geq (1 - \bar{p}^{rec}) \sum_{i \in B} \sum_{g \in C_R} \sum_{t \in T} \bar{G}_{igts} \quad \forall s \in S \quad (4.21')$$

$$z_{line} + z_{storage} + z_{om} \leq budget \quad (4.37)$$

In the model presented above,  $\bar{p}^{ls}$  and  $\bar{p}^{rec}$  are the decision variables and Constraints (4.20') and (4.21') determine the minimum  $\bar{p}^{ls}$  and  $\bar{p}^{rec}$  in the system, respectively. For this analysis, we also limit the total system cost with a budget represented by Constraint (4.37).

The  $\epsilon$ -constraint method is a widely used approach for solving multi-objective problems [117]. In this method, one of the objective functions is selected to be optimized and the other one is added to the model as a new constraint with a bound. In this chapter, a variation of this method is used to obtain only non-dominated solutions. In the augmented  $\epsilon$ -constraint method [117], the second objective is also added to the objective function by multiplying with a small coefficient,  $\gamma$ . By sequentially increasing/decreasing the bound of the second objective,  $\epsilon$ , all Pareto-optimal solutions are found. The objective function and the new constraint added to the model to solve the problem with the  $\epsilon$ -constraint method is represented as follows:

$$\min \quad \bar{p}^{ls} + \gamma \bar{p}^{rec} \quad (4.38)$$

$$\bar{p}^{rec} \leq \epsilon \quad (4.39)$$

For discussing the effect of TS on REC and LS, we utilize the solution obtained with  $(p^{ls}, p^{rec}) = (0.2, 0.4)$  for the ESS case and limit the total system cost by \$148.741M, which is the optimal solution value of that instance.

Figure 4.11 demonstrates the sets of pareto optimal solutions for the ESS

and ESS-TS cases. Transmission switching operations improve the efficiency of the power system and yield to lower  $p^{rec}$  limits for the same  $p^{ls}$ . Moreover, TS operations decrease the minimum  $p^{ls}$  limit from 0.18 to 0.16. We also emphasize that the highest RES penetration level, (i.e. the lowest  $p^{rec}$ ) in the ESS case (37.71%) is worse than the lowest RES penetration level, (i.e the highest  $p^{rec}$ ) in the ESS-TS case (37.75%). Hence, TS helps system operators increase the share of RES in the total supply and improve quality of life without allocating more resources. We note that these results are clearly dependent on a predetermined budget, and therefore, the value of TS could be more significant with budget limits other than the one presented here.

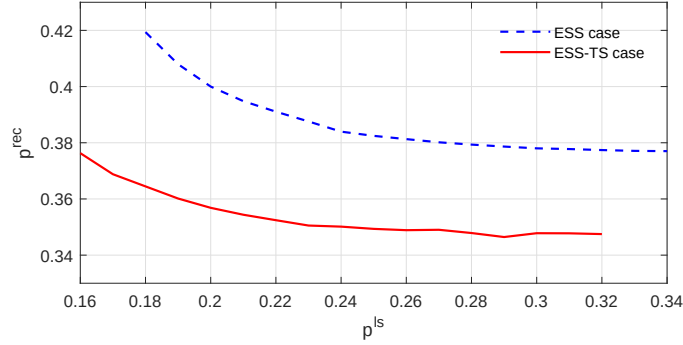


Figure 4.11: Effect of TS on REC and LS with a \$148.741M budget for the total system cost.

## 4.3 Conclusion

This chapter provides a mathematical model that co-optimizes transmission switching operations, ESS siting and sizing decisions and considering limits on maximum allowable load shedding and renewable energy curtailment amounts in a power system. Utilizing an extensive computational study on the IEEE 24-bus power system, we precisely characterize the effect of transmission switching on total system cost, ESS locations and sizes, load shedding and renewable energy curtailment control mechanisms. Our results provide insights about the role of storage at different limits for load-shedding and renewable energy curtailment control mechanisms. The modeling framework discussed in this chapter can also

be extended to optimizing storage portfolios for power systems. Our results show that total system cost and total ESS size can be decreased by as much as 17% and 50%, respectively, and the full potential of ESS in the power system can be revealed for a vertically integrated utility when switching operations are utilized. The results also demonstrate that switching lines helps system operators use their budgets to apply better demand-side management and/or renewable energy curtailment policies due to increased utilization of system components.



## Chapter 5

# Assessing the Value of Demand Flexibility for Peak Load Management

This chapter assesses the value of demand response (DR) programs (i.e. load-shedding (LS), load-shifting(LSHF)) for peak load management and develops a conceptual framework to characterize incentives for having flexible demand in the system. We develop a MILP model that minimizes total cost associated with deploying generation from peaking power plants and incentives for LS and LSHF implementations for one year with hourly time bucket while taking hourly generation costs of peaking power plants as reference points. An analysis has been performed to identify the break-even ratios between the costs of LSHF, LS and operating peaking power plants for the alternative DR policies. Results obtained using a real data from the Turkish power system demonstrate that cost-efficient DR programs can increase flexibility in the systems by reducing operations of peaking power plants.

This chapter is organized as follows. Section 5.1 defines the problem and presents the mathematical model. The results for different scenarios using the real data from the Turkish power system are presented and discussed in Section

5.2. We conclude with final remarks and future research plans in Section 5.3.

## 5.1 Problem Definition and Mathematical Formulation

Figure 5.1 depicts a general load profile for 24 hours. Thick green line shows the total hourly available supply in the system and dashed black line represents the total hourly available base and intermediate supply, which is the maximum power that can be generated by low-cost generators such as coal power plants. When demand exceeds this threshold, peaking power plants with high operational costs (e.g. fuel-oil generators) are used to maintain the system balance. As these power plants are used only for a limited time of a year or a day, profits of these plants may not even cover their fixed cost, and thus these plants might be unprofitable [118]. Therefore, balancing authorities would want to reduce peak demand, and avoid building and operating peaking power plants. The shaded area in Figure 5.1 shows the demand which is required to be either supplied by generation from peaking power plants or reduced by DR programs. Thus, to motivate consumers to participate in DR programs, balancing authorities offer incentives for either shifting or shedding load.

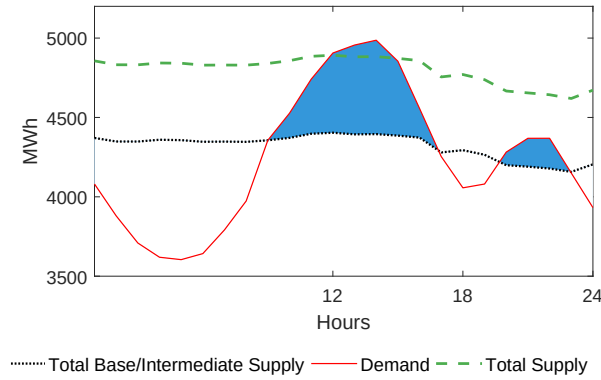


Figure 5.1: An illustrative example for the problem.

The proposed model finds the shifted and curtailed load, and deployed generation from base and peaking power plants to maintain the system balance. We also determine starting and duration time of LSHF programs as rebound effect of LSHF can cause a new peak demand [71]. The model minimizes total operating costs and incentives offered for LS and LSHF programs. In the model, we allow shifting load to only later time periods. One can easily modify the following model for allowing shifting to both later and earlier time periods. In this chapter, our time horizon is one year with  $N$  days and hourly time bucket. We emphasize here that, in this chapter our aim is to develop a conceptual framework to characterize incentives for having flexible demand rather than planning for a target year. We use the following notation for the mathematical programming model.

|                             |                                                                                                        |                      |                                                                                                |
|-----------------------------|--------------------------------------------------------------------------------------------------------|----------------------|------------------------------------------------------------------------------------------------|
| <b>• Sets (Indices)</b>     |                                                                                                        | $T_{min}$            | Minimum duration of a LSHF program                                                             |
| $I$                         | Set of generation units ( $i$ )                                                                        | $T_{max}$            | Maximum duration of LSHF program                                                               |
| $J$                         | Set of consumers ( $j$ )                                                                               | $\bar{B}$            | Maximum number of using a LSHF program                                                         |
| $T$                         | Set of time periods ( $t, k$ )                                                                         |                      |                                                                                                |
| $N$                         | Set of days ( $n$ )                                                                                    | $\bar{M}$            | Maximum number for starting a LSHF program in one day                                          |
| <b>• Parameters</b>         |                                                                                                        |                      |                                                                                                |
| $c_{jt}^{ls}$               | Incentive payment for LSHF for consumer $j$ at time period $t$ (TL/MWh)                                | $\underline{E}_{jt}$ | Minimum demand by consumer $j$ at time period $t$ (MWh)                                        |
| $c_t^{voll}$                | Incentive payment for LS (value of loss load) (TL/MWh)                                                 |                      |                                                                                                |
| $c_{it}^g$                  | Cost of using deploying generation from plant $i$ at time period $t$ (TL/MWh)                          |                      |                                                                                                |
| $D_{jt}$                    | Demand of consumer $j$ at time period $t$ (MWh)                                                        |                      |                                                                                                |
| $C_{it}$                    | Available generation capacity of base and/or intermediate generation unit $i$ at time period $t$ (MWh) |                      |                                                                                                |
| $CP_{it}$                   | Available generation capacity of peaking plant $i$ at time period $t$                                  |                      |                                                                                                |
| $\bar{U}(\underline{U})$    | Maximum (Minimum) load that can be shifted in a time period (MWh)                                      |                      |                                                                                                |
| $L$                         | Maximum time for shifting load (in hours)                                                              |                      |                                                                                                |
| <b>• Decision Variables</b> |                                                                                                        |                      |                                                                                                |
|                             |                                                                                                        | $U_{jtk}$            | Shifted load of consumer $j$ at time period $t$ to time period $k$ (MWh)                       |
|                             |                                                                                                        | $G_{it}$             | Deployed generation from base and/or intermediate generation unit $i$ at time period $t$ (MWh) |
|                             |                                                                                                        | $GP_{it}$            | Deployed generation from peaking plant $i$ at time period $t$ (MWh)                            |
|                             |                                                                                                        | $S_{jt}$             | Shed load of consumer $j$ at time period $t$ (MWh)                                             |
|                             |                                                                                                        | $Z_{jt}$             | 1 if a LSHF program is started for consumer $j$ at time period $t$ , 0 o.w                     |
|                             |                                                                                                        | $Y_{jt}$             | 1 if a LSHF program is used for consumer $j$ at time period $t$ , 0 o.w                        |

Objective function minimizes the cost of generation from peaking power plants ( $z_{gen}$ ) and incentives for LSHF ( $z_{shift}$ ) and LS ( $z_{shed}$ ), respectively. The objective function (5.1) is presented below and subject to the following constraints:

$$\min z_{gen} + z_{shift} + z_{shed} \quad (5.1)$$

$$\begin{aligned} z_{gen} &= \sum_{i=1}^I \sum_{t=1}^T c_{it}^g GP_{it} \\ z_{shift} &= \sum_{j=1}^J \sum_{t=1}^T \sum_{k=t+1}^{t+L} c_{jt}^{ls} U_{jtk} \\ z_{shed} &= \sum_{j=1}^J \sum_{t=1}^T c_t^{voll} S_{jt} \end{aligned}$$

• *Power Balance Constraint:*

$$\sum_{j=1}^J D_{jt} + \sum_{j=1}^J \sum_{k=t-L}^{t-1} U_{jkt} - \sum_{j=1}^J \sum_{k=t+1}^{t+L} U_{jtk} - \sum_{j=1}^J S_{jt} \leq \sum_{i=1}^I GP_{it} + \sum_{i=1}^I G_{it} \quad \forall t \in T \quad (5.2)$$

Constraint (5.2) ensures supply and demand balance at each time period and guarantees that total generation from base and/or intermediate power plants and peaking power plants at time  $t$  is larger than or equal to the net demand at the same time.

• *Generation Dispatch Constraints:*

$$G_{it} \leq C_{it} \quad \forall i \in I, t \in T \quad (5.3)$$

$$GP_{it} \leq CP_{it} \quad \forall i \in I, t \in T \quad (5.4)$$

Constraints (5.3) and (5.4) limit generation from base and/or intermediate generators and peaking power plants by their available capacities, respectively.

• *LSHF Constraints:*

$$\sum_{k=t+1}^{t+L} U_{jtk} \leq \overline{U}Y_{jt} \quad \forall j \in J, t \in T \quad (5.5)$$

$$\underline{U}Y_{jt} \leq \sum_{k=t+1}^{t+L} U_{jtk} \quad \forall j \in J, t \in T \quad (5.6)$$

$$\underline{E}_{jt} \leq D_{jt} + \sum_{j=1}^J \sum_{k=t-L}^{t-1} U_{jkt} - \sum_{k=t+1}^{t+L} U_{jtk} - S_{jt} \quad \forall j \in J, t \in T \quad (5.7)$$

$$\sum_{t'=t-T_{min}}^t Z_{jt'} \leq Y_{jt} \quad \forall j \in J, t \in T \quad (5.8)$$

$$Y_{jt} \leq \sum_{t'=t-T_{max}}^t Z_{jt'} \quad \forall j \in J, t \in T \quad (5.9)$$

$$\sum_{t=1}^T Y_{jt} \leq \overline{B} \quad \forall j \in J \quad (5.10)$$

$$\sum_{m=24(n-1)+1}^{24n} Z_{jm} \leq \overline{M} \quad \forall j \in J, n \in N \quad (5.11)$$

Constraints (5.5) and (5.6) are the upper and lower limits for shifted load, respectively. Constraint (5.7) enforces a minimum hourly energy consumption for each consumer after shifting and curtailing load. Constraints (5.8) and (5.9) satisfy the minimum and maximum duration of a load-shifting program. Constraint (5.10) limits the number of time periods in which a load-shifting program is used for consumer  $j$  and Constraint (5.11) limits starting a load-shifting program by  $\overline{M}$  in each day for each consumer  $j$ .

• *Domain Constraints:*

$$G_{it} \geq 0, GP_{it} \geq 0 \quad \forall i \in I, t \in T \quad (5.12)$$

$$U_{jtk} \geq 0 \quad \forall j \in J, t \in T, k \in T \quad (5.13)$$

$$Z_{jt} \in \{0, 1\}, Y_{jt} \in \{0, 1\}, S_{jt} \geq 0 \quad \forall j \in J, t \in T \quad (5.14)$$

Constraints (5.12)-(5.14) are for the domain restrictions. Some other costs such as start-up/shut down costs of generation units or constraints such as ramp-up/ramp-down limitations of units can also be easily incorporated in the above

model. We also note that the proposed model can be easily adopted to include total generation cost in order to discuss effect of demand flexibility on the total operating cost by using a centralized approach. Since our objective is to quantify incentives considering generation costs of peaking power plants, generation costs of base and/or intermediate generation units is not included to the model.

## 5.2 Application on the Turkish Power System

In Turkey, installed generation and infrastructure capacities are customarily sized based on the peak demand. Figure 5.2 shows that between 2012 and 2016, the peak demand is more than twice of the minimum demand [119] and around 10% of the available supply is used to meet only 5% of demand. These values clearly state that increasing demand flexibility in the Turkish power system will possibly help postpone new investments and reduce operating peaking plants. Moreover, since the Turkish transmission system is characterized by *east to west*, that is, large electricity plants are located at east and demand is at west, sizing of transmission capacity is also planned based on the peak demand. This planning also requires high transmission capacity and results in under-utilized transmission lines. Figure 5.3 and Figure 5.4 present high variations in both monthly and daily load curves for two sample days, respectively and they reveal the need for peak demand management in the Turkish power system. Smoothing these curves by DR implementations can increase efficiency in the system and reduce the need for building and operating peaking power plants.

The proposed model is applied to the Turkish power system using real data for a reference year 2016 to demonstrate the benefits of load-shifting and shedding, and quantify incentive payments for the DR applications. In 2016, the annual hourly average supply capacity is 48.08 GW and the average hourly load demand is 31.28 GW (65.06% of the average supply capacity), respectively [120, 121].

In the following results, the duration of each time period is set to one hour and planning horizon is one year. Minimum and maximum durations of a LSHF

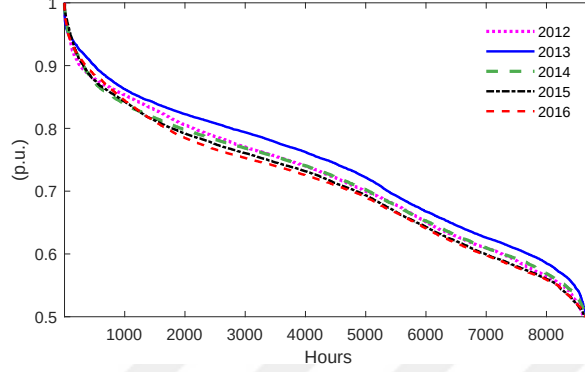


Figure 5.2: Normalized load-duration curves observed between 2012-2016.

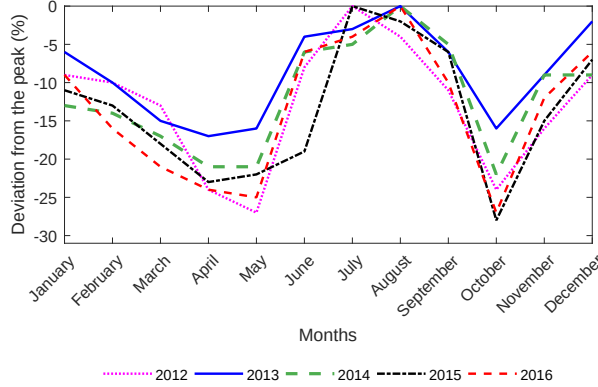


Figure 5.3: Monthly difference from the peak demand.

program are one and three hours, respectively, and the maximum time for shifting load is set to 10 hours.

The hourly generation costs independent of the units,  $c_t^g$ , are obtained from [119]. To examine the relationship between the incentive amounts and generation costs, we consider that cost of load-shifting and load-shedding are functions of generation cost of plants. We consider that cost of load-shifting,  $c_{jt}^{ls}$ , and load-shedding,  $c_t^{voll}$  are linearly dependent on the generation cost of plants,  $c_t^g$ , and set  $c_{jt}^{ls} = \alpha c_t^g$  and  $c_t^{voll} = \beta c_t^g$ . In our computational study, we vary  $\alpha$  and  $\beta$  values and analyze the optimal solutions obtained for different cases of  $\alpha$  and  $\beta$

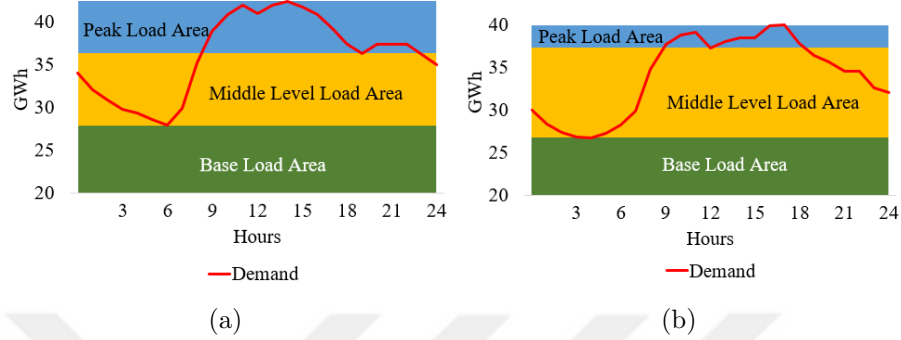


Figure 5.4: Daily variation of consumption for two sample days (a) July 30, 2015 (b) December 17, 2015.

values. Experiments are performed on a Linux environment with 2.4GHz Intel Xeon E5-2630 v3 CPU server with 64GB RAM. Results are obtained in Java Platform, Standard Edition 8 Update 91 (Java SE 8u91) and CPLEX 12.7.1 in parallel mode using up to 32 threads.

### 5.2.1 Base Scenario

For a fixed generation cost of plants, decreasing an incentive payment of either load-shifting or load-shedding while holding the other one constant obviously reduces the total system cost. However, when both incentives are changed (i.e. one is increased and the other one is decreased), the effect of DR programs on total cost and solutions may not be derived easily. In this section, we discuss the effect of incentives on the solutions and find out break-even points for these amounts. In the following results, we set  $\bar{U}$  and  $\bar{M}$  to 1,000 MWh and one, respectively and total available generation capacity of peaking power plants is considered to be 10% of total available generation capacity in the system. We vary  $\alpha$  between 0.5 and 2, and  $\beta$  between 0.5 and 10.

In Figure 5.5, each color represents a unique solution. It is interesting to observe that there are certain ranges for  $\alpha$  and  $\beta$  values, for which we can obtain the same solution. For the cases when  $\alpha > 1$  and  $\beta > 1$ , the same solution

is observed when  $\alpha$  and  $\beta$  values are both increased or decreased by the same amount. Thus, we observe a stair-case trend for these ranges. A similar behavior is also observed when  $\alpha < 1$  and  $\beta > 1$ . However, in this area, the same solution is obtained when  $\beta$  is increased and  $\alpha$  is decreased by the same amount.

Figure 5.5 also suggests that  $\beta = 1$  for all  $\alpha$  values,  $\alpha = 1$  for all  $\beta$  values except for  $0.5 \leq \beta < 1$  and  $\frac{\beta}{\alpha} = 1$  are the critical points that always change the solution. Six is the last break-even point for  $\beta$  that affects the solutions since the optimal results for  $\beta > 6$  are the same for all  $\alpha$  values in our range and we only discuss solutions for cases with  $\beta \leq 6$  in Figure 5.5 and Figure 5.6. Therefore, offering an incentive payment for load-shedding more than around 5.5 times of the generation cost of peaking power plants does not change the optimal results.

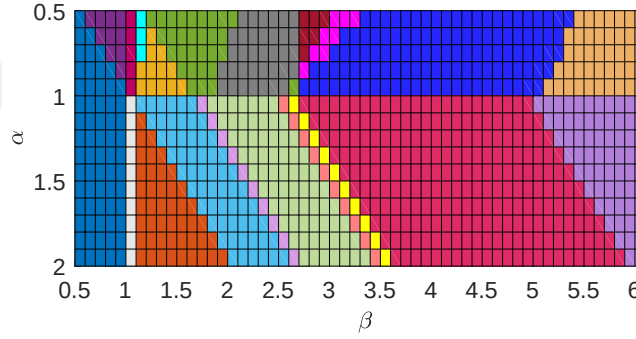


Figure 5.5: Illustration of solutions (Each color represents a unique solution).

Figure 5.5 also shows that different solutions are observed especially when  $\alpha$  and  $\beta$  values are close to each other or when  $\beta$  is less than 3. Thus, we detail the solutions in Figure 5.5 in terms of total generation from peaking power plants (Figure 5.6a), total shifted load (Figure 5.6b) and total shed load (Figure 5.6c).

We first observe that for total generation from peaking power plants,  $\alpha = 1$ ,  $\beta = 1$  and the other two break-even points (i.e.  $\beta$  is around 3 and 5.5) are also the most critical break-even lines (Figure 5.6a) which affect total generation considerably. On the other hand, although different solutions are observed in Figure 5.5 for the cases with  $\beta < 3$ , these solutions are similar to each other in terms of total generation. We also observe that total shifted load is highly affected by both incentive payments since Figure 5.6b shows all break-even points, except

for  $\beta = 1$ , obtained in Figure 5.5.

For total shed load, incentive payment for load-shifting is not as important as in total generation (Figure 5.6a) or total shifted load (Figure 5.6b) since optimal solutions do not considerably change with  $\alpha$ . Offering an incentive payment for load-shedding more than 3.5 times of generation costs does not change the total shed load.

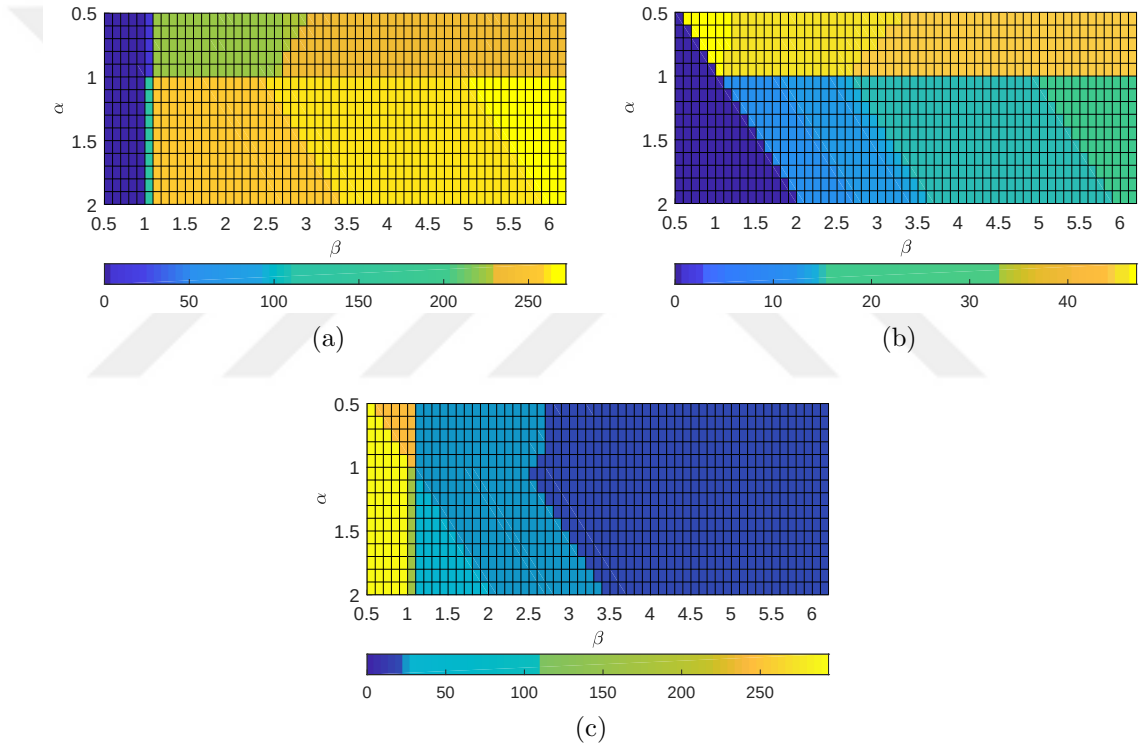


Figure 5.6: (a) Total generation amount (b) Total shifted load (c) Total shed load for Base Scenario.

### 5.2.2 Effect of $\bar{U}$

Independent from the incentive amounts, consumers may not be willing to participate in DR programs and may not prefer changing their comfort level. Therefore, balancing authorities may have a limited amount of load that can be shifted to a later time period. In this section, we discuss the effect of the maximum load that can shifted ( $\bar{U}$ ) on break-even points of incentive payments. Figure 5.7 depicts

the break-even points for scenarios with  $\bar{U}=250$  MWh, 1,000 MWh and 2,000 MWh, respectively for the same range of  $\alpha$  and  $\beta$  values as in Base Scenario. We note that Figure 5.7b demonstrates the same solutions as in Figure 5.5 and each color represents a unique solution.

The solutions in Figure 5.7 indicate that break-even values are highly dependent on  $\bar{U}$  values. When  $\bar{U}=250$  MWh, independent from  $\alpha$ , values around 2.5 are the last break-even points for  $\beta$ , and thus offering incentive payment for load-shedding more than 2.5 times of generation costs does not change the optimal solutions. On the other hand, when  $\bar{U}=2,000$  MWh, optimal solutions change for high incentive payments and 7.7 is now the last break-even point for  $\beta$ .

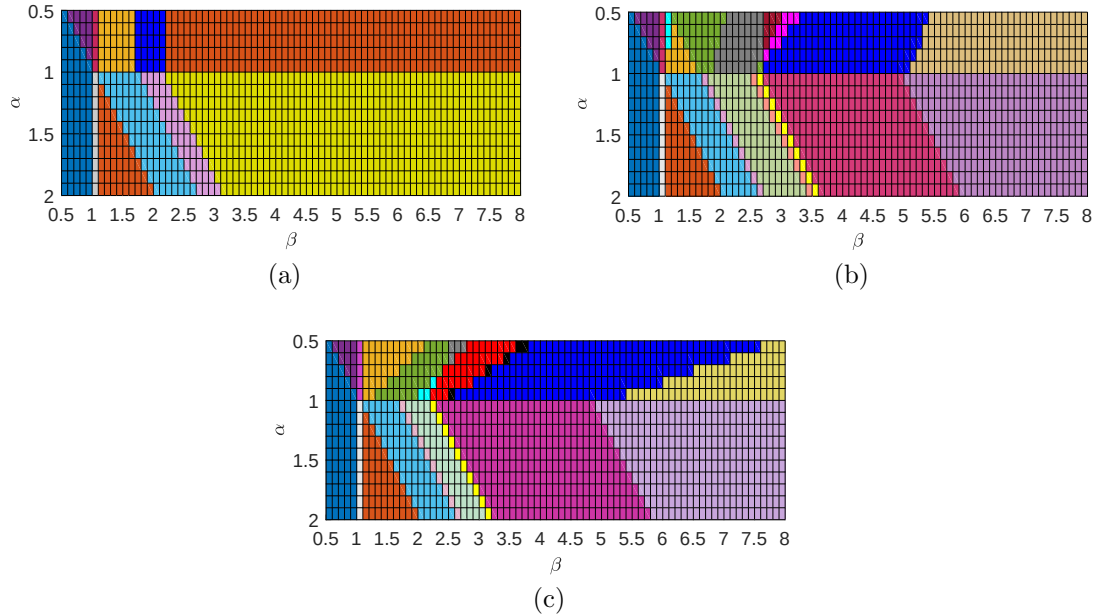


Figure 5.7: (a) Illustration of solutions for different  $\bar{U}$  values (a)  $\bar{U} = 250$  MWh (b)  $\bar{U} = 1,000$  MWh (c)  $\bar{U} = 2,000$  MWh.

Figure 5.7 also demonstrates that the stair-case trend observed in our Base Scenario changes with  $\bar{U}$ . For the cases with  $\alpha < 1$ , the break-even points are independent from  $\alpha$  values when  $\bar{U} = 250$  MWh (i.e. solutions are the same for different  $\alpha$  values) and stair-case trend is not observed at all. On the other hand, the optimal solutions are highly dependent on  $\alpha$  values when  $\bar{U} = 2,000$  MWh and the last break-even point for load-shedding incentive amount vary between 5.5 and 7.7 depending on the  $\alpha$  values.

Table 5.1 details the effect of  $\bar{U}$  on the solutions by comparing the results for different  $\bar{U}$  values in different cost scenarios. Note that  $\bar{U} = 0$  MWh corresponds to the case without load-shifting. As expected, increasing  $\bar{U}$  reduces the total system cost in all cost scenarios since more consumption amount can be moved across periods and generation from peaking power plants can be reduced. Obviously, the total shifted load increases as  $\bar{U}$  is relaxed, however, the increase is totally dependent on the cost ratios. On the other hand, regardless of the  $\alpha$  and  $\beta$  values, the decrease in the total shed load with the increase in  $\bar{U}$  does not change significantly for different cost scenarios and in all scenarios, total shed load is almost reduced by the same amount.

Table 5.1: Comparison of cases with different  $\bar{U}$

|                                 |                                      | $\bar{U}$ |        |        |        |
|---------------------------------|--------------------------------------|-----------|--------|--------|--------|
|                                 |                                      | 0         | 250    | 1000   | 2000   |
| $\alpha = 0.8$<br>$\beta = 1.4$ | $z$ (M TL)                           | 130.20    | 128.35 | 124.37 | 121.36 |
|                                 | total gen. from peaking plants (GWh) | 257.12    | 246.31 | 223.21 | 198.03 |
|                                 | total shifted load (GWh)             | 0         | 14.75  | 46.15  | 74.56  |
|                                 | total shed load (GWh)                | 36.28     | 32.34  | 24.04  | 20.81  |
| $\alpha = 1.2$<br>$\beta = 1.4$ | $z$ (M TL)                           | 130.20    | 129.82 | 129.03 | 128.63 |
|                                 | total gen. from peaking plants (GWh) | 257.12    | 257.12 | 257.12 | 257.12 |
|                                 | total shifted load (GWh)             | 0         | 4.01   | 12.25  | 16.46  |
|                                 | total shed load (GWh)                | 36.28     | 32.28  | 24.04  | 19.83  |
| $\alpha = 1.2$<br>$\beta = 2.0$ | $z$ (M TL)                           | 140.53    | 139.00 | 135.84 | 134.23 |
|                                 | total gen. from peaking plants (GWh) | 257.12    | 257.30 | 257.90 | 257.99 |
|                                 | total shifted load (GWh)             | 0         | 4.19   | 13.02  | 17.32  |
|                                 | total shed load (GWh)                | 36.28     | 32.09  | 23.26  | 18.96  |

### 5.2.3 Effect of $\bar{M}$

To study the effect of the number for starting a LSHF program per day ( $\bar{M}$ ) on incentive payments and break-even points, we compare our results presented in Figure 5.5 (i.e.  $\bar{M} = 1$ ) with the optimal solutions obtained with  $\bar{M} = 3$ . Figure 5.8 depicts the break-even points for the two scenarios and shows that while offering an incentive payment for LS up to 6 times of generation cost can change the solutions for the scenarios with  $\bar{M} = 1$ , the solutions do not change for  $\beta$  values greater than 3.5 when  $\bar{M} = 3$ . Thus, balancing authorities may decrease the incentive payments for DR programs when consumers are willing

to participate in DR programs more than once per day or there are different consumer groups who are ready to participate in DR programs at different hours.

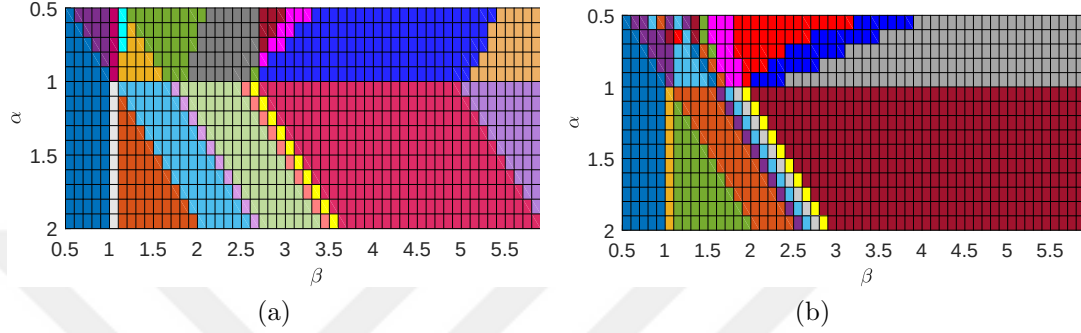


Figure 5.8: (a) Illustration of solutions for different  $\bar{M}$  values (a)  $\bar{M} = 1$  (b)  $\bar{M} = 3$ .

Table 5.2 details the solutions in Figure 5.8 for the same cost scenarios given in Table 5.1. Note that  $\bar{M} = 0$  corresponds to the scenario without load-shifting. Obviously, increasing  $\bar{M}$  decreases the total system cost in all cost scenarios as more consumption can be shifted to later periods. Moreover, regardless of  $\alpha$  and  $\beta$  values, increasing  $\bar{M}$  reduces total shed load and increases total shifted load. However, with high incentive payments for load-shedding, total generation from peaking power plant also increases significantly. Thus, although total system cost reduces, generation from peaking power plants may increase depending on the cost ratios of DR programs.

#### 5.2.4 Effect of Available Capacity of Peaking Power Plants

Since DR programs are used as alternatives to generation from peaking power plants, available capacity of peaking power plants is one of the key parameters for determining incentive payments. In this section, we analyze the effect of available supply of peaking power plants on the break-even points. We gradually increase the ratio of total available supply of peaking power plants to the total available supply by 5%. Figure 5.9 demonstrates that offering high incentive payments for LS (e.g. 5.5 times of generation cost) can affect the solutions when

Table 5.2: Comparison of cases with different  $\overline{M}$ 

|                |                                      | $\overline{M}$ |        |        |
|----------------|--------------------------------------|----------------|--------|--------|
|                |                                      | 0              | 1      | 3      |
| $\alpha = 0.8$ | $z$ (M TL)                           | 130.20         | 124.37 | 120.90 |
| $\beta = 1.4$  | total gen. from peaking plants (GWh) | 257.12         | 223.21 | 185.85 |
|                | total shifted load (GWh)             | 0              | 46.15  | 93.83  |
|                | total shed load (GWh)                | 36.28          | 24.04  | 17.69  |
|                | number of hours with                 |                |        |        |
|                | generation from peaking plants       | 141            | 114    | 87     |
|                | load-shifting                        | 0              | 75     | 161    |
|                | load-shedding                        | 34             | 27     | 24     |
| $\alpha = 1.2$ | $z$ (M TL)                           | 130.20         | 129.03 | 128.80 |
| $\beta = 1.4$  | total gen. from peaking plants (GWh) | 257.12         | 257.12 | 257.12 |
|                | total shifted load (GWh)             | 0              | 12.25  | 14.62  |
|                | total shed load (GWh)                | 36.28          | 24.04  | 21.65  |
|                | number of hours with                 |                |        |        |
|                | generation from peaking plants       | 141            | 141    | 141    |
|                | load-shifting                        | 0              | 19     | 26     |
|                | load-shedding                        | 34             | 27     | 26     |
| $\alpha = 1.2$ | $z$ (M TL)                           | 140.53         | 135.84 | 134.31 |
| $\beta = 2.0$  | total gen. from peaking plants (GWh) | 257.12         | 257.90 | 266.46 |
|                | total shifted load (GWh)             | 0              | 13.02  | 23.96  |
|                | total shed load (GWh)                | 36.28          | 23.26  | 12.32  |
|                | number of hours with                 |                |        |        |
|                | generation from peaking plants       | 141            | 143    | 145    |
|                | load-shifting                        | 0              | 19     | 36     |
|                | load-shedding                        | 34             | 26     | 19     |

the ratio is small (i.e. 5% and 10%). On the other hand, high incentive payments does not affect the optimal results when the ratio is 15% and values around 4 are now the last break-even points for this scenario.

### 5.2.5 Effect of Fixed Incentives

Offering monetary incentive payments is a common approach to motivate consumers to change their energy consumption profiles. As customarily done in the literature, a fixed penalty cost or a fixed price-incentive payment policy [50]-[52] is considered for DR programs. To observe the value of a time-dependent incentive payment policy, we compare our results of the Base Scenario with a new one where cost of LSHF ( $c_{jt}^{ls}$ ) and cost of LS ( $c_t^{voll}$ ) are set to  $203.5\alpha$  and  $203.5\beta$ , respectively, and 203.5 is the average value of generation cost of peaking power plants for the planning horizon.

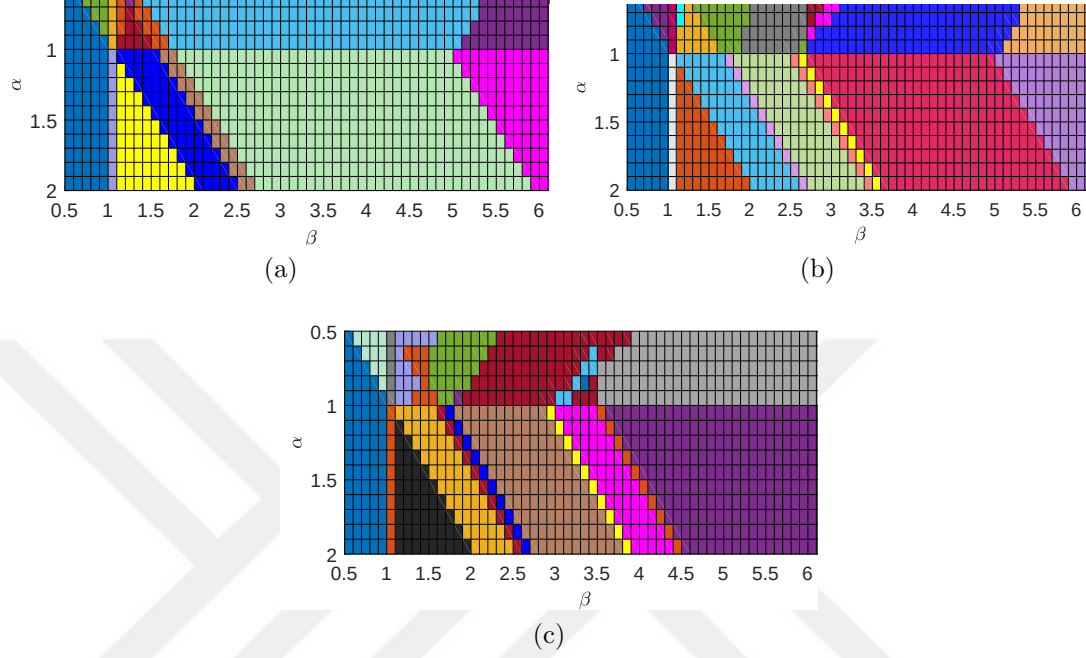


Figure 5.9: (a) Illustration of solutions for different ratio of total available supply of peaking power plants to the total available supply (a) 5% (b) 10% (c) 15%.

Figure 5.10a shows the solutions for our Base Scenario and Figure 5.10b represents the solutions with the fixed incentive payment policy. Although we observe the stair-case trend for the time-dependent incentive payments and obtain the same solutions for certain ranges of  $\alpha$  and  $\beta$  values, we deduct that optimal results are more sensitive to  $\alpha$  and  $\beta$  values with a fixed incentive payment policy.

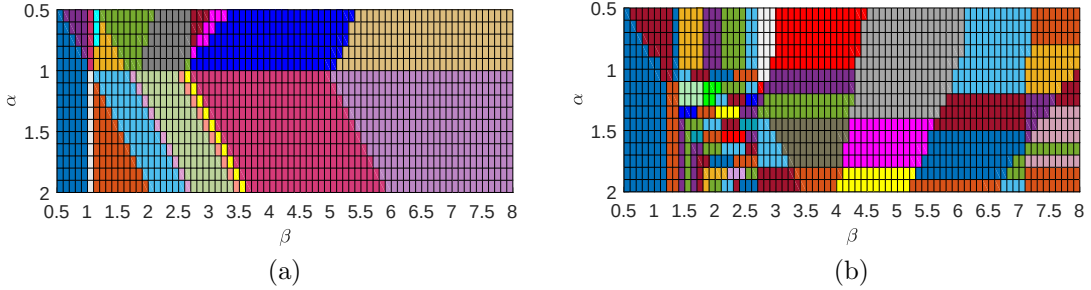


Figure 5.10: (a) Illustration of solutions for (a) time-dependent incentives (b) fixed incentives.

## 5.3 Conclusion

This chapter presents a MILP model and develops a conceptual framework in the macro level for quantifying incentive payments while taking hourly generation cost of peaking power plants as reference points. We discuss benefits of DR programs and our results show that cost-effective DR contracts can reduce generation from peaking power plants and can be considered as an alternative to keeping high levels of peaking power plant capacities.

Our work characterizes the break-even points for the incentives of DR applications using the Turkish power system as our case study. For our Base Scenario, regardless of the load-shifting incentive payments, increasing load-shedding incentive payments up to around 3 times of generation cost highly affects the optimal solutions, however, offering incentive payments more than 5.5 times of generation cost does not change solutions. We also analyze effects of some key parameters such as maximum load that can be shifted and peaking power plant capacities on the solutions and break-even points. Analyzing effect of key parameters on different real-world power systems, and different load and/or generation profiles will be a future research direction that can provide insights to balancing authorities about incentive payments of DR programs.

## Chapter 6

# A Two-Stage Stochastic Programming Approach for Reliability Constrained Power System Expansion Planning

Chapter 6 focuses reliability constrained generation and transmission expansion planning problem (R-GTEP). We propose a two-stage stochastic programming model that includes contingency-dependent transmission switching as recourse actions. To overcome the computational burden of the problem, we propose a solution methodology with a filtering technique that aggregates scenarios and reduces number of scenarios in consideration. Results of the model and solution methodology are presented on the IEEE Reliability Test System, IEEE 118-bus power system and a new data set for the 380-kV Turkish transmission network. Suggestions for possible extensions of the problem and the modifications of the solution approach to handle these extensions are also discussed.

In Section 6.1, we present the mathematical model and explain the solution methodology for the problem. We then discuss the results on the IEEE 24-bus and IEEE 118-bus power systems for different instances in Section 6.2. We

also present the dataset of the current Turkish transmission network and the solutions for this dataset in the same section. In Section 6.3, we discuss possible extensions of the problem, and modifications to the proposed model and the solution approach to handle these extensions. This chapter concludes with final remarks in Section 6.4. The results of this chapter is published in International Journal of Electrical Power & Energy Systems [122] and the new data set for the 380-kV Turkish transmission network is published in Mendeley Data<sup>3</sup>.

## 6.1 Problem Formulation and Solution Methodology

Contingency-dependent R-GTEP (CD-R-GTEP) problem determines the optimal expansion plan and optimal network configuration for each contingency that satisfies the required N-1 reliability level<sup>4</sup>. Considering the operational costs during the contingency states and changing the network topology for each contingency can affect the reliability of the power system and the investment plans significantly. Especially for power systems that have flexible generators, after a line or generator outage, corrective actions such as changing the outputs of the flexible generators and network topology by switching transmission lines can be taken to address the contingency [123].

In this chapter, we represent outage of each line as a single scenario with a certain probability of happening. As the operational cost in each scenario can be different due to unavailability of the line in that scenario, we propose a two-stage stochastic model to handle the probabilistic realization of outages. The first stage decisions of the proposed model include the investments of generation units and transmission lines. Power flows, generation amounts and status of transmission lines are recourse actions of the second-stage. For calculating the probability of

<sup>3</sup>Peker, Meltem; Kocaman, Ayse Selin; Kara, Bahar (2018), "A real data set for a 116-node power transmission system", Mendeley Data, v1 <http://dx.doi.org/10.17632/dv3vjnwwf9.1>

<sup>4</sup>A power system that satisfies N-1 reliability criterion remains feasible after outage of a single line or generation unit. In this chapter, we only consider failure of transmission lines.

scenarios, we utilize forced outage rate (FOR) of transmission lines. Operational costs of scenarios are included in the objective function in the expected form. A set of generation technologies and a set of transmission lines with different properties are considered. As the problem discussed in this chapter is complex and nonlinear, we use a Direct Current (DC) approximation of power flow constraints as customarily done in majority of the studies in this field e.g. [5, 26, 57, 85].

### 6.1.1 Mathematical Model

This section first presents the standard form of a two-stage stochastic programming model and then provides the extensive form of the model. In the standard form of a two-stage stochastic model, the first stage decisions are generally represented by  $x$ , and the second stage decision variables are represented by  $y(\omega)$  for a realization of  $\omega$  in the probability space  $(\Omega, P)$ . The standard form of a two-stage stochastic programming model is represented as:

$$\begin{aligned} \min \quad & c^T x + \mathbf{E}_\omega[Q(x, \omega)] \\ \text{s.t} \quad & Ax = b \\ & x \geq 0 \end{aligned}$$

where  $Q(x, \omega) = \min_{y(\omega) \geq 0} \{q(\omega)y(\omega) : T(\omega)x + W y(\omega) = h(\omega)\}$  and  $\mathbf{E}_\omega[Q(x, \omega)]$  is the expected value of the second stage. With a finite number of second stage realizations,  $S$ , we obtain the extensive form of the two-stage model:

$$\begin{aligned} \min \quad & c^T x + \sum_{s=1}^S p_s q_s y_s \\ \text{s.t} \quad & Ax = b \\ & T_s x + W y_s = h_s \quad \forall s = 1 \dots S \\ & x \geq 0, y_s \geq 0 \end{aligned}$$

where  $p_s$  is the probability of the scenario  $s$  and  $\sum_{s=1}^S p_s q_s y_s$  is the expectation of the second stage.

We use the following notation for the mathematical programming model and plan for a target year with a duration of  $dur$  hours. The model (CD-TS) is the extensive form of the two-stage stochastic programming model for the problem where the first stage decisions include investment of assets and the second stage decisions are scenario-based operational decisions such as power flows, generation amounts and status of transmission lines (open/close). Each decision variable except  $X_{ig}$  and  $L_a$  has a dimension  $k$  to represent scenario-based operational decisions. Scenario  $k = 0$  represents the no-contingency state and scenarios  $k > 0$  represent a scenario associated with a contingency state with outage of a single line.

|                         |                                                                                                                       |                             |                                                                       |
|-------------------------|-----------------------------------------------------------------------------------------------------------------------|-----------------------------|-----------------------------------------------------------------------|
| <b>• Sets (Indices)</b> |                                                                                                                       | $\underline{G}_{ig}$        | Minimum generation from unit $g$ in node $i$ (MW)                     |
| $B$                     | Set of all nodes $(i, j)$                                                                                             |                             |                                                                       |
| $EG$                    | Set of existing generation units                                                                                      | $c_g^{inv}$                 | Annualized investment cost of unit $g$ (\$)                           |
| $CG$                    | Set of candidate generation units                                                                                     | $c_g^{om}$                  | Operation cost of unit $g$ (\$/MWh)                                   |
| $C$                     | Set of all generation units,<br>$C = EG \cup CG (g)$                                                                  | $cf_g$                      | Capacity factor of unit $g$                                           |
| $NG$                    | Set of all non-flexible generators,<br>$NG \subset C$                                                                 | $c_a^{line}$                | Annualized investment cost of line $a$ (\$)                           |
| $EA$                    | Set of existing lines                                                                                                 | $\varphi_a$                 | Susceptance of line $a$ (p.u.)                                        |
| $CA$                    | Set of candidate lines                                                                                                | $\sigma_a$                  | Forced outage rate of line $a$                                        |
| $A$                     | Set of all lines, $A = EA \cup CA (a)$                                                                                | $\Gamma_a^k$                | 1, if line $a$ is on under contingency $k$ ,<br>0, if it is off       |
| $AS_{ij}$               | Set of lines between nodes $i$ and $j$                                                                                | $dur$                       | Duration of the planning horizon                                      |
| $\Psi^+(a)$             | Sending-end node of line $a$                                                                                          | <b>• Decision Variables</b> |                                                                       |
| $\Psi^-(a)$             | Receiving-end node of line $a$                                                                                        | $X_{ig}$                    | 1 if unit $g$ is built at node $i$ , 0 o.w.                           |
| $K$                     | Set of contingencies/scenarios, $k=0$<br>no-contingency state, $k = k_a$<br>contingency stage with outage of line $a$ | $G_{ig}^k$                  | Generation of unit $g$ in node $i$<br>under contingency $k$ .         |
| <b>• Parameters</b>     |                                                                                                                       | $L_a$                       | 1 if line $a$ is built, 0 o.w.                                        |
| $D_i$                   | Demand of node $i$ (MW)                                                                                               | $Z_a^k$                     | 1 if line $a$ is closed under contingency $k$<br>and 0, if it is open |
| $\overline{F}_a$        | Capacity of line $a$ (MW)                                                                                             | $f_a^k$                     | Power flow on line $a$ under contingency $k$                          |
| $\overline{G}_{ig}$     | Maximum generation from unit $g$ in<br>node $i$ (MW)                                                                  | $\theta_i^k$                | Voltage angle of node $i$<br>under contingency $k$                    |
|                         |                                                                                                                       | $p^k$                       | Probability of contingency $k$                                        |

The objective function of CD-TS is presented as follows:

$$\begin{aligned}
\min \quad & z_{gen} + z_{line} + \sum_{k \in K} dur p^k z_{om}^k \\
z_{gen} = & \sum_{i \in B} \sum_{g \in CG} c_g^{inv} X_{ig} \\
z_{line} = & \sum_{a \in CA} c_a^{line} L_a \\
z_{om}^k = & \sum_{i \in B} \sum_{g \in C} c_g^{om} c_{fg} G_{ig}^k
\end{aligned} \tag{6.1}$$

The objective function (6.1) minimizes the total system cost for the target year. The first two terms are the annualized investment costs of the new generation units and new transmission lines, respectively.  $z_{om}^k$  is the operational cost of scenario  $k$  and by multiplying the operational cost of scenario  $k$  with the duration of planning horizon and its probability of happening,  $p^k$ , the expected operational cost of all scenarios is included in the objective function. The objective function is subject to following constraints:

- *Power Balance Constraint:*

$$\sum_{g \in C} G_{ig}^k + \sum_{a \in AS_{ij}: \Psi^-(e)=i} f_a^k - \sum_{a \in AS_{ij}: \Psi^+(e)=i} f_a^k = D_i \quad \forall i \in B, k \in K \tag{6.2}$$

Constraint (6.2) enforces power balance at each node  $i$  for any scenario  $k$  which includes generation from the existing and new sources, incoming/outgoing flows and demand.

- *Generation Dispatch Constraints:*

$$\underline{G}_{ig} \leq G_{ig}^k \leq \overline{G}_{ig} \quad \forall i \in B, g \in EG, k \in K \tag{6.3}$$

$$\underline{G}_{ig} X_{ig} \leq G_{ig}^k \leq \overline{G}_{ig} X_{ig} \quad \forall i \in B, g \in CG, k \in K \tag{6.3'}$$

$$G_{ig}^{k_a} = G_{ig}^0 \quad \forall i \in B, g \in NG, k_a \in K \tag{6.4}$$

The power generation under contingency  $k$  for existing and new plants are limited by Constraints (6.3) and (6.3'), respectively; and they (i.e. flexible generators) can adjust their outputs based on their capacity limits under each contingency. Constraint (6.4) guarantees that the output of power generated at the non-flexible generators does not change with any line contingency. Thus, for these types of generators, the generation under any contingency is equivalent to the generation under no-contingency scenario.

- *Network Constraints:*

$$-\bar{F}_a \Gamma_a^k Z_a^k \leq f_a^k \leq \bar{F}_a \Gamma_a^k Z_a^k \quad \forall a \in A, k \in K \quad (6.5)$$

$$f_a^k = \varphi_a \Gamma_a^k Z_a^k (\theta_i^k - \theta_j^k) \quad \forall a \in AS_{ij}, k \in K \quad (6.6)$$

$$Z_a^k \leq L_a \quad \forall a \in A, k \in K \quad (6.7)$$

We introduce a binary parameter  $\Gamma_a^k$  which takes value 1 if line  $a$  is on (in operation), under contingency  $k$  and takes 0 if it is off. We also introduce a binary decision variable for switching transmission lines and  $Z_a^k$  is equal to 0 if the line  $a$  is opened under contingency  $k$ , and 1 if the line is closed under this contingency. Constraint (6.5) enforces the power flow limitations on each line that depends on the scenarios and statuses (on/off) of lines. If the line  $a$  is off in scenario  $k$ ,  $\Gamma_a^k = 0$ , or it is opened,  $Z_a^k = 0$ , then Constraint (6.5) reduces to  $f_a^k = 0$  which is consistent since there cannot be flow on that line. In the other case, i.e. line  $a$  is on and closed in scenario  $k$ , then Constraint (6.5) sets the lower and upper bounds for the flow on line  $a$ . Constraint (6.6) defines the power flow on line  $a$  for scenario  $k$  as a function of voltage angles differences of buses. Similar discussions for Constraint (6.5) can also be deducted for Constraint (6.6): if the line  $a$  is off or opened, then  $f_a^k = 0$ , otherwise it is equal to DC representation of Kirchoff's law. We note here that, Constraint (6.6) is nonlinear and we linearize this constraint below using a Big-M type linearization technique. Constraint (6.7) satisfies that a line can be on if the line already exists or is built.

• *Domain Constraints:*

$$-\pi \leq \theta_i^k \leq \pi \quad \forall i \in B, k \in K \quad (6.8)$$

$$\theta_{ref}^k = 0 \quad \forall k \in K \quad (6.9)$$

$$L_a = 1 \quad \forall a \in EA \quad (6.10)$$

$$X_{ig} \in \{0, 1\}, G_{ig}^k \geq 0, \theta_i^k \text{ urs} \quad \forall i \in B, g \in C, k \in K \quad (6.11)$$

$$L_a \in \{0, 1\}, Z_a^k \in \{0, 1\}, f_a^k \text{ urs} \quad \forall a \in A, k \in K \quad (6.12)$$

Constraint (6.8) limits the voltage angles at every bus under each scenario and Constraint (6.9) is the reference point for voltage angle profile of buses. Constraint (6.10) represents the existing transmission lines. Constraints (6.11) and (6.12) are the domains of the decision variables.

We remark that Constraint (6.6) is nonlinear due to multiplication of decision variables  $Z_a^k$  and  $\theta_i^k$ . We linearize the equation by using a similar technique used in [20] and in Chapter 3. Two nonnegative flow variables,  $f_a^{k+}$  and  $f_a^{k-}$ , each one representing one direction for the same line  $a$  for scenario  $k$ , express the unrestricted variable  $f_a^k$  as the difference between two nonnegative decision variables as follows:

$$f_a^k = f_a^{k+} - f_a^{k-} \quad \forall a \in A, k \in K \quad (6.13)$$

Similarly, two nonnegative variables,  $\Delta\theta_a^{k+}$  and  $\Delta\theta_a^{k-}$  express the difference of voltage angles of buses  $i$  and  $j$  for scenario  $k$  as follows:

$$\theta_i^k - \theta_j^k = \Delta\theta_a^{k+} - \Delta\theta_a^{k-} \quad \forall a \in AS_{ij}, k \in K \quad (6.14)$$

By using Constraints (6.13) and (6.14), Constraint (6.6) is linearized and replaced with the following Constraints (6.15)-(6.18):

$$f_a^{k+} \leq \varphi_a \Gamma_a^k \Delta \theta_a^{k+} \quad \forall a \in AS_{ij}, k \in K \quad (6.15)$$

$$f_a^{k-} \leq \varphi_a \Gamma_a^k \Delta \theta_a^{k-} \quad \forall a \in AS_{ij}, k \in K \quad (6.16)$$

$$f_a^{k+} \geq \varphi_a \Gamma_a^k \Delta \theta_a^{k+} - M_a(1 - Z_a^k) \quad \forall a \in AS_{ij}, k \in K \quad (6.17)$$

$$f_a^{k-} \geq \varphi_a \Gamma_a^k \Delta \theta_a^{k-} - M_a(1 - Z_a^k) \quad \forall a \in AS_{ij}, k \in K \quad (6.18)$$

Constraints (6.15)-(6.18) correctly linearize Constraint (6.6) for a sufficiently large positive number  $M_a$  in Constraints (6.17) and (6.18) so that the new constraints does not cut any feasible solution if the line  $a$  is open, and  $M_a = 2\pi\varphi_a$  can be used for the proposed model. When line  $a$  is open in scenario  $k$  (i.e.  $Z_a^k = 0$ ), Constraints (6.17) and (6.18) become redundant as  $f_a^{k+}$  and  $f_a^{k-}$  are already greater than or equal to 0. For this case, Constraints (6.15) and (6.16) are also redundant and do not cut any feasible solution since  $f_a^k$  is already equal to zero from Constraint (6.5). When  $Z_a^k = 1$ , (6.15) and (6.17) reduce to  $f_a^{k+} = \varphi_a \Gamma_a^k \Delta \theta_a^{k+}$  and (6.16) and (6.18) reduce to  $f_a^{k-} = \varphi_a \Gamma_a^k \Delta \theta_a^{k-}$ . By using the equalities in (6.13) and (6.14), we obtain  $f_a^k = \varphi_a \Gamma_a^k \Delta \theta_a^k$  which is the same equation obtained from Constraint (6.6) when  $Z_a^k = 1$ . Thus, adding Constraints (6.15)-(6.18) and removing Constraint (6.6) linearize the proposed model CD-TS.

In our model, we consider the scenarios only for no-contingency and single-line contingency. To include the expected operational cost of scenarios to the objective function, we first define the probabilities of no-contingency and single-line contingency scenarios, which are shown in Equations (6.19) and (6.20), respectively. To define the probabilities, we use the binomial distribution and FOR of transmission lines,  $\sigma_a$ , to describe the unavailability of transmission lines [96].

$$p^0 = \prod_{a \in A} (1 - \sigma_a L_a) \quad (6.19)$$

$$p^k = \sigma_k L_k \prod_{a \in A: a \neq k} (1 - \sigma_a L_a) \quad (6.20)$$

In this chapter, we assume independent outage of lines (ruling out the possibilities of events where one line outage leads to the outage of other lines) and consider

only no-contingency and single-line contingency scenarios as in [93] due to high probabilities of these cases as also presented in Section 6.2. However, one can easily consider N-m reliability criterion (loss of  $m$  lines simultaneously,  $m > 1$ ), include the corresponding scenarios to the model and calculate the probabilities for these scenarios using the binomial distribution and FOR of transmission lines.

We note that the objective function is still nonlinear and can be linearized by applying a similar technique used in [93]. However, the proposed solution methodology in the next section does not require a linear objective function. We update the number of contingency states (scenarios) and recalculate their probabilities if a new line is built to calculate a more accurate operational costs of contingencies. Next section describes the solution methodology to solve the computationally complex CD-R-GTEP problem.

### 6.1.2 A Scenario Reduction Based Solution Methodology

The number of lines and contingencies has a significant impact on the solution time of the model especially for a large-size network. Considering all the contingencies simultaneously may increase the size of the problem dramatically and may also lead to memory problems. However, most of the contingencies do not affect power systems' reliability in real world examples [88]. These observations motivate us using a filtering technique as in [88] to find the redundant contingencies where the reliability of the power system is still maintained after removing these contingencies from the consideration. A similar filtering technique has been also utilized in [89] to reduce the number of scenarios related to the uncertainties of renewable generation units. Unlike our study, [88] and [89] do not consider operational costs during the contingency states. They only consider the lines (important lines) such that their outage will cause overloads on the other lines. However, in our solution approach, addition to the important lines discussed in [88, 89], we should consider the remaining lines for analyzing the effect of randomness in outages on the power system expansion plans. Our proposed *scenario reduction based solution methodology* (SRB) is explained via the following steps:

*Step 1:* Check whether the existing network topology (i.e. without allowing new investments) is feasible or not for the no-contingency state, which is equivalent to checking feasibility of the proposed model CD-TS for only scenario  $k = 0$ . For the feasibility check, add the following constraints to CD-TS and set contingency list  $K = \{0\}$ .

$$X_{ig} = 0 \quad \forall i \in B, g \in CG \quad (6.21)$$

$$L_a = 0 \quad \forall a \in CA \quad (6.22)$$

If it is not feasible, solve the original model CD-TS (after removing Constraints (6.21) and (6.22)) for only scenario  $k = 0$ . Get the optimal solution of the model and update the sets based on the new investments obtained from the optimal solution: add new transmission lines and generation units to the sets of existing transmission lines,  $EA$ , and existing generation units,  $EG$ , respectively, and remove these new lines and new generation units from the sets of candidate transmission lines,  $CA$ , and candidate generation units,  $CG$ , respectively.

*Step 2:* Calculate the probabilities of contingency states for all lines using the following equations. Here, we only consider the scenarios associated with the existing lines in  $EA$ . Thus, we set probabilities of the scenarios for the candidate lines to 0. We remind that in order to define the probabilities, we use the binomial distribution and FOR of transmission lines, which is denoted by  $\sigma_a$ .

$$p^0 = \prod_{a \in EA} (1 - \sigma_a) \quad (6.23)$$

$$p^s = \sigma_s \prod_{a \in EA: a \neq s} (1 - \sigma_a) \quad \forall s \in EA \quad (6.24)$$

$$p^s = 0 \quad \forall s \in CA \quad (6.25)$$

*Step 3:* Decompose the problem into number of scenarios whose probability calculated in (6.23)-(6.25) is larger than 0 and create  $|EA| + 1$  subproblems,  $P_0, P_1, \dots, P_k, \dots, P_{|EA|}$  where  $P_0$  corresponds to the updated network topology for scenario  $k = 0$  (i.e. no contingency state) and  $P_k$  is the topology when the  $k^{th}$  line in the set  $EA$ , is out of service. In this step, all candidate lines are also considered

as out of service. Let  $FR(P_k)$  be the feasible region of the  $k^{th}$  subproblem. Check the feasibility of each subproblem for the network obtained at the end of Step 1. If the  $k^{th}$  subproblem is infeasible, (i.e. there does not exist any power dispatch that satisfies the load without requiring any new investments), define the  $k^{th}$  line as *critical line* and the corresponding contingency as *critical contingency*. If the  $k^{th}$  subproblem is feasible (i.e. there exists at least one solution that satisfies the load without requiring any new investments), then define the  $k^{th}$  line as *non-critical line* and the corresponding contingency as *non-critical contingency*. Let  $CC$  be the set for the *critical contingencies* (or critical lines) and  $NCC$  be the set for the *non-critical contingencies* (or non-critical lines).  $CC$  and  $NCC$  are defined as follows:

$$CC = \{k : FR(P_k) = \emptyset\} \quad (6.26)$$

$$NCC = \{k : FR(P_k) \neq \emptyset\} \quad (6.27)$$

*Step 4:* Generate a new scenario, referred to as *super scenario* ( $ss$ ) and the corresponding subproblem for this scenario. The feasible region of the new subproblem is the same with the feasible region of  $P_0$  and the probability of this scenario is equal to the sum of the probabilities of all the scenarios in the set  $NCC$ :  $p^{ss} = \sum_{k \in NCC} p^k$ . We note here that, the new generation plants and/or new transmission lines that are built can also be used for the scenarios in the set  $NCC$ . Thus, for the correct capacity planning of the new plants and/or lines, we incorporate all the scenarios in the set  $NCC$  and hence the non-critical lines are considered in the planning process. Define contingency set,  $K$ , as the union of the scenarios in  $CC$  and super scenario, i.e.  $K = \{k : k \in CC \text{ and } ss\}$ . Solve the model CD-TS optimally with only the scenarios in the updated set  $K$ , get the optimal solution and find the required new investments. Report the expansion plan (new generation units and transmission lines), and investment costs ( $z_{gen}, z_{line}$ ).

*Step 5:* The super scenario may underestimate or overestimate the true operational costs for the scenarios in the set  $NCC$  due to having different feasible region than  $P_0$ . Thus, in this step, the expected operational cost for all the scenarios is recalculated. Using the solution obtained at the end of Step 4, update the sets

of the existing,  $EA$ , and new transmission lines,  $CA$ , and sets of existing,  $EG$ , and new generation units,  $CG$ , using the same arguments as in Step 1. Update also the probabilities of the scenarios,  $p^0$  and  $p^s \forall s \in EA$  using Equations (6.23)-(6.25) as probabilities may change with the new set of the existing lines,  $EA$ . Define contingency set,  $K$  as the union of all scenarios in  $CC$  and  $NCC$  such that  $K = \{k : k \in CC \text{ and } k \in NCC\}$ . Solve the proposed model without allowing new expansions and add Constraints (6.21) and (6.22) to the CD-TS. Solve the proposed model CD-TS with the new contingency set,  $K$ .

Return the expected operational cost and report the final solution by combining with the output obtained at the end of Step 4. The flow chart of the solution methodology is presented in Figure 6.1.

## 6.2 Computational Study

In this section, we discuss the value of considering expected operational cost and effect of contingency-dependent TS. The model (CD-TS) and the scenario reduction based solution methodology (SRB) is applied to the IEEE 24-bus and IEEE 118-bus power systems. The results of SRB are also presented for the Turkish power system. Experiments are performed on a Linux environment with a 4xAMD Opteron Interlagos 16C 6282SE 2.6G 16 M 6400MT server with 96 GB RAM. Solution approach is implemented in Java Platform and results are obtained in Cplex 12.6.0 in parallel mode using up to 32 threads.

### 6.2.1 IEEE 24-bus Power System

IEEE 24-bus power system includes 24 nodes, 32 generation plants and 35 corridors for building transmission lines. The parameters of the existing generation units and transmission lines are given in [108]. We use the same configuration of the network and expansion alternatives for the generation units and lines presented in Chapter 3.

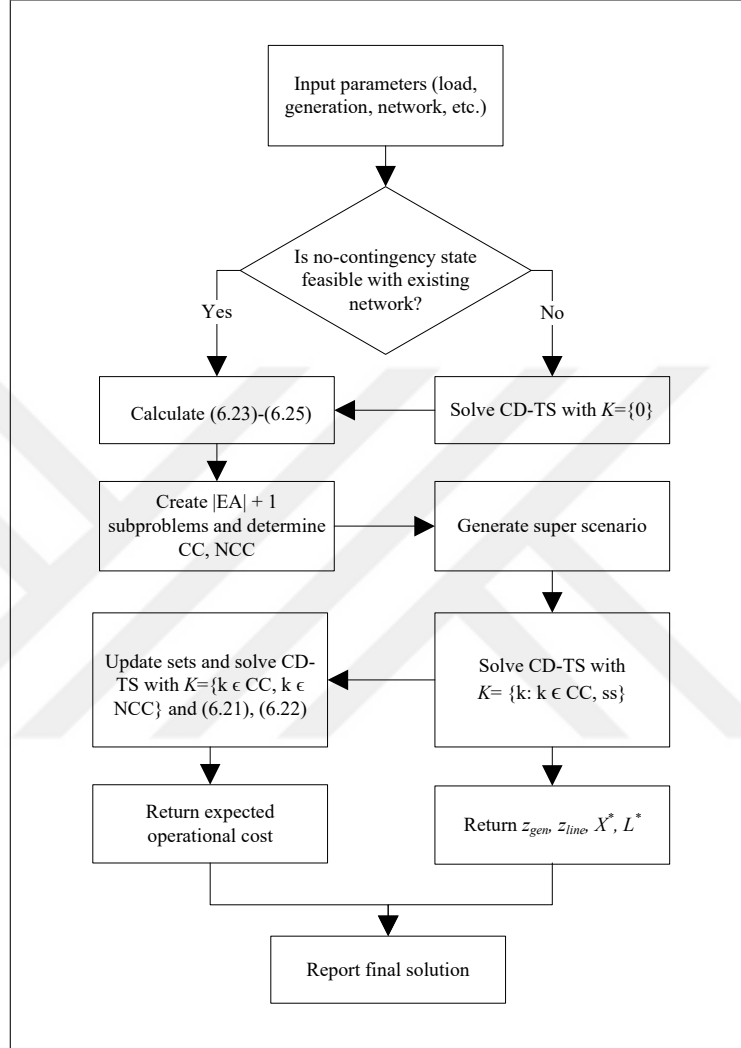


Figure 6.1: Flow chart of the proposed scenario reduction based solution methodology (SRB).

Although TS increases utilization of the network, system operators may not consider switching many lines simultaneously as this can decrease grid reliability. Thus, in this section, we restrict number of switchable lines and analyze six cases with different levels of switching: *no-switch case* and the cases with the number of lines that can be switched is restricted from 1 to 5. We add the following constraints to CD-TS for this restriction:

$$L_a \leq Z_a^k + s_a \quad \forall a \in A, k \in K \quad (6.28)$$

$$\sum_{a \in A} s_a \leq \tau \quad (6.29)$$

$s_a$  is a binary variable which takes value 1 if line  $a$  is switched in any scenario  $k$  and 0 o.w.  $\tau$  is the number of transmission lines that can be switched. For the following analyses, we use Equations (6.23)-(6.25) to calculate the probability of scenarios for the no-contingency and single-line contingency scenarios. Using the binomial distribution and FOR of transmission lines given in [108], we calculate that the sum of the probabilities for only these scenarios is 93%.

We first emphasize the benefits of two-stage stochastic programming approach. Table 6.1 presents the results of the proposed CD-TS model and expected value of perfect information (EVPI) for the six cases defined above. The difference between the optimal values of CD-TS and EVPI is referred to as the maximum value that the system operator would pay for acquiring additional information for the uncertainty and this information can be used to analyze the need for reinforcing the system (e.g. for decreasing outage rates of lines by replacing them). In our problem setting, since the outage of lines are the source of uncertainty, the system operator is considered to be willing to pay almost \$10M in all cases or on the average 7.73% more money than that is required with perfect information to handle this uncertainty.

Table 6.1: Value of two-stage stochastic programming on the IEEE 24-bus power system

| $\tau$  | CD-TS (M\$) | EVPI (M\$) | Difference (%) |
|---------|-------------|------------|----------------|
| 0       | 153.74      | 141.18     | 8.90           |
| 1       | 151.63      | 139.08     | 9.02           |
| 2       | 149.61      | 138.95     | 7.67           |
| 3       | 148.93      | 138.67     | 7.39           |
| 4       | 147.92      | 138.63     | 6.70           |
| 5       | 147.79      | 138.53     | 6.68           |
| Average |             |            | 7.73           |

We then discuss the benefits of the proposed transmission switching concept by comparing the solutions of CD-TS with the solutions when preventive security constrained TS is applied. For preventive security constrained TS concept, we guarantee that the network topology remains the same for all contingencies with the following equation and CD-TS with Constraint (6.30) is referred as preventive

security constrained TS (PSC-TS).

$$L_a = Z_a^k + s_a \quad \forall a \in A, k \in K \quad (6.30)$$

Figure 6.2 compares the optimal solution values of CD-TS and PSC-TS for the six switching possibilities. By allowing different network topologies for each contingency, the optimal solution values are reduced up to 1.92% and the highest improvement is obtained when at most 5 lines are allowed to be switched ( $\tau = 5$ ). We note that, the optimal solution values of CD-TS always decreases as  $\tau$  increases. However, the optimal solution values of PSC-TS are the same for the cases where the number of switchable lines,  $\tau$ , are larger than or equal to 2. Hence, we conclude that, the number of switchable lines for PSC-TS can be insignificant after some point, although it is valuable for CD-TS.

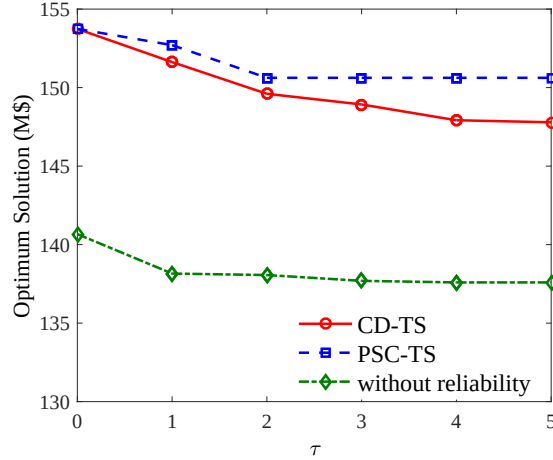


Figure 6.2: Optimal solutions of CD-TS, PSC-TS and without reliability.

Figure 6.2 also shows the optimal solution values of the model for the same instances when reliability is not considered to evaluate the effect of reliability on the results. For this analysis, we eliminate all the scenarios associated with the contingency states and the constraints related to these scenarios, in other words, the contingency set  $K$  includes only the scenario for the no-contingency state, i.e.  $K = \{0\}$ . In order to be consistent with the reliability considered solutions (CD-TS and PSC-TS), we update the probability of no-contingency scenario,  $p^0$ , for the case when reliability is not considered. For this case, the probability of the scenario  $k = 0$  is equal to the sum of all scenarios,  $p^0 = \sum_{k \in K} p^k$ .

Figure 6.2 shows that for all switching possibilities the optimal solutions without having any reliability consideration are significantly less than the optimal solutions of the reliability considered solutions. The difference between the solutions of the case *without reliability* and CD-TS can be interpreted as the cost of incorporating reliability into the power system, which costs about \$15M. Note that, when the preventive security constrained TS approach is applied, the required investments will be more costly than the required investment cost with contingency-dependent TS approach. We also note that, EVPI and *without reliability* solutions are presented to evaluate different concepts. While the first one discusses the value of perfect information, the latter one analyses the effect of considering reliability in the optimal decisions.

Table 6.2 details the solutions of CD-TS and PSC-TS, and reports the installed and switched lines for the six cases. As expected, when  $\tau = 0$ , the installed lines are the same for both CD-TS and PSC-TS since they reduce to the same problem without switching option. For the cases with  $\tau = 1$  and  $\tau = 2$ , although the number of installed lines are the same, the switched lines are different. Hence, the key difference between the optimal solution values is due to their expected operational costs. Thus, by only using different network topologies for each scenario, the expected operational cost and therefore, the total system cost can be decreased. When contingency-dependent TS concept is used in the power system, not only switched lines but also expansion plans may be affected. In all cases except for  $\tau = 0$  and  $\tau = 1$ , at least one of the new transmission lines is different for the two switching approaches. Moreover, as in cases with  $\tau = 4$  and  $\tau = 5$ , one less transmission line is built when contingency-dependent TS concept is applied. We again emphasize that, the solutions with preventive security constrained TS concept are the same when  $\tau \geq 2$ . Thus, the number of switched lines happens to be 2 in the optimal solution of PSC-TS even though switching more than two lines is allowed.

Table 6.2 also presents the value of transmission switching. For the IEEE 24-bus power system, we compare the solutions for the six cases ( $0 \leq \tau \leq 5$ ) as the solutions with  $\tau > 5$  remain almost the same for the CD-TS. Therefore, to discuss the value of TS, we compare the solutions obtained with  $\tau = 0$  and

Table 6.2: Installed and switched lines in the solutions of CD-TS and PSC-TS on the IEEE 24-bus power system

| $\tau$ |        | Installed Lines                                         | Switched Lines                            |
|--------|--------|---------------------------------------------------------|-------------------------------------------|
| 0      | CD-TS  | (3,24) (7,8) (9,12) (15,21)<br>(15,24) (16,17) (20,23)  |                                           |
|        | PSC-TS | (3,24) (7,8) (9,12) (15,21)<br>(15,24) (16,17) (20,23)  |                                           |
| 1      | CD-TS  | (3,24) (7,8) (14,16) (15,21)<br>(15,24) (16,17) (20,23) | (6,10)                                    |
|        | PSC-TS | (3,24) (7,8) (14,16) (15,21)<br>(15,24) (16,17) (20,23) | (1,2)                                     |
| 2      | CD-TS  | (3,24) (7,8) (15,21)<br>(15,24) (16,17) (20,23)         | (6,10) (9,11)                             |
|        | PSC-TS | (3,24) (7,8) (14,16)<br>(15,21) (15,24) (20,23)         | (15,16) (17,18)                           |
| 3      | CD-TS  | (3,24) (7,8) (15,21)<br>(15,24) (16,17) (20,23)         | (2,4) (6,10) (9,11)                       |
|        | PSC-TS | (3,24) (7,8) (14,16)<br>(15,21) (15,24) (20,23)         | (15,16) (17,18)                           |
| 4      | CD-TS  | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (6,10) (10,11)<br>(15,16) (17,18)         |
|        | PSC-TS | (3,24) (7,8) (14,16)<br>(15,21) (15,24) (20,23)         | (15,16) (17,18)                           |
| 5      | CD-TS  | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (6,10) (10,11) (15,16)<br>(17,18) (18,21) |
|        | PSC-TS | (3,24) (7,8) (14,16)<br>(15,21) (15,24) (20,23)         | (15,16) (17,18)                           |

$\tau = 5$ , where they correspond to without switching and with switching cases, respectively. Even for this small dataset, the value of switching is valuable and a 3.87% decrease in the total system cost is achieved by only allowing switching in the network. Moreover, when switching is not used, 2 more lines (i.e. (9,12) and (16,17)) should be built to maintain the required reliability level. Thus, by allowing TS in the system, expansion plans can be affected beside decreasing the total system cost.

Figure 6.3a and Figure 6.3b present the optimal solutions of the transmission switching concepts compared to the case where only operation cost for no-contingency scenario,  $k = 0$ , is included to the objective function of CD-TS and

PSC-TS, respectively. We observe that the solutions that only consider the operational cost of no-contingency scenario underestimate the total expected cost and especially for small  $\tau$  values, the difference between the solutions are significant and up to \$2.74M cost (1.83%) is underestimated for this example if the outcomes during the contingency states are ignored. We also note the underestimated monetary value might be higher than this one for the power systems with more flexible generators or renewable generators with highly variable outputs.

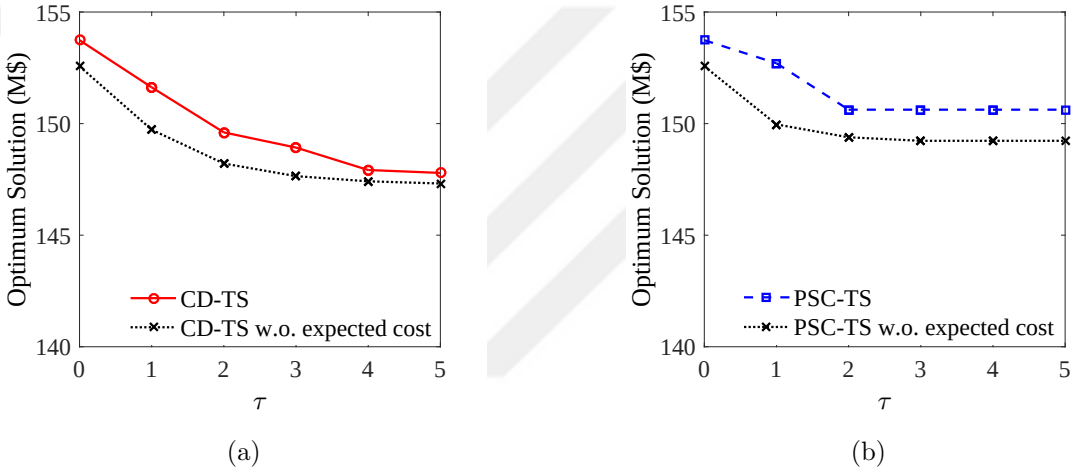


Figure 6.3: Value of adding expected operational cost to (a) CD-TS (b) PSC-TS.

Table 6.3 details the solutions of Figure 6.3a and presents the installed and switched lines for the proposed switching concept. In the case with  $\tau = 2$ , as all the installed and switched lines are the same, the cost difference is due to not considering operation costs during the contingency states. However, as in other cases, including expected operational cost to the problem not only affect the optimal solution values, but also change the expansion plans. For the cases with  $\tau = 1$  and  $\tau = 3$ , one more transmission line is installed when the expected operational cost term is included to the objective function and the key difference between the solutions of these instances is due to the change in  $z_{line}$ . In other cases with  $\tau \geq 4$ , although the number of installed lines are the same, at least one of the switched lines are different from each other, which is also one of the reasons for the difference between the optimal solution values as the generation outputs are different from each other. Therefore, considering probabilistic realization of outages and defining transmission switching as recourse actions affect the planning decisions, network topologies and cost of the expansion plans.

Table 6.3: Installed and switched lines in the solutions of CD-TS and CD-TS without expected cost on the IEEE 24-bus power system

| $\tau$ |                     | Installed Lines                                         | Switched Lines                            |
|--------|---------------------|---------------------------------------------------------|-------------------------------------------|
| 0      | CD-TS               | (3,24) (7,8) (9,12) (15,21)<br>(15,24) (16,17) (20,23)  |                                           |
|        | CD-TS w.o. exp cost | (3,24) (7,8) (9,12) (15,21)<br>(15,24) (16,17) (20,23)  |                                           |
| 1      | CD-TS               | (3,24) (7,8) (14,16) (15,21)<br>(15,24) (16,17) (20,23) | (6,10)                                    |
|        | CD-TS w.o. exp cost | (3,9) (7,8) (14,16)<br>(15,21) (16,17) (20,23)          | (6,10)                                    |
| 2      | CD-TS               | (3,24) (7,8) (15,21)<br>(15,24) (16,17) (20,23)         | (6,10) (9,11)                             |
|        | CD-TS w.o. exp cost | (3,24) (7,8) (15,21)<br>(15,24) (16,17) (20,23)         | (6,10) (9,11)                             |
| 3      | CD-TS               | (3,24) (7,8) (15,21)<br>(15,24) (16,17) (20,23)         | (2,4) (6,10) (9,11)                       |
|        | CD-TS w.o. exp cost | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (6,10) (9,11) (15,16)                     |
| 4      | CD-TS               | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (6,10) (10,11)<br>(15,16) (17,18)         |
|        | CD-TS w.o. exp cost | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (6,10) (10,11)<br>(15,16) (18,20)         |
| 5      | CD-TS               | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (6,10) (10,11) (15,16)<br>(17,18) (18,21) |
|        | CD-TS w.o. exp cost | (3,24) (7,8) (15,21)<br>(15,24) (20,23)                 | (1,2) (6,10) (10,11)<br>(15,16) (18,21)   |

For this example, Step 2 of SRB finds 16 and 9 critical contingencies (or scenarios) for the cases A and B, respectively. Thus, we also verify our motivation for the SRB methodology as most of the contingencies do not affect power system reliability. As we reduce the number of scenarios in the system, we find the solutions for these instances using SRB in significantly shorter solution times.

Table 6.4 compares solution times of the proposed method (SRB) with the solution times of proposed CD-TS model. We considerably reduce number of scenarios with our proposed solution approach and whereas we have 35 scenarios in CD-TS (that is equal to number of transmission lines), SRB has only 16 scenarios for this dataset. We remind that the remaining 19 scenarios do not affect the feasibility of the problem. In all the cases for different levels of switching, SRB finds the optimal results in significantly less solution time and up to 94.07%

improvement is achieved for the case with  $\tau = 5$  when the SRB is applied, and on the average the improvement in the solution times is 78.27%. We note that in SRB, although we temporarily reduce the number of scenarios from 35 to 16, since Step 5 of the SRB recalculates operational costs of all 35 scenarios, it finds the optimal solution for the original problem. Thus, it is a prominent solution methodology to overcome the computational complexity of reliability constrained problems that can lead to memory problems. In the following sections, we test the performance of proposed methodology on larger datasets.

Table 6.4: Solution times of the model and the solution methodology on the IEEE 24-bus power system

| $\tau$  | CD-TS (h) | SRB (h) | Improvement (%) |
|---------|-----------|---------|-----------------|
| 0       | 0.13      | 0.02    | 87.45           |
| 1       | 1.23      | 0.24    | 80.49           |
| 2       | 4.89      | 2.67    | 45.40           |
| 3       | 18.97     | 2.53    | 86.66           |
| 4       | 7.04      | 1.72    | 75.57           |
| 5       | 11.30     | 0.67    | 94.07           |
| Average | 7.26      | 1.31    | 78.27           |

### 6.2.2 IEEE 118-bus Power System

IEEE 118-bus power system includes 118 buses, 19 generation plants and 186 transmission lines [5, 124]. In the original network, the total installed capacity and total demand are 5,859 MW and 4,519 MW, respectively. As the operation cost of generation units are relatively low compared to today's values provided in the next section for a real-life case, we multiply the operation costs of generation units by 2.5. We also reduce the capacities of the transmission lines by 20% in order to increase the congestion in the system and observe the effect of TS on the grid. Forced outage rates (FOR) of transmission lines,  $\sigma_a$ , are set to 0.005 for all lines.

Table 6.5 presents the results of our proposed CD-TS model and SRB method on this power system for two cases: (A) switching is allowed only on the new lines

and (B) switching is allowed on all the lines. For the CD-TS model, we provide a warm-start solution obtained by utilizing SRB methodology with a starting value of \$47.23M. But, the solution is not improved for the next 12 hours and the reported gaps by the solver at the end of 12 hours time limit, are 16.79% and 23.92% for the cases A and B, respectively.

For this example, Step 2 of SRB finds 16 and 9 critical contingencies (or scenarios) for the cases A and B, respectively. Thus, we also verify our motivation for the SRB methodology as most of the contingencies do not affect power system reliability. As we reduce the number of scenarios in the system, we find the solutions for these instances using SRB in significantly shorter solution times. We obtain solutions in less than 1 hour for case A, and less than 6 hours for case B. We also emphasize that in both cases, the solutions obtained from SRB methodology is less than the best integer solution obtained with CD-TS model within 12 hours. Hence, efficiency of the SRB methodology is more obvious for this large data set. We also emphasize the benefits of two-stage stochastic programming approach that includes the expected value of operational costs in the objective function. By solving several single-scenario problems on the IEEE 118-bus power system and taking the expected value of the solutions of the single scenario problems, we calculate the expected value of perfect information (EVPI) for both cases. The differences between the solutions of SRB and EVPI are 15.92% and 15.78% for cases A and B, respectively, which is the maximum value that system operator is considered to be willing to pay to acquire additional information for the outage of transmission lines.

Table 6.5: Results for CD-TS and SRB on the IEEE 118-bus power system

|       |                     | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|-------|---------------------|----------------------------------|----------------------------------|
| CD-TS | Best solution (M\$) | 47.23                            | 47.23                            |
|       | Solution time (h)   | > 12                             | > 12                             |
|       | Gap (%)             | 16.79                            | 23.92                            |
| SRB   | Best solution (M\$) | 41.65                            | 37.43                            |
|       | Solution time (h)   | 0.78                             | 5.51                             |

Table 6.6 details the solutions of SRB methodology for the two cases to analyze

the value of transmission switching. As switching is allowed on all the lines, a 10.13% improvement is obtained and not only investment cost, but also expected operational cost decreases with incorporating switching option for all lines. Moreover, switching lines can affect the investment plans as one less transmission line is built in case B, which costs approximately \$2M.

Table 6.6: Results for the IEEE-118 bus power system for two cases

|                         | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|-------------------------|----------------------------------|----------------------------------|
| $z_{line}$ (M\$)        | 11.40                            | 9.45                             |
| # of new lines          | 12                               | 11                               |
| Expected op. cost (M\$) | 30.25                            | 27.98                            |

### 6.2.3 Turkish Power System

Turkish transmission network is comprised of 380-kV, 220-kV, 154-kV and 66-kV voltage levels. 380-kV transmission network is considered as the Turkish main transmission system [125] and this section analyzes this backbone network in terms of N-1 reliability criterion.

Figure 6.4 presents the 380-kV transmission network and the substations. Table 6.7 summarizes the Turkish power system data for 2016 [126]. As demands of the buses or substations are not available, for this analysis, we calculate the demand of each node based on the profiles provided in [127]. The characteristics of the overhead transmission lines and generation technologies are presented in Table 6.8.

Table 6.7: Summary of the Turkish power system data

|                           |           |
|---------------------------|-----------|
| # of nodes (buses)        | 970       |
| # of transmission lines   | 245       |
| # of substations          | 118       |
| # of generation units     | 1244      |
| Total peak demand         | 44,734 MW |
| Total generation capacity | 77,737 MW |

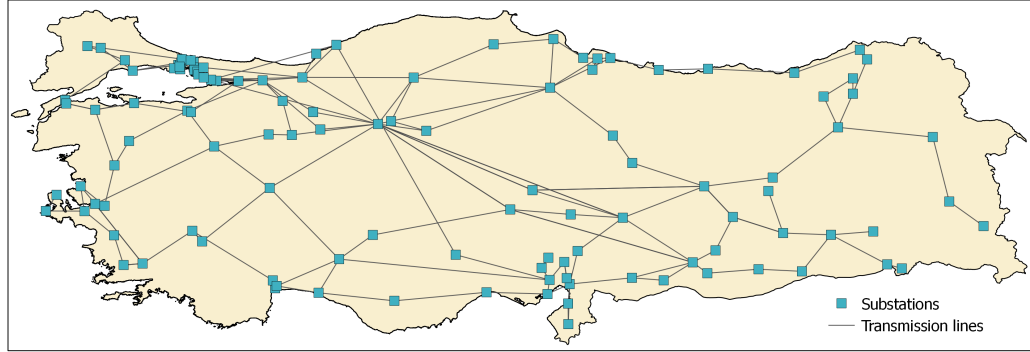


Figure 6.4: Substations and lines on the 380-kV transmission network in Turkey.

Table 6.8: Characteristics of Turkish power system data

| Transmission Lines |               |                    | Generation Units |        |                              |
|--------------------|---------------|--------------------|------------------|--------|------------------------------|
| Type               | Capacity (MW) | Reactance (ohm/km) | Technology       | Number | Distribution of capacity (%) |
| 2xRail             | 500           | 0.3190             | Thermal          | 452    | 56.59                        |
| 2xCard.            | 500           | 0.3168             | Hydro            | 605    | 34.32                        |
| 3xCard.            | 750           | 0.2621             | Wind             | 153    | 7.39                         |
| 3xPhea.            | 1000          | 0.2559             | Geothermal       | 32     | 1.06                         |
|                    |               |                    | Solar            | 2      | 0.02                         |

We apply a similar methodology referred to as *power island model* [128] to reduce number of nodes that we used in our analysis. We assume a generation unit dispatches power to its closest existing substation and demand nodes are fed from their closest substations. In this power island model, we assign all the demand nodes and generation units to their closest substations. We aggregate demand values and generation capacities to 118 substations and these substations are considered as nodes (buses) in the model. Thus, at the end of this procedure, we obtain a *simplified Turkish power system* with 118 buses and 245 existing transmission lines. The schematic representation of the power island model is shown in Figure 6.5.

Candidate transmission lines and locations of generation units are in accordance with future expansion plans [129]. The number of candidate generation units is 696 that can be built at 103 buses. The parameters of candidate generation units for each technology is presented in Table 6.9 and we estimate capital

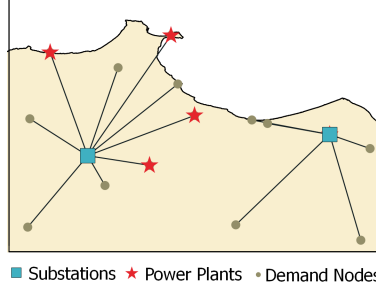


Figure 6.5: Power island model.

and operational costs of them by utilizing the data in [130]. The parameters are also the same for the existing plants. The life time of new power plants is taken as 30 years and the discount rate that includes inflation is 5%. 3xCardinal and 3xPheasant cables are considered for the new lines. All corridors are considered for expansion and at most two lines can be built from each type on the same corridor. The investment costs of these transmission lines are estimated as \$1.7M/km for 3xCardinal type and \$1.9M/km for 3xPheasant type [131]. Life time of transmission lines is taken as 50 years with the same interest rate. We calculate the probability of each contingency based on the system fault index of the transmission system [132] and the sum of the probabilities for no-contingency and single-line contingency is equal to 95%. The details of the data and related analyses can be shared upon contacting with authors.

Table 6.9: Characteristics of the generation technologies

| Type       | Capacity<br>(MW) | Capital cost<br>(M\$/MW-year.) | Operation cost<br>(\$/MWh) | Capacity<br>factor (%) |
|------------|------------------|--------------------------------|----------------------------|------------------------|
| Thermal    | 500              | 0.08                           | 4.28                       | 80.00                  |
| Hydro      | 350              | 0.15                           | 6.85                       | 29.00                  |
| Wind       | 150              | 0.10                           | 4.57                       | 28.00                  |
| Geothermal | 100              | 0.16                           | 5.71                       | 78.00                  |
| Solar      | 100              | 0.11                           | 1.90                       | 17.00                  |
| Nuclear    | 2000             | 0.29                           | 17.88                      | 85.00                  |

The proposed SRB solution methodology is applied to the 380-kV simplified Turkish power system for the same two cases used in the previous section and in Case A, we only allow switching on the new lines and in Case B, we allow switching on all the lines. Step 2 of SRB identifies the redundant contingencies

and at this step after temporarily removing the redundant ones, 29 and 12 of them are considered as critical contingencies and added to the critical contingency (CC) set for cases A and B, respectively. Thus, in any cases, the current system does not satisfy N-1 reliability criterion. As seen in Figure 6.4, there are radial 380-kV transmission elements which are also counted in this analysis. However, these radial lines can be removed from the contingency set as in [5]. Table 6.10 summarizes the results of the solution method for the two cases. When switching is allowed on the new lines (Case A), 14 transmission lines are installed with a total investment cost of \$82.38M and when switching is allowed on all the lines (Case B), 11 transmission lines are installed to satisfy the N-1 reliability criterion and the total investment cost is \$79.85M. Hence, we observe that using contingency-dependent TS for all the lines decreases the number of lines that should be installed by 3 and cost by \$14.78M.

Table 6.10: Results for the 380-kV Turkish transmission network for two cases

|                         | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|-------------------------|----------------------------------|----------------------------------|
| # new lines             | 14                               | 11                               |
| $z_{line}$ (M\$)        | 82.38                            | 79.85                            |
| Expected op. cost (M\$) | 933.47                           | 918.69                           |

The difference in the solutions are also shown in Figure 6.6 for Kocaeli-Istanbul region. Figure 6.6 presents the substations, existing lines between these substations (thin lines) and installed lines (bold lines) for the cases A and B. Figure 6.6b shows four of the 11 installed lines for Case B. When the switchable lines are restricted with the new lines, two more transmission lines are installed in the same region which is presented in Figure 6.6a. Although in the current power system, switching transmission lines can raise different problems, transmission switching in expansion planning is worth to discuss [57] as the investment plans and estimated operational costs of generation can be significantly affected.

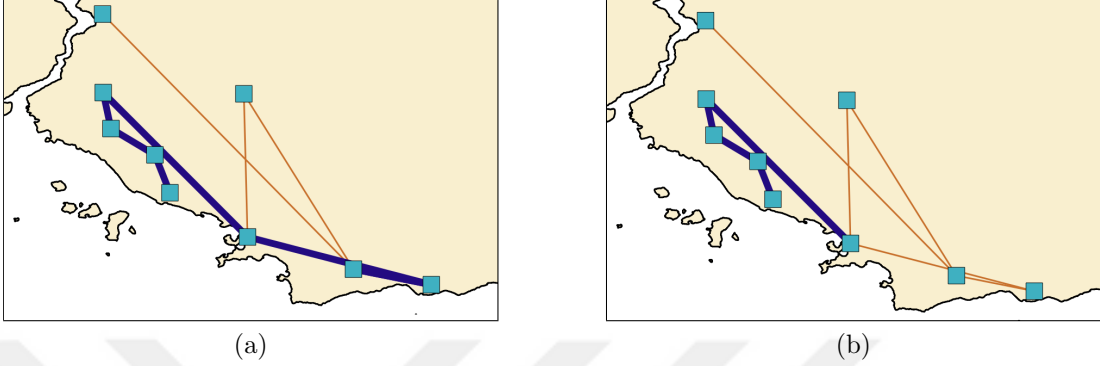


Figure 6.6: (a) Installed lines (represented by bold lines) (a) when switching is allowed only on the new lines (b) when switching is allowed on all the lines.

## 6.3 Extensions and Discussions

In this section, we discuss the extensions of the focused problem explained in Section 6.1. The problem setting can be easily modified for the possible extensions that could be multi-stage expansion planning, demand uncertainty or renewable generation uncertainty and in the following sections, we will analyze the multi-stage expansion planning and demand uncertainty cases among the possible ones. We first explain the modifications to the proposed CD-TS model and proposed SRB solution approach. We then discuss the results obtained with the modified versions of the CD-TS and SRB for the IEEE 24-bus power system and Turkish transmission network for the extensions.

### 6.3.1 Multi-stage Expansion Planning

The proposed CD-TS model is easily extendable for multi-stage expansion planning problem with an additional dimension  $t$  to represent the decisions in year  $t$ . As the demand is exogenously given to the model, we also add the time dimension  $t$  to  $D_i$ , such that  $D_i^t$  is the demand of node  $i$  in year  $t$ . Each constraint set of the model CD-TS is reproduced for each year  $t \in T$  where  $T$  is the planning horizon.

We also need to add the following constraints to the model:

$$L_a^{t-1} \leq L_a^t \quad \forall a \in A, t \in T \quad (6.31)$$

$$X_{ig}^{t-1} \leq X_{ig}^t \quad \forall i \in N, g \in C, t \in T \quad (6.32)$$

Constraints (6.31) and (6.32) are the time coupling constraints. Constraint (6.31) guarantees that a new line built in year  $t-1$  can be used in year  $t$ . Similarly, Constraint (6.32) guarantees that a new generation unit built in year  $t-1$  can also be used in year  $t$ . We also note that the existing lines are added to the new version of the model by replacing Constraint (6.10) with the following one:

$$L_a^0 = 1 \quad \forall a \in EA \quad (6.33)$$

The proposed solution methodology can be extended for the multi-stage expansion planning by generating critical contingency ( $CC$ ) and non-critical contingency ( $NCC$ ) lists for each time period. First, we decompose the multi-period problem into a set of single period problems as many as the number of expansion periods,  $|T|$ , and apply the steps of the SRB for the first subproblem (for  $t = 1$ ) and get the new investments. Then we fix these new investments and apply the steps of the solution methodology for the second subproblem (for  $t = 2$ ) and get the optimal results. After solving all single-period problems iteratively by the proposed SRB method in Section 6.1.2, we combine all the solutions for each subproblem and get the solution for the original multi-stage expansion planning problem.

Table 6.11 presents the solutions of the modified versions of the CD-TS model and SRB method for the IEEE 24-bus power system for the same cases discussed in Sections 6.2.2 and 6.2.3. Annual demand growth rate is assumed to be 3% for the next 4 years and capacities of transmission lines are reduced by 40% to allow new investments. The modified version of CD-TS model finds the optimal solution of Case A (i.e. only new lines are switchable) within 24 minutes. However, when all lines are switchable, the optimality of the problem is not verified within 12 hours time limit and the solver reports 1.4% gap at the end of the time limit. For the same cases, although the modified version of SRB cannot find the

optimal solutions, the solution times of the SRB method is significantly less than the solution times of the CD-TS. Thus, we conclude that the proposed solution approach is still a promising method to decrease computational complexity of the problem for larger datasets.

Table 6.11: Results of CD-TS and SRB on the IEEE 24-bus power system for multi stage expansion

|       |                     | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|-------|---------------------|----------------------------------|----------------------------------|
| CD-TS | Best solution (M\$) | 718.68                           | 720.80                           |
|       | Solution time (h)   | 0.39                             | >12                              |
|       | Gap (%)             | –                                | 1.4                              |
| SRB   | Best solution (M\$) | 751.04                           | 730.18                           |
|       | Solution time (h)   | 0.01                             | 0.01                             |

We also apply the modified version SRB solution method to the 380-kV Turkish transmission network. Estimated annual growth rates are 4.3%, 4.9%, 5.1% and 5.2% for the next 4 years, respectively [133]. Table 6.12 presents the results of the SRB method for the same cases for the Turkish transmission network. At the end of planning horizon, as 21% demand increase is estimated, a new generator is built at the same node in both cases. Similar to previous discussions in Section 6.2.3, transmission switching decreases the expected operational cost in the system. Moreover, as switching lines affect the expansion plans, the number of lines in Case B is also less than the number of lines in Case A. We note that, we use the estimated annual growth rate to increase the demand. However, more detailed analyses can be conducted by considering load blocks within each year. Demand in each load block can be estimated using a similar technique described in [134] to consider the correlations between the load blocks.

### 6.3.2 Demand Uncertainty

In Section 6.1, the proposed two-stage stochastic model includes the probabilistic realization of outages in transmission lines. Our model can easily be extended and other uncertainties can be incorporated into the model at an expense of

Table 6.12: Results for the 380-kV Turkish transmission network for multi stage expansion

|                         | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|-------------------------|----------------------------------|----------------------------------|
| # new generator         | 1                                | 1                                |
| # new lines             | 25                               | 19                               |
| $z_{line}$ (M\$)        | 120.86                           | 98.41                            |
| Expected op. cost (M\$) | 5255.61                          | 5220.01                          |

increased computation time and memory. In this subsection, we discuss the effect of including demand uncertainty to the problem and the modifications required to handle these uncertainties in the proposed model and solution methodology. Different demand levels are considered to take into account demand uncertainty.

For this extension, we keep first stage decision variables,  $X_{ig}$  and  $L_a$  as in CD-TS. Each decision variables in the second stage such as power flow and generation amount have a new dimension  $w$  to represent the demand levels. We also change the parameter  $D_i$  with  $D_i^w$  to represent load in bus  $i$  in demand level  $w$ . Each constraint set (6.2)-(6.9),(6.11),(6.12) should be satisfied for each demand level  $w \in W$  where  $W$  is the set of demand levels. We then modify the objective function to incorporate demand uncertainty as we assume independent and identically distributed outages of transmission lines and demand levels. In (6.33),  $\rho^w$  represents the probability of demand level  $w$ .

$$\min \quad z_{gen} + z_{line} + \sum_{w \in W} \rho^w \sum_{k \in K} z_{om}^{kw} \quad (6.34)$$

In the SRB approach, for handling different demand levels, we modify Step 3 and Step 4 of the methodology explained in Section 6.1. We now define  $CC^w$  and  $NCC^w$  for the critical and non-critical contingencies in demand level  $w$  and generate a super scenario for each  $w \in W$ , ( $ss^w$ ). We then define  $K^w$  for the contingency set of demand level  $w$ , i.e.  $K^w = \{k : k \in CC^w \text{ and } ss^w\}$ . We then solve the CD-TS for each demand level  $w$  and for each scenario in the contingency set of the  $w$ , (i.e.  $\forall w$  and  $\forall k \in K^w$ ).

Table 6.13 compares the results of the modified versions of CD-TS, PSC-TS and SRB methodology for the IEEE 24-bus power system for the two cases given above. In this analysis we consider three demand levels ( $D_i^1 = D_i$ ,  $D_i^2 = 1.05 D_i$  and  $D_i^3 = 1.1 D_i$ ) as in [135] with equal probabilities. Similar to the results in Table 6.11, the modified version of CD-TS finds the optimal solution for Case A within 25 minutes, whereas it concludes with 8.37% gap at the end of 12 hours time limit. In these instances, the modified version of SRB method finds the optimal solution of Case A within 19 minutes. Moreover, the solution obtained with the proposed method for Case B is lower than the solution obtained with the CD-TS at the end of time limit.

Table 6.13: Results of CD-TS, PSC-TS and SRB on the IEEE 24-bus power system with demand uncertainty

|        |                     | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|--------|---------------------|----------------------------------|----------------------------------|
| CD-TS  | Best solution (M\$) | 159.71                           | 162.09                           |
|        | Solution time (h)   | 0.41                             | >12                              |
|        | Gap (%)             | –                                | 8.37                             |
| PSC-TS | Best solution (M\$) | 159.78                           | 158.65                           |
|        | Solution time (h)   | 0.08                             | 8.26                             |
| SRB    | Best solution (M\$) | 159.71                           | 150.18                           |
|        | Solution time (h)   | 0.31                             | 2.01                             |

Table 6.13 also discuss the benefits of the proposed switching concept. When switching is allowed on only new lines, the value of the switching is not remarkable. However, when switching is allowed on all the lines, despite the fact that the optimality of Case B is not verified by the CD-TS, we obtained a solution with \$150.18M with the SRB method. Thus, the proposed switching concept leads to a 5.34% decrease in the total cost. We also note that, as the solution obtained from the SRB may not be optimal, the value of contingency-dependent switching may be higher than 5.34%.

We then apply the SRB solution method on the Turkish power system and Table 6.14 depicts the results. In the previous section, we provide the annual growth rate for the next 4 years. In this section, the demand in the year 2020 is considered as the medium demand level and a 10% lower and higher than this

average value is considered for the other demand levels. When switching existing transmission lines are not allowed, a new generator and 31 new transmission lines are built in the optimal solution. However, when switching operations are allowed on all lines, the generator and two transmission lines are not required any more. On the other hand, expected operational cost is higher in Case B than the expected operation cost in Case A. Hence, in Case B, the expensive generators are utilized instead of building new generator and new transmission lines. We note here that, the modified SRB approach discussed above can be easily extended to the problems with different uncertainties such as solar, wind generators or market prices.

Table 6.14: Results for the 380-kV Turkish transmission network with demand uncertainty

|                         | Case A (New<br>lines switchable) | Case B (All<br>lines switchable) |
|-------------------------|----------------------------------|----------------------------------|
| # new generator         | 1                                | –                                |
| # new lines             | 31                               | 29                               |
| $z_{line}$ (M\$)        | 174.07                           | 131.54                           |
| Expected op. cost (M\$) | 3505.92                          | 3555.89                          |

## 6.4 Conclusion

This chapter presents a two-stage stochastic programming model for a N-1 reliability constrained generation and transmission expansion planning problem. Operational decisions such as status of transmission lines, generation amounts and power flow decisions are defined as recourse actions of the two-stage stochastic programming model for each contingency state and the model makes it possible to calculate the expected value of operational costs during the contingencies in a more accurate manner. A scenario reduction based solution methodology with a filtering technique is also proposed to overcome the computational complexity of the problem.

The model and the proposed solution approach are tested on the IEEE 24-bus and 118-bus power systems. We first show that considering the operational costs during the contingency states and changing the network topology for each contingency affect the expansion plans and overall costs of the expansion plans significantly. Our results demonstrate that the proposed contingency-dependent transmission switching concept can decrease the total system by as much as 10.13%. We also compare the solutions obtained with the model and proposed solution approach to discuss the computational efficiency of the solution method. For the IEEE 24-bus power system, the solution method finds the optimal solutions with significantly shorter solution times (78.27% on the average). For the IEEE 118-bus power system, while the model cannot verify the optimality within the time limit, the solution method results with lower total system cost than the cost obtained with the model.

This chapter also introduces a real-world data set for the 380-kV Turkish transmission network. Using the proposed solution approach, we find expansion plans that satisfies the N-1 reliability criterion and show that allowing contingency-dependent TS can reduce the total cost of the system. We also note that, the value of TS are expected to be more important for power systems that have flexible generator or renewable generator with highly variable outputs.

In this chapter, as customarily done in the literature, we plan for a target year, and all the discussions are demonstrated for a single year. We remark here that, our model and scenario reduction based methodology is applicable to handle possible extensions such as multi-stage expansion planning and demand uncertainty, and we also discuss the modifications required to handle these extensions. We first show the efficiency of the proposed solution method on the IEEE 24-bus power system and discuss the results of the 380-kV Turkish transmission network for two cases. Different uncertainties for the generation units and alternative current modelling approach can also be added to the model in expense of increased number of scenarios and computational complexity in the model.

## Chapter 7

# Conclusion and Future Work

Uncertainty of renewable energy sources, forecast errors and unexpected failures of components have led operators to utilize different control mechanisms to design and operate power systems. In this dissertation, we focused on assessing the value of control mechanisms in power system operations and planning problems. We provided formal definitions for the challenging problems in energy field from operations research point of view and presented nonlinear and linear mathematical programming formulations. We also used operations research techniques to provide new solution approaches for the problems and tested both models and solution approaches on small, medium and large-scale datasets.

We first considered generation and transmission expansion planning problem with transmission switching operations for a long-term planning horizon. We proposed a mixed integer linear programming model that explicitly includes decisions related to locations and capacities of substations. We compared our results obtained by the model with the solutions obtained by using a sequential approach and showed value of adding decisions related to substations to the problem. To overcome the computational challenge and possible memory problems, we also presented a time-based solution approach. We deducted that improving network density increases the solution time of the proposed model and for these cases the proposed time-based solution approach can be utilized since it finds near optimal

solutions in shorter solution times than the solution times of the model. We also discussed the effect of transmission switching operations on planning (i.e. location and capacity) and operation decisions of the expansion planning problem.

Improving the proposed time-based solution approach may be a future research direction since it provides better results compared to the results obtained with the model and improving the solution approach may worth as savings in monetary values are large. Value of solution approach could also be tested for nonlinear demand increase. Instead of decomposing problem into a set of single-period problems, a decomposition strategy considering two-time period resolutions that has a *look-ahead possibility* may be utilized to give more flexibility to the model than it has with a single period decomposition strategy. The two-time period decomposition strategy might provide better solutions for non-monotone demand increase.

We later explored the value of co-optimizing control mechanisms to handle variability in generation from renewable energy sources. In Chapter 4, we proposed a two-stage stochastic programming model that finds locations and sizes of storages, locations of new lines and transmission switching operations subject to limitations on load-shedding and renewable energy curtailment amounts. An extensive computational study on the IEEE 24-bus power system shows that total system cost and total storage size can be decreased by as much as 17% and 50%, respectively, when switching lines are considered in the power system. Thus, we found out that switching operations can be a cheaper and efficient solution compared to building new lines or storages, and leads to higher social welfare by decreasing total cost, enhancing life quality by reducing curtailed load and using cleaner sources more in power generation.

In Chapter 4, we presented a static planning model for a target year with hourly time bucket. The proposed model can easily be adapted to the dynamic planning problem, where the time of building new lines and storage units can be determined, which will lead to a problem with more computational complexity. Thus, effective heuristics and/or sophisticated solution techniques could be future research directions to find optimal solutions for dynamic planning problem and

larger power systems.

Another future research direction is to discuss value of co-optimizing control mechanism with different set of scenarios and with respect to the number of scenarios in the model. In the computational study, we determined 5 days using a K-means algorithm to represent the target year. Different clustering methods for selecting representative days and different number of scenarios that represents the target year can be tested to analyze the sensitivity of our findings.

In Chapter 5, we developed a conceptual framework for characterizing the incentive payments to motivate consumers to reshape their load profiles. We proposed a model in which demand response programs are considered as alternatives of using peaking power plants. With an extensive computational study on a real data of the Turkish power system, we found out that offering incentives more than 5.5 times of generation cost does not change the optimal results. We also discussed the effects of different key parameters of the model on the solutions and incentive payments.

Analyzing the effect of key parameters on different real-world power systems and with different load and/or generation profiles will be a future research direction. These results can provide insights to balancing authorities about incentive payments of demand response programs. Another research area related to the incentives is to increase flexibility in the system by allowing shifting demand to earlier time periods or by changing generation profile of renewable sources with energy storage systems. The optimal solutions could also provide insights for the power systems in which demand response and storages can be utilized simultaneously.

As a final problem, we discussed reliability aspect of power system expansion planning problem and assessed the value of transmission switching operations to guarantee required reliability criterion in the power system. We presented a two-stage stochastic programming model which considers status of transmission lines as a recourse actions of our model. Results obtained on the IEEE 24-bus

power system show that considering status of transmission lines as recourse actions decreases the total system cost by as much as 10.13%. To overcome the computational complexity of the problem we also developed a scenario reduction based solution methodology and tested the model and the proposed solution approach on the IEEE 24-bus and IEEE 118-bus power systems. We then showed that our model and solution methodology are applicable to handle possible extensions such as multi-stage expansion planning and demand uncertainty. In this chapter, we also introduced a real-world data set for the 380-kV Turkish transmission network. Using the proposed solution approach, we found expansion plans that satisfy the required reliability criterion.

Probability of contingencies in this chapter are defined using forced outage rates of transmission lines. Criticality of the lines (i.e. a transmission line that connects a large power plant to the grid may be considered as a critical line even if it has a low failure rate) might also be discussed and included while determining the probabilities.

Further research of this thesis can be directed towards smart grid functions in electricity distribution and decentralized systems. Our findings and solution approaches can be extended to the problems that include operating storages and demand response programs with distributed generation sources. Effects of storages, demand-side management and renewable energy curtailment control mechanisms can also be explored on reliability requirements in these systems.

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# Appendix A

## Data in Chapter 3

Table A.1: Demand of 6-bus power system

| node        | 1  | 2  | 3  | 4  | 5  | 6  |
|-------------|----|----|----|----|----|----|
| demand (MW) | 20 | 60 | 10 | 40 | 60 | 10 |

Table A.2: Characteristics of lines for 6-bus power system

| line  | reactance (p.u) | length (km) |  | line  | reactance (p.u) | length (km) |
|-------|-----------------|-------------|--|-------|-----------------|-------------|
| (1-2) | 0.4             | 40          |  | (2-6) | 0.3             | 30          |
| (1-3) | 0.38            | 38          |  | (3-4) | 0.59            | 59          |
| (1-4) | 0.6             | 60          |  | (3-5) | 0.2             | 20          |
| (1-5) | 0.2             | 20          |  | (3-6) | 0.48            | 48          |
| (1-6) | 0.68            | 68          |  | (4-5) | 0.63            | 63          |
| (2-3) | 0.2             | 20          |  | (4-6) | 0.3             | 30          |
| (2-4) | 0.4             | 40          |  | (5-6) | 0.61            | 61          |
| (2-5) | 0.31            | 31          |  |       |                 |             |

Table A.3: Characteristics of available line types for 6-bus power system

| type | capacity (MW) | cost (\$/km) |
|------|---------------|--------------|
| 1    | 50            | 144,000      |
| 2    | 100           | 240,000      |

Table A.4: Characteristics of available generation types

| type              | 1   | 2   | 3   |
|-------------------|-----|-----|-----|
| capacity (MW)     | 200 | 400 | 600 |
| inv. cost(M \$)   | 100 | 180 | 260 |
| O&M cost (\$/MWh) | 20  | 15  | 12  |

Table A.5: Characteristics of available substations types

| type             | 1    | 2     | 3     | 4     | 5    |
|------------------|------|-------|-------|-------|------|
| capacity (MVA)   | 100  | 200   | 300   | 400   | 500  |
| inv. cost (M \$) | 8.26 | 14.92 | 19.98 | 23.44 | 25.3 |

Table A.6: Characteristics of transmission lines on the IEEE 24-bus power system

| corridor           | reactance<br>(per unit) | investment<br>cost ( $10^5\$$ ) | capacity<br>(MW) | corridor | reactance<br>(per unit) | investment<br>cost ( $10^5\$$ ) | capacity<br>(MW) |
|--------------------|-------------------------|---------------------------------|------------------|----------|-------------------------|---------------------------------|------------------|
| existing corridors |                         |                                 |                  |          |                         |                                 |                  |
| 1 - 2              | 0.0139                  | 7.04                            | 87.5             | 11 - 13  | 0.0476                  | 24.1                            | 250              |
| 1 - 3              | 0.2112                  | 106.92                          | 87.5             | 11 - 14  | 0.0418                  | 21.16                           | 250              |
| 1 - 5              | 0.0845                  | 42.78                           | 87.5             | 12 - 13  | 0.0476                  | 24.1                            | 250              |
| 2 - 4              | 0.1267                  | 64.14                           | 87.5             | 12 - 23  | 0.0966                  | 48.9                            | 250              |
| 2 - 6              | 0.192                   | 97.2                            | 87.5             | 13 - 23  | 0.0865                  | 43.79                           | 250              |
| 3 - 9              | 0.119                   | 60.24                           | 87.5             | 14 - 16  | 0.0389                  | 19.7                            | 250              |
| 3 - 24             | 0.0839                  | 42.47                           | 200              | 15 - 16  | 0.0173                  | 8.76                            | 250              |
| 4 - 9              | 0.1037                  | 52.5                            | 87.5             | 15 - 21  | 0.049                   | 24.81                           | 250              |
| 5 - 10             | 0.0883                  | 44.7                            | 87.5             | 15 - 24  | 0.0519                  | 26.27                           | 250              |
| 6 - 8              | 0.0614                  | 31.08                           | 87.5             | 16 - 17  | 0.0259                  | 13.11                           | 250              |
| 6 - 10             | 0.0605                  | 30.63                           | 87.5             | 16 - 19  | 0.0231                  | 11.7                            | 250              |
| 7 - 8              | 0.0614                  | 31.08                           | 87.5             | 17 - 18  | 0.0144                  | 7.29                            | 250              |
| 8 - 9              | 0.1651                  | 83.58                           | 87.5             | 17 - 22  | 0.1053                  | 53.31                           | 250              |
| 8 - 10             | 0.1651                  | 83.58                           | 87.5             | 18 - 21  | 0.0259                  | 13.11                           | 250              |
| 9 - 11             | 0.0839                  | 42.47                           | 200              | 19 - 20  | 0.0396                  | 20.05                           | 250              |
| 9 - 12             | 0.0839                  | 42.47                           | 200              | 20 - 23  | 0.0216                  | 10.93                           | 250              |
| 10 - 11            | 0.0839                  | 42.47                           | 200              | 21 - 22  | 0.0678                  | 34.32                           | 250              |
| 10 - 12            | 0.0839                  | 42.47                           | 200              |          |                         |                                 |                  |
| new corridors      |                         |                                 |                  |          |                         |                                 |                  |
| 1 - 8              | 0.1344                  | 35                              | 87.5             | 14 - 23  | 0.062                   | 86                              | 250              |
| 2 - 8              | 0.1267                  | 33                              | 87.5             | 16 - 23  | 0.0822                  | 114                             | 250              |
| 6 - 7              | 0.192                   | 50                              | 87.5             | 19 - 23  | 0.0606                  | 84                              | 250              |
| 13 - 14            | 0.0447                  | 62                              | 250              |          |                         |                                 |                  |

# Appendix B

## Results of Chapter 5

Table B.1: ESS locations with maximum energy capacity common to the ESS and ESS-TS cases

|          |             | $p^{rec}$      |              |              |              |              |              |              |
|----------|-------------|----------------|--------------|--------------|--------------|--------------|--------------|--------------|
|          |             | 0.20           | 0.25         | 0.30         | 0.35         | 0.40         | 0.45         | 0.50         |
| $p^{ls}$ | <b>0.05</b> | 3,5,7,21,23,24 | 5,7,20,21,23 | 5,7,21,22,23 | 5,7,21,22,23 | 5,7,21,22,23 | 5,7,21,22,23 | 5,7,21,22,23 |
|          | <b>0.10</b> | 3,5,7,21,22,23 | 3,5,7,21     | 5,7,23       | 5            | 5            | 5            | 5            |
|          | <b>0.15</b> | 3,5,7,21,22,23 | 3,5,7,21     | 3,5,7,21,23  | 5,7          | —            | —            | —            |
|          | <b>0.20</b> | 3,5,7,21,22,23 | 5,7,21       | 5,7,21,23    | 5,7          | —            | —            | —            |
|          | <b>0.25</b> | 3,5,7,21,22,23 | 3,5,7,21     | 3,5,7,21,23  | 5,7          | —            | —            | —            |
|          | <b>0.30</b> | 3,5,7,21,22,23 | 3,5,7,21     | 3,5,7,21,23  | 5,7          | —            | —            | —            |
|          | <b>0.35</b> | 3,5,7,21,22,23 | 3,5,7,21     | 3,5,7,21,23  | 5,7          | —            | —            | —            |
|          | <b>0.40</b> | 3,5,7,21,22,23 | 3,5,7,21     | 3,5,7,21,23  | 5,7          | —            | —            | —            |

Table B.2: ESS locations with maximum power rating common to the ESS and ESS-TS cases

|          |             | $p^{rec}$  |      |       |      |      |      |      |
|----------|-------------|------------|------|-------|------|------|------|------|
|          |             | 0.20       | 0.25 | 0.30  | 0.35 | 0.40 | 0.45 | 0.50 |
| $p^{ls}$ | <b>0.05</b> | 3,21,23    | 21   | —     | —    | —    | —    | —    |
|          | <b>0.10</b> | 3,21,22,23 | 21   | —     | —    | —    | —    | —    |
|          | <b>0.15</b> | 3,21,22,23 | 21   | 21,23 | —    | —    | —    | —    |
|          | <b>0.20</b> | 3,21,22,23 | 21   | 21,23 | —    | —    | —    | —    |
|          | <b>0.25</b> | 3,21,22,23 | 21   | 21,23 | —    | —    | —    | —    |
|          | <b>0.30</b> | 3,21,22,23 | 21   | 21,23 | —    | —    | —    | —    |
|          | <b>0.35</b> | 3,21,22,23 | 21   | 21,23 | —    | —    | —    | —    |
|          | <b>0.40</b> | 3,21,22,23 | 21   | 21,23 | —    | —    | —    | —    |

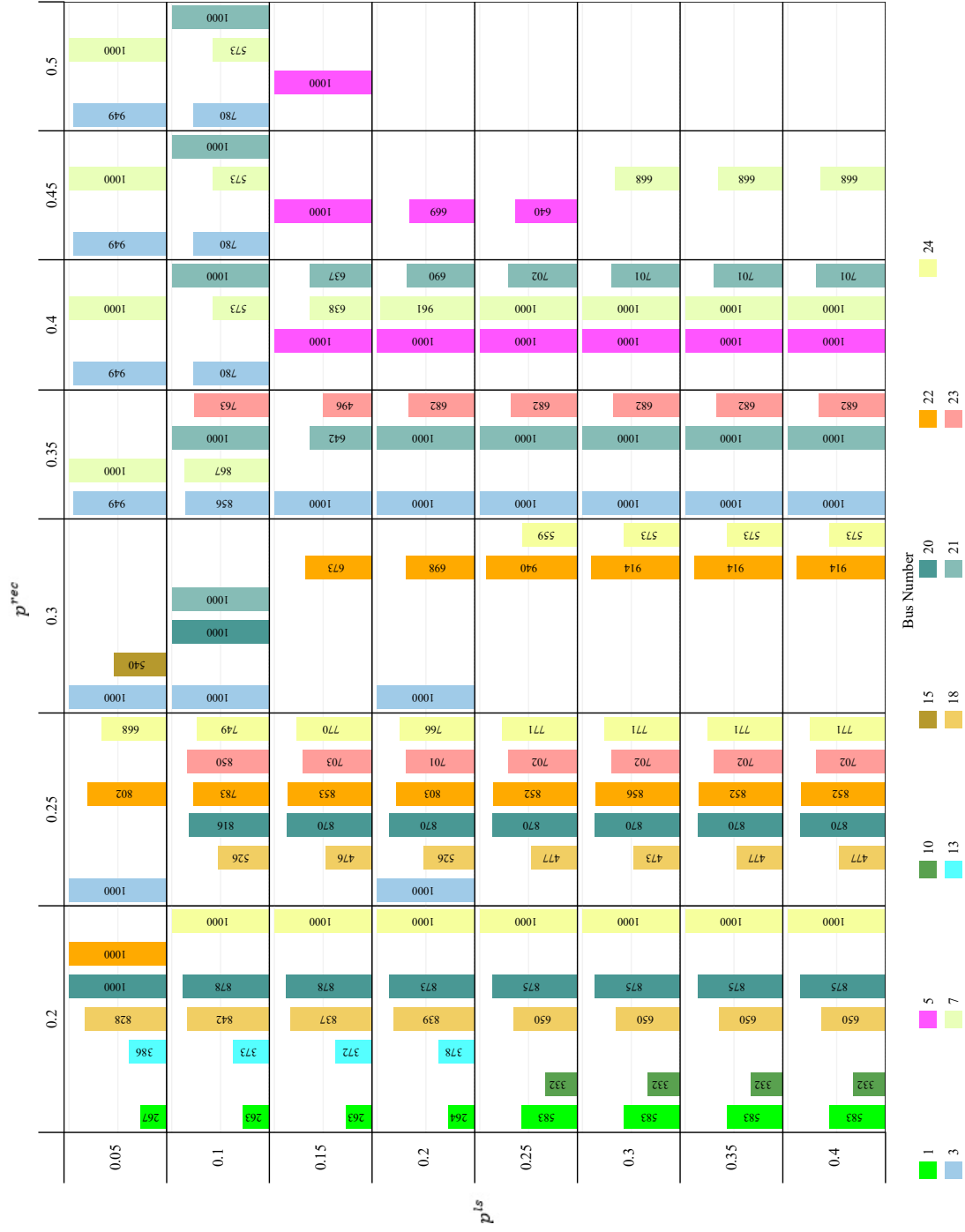


Figure B.1: ESS locations and energy capacities (MWh) for the ESS case.

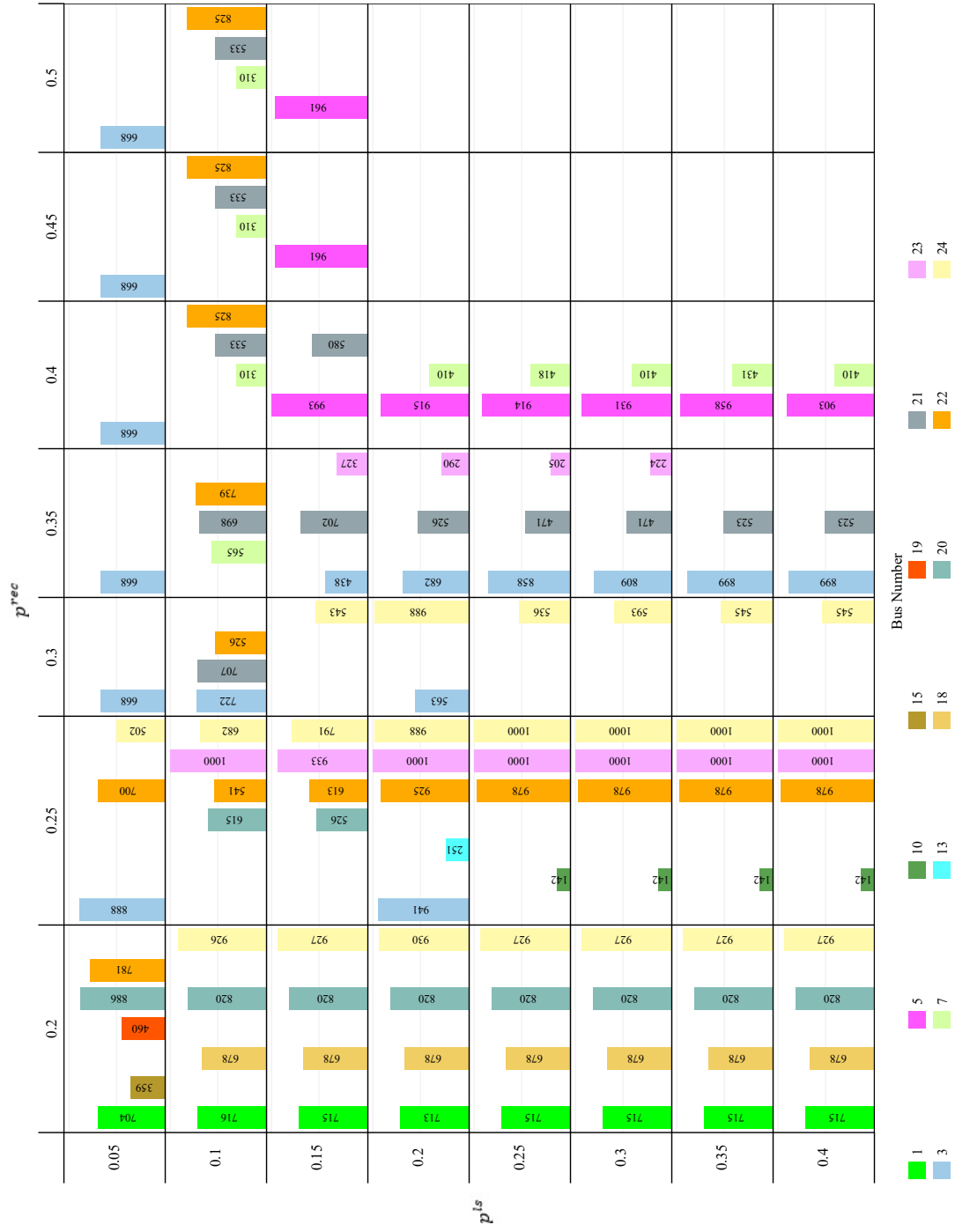


Figure B.2: ESS locations and energy capacities (Mwh) for the ESS-TS case.



Figure B.3: ESS locations and power ratings (MW) for the ESS case.

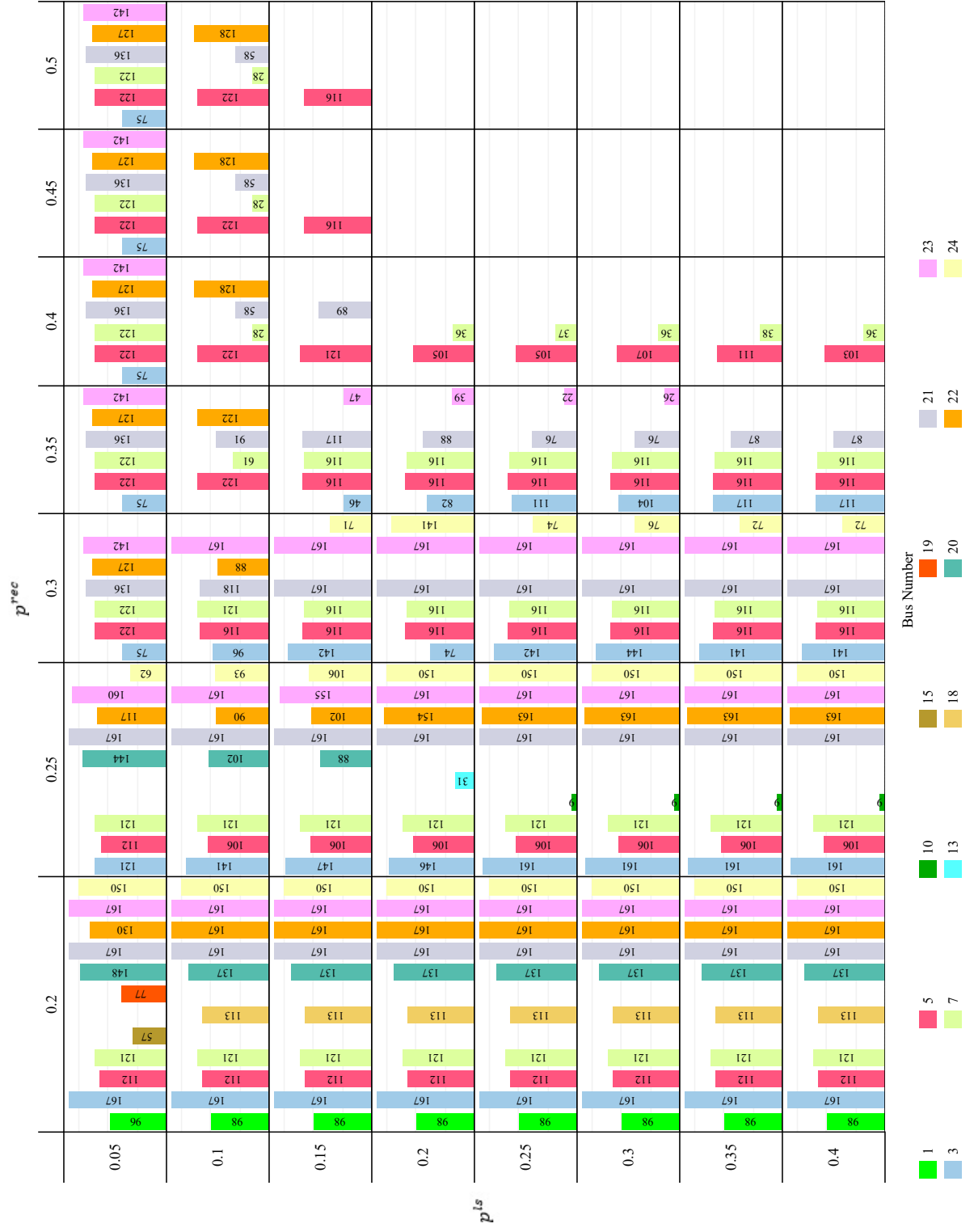


Figure B.4: ESS locations and power ratings (MW) for the ESS-TS case.