CONGESTION-DRIVEN TRANSMISSION PLANNING CONSIDERING INCENTIVES FOR GENERATOR INVESTMENTS

A THESIS SUBMITTED TO
THE GRADUATE SCHOOL OF NATURAL AND APPLIED SCIENCES
OF
MIDDLE EAST TECHNICAL UNIVERSITY

BY

OSMAN BÜLENT TÖR

IN PARTIAL FULFILLMENT OF THE REQUIREMENTS
FOR
THE DEGREE OF DOCTOR OF PHILOSOPHY
IN
ELECTRICAL AND ELECTRONICS ENGINEERING

JUNE 2008

Approval of the thesis:

"CONGESTION-DRIVEN TRANSMISSION PLANNING CONSIDERING INCENTIVES FOR GENERATOR INVESTMENTS"

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ABSTRACT

CONGESTION-DRIVEN TRANSMISSION PLANNING
CONSIDERING INCENTIVES FOR GENERATOR INVESTMENTS

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June 2008, 152 Pages

This thesis study focuses on transmission expansion planning (TEP) problem for restructured power systems and addresses challenges specifically in countries where electricity market is in developing phase after liberalization of power industry for establishing a competitive market, like Turkey. A novel multi-year TEP approach is developed which considers generation investment cost and transmission congestion level in the planning horizon. The model assesses the impact of generation investments on TEP problem. Benders decomposition methodology is utilized successfully to decompose the complex mixed-integer programming TEP problem into a master problem and two subproblems. Security subproblem assesses single-contingency criteria. Transmission congestion cost is considered within operational subproblem given that congestion level is a proper criterion for measuring competitiveness level of an electricity market. The proposed approach is applied to the Turkish power system.

The proposed approach could be utilized to provide indicative plans, which might be quite necessary particularly during development of a competitive market. However, there is no guarantee that independent power producers (IPPs) will follow those plans which concern the maximization of social-welfare. Given the necessity of coordinating monopoly transmission and decentralized generator investment decisions, the proposed approach is improved further to include promoting decentralized generator investments through incentive payments. Such incentives might be necessary to trigger IPPs earlier than their projections, as illustrated by numerical examples including IEEE 30-bus system.

Keywords – Benders decomposition, Coordinated planning, Electricity restructuring, Independent power producers, Decentralized generation, Multi-year transmission expansion, Transmission congestion, Transmission security.

ÖZ

GENERATÖR YATIRIMI TEŞVİKLERİNİ GÖZ ÖNÜNE ALAN
GÜVENLİK ODAKLI İLETİM PLANLAMASI

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Haziran 2008, 152 Sayfa

Elektrik sektöründe yeniden yapılanma sonrası karmaşık bir hale gelen iletim sistemi planlama (İSP) problemine odaklanan bu tez çalışmasında, rekabetçi bir elektrik piyasasının henüz gelişme sürecinde olduğu Türkiye gibi ülkelerdeki İSP problemi ele alınmıştır. Generatör yatırımlarının iletim yatırımlarına etkisini değerlendirilebilmek amacıyla, generatör yatırımı ve iletim kısıtlılıkları maaliyetlerini değerlendiren çok-yıl bazlı (dinamik) yeni bir İSP modeli geliştirilmiştir. Bir karma-tamsayılı-programlama problemi olan İSP, Benders ayrışım tekniği kullanılarak bir ana problem (yatırım) ve iki adet yardımcı problemlere (güvenlik ve optimum işletme) başarılı bir biçimde ayrıştırılmıştır. Güvenlik problemi şebeke elemanlarından tekinin kaybı kriterini değerlendirmektedir. Bir elektrik piyasasında iletim sistemindeki kısıtlamaların seviyesi piyasadaki rekabet seviyesinin bir ölçüsüdür düşüncesiyle, iletim darboğaz maaliyetleri optimum işletme problemi olarak ele alınmıştır. Geliştirilen yöntem Türkiye güç sistemine uygulanmıştır.

Geliştirilen İSP yöntemi ile piyasa katılımcılarına ve otoritelere bilgi amaçlı sistem genişleme planlamaları hazırlanabilir. Bu, - özellikle de rekabete dayalı bir

piyasanın gelişme sürecinde - oldukça yararlı, hatta elzem olabilir. Fakat, sosyal refahı gözeterek hazırlanan bu planlamaların, kar gözeten bağımsız elektrik üreticileri (BEÜ) tarafından takip edilmesinin garantisi yoktur. Önerilen İSP modeli, halen tekel olan iletim ve deregülasyon sonrası artık tekel olmayan üretim planlamalarını koordine etmek amacıyla, BEÜ'ler tarafından gerçekleştirilecek yatırımları teşvik etmeyi de kapsayacak şekilde geliştirilmiştir. Yatırım kararı almayı bekleyen BEÜ'leri harekete geçirmek amaçlı bu tür yatırım teşviklerinin, sistem güvenliği ve sosyal refah için, özellikle de piyasanın olgunlaşma döneminde oldukça gerekli olabileceği sayısal örneklerle (IEEE 30-baralı sistem) gösterilmiştir.

Anahtar kelimeler – Benders ayrışımı, Bağımsız elektrik üreticileri, Çok yıla dayalı iletim planlama, Elektrik sektöründe yeniden yapılanma, İletim darboğazı, İletim güvenliği, Koordine planlama, Merkezi olmayan elektrik üretimi.

To My Family

ACKNOWLEDGMENTS

I wish to express my deepest gratitude to my worthy supervisor Prof. Dr. Nezih Güven for his guidance, encouragement and support throughout my research, and trust in me during my academic career. I would like to express my sincere gratitude to Prof. Dr. Mohammad Shahidehpour for his guidance, support and encouragement during my research studies in Illinois Institute of Technology (IIT), Chicago, USA, and insight throughout my research.

I would like to express my gratitude to my worthy instructor Prof. Dr. Nevzat Özay for his endless guidance and support whenever I need, and suggestions for the research. I would also like to express my gratitude to Prof. Dr. Arif Ertaş for teaching me fundamentals of power system engineering and encouraging me in my doctoral program in METU, and to Prof. Dr. Osman Sevaioğlu for the contributive discussions regarding the challenges with the electricity restructuring progress in Turkey. I would like to thank to Prof. Dr. Cengiz Taplamacıoğlu for his worthy suggestions for the research.

I would like to thank to my coordinator Abdullah Nadar in TÜBİTAK–UZAY for his support, encouragement and insight. I would also like to thank my project colleagues Ulaş Karaağaç, Oğuz Yılmaz, Mahmut Erkut Cebeci, and Müfit Altın for their supports and insights. I would also like to thank all the other members of Hardware Development and Power System Group of TUBITAK-UZAY for advices and providing a friendship environment. The facilities provided by TÜBİTAK-UZAY and TEİAŞ are gratefully acknowledged.

Last but not least, my special gratitude goes to my wife Senem for her love and support and to our daughter Perim for their patience also during periods when this research took a lot of my spare time.

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LIST OF ABBREVIATION

All chapters (the most frequent ones):

TEP	Transmission expansion planning
AOCC	Additional operation cost due to congestion
TSO	Transmission system operator
ISO	Independent system operator
GENCO	Generator company
EPI	Electric power industry
TUoS	Transmission use of system
IRP	Integrated resource planning
SBM	Single buyer model
T&G	Transmission and generation

Chapter 3:

b	Load duration block index
B	Number of load duration blocks
i	Existing or candidate generator index
j	Existing or candidate line index (from bus m to n)
k	Bus index
t	Year index along the planning horizon
n	Benders iteration index
q	N-1 contingency index
T	Planning horizon (year)
CG	Number of candidate generators

CL Number of candidate transmission lines

NG Number of committed generators

N Number of bus

$PG_{i,\max}$ Capacity of generator i (MW)

$PG_{i,\min}$ Lower limit of generator i (MW)

$PG_{i,bt}$ Dispatched capacity of generator i at subperiod b in year t (MW)

$PL_{j,\max}$ Capacity of line j (MW)

$PL_{j,bt}$ Flow on line j at subperiod b in year t (MW)

$PC_{k,bt}$ Curtailment at bus k at subperiod b in year t (MW)

DT_{bt} Duration of subperiod b in year t (h)

$OC_{i,bt}$ Operating costs of generator i at subperiod b in year t ($/MWh)

$AOCC_{bt}$ Total additional operation cost due to congestion at subp. b in year t ($)

γ_{mn} Line susceptance in vector form (from bus m to n)

θ Bus angle

θ_{ref} Reference bus angle

$\boldsymbol{d}$ Node load in vector form

$\boldsymbol{f}$ Power flow in vector form

$\boldsymbol{p}$ Bus real generation in vector form

$\boldsymbol{r}$ Load curtailment in vector form

$\boldsymbol{s}$ Node-branch incidence matrix

$\boldsymbol{1}$ Vector of ones

CI_{it} Capital investment cost of generator i in year t ($)

CI_t Total capital investment in year t ($)

CI_{jt} Capital investment cost of line j in year t ($)

CT_i Required construction time for candidate generator i

CT_j Required construction time for candidate line j (year)

UC_t Upper limit for line capacity added in year t (MW)

UN_t Upper limit for the # of lines added in year t

X_{it} Investment status of candidate generator i in year t, 1 if installed, o.w. 0

X_{jt} Investment status of candidate line j in year t (0 or 1)

Chapter 4:

b Index for subperiod

d Discount rate

i Index for generator (existing and candidate)

j Index for bus

k Index for line (from bus m to bus n)

n Benders iteration index

q Single contingency index

t Year index

CL Number of candidate transmission lines

NCG Number of candidate generators (i.e., IPPs)

NG Number of existing generators

ND Number of buses

NS Number of subperiods

NT Number of planning year

$P_{G,i}^{\max}$ Generator capacity of existing generator i (MW)

$P_{G,i}^{\min}$ Operational limit of existing generator i (MW)

$P_{GC,i}^{\max}$ Generator capacity of candidate generator i (MW)

$P_{GC,i}^{\min}$ Operational limit of candidate generator i (MW)

$PL_{k}^{\max}$ Capacity of line k (MW)

α_i Profit coefficient of IPP i (%)

θ Bus angle

θ_{ref} Reference bus angle

CI_{it} Capital investment cost of IPP i in year t (\$/yr)

CI_{kt} Capital investment cost of transmission line k in year t (\$/yr)

CI_t Total transmission capital investment in year t (\$/yr)

DT_{bt} Duration of subperiod b in year t (h)

OC_{ibt} Operating costs of existing IPP i at subperiod b in year t (\$/MWh)

$OC_{GC,ibt}$ Operating costs of candidate IPP i at subperiod b in year t (\$/MWh)

$AOCC_{bt}$ Additional operation cost due to congestion at subperiod b in year t (\$/yr)

$P_{G,ibt}$	Dispatched capacity of existing generator *i* at subp. *b* in year *t* (MW)
$P_{GC,ibt}$	Dispatched capacity of cand. generator *i* at subp. *b* in year *t* (MW)
$P_{C,jbt}$	Load curtailment at bus *j* at subp. *b* in year *t* (MW)
PL_{kbt}	Line flow on line *k* at subperiod *b* in year *t* (MW)
R_{ibt}	Energy sales price of existing IPP *i* at subp. *b* in year *t* ($/MWh)
$R_{C,ibt}$	Energy sales price of candidate IPP *i* at subp. *b* in year *t* ($/MWh)
IP_{it}	Incentive payment to IPP *i* in year *t* ($/yr)
X_{it}	Installation status of cand. generator of IPP *i* in year *t*, 1 if installed, o.w. 0
X_{kt}	Investment status of candidate line *k* in year *t* (0 or 1)
CT_k	Required construction time for candidate line j (year)
UC_t	Upper limit for line capacity added in year *t* (MW)
UN_t	Upper limit for the # of lines added in year *t*
$\boldsymbol{d}$	Node load in vector form
$\boldsymbol{f}$	Power flow in vector form
$\boldsymbol{p}$	Bus real generation in vector form
$\boldsymbol{r}$	Load curtailment in vector form
$\boldsymbol{s}$	Node-branch incidence matrix
$\boldsymbol{1}$	Vector of ones

CHAPTER 1

INTRODUCTION

The electricity industry throughout the world, which has long been dominated by vertically integrated utilities, is undergoing enormous changes. The electricity industry is evolving into a distributed and competitive industry in which market forces drive the price of electricity and reduce the net cost through increased competition. Restructuring has necessitated the decomposition of the three components of electric power industry: generation, transmission, and distribution. An independent operational control of transmission grid in a restructured industry could facilitate a competitive market for power generation and direct retail access [1]-[3].

In deregulated electricity markets, the transmission network is the interface where buyers and sellers interact with each other. In a competitive environment, the transmission network not only serves as physical route to deliver electrical power, but also causes a strong externality which may prevent perfect competitions among market participants. Any form of transmission constraints in the transmission network will prevent perfect competition between market participants. This ultimately gives rise to market power and leads to price hikes above marginal costs, as experienced in some markets [3]. Therefore, it is very important to make effective operation and expansion plan of the transmission system.

Transmission expansion planning (TEP) is the process of designing future network configurations that meet predicted future needs. Traditionally, utilities have served peak demand by building central generation and transmission infrastructure. Coordination between generation resource and transmission planning was to minimize the operation cost and investment involving new generating units and transmission lines while satisfying the system security. Taking advantage of the coordination, peak load could be served at a lower overall cost by utilizing a combination of expansion options [4].

The liberalization and restructuring process worldwide have introduced new complexities to the TEP problem [5]-[7]. This movement introduced competition at the extreme activities of the industry (i.e., generation and retailing) while keeping network transmission and distribution areas as natural monopolies. TEP must now be prepared in a decoupled way from generation and distribution despite their natural and indispensable dependency. This means that, in some way, transmission networks will now have to run after new users both at the generation and the demand side, introducing a new level of uncertainty regarding the TEP. However, there is an inherent and indispensable dynamic relation between generation and transmission planning that need to be captured in the evaluation of transmission projects.

In specific electricity markets, generation expansion remains to be a political issue with certain legal requirements for generation expansion planning, in particular during the market development phase after restructuring. This will probably continue until the market has developed to a certain level such that competition among participants is solely sufficient driving factor for generation expansion, like the USA markets. Certain European countries, including Turkey, are considered as such examples in which most of the transmission network-related activities after restructuring are conducted within an integrated framework [1]. That is, both ownership and system operation are carried out by a state-owned transmission company under regulation. Such integrated state-owned companies are generally responsible to prepare *indicative* plans for the *network* expansion (i.e., both transmission and generation; T&G) considering the supply security (often called reliability) and economical operation of the network. These are indeed the two main objectives for establishing an electricity market: ensuring supply security and facilitating an economical operation by competitive forces.

The organizational structure regarding transmission services could be different from country to country depending on the unbundling degree of the market and the historical development of the sector. The integrated form (i.e., ownership and operation) of transmission organization is often called as *state-owned* transmission system operator (TSO) in most of European countries. On the other hand, in USA electricity markets, *non-utility* transmission companies (often reffered as TRANSCOs) are the owners of the transmission system at specific regions where the system operation is performed by independent system operators (ISOs). Transmission service organizations and their responsibilities after restructuring of power systems are discussed in Chapter 2 in more details.

Since transmission system operation is provided as a monopoly due to its inherent monopoly characteristic, system operation activities are being regulated from technical and economic point of view. In the integrated organizational case, *ownership* related facilities (i.e., transmission planning, investments, maintenance, etc.) are due to regulation as well. The state-owned transmission company must plan the grid according to a number of indices specified by the regulatory agency [1]. Essentially, the least cost planning approaches, which take into account the most suitable options for the grid planning, including both the transmission and generation investments, should be prepared by the company in order to convince the authorities. This is the case in Turkey where the state-owned transmission company, Türkiye Elektrik İletim AŞ (TEİAŞ), is responsible for the grid expansion in an optimal manner indeed, although generation expansion is the problem of competitive non-utility companies. Its activities are being regulated by the regulatory authority of the country, Enerji Piyasası Denetleme Kurulu (EPDK) [8]. The electricity market design of Turkey and the responsibilities of both state-owned transmission company and the regulatory authority are discussed in Chapter 2 in the context of the TEP problem.

This thesis study is dealing with the TEP issue after restructuring of power systems considering the roles of regulatory authority, transmission service company and competitive generation companies in the network expansion. In the literature, the recent transmission planning related studies have focused rather on *market-based* TEP approaches which consider costs associated with investment, operation, congestion, load curtailment, and system security. Shrestha and Fonseka presented a framework for the transmission network expansion planning in a competitive market, which takes into account approaches for *congestion* cost saving and upper-bounds for congestion revenues [9]. The study proposes a combination of the two criteria to find an optimal congestion level in transmission planning. Buygi *et al* proposed a TEP approach which facilitates market competition and provides nondiscriminatory access to the least cost dispatch by enabling a flat price profile throughout the transmission network [10]. The flatness of locational price profile, which essentially means lack of congestion, is taken as the proper criterion for measuring the degree of competitiveness of the transmission network. Zu *et al* proposed a hybrid multi-objective planning method for transmission expansion with security assessment [11]. Multiple market operation and planning objectives are tackled simultaneously in the proposed approach by using goal programming techniques. Fang and Hill [12] developed a new strategy to handle future generation and load patterns in a competitive market environment. The popularity of considering *transmission congestion* in the recent publications, which deal with TEP problems for competitive markets, is noticable. This could be explained as follows.

In order to mitigate transmission congestions in the network, it is desirable that generation be places as close as possible to the demand centers. In practice, demand centers are physically located in urban areas where generation capacity additions are difficult. This results in suboptimal placement of generation with possible transmission congestion and load pockets with high price volatility. Transmission congestion (also referred as 'constraints'/'bottlenecks') will restrict flow of power from low cost nodes to high value nodes creating supply-demand price imbalances. The presence of congestion on one circuit produces price differentials not only across this circuit, but also across many other non-congested circuits as well. In short, congestion means more trade is desired than what can be supported by available transmission facilities. Consequently, transmission congestion has become an important yardstick to evaluate the network adequacy, and therefore it has begun to be considered within network expansion planning problems in competitive markets [9].

The ability of transmission planners and regulators to control the direction of the *decentralized* investments towards the desired social optimum is among the major challenges after the deregulation of generation industry. Some mechanisms have been introduced worldwide to provide locational signals to guide market participants to achieve this. An example can be given from Turkey where generation segment has been decentralized after opening a bilateral contract based market in 2001. The entire transmission network, which is both owned and operated by the state-owned company TEIAS, has been separated into different zones of transmission-use-of-system (TUoS) charge with a uniform tariff within each zone. The intention is to send long-term signals for the positioning of new generators and loads in the transmission grid so as to postpone transmission network reinforcements as far as possible. However, according to the recent regulatory figures, this mechanism has not provided sufficient incentive for generation companies since its procurement [1], [8].

The uncertainty problem in generation expansion after restructuring of power systems, which is indeed among the most challenging issue of TEP in the new environment, has been considered by many authors. Botterud *et al* presented a stochastic dynamic generator investment model which offers a comprehensive treatment of long-term uncertainties and their influence on optimal generator investment decisions in a competitive environment [13]. The proposed model assesses optimal investment strategies when the increase in demand, and thereby future prices, are uncertain. However, it considers only the generator investment decision and ignores its close linkage with transmission expansion. Braga and Saraiva [14] described an integrated approach to identify adequate TEP together with setting tariffs for the use of transmission networks based on long-term marginal costs (LTMCs). The basic idea is that the transmission investments should be adequate as they have a direct impact on consumer tariffs. The proposed

TEP problem considers a *generation* investment forecast, which is already made *in advance*, and it tries to find an optimum transmission expansion to meet the load forecast under such a generator expansion assumption. Given the uncertainty in the generation expansion, the proposed approach could essentially result in a suboptimal TEP solution.

This thesis study proposes a novel multi-year TEP model which considers the transmission congestion and the impact of generation investments in the planning horizon. The multi-year (also referred as 'dynamic') TEP is a complex mixed integer programming (MIP) problem, as discussed in Chapter 2. In order to solve this problem, 'Benders decomposition methodology' is utilized which decomposes TEP into a *master* problem (i.e., minimizing the investment cost; an integer-programming-problem) and two subproblems representing *security* and *optimal operation* both of which are continuous-programming-problems [15]. The security subproblem assesses the single-contingency criteria. The concept of total 'additional operation cost due to congestion' (AOCC) is introduced in the optimal operation subproblem of the proposed model, given the importance of congestion level for developing markets. The proposed planning model evaluates sensitivity of the optimal TEP to congestion level, planning horizon, and financial constraints. It provides long-term *indicative plans* to the interested parties including the market participants and the regulatory authorities.

It is presented with numerical examples that the annual evaluation of transmission investments and congestion level along with local generation investment costs enables more realistic assessments of generation and transmission investment decisions. Although the proposed integrated solution provides an optimum planning solution for the *network* expansion (i.e., an indicative T&G expansion plan), there is no guarantee that the market participants will follow the proposed options in a competitive environment. After opening generation activities to competition, the main objective of a generation investment planning problem performed by independent power producers (IPPs) (also referred as 'non-utility investors') is essentially to maximize profit from the investment.

A generation investment project is profitable for an investor if the difference between the expected revenue (product of the price and the expected amount of electricity sales) and expenses (capital and operating costs) is positive. Internal rate of return (IRR) is a popular concept for measuring project returns considering the discounted benefits [16]. Optimum timing of a non-utility generator investment is generally based on the expected energy sale, which depends on the energy sale price and the expected operation (i.e., dispatch) of the generator. If a generator investor could foresee the amount of energy sale for a predefined energy sale price, then the investment decision would be simply forecasting the IRR from the procurement.

In contrast, the objective of a regulatory body or the system operator (or the state-owned transmission company like in Turkey) is to operate the system reliably by supplying the load economically while managing contingencies. Coordination of the two objectives (i.e., monopoly transmission and decentralized generation planning decisions) is essential in optimum system planning which is a formidable task after decentralization of generation investments [17]-[19]. Considering this requirement, new methods have been proposed to coordinate T&G expansion to optimize the long-term network planning in competitive markets.

Roh *et al* proposed a model that brings transmission and electricity market into the sphere of long term generation resource planning [17]. Security payments to generation companies (GENCOs) by ISO are proposed for supplying the load and satisfying the network security in a competitive market. It is presented within an example that a proper expansion of transmission capacity could contribute to reduction of ISO’s security payment to GENCOs. The study points out the important necessity for coordinating transmission and decentralized generation planning decisions.

In response to this and to direct competitive market participants through optimum plans which concern maximization of the social-welfare in the sense of system security, the proposed TEP method is improved further. After some modifications, the TEP model gauges the level of transmission congestion and security with respect to transmission investments while considering the promotion of generator investments within the planning problem through *incentive* payments. It is presented that such incentives might be necessary to trigger generator investments earlier than the decentralized projections which might threat power system security in particular during the development of the competitive market. Benders decomposition technique is utilized successfully to optimize the sum of transmission investment cost, incentive payments to IPPs and the congestion level along the planning horizon, as illustrated by numerical examples. The proposed planning model is applicable to power systems after restructuring, in particular when uncertainties in the sector could result in delay of generator investment decisions by the IPPs. It inherently addresses the concern of whether the market participants would follow the indicative plans or not.

The thesis is organized as follows. Chapter 2 reviews the TEP issues in a general perspective and addresses challenges in developing markets, focusing on Turkey where the liberalization of the electric power industry is underway for establishing a competitive electricity market. In this thesis study, Turkey is referred many times as an example country which has to deal with network planning challenges connected with electricity restructuring and unbundling of the power industry. Essentially, this research study focuses TEP concerns particularly for developing markets, rather than developed markets like those in USA in which T&G investments are driven by solely competitive forces [3].

Chapter 3 presents a novel planning model for considering the transmission system security and congestion level in the long-term multi-year TEP problem. A planning framework is proposed which evaluates the impact of potential generation investments on the optimum TEP. In Chapter 4, the TEP model that proposed in Chapter 3 is developed further to consider the promotion of generator investments through incentive payments within the planning problem to coordinate *monopoly* transmission and *decentralized* generator investment planning decisions. The conclusions drawn from this thesis study are given in Chapter 5.

Appendix-A presents the definitions and theorems of ‘Benders decomposition methodology’ which is utilized in developing the multi-year TEP algorithms as described in Chapters 3 and 4. The information is quite useful for those readers who are interested in utilizing such decomposition techniques to handle any kind of mixed integer programming (MIP) problems. Appendix-B and C present the Turkish system data and the modified IEEE 30-Bus data, respectively, which are utilized in case studies of Chapter 3 and 4. Appendix-D includes solutions of the numerical examples presented in Chapter 4. Optimum planning solutions of some case studies are presented in tables separately, which include the planning cost, investment status of candidate investments and economic dispatch along the planning horizon. Data of the other case studies are already provided in corresponding sections of the Chapters 3 and 4.

CHAPTER 2

TRANSMISSION EXPANSION PLANNING PROBLEM AFTER RESTRUCTURING OF POWER SYSTEMS

2.1. Introduction

Transmission systems signify an interconnected group of lines and associated equipments for the transfer of electricity at high voltage between supply and delivery points. In today's restructured power industry, transmission system has become the market place for trading electricity by furnishing the required environment for competition among market participants. Regardless of the market mechanism introduced after restructuring of power systems, an adequate transmission capacity is needed for a wide range of correlated reasons that can be broadly categorized as follow:

- **Technical Issues:** Transmission systems must withstand critical system disturbances or contingencies by operating reliably within specified thermal, voltage, and stability limits. If the transmission capacity of a power system that consists of several regions is inadequate in the event of emergencies in one region, the available generation in other regions may not be able to supply the backup energy to the faulted region.

- **Financial Issues:** Costs involved in using the transmission system can be classified into two main categories that are closely linked: *direct* and *indirect* costs [20]. Direct costs are capital, operation, and maintenance costs. Indirect costs are associated with system operations including line losses (i.e., i^2R losses), cost of mitigating transmission congestion (i.e. re-dispatch cost), and the cost of ancillary services that are used by system operators to maintain the system reliability [3]. Direct costs could impact indirect costs severely in a constrained network. In essence, if transmission constraints persist due to an inadequate transmission capacity, regional generation resources cannot support the minimum load dispatch or the reliability requirement in neighboring utilities. It is conceivable that the regional economy would be linked strongly to improving wholesale competition and trading opportunities in electricity markets.

Transmission expansion planning (TEP) addresses the problem of expanding and enforcing an existing transmission network for serving the growing demand subject to a set of economical and technical constraints. Traditionally, TEP was accomplished by vertically integrated utilities based on centralized generation and transmission planning which was a part of an *integrated resource planning* (IRP). The primary objective of IRP was to identify the type, location, and scale of new facilities for delivering power from generating plants to load centers at the lowest cost and to ensure that loads are served reliably. Since vertically integrated electric utilities have been regulated and regulators have guaranteed full investment recovery and return in transmission expansion, there was no transmission investment risk (or the risk is limited to ensure efficient transmission services). In a competitive environment, however, generation planning is mainly a decision-making process made by generating companies or investors, and transmission planning is made separately in response to expected changes in generation and load patterns. Today, main targets of transmission services include the maximization of energy trade opportunities among market participants in addition to satisfying reliability requirements [3], [18].

Traditionally, the transmission network expansion planning problem, though it has a *dynamic* nature, as described in Section 2.7, has been often simplified by the planners to a mathematical model for solving a *static* transmission problem. In this traditional approach, the aim is to determine *where* and *how many* new circuits are needed and should be installed at the minimum investment cost, subject to operational constraints, to meet the power system requirements for a *single future demand* and the generation confirmation expected in some future year [21]. Such a transmission planning model is based on the scenario that generation planning is in integral part of a centralized power system planning and that generation dispatch is fully controlled by an authorized central organization. However, this has been changed in a deregulated market where the closed link between generation planning and transmission planning no longer exists and the transmission planner may not control location, timing, and dispatch parameters of new generators. This situation needs to be properly considered in the transmission planning problem.

This chapter addresses TEP issues in a general perspective and points out transmission expansion challenges after restructuring of power systems. Some recommendations are given directed to ensuring adequate transmission expansion particularly for those countries like Turkey, where electricity reforms are underway toward a competitive electricity market. In a competition era, transmission expansion will be more difficult than before in such countries because of additional uncertainties and corresponding risks due to ongoing electricity liberalization processes. Therefore, there is a clear need for research on a number of fronts to ensure that the transition to an open and competitive market is made without jeopardizing to power system security and adequacy.

Sections 2.3-2.7 present the main issues with transmission planning after deregulation of power systems. Before these, in order to comprehend the challenges connected to deregulation of power industry, the following section summarizes the history of liberalization efforts in electricity sector worldwide, focusing on the developments in Turkey.

2.2. Electricity Restructuring and Market Design

In many countries across the globe, electricity services have historically been supplied by vertically integrated enterprises encompassing generation, transmission, and distribution activities. Such enterprises are managed as monopolies under public ownership. The performance of these regulated monopolies has varied widely across countries. Many developing countries have nevertheless faced common problems in their expanding power sector, including low labor productivity, poor service quality, substantial megawatt losses (both technical and theft losses), inadequate investment in power supply facilities, and cross-subsidized electricity prices too low to cover actual generation and transmission costs and support expansion investments in a constrained power system [22]-[23].

These issues and the pressures from international financial organizations and donor agencies such as the International Monetary Fund (IMF) and World Bank have been the principal driving forces behind the electricity power industry (EPI) reforms in many of the developing countries. In more developed countries, however, the aim of electricity reform has been cited as improving the performance of relatively efficient power systems. Ever-increasing customer expectations on power quality and reliability, local and federal governments' willingness to deregulate the industry by reducing their monitoring role, further EPI investment mandates by government sectors, and governments' commitments to spend existing resources in other sectors and on more urgent social projects were among the more direct motives for EPI restructuring in those countries [24]-[25].

Actual reform programs exhibit a variety of designs, particularly in terms of market structure, degree of private involvement, and sequencing of reform stages. No one model fits all participating countries, and no matter which model is initially chosen, electricity restructuring is an ongoing and evolving activity. Therefore, the design of reform programs in individual countries should reflect the particular socioeconomic circumstances of a country and its electricity sector. Many power sector reform programs in developing countries, particularly in those where the power industry is organized as monopolies under public ownership (like Turkey), are focused on moving from a monopoly to either a *single buyer model* (SBM) or directly to a *wholesale competition model*.

The popularity of the modest SBM is due to several economic, technical, and institutional factors, including the ease of network operation and control and simplicity of tariff regulation. Indeed, the simplicity of the tariff regulation process would make the SBM more favorable during the market transition phase, provided that the additional generation capacity required during the transition phase is supplied by IPPs through a competitive process. However, the main risks involved with the implementation of this model include the ability of governments to impose inefficient regulatory practices on the market for manipulating the single buyer, the possibility of existing monopolies imposing market power, a lack of initial financial resources to implement SBM, a lack of social desire by customers to make changes in electricity utilization to empower restructuring, and the lack of government commitment to full reform in order to avoid politically controversial consequences of introducing privatization and competition [26].

Under the SBM, the IPPs could benefit from long-term power purchase agreements (PPAs) backed by government guarantees for raising long-term financial requirements. One of the major disadvantages of the SBM is that PPAs between the single buyer and private generator companies could create a contingent liability for the government. When government guarantees are attractive to investors, there may be an upward bias in the generation capacity procurement, and government officials may find it difficult to resist powerful interest groups pushing for treasury-guaranteed capacity expansion. Accordingly, decisions to add generating capacity could be influenced by government officials who will not have to directly bear the financial consequences of their actions. This was experienced in Turkey during the 1990s as discussed in the next section.

2.2.1. Electricity Restructuring in Turkey: A Quick View

One of the main drivers of reforms in the Turkish EPI was the rapid growth in electricity demand combined with the inability of government sectors to meet that demand through public investments or treasury-guaranteed private investments, given the deteriorating fiscal situation in Turkey [2]. There have been several approaches employed over the last two decades to restructure the power sector and solicit private investments in the country. Different models used for restructuring to attract private investment include build-operate-transfer (BOT) and build-own-operate (BOO) models for new power plants. These long-term PPAs, which were signed between the private party and utility, include treasury guarantees. The BOT-type PPAs especially were heavily front-end loaded with higher capacity charges within the first few years of operation to allow for early recovery of investment costs in addition to the relatively high electricity cost. Indeed, these PPAs attracted substantial foreign power plant investments during the 1990s, particularly when the average increase in annual electricity consumption in Turkey was very high. However, they led the government to sign long-term PPAs at wholesale tariffs that were unsustainable given the retail tariffs and collections record. Consequently, by provision of contractual safeguards awarded to foreign investors in the form of treasury guarantees and take-or-pay assurances, PPAs have in effect become foreign debt assumed by the government.

The Electricity Market Law (EML), enacted in 2001, aimed to put an end to those types of PPAs. EML envisioned a wholesale electricity market based on *bilateral contracts* allowing generation companies and wholesale trade companies, distribution companies, independent retail companies, and eligible customers (consuming more than a threshold amount of energy per year) to buy electricity from their regional distributor or retailer, a wholesaler, a new independent retailer, or an independent generator. Captive customers, on the other hand, had no choice but to buy their electricity from a regional distributor or retailer. EML covers generation, transmission, distribution, wholesale, retail, and respective electricity services (including its import and export), the rights and responsibilities of individuals connected with those services, the establishment of a regulatory body, and its running procedures and principals as well as actions to be followed for the privatization of generation and distribution assets.

After the enactment of EML, a regulatory authority (EPDK) was established, and generation, transmission, and trading parts of the state monopoly were unbundled. The generation company is named Turkish Electricity Generation Co. (EUAS), the transmission company Turkish Electricity Transmission Co. (TEIAS), and the wholesale trade company Turkish Electricity Trading and Contracting Co. (TETAS). The distribution company, Turkish Electricity Distribution Co.

(TEDAS), which had already been separated from the monopoly (TEK) in 1993 with an attempt to prepare it for privatization, continues to be in charge of distribution with its regional affiliate companies. Under the new structure, state-owned EUAS will take over and operate the state's existing power plants that have not transferred to the private sector. TEIAS is responsible for transmission assets, system operation and maintenance, planning new transmission investments, and building new transmission facilities. TETAS was created to carry out wholesale electricity trading; it will take over all existing energy sale and purchase agreements from TEAS and TEDAS. Indeed, dealing with the long-term treasury-guaranteed PPAs and the associated stranded costs is a primary reason for the creation of TETAS, which will be regulated because it will be the dominant buyer and seller in the market for the foreseeable future.

Market Design Issues

The dominant role of a state-owned trading company (TETAS) induces many concerns [27]. One concern is the provision for additional power generation capacity by private companies during the development of a competitive market. IPPs will feel the need to sign long-term contracts with the government in order to protect their investments, unless they are confident in the continued competitiveness of the wholesale electricity market and the liquidity of market contracts. These conditions are only plausible with the insurance of distribution companies' creditworthiness and the provision of cost-reflected electricity tariffs. However, distribution companies in Turkey are facing big financial difficulties mainly due to high technical and non-technical losses (electricity theft and nonpayment) and free electricity supply.

The privatization of state-owned distribution companies by the Turkish government through transferring their operational rights (not the ownership) is expected to solve the financial difficulties of the distribution sector, improve collections, enforce the punitive actions against nonpaying customers, and improve the reliability and quality of the supplied electricity. It may be argued that privatization can achieve these targets. However, these issues are highly political and sensitive in nature, and the punitive disconnection of nonpaying customers could ultimately need political approval. Therefore, privatization will not remove the government's responsibility and role. It is also arguable that if the government is not able to initiate these measures, private (and often foreign) ownership alone could at best only partially achieve the restructuring targets. Moreover, privatization could result in higher electricity prices in order for private investors to guarantee their service obligations. Current subsidies for residential electricity prices could make the privatization process more difficult; the removal of subsidies and ensuring a higher quality of service are major challenges, which could create social and political headaches for authorities [2].

Competition at the Generation Segment

It is pointless to free up the electricity market in Turkey when there is no cost-responsive tariff implementation (i.e., under subsidy). How can IPPs compete with the state-owned generation companies under the subsidy of electricity prices? On the other hand, if the subsidies are relaxed to a competitive level, then how can the state-owned trading company compete with the IPPs entering the market? The industrial customers (or eligible customers) that have been subsidizing residential and other customers will no longer be a source of cross-subsidies if they have the option to buy from a cheaper supplier. This in turn may lead to the need for a big, immediate increase in retail tariffs for non-industrial customers (that is, captive customers), rather than a series of phased-in increases over a longer period of time.

An ongoing electricity project the Turkish authorities are very keen to achieve is the link to the European Union (EU) electricity network, that is, the Union of Coordination of Transmission of Electricity (UCTE). Turkey eventually plans to interconnect its electrical system with the UCTE grid via the Greek and Bulgarian grid and take advantage of cross-border electricity trading with the UCTE member countries. Preliminary works for this interconnection have been carried out according to UCTE regulations. The importance of this project has increased recently, especially after Turkey attained its candidacy for the EU membership in 2004. The actual interconnection is expected to be realized within a few years.

However, recent directives issued by the European Commission (EC) underscore the importance of the full opening of energy markets to improve Europe's competitiveness.

The development of the EU electricity market with the provision of an interconnection with the Turkish electricity network seems to provide new electricity trading opportunities for companies in EU membership countries. If the market is freed up completely and subsidies on electricity prices are relaxed to a competitive level, foreign companies will be able to trade with non-captive customers through interconnected transmission lines without the need for making new investments in Turkey.

Nevertheless, a key to enhancing electricity restructuring in Turkey, like all markets worldwide indeed, is to have an adequate competition in the generation sector of power industry. The success of liberalization efforts depends strongly on the participation of the non-utility generators in the market eventually. Apart from the market design issues and the legislative concerns during and after the transition to a competitive market, this requires a sufficient transmission capacity to support trading in electricity markets while maintaining the system reliability. On the other hand, the transmission for managing adequate transmission capacity is a major challenge in the new environment which involves complexities including uncertainties and risks, as discussed in the following section.

2.3. TEP Challenges after Deregulation of Power Systems

Transmission networks play a critical role in providing access to all participants in a competitive market for supply and delivery of electric power after deregulation of power systems. Moreover, to extend possible, it is desirable that the network provides for an economic level playing field. A more robust transmission system would bring in competitive participants from far away and eliminate market pockets in which dominant generators can exercise market power due to the transmission restraints.

The objective for TEP under the deregulated environment may be different from that in the traditional power industry. Although social-welfare is still a constrained factor to be accounted for, the transmission network owner could be more interested in maximizing own profit or minimizing the cost. However, since the transmission network is still a monopoly, regulation by the government is still inevitable. This brings new challenges to the transmission planning problem. These challenges are of a nature which requires the transmission owners and investors to define new planning objectives, re-examine conventional planning principles, and develop new models and means to meet these objectives [28]-[30]. The prominent challenges are underlined below.

- Transmission projects are capital intensive and have large economies of scale. It is obvious that there is a need to capture long-term benefits of transmission assets with a useful life of 40-60 years. That is, constructing a transmission line with an excess capacity than what is required at this time could typically reduce long-term expenses. In addition, transmission investments are lumped in discrete blocks of capacity rather than increasing continuously. For this reason, investments must be made much in advance. However, this requirement contributes to the inherent uncertainty in TEP problem.

- In traditional power system planning, generation planning is the core while transmission planning is based on generation planning. In the new environment, generation planning will mainly be a decision-making issue of non-utility generating companies or investors, and transmission planning is done separately and is still in response to expected changes in the generation/load patterns. However, the close linkage between the two which previously is a vertically integrated organization is now broken.

In many countries, like Turkey, T&G expansion planning has been centrally determined by the government. In the new environment, private investors are taking independent decisions according to their own assessments, and now generating plants and transmission lines are being built based on those assessments rather than those of the government bodies. A challenge hence arises: how to reconcile the private and the public interests in the expansion planning? In response to this question, this thesis study investigates finding the ways of coordination between the monopoly transmission and decentralized generation planning decisions, as discussed in Chapters 3 and 4. Involvement of the regulatory authority in this issue especially for the transmission planning is inevitable.

- TEP problems are multi-period dynamic in nature in the sense it is crucial to adopt a holistic view over the entire horizon although this horizon can be discretized in a number of periods, for instance annual ones. This means that an expansion planning exercise over *np* periods does not correspond to run *np* independent exercises in a sequential way. On the contrary, the whole horizon should be treated at one time in the sense that an expansion is commissioned for a period taking not only in consideration the requirements of that period but also its impacts in the future. This dynamic nature of the TEP problem is discussed in details in Section 2.7.3.

- TEP problems exhibit geographic coupling in the sense that the planner should not restrict himself to build installations as answers to local problems. In meshed networks, the addition or enhancement of any grid components is likely to affect flows throughout the grid. It is rather impossible to directly control electricity flows on individual transmission elements without impacting the rest of the grid. The inability to control individual line flows could cause independent transmission expansion projects rather complicated.

Transmission expansion projects are distinguished in two conceptual categories: radial and grid projects [5]. Radial projects involve the transmission link between two participants such as the interconnection of a remote generator to a load center. These projects could involve the strengthening of a transmission corridor between two regional participants to take advantage of peak diversity, provide surplus economic energy and capacity exchanges, and mitigate transmission congestion.

On the other hand, grid projects could be associated with reinforcements in the existing power grid. These projects are justified for their contribution to reliability. For example, as the load demand increases in urban centers, the construction of additional transmission lines becomes necessary for assuring the reliability of transmission network. A single line could possess both radial and grid characteristics over the course of its life which is one of the uncertainties issues associated with TEP.

- TEP problems are affected by load uncertainty over the horizon. A plan should be adequate not only for a given load evaluation but the decision maker should not feel any significance regret if the future will not be exactly as expected. This immediately leads to risk analysis under which flexible solutions are most welcome.

In addition, the location, timing and capacities of new generators, as well as closure of existing generators permanently are becoming uncertain, and the possible number of power plants locations increases. As a result, and because of the lengthened lead times for transmission construction, there is considerable uncertainty with regard to the transmission capacity requirement in the future at the time transmission commitments must be made.

Uncertainties lead to risk. Risk may refer to different aspects such as investment risk and the risk of a bad planning outcome. A key problem is how to quantify and minimize the risk created by uncertainties. Ranges and combinations of uncertainties must be accounted for. Indicative plans prepared by authorities might be a good solution to mitigate the generation investment uncertainty risk. A multi-year network planning approach which enable preparing such indicative plans within the TEP problem are developed in this thesis study as presented in Chapter 3.

- The increased uncertainty that accounts for multiple generation scenarios also affects the scope of planning horizons [21]. Beyond a 5 or 10 year horizon, generation scenarios can be largely unknown and unbounded. In this sense, the benefit of detailed studies in far future planning schemes is debatable. However, transmission equipment has a useful lifetime of 40-60 years, and hence, there is a need for transmission planners to consider utilization of equipment in the long run. This is a dilemma. The sensitivity of planning horizon on the optimal TEP solution is illustrated with numerical examples in Chapter 3.

- Since the current transmission systems were not originally designed for handling supply and demand patterns in competitive markets, some parts of the existing transmission network will be utilized in ways different from those originally planned or historically used. New transmission bottlenecks may be created and some existing transmission constraints may be binding more often and with more economic significance. Thus some measures to relieve congestion may be more demanding than ever, and solving this problem may require additions of new transmission lines.

- In some deregulated electricity markets, large customers are permitted to buy power from suppliers directly. An assessment report made by Electric Power Research Institute (EPRI) of USA mentions that, as the market develops, large amount power transactions have increased significantly and the distance of power transactions is becoming longer and longer. Hence, higher transfer capability will be required and analysis of this capability has become more important. This will pose new requirements for TEP.

- A good transmission expansion plan should be the one with good economic effect (in the sense of maximizing social-welfare) and meeting reliability requirements. To this end, it is vital to decide what planning criteria should be used for determining future transmission additions. It is agreed that the least cost expansion planning is no longer viable in an unbundled system, although there also exist different views. There may be different answers to these questions. For example, minimization of the expected unserved energy may be an option. Several entities insisted that the continued use of least cost planning was appropriate.

Some entities believed that building new transmission lines should be the last alternative. Instead, they argued that congestion pricing and the interconnection of new generation at strategically located sites are the answer [6].
These discussions resulted in the recommendation that future planning should center around elimination of major constraints that significantly limit the market or reduce the ability to meet operating reliability requirements and around the ability to accommodate new generation projects.

- A problem much discussed is "does competition improve or compromise reliability?" The transmission system is generally more stressed under deregulation, and moreover, it may be necessary to redefine certain reliability criteria. In many countries around the world, state legislatures are developing performance driven strategies with penalties and incentives. The request for use of the transmission system by power marketers and IPPs is extending the traditional analysis of transmission reliability far beyond traditional institutional boundaries. The meaning of reliability then becomes how the customer is impacted, not how reliable the equipment or parts of the system are [30].

It is commonly agreed worldwide that, the transmission services, particularly the system operation, should be regulated in order to provide nondiscriminatory open access to all transmission system users. Planning activities of state-owned transmission companies (like TEİAS of Turkey), which are responsible from both owning and operating the network, are due to regulation as well because of their monopoly structures. Although the re-organization of transmission services differs from country to country based on the country-specific historical developments of the sector and institutional organizations, the organization of transmission services can be classified into two broad approaches depending on the degree of unbundling, as described in the following Section.

2.4. Transmission Service Organizations

One of the most disputed issues of the electricity industry restructuring is the organization of the transmission sector. It is now generally agreed that although the deregulation has resulted in many variations in the power industry, transmission is a natural monopoly due to economic, technical and geographical reasons. As a result, transmission planning should still be controlled or regulated by a governmental organization or a regulator. However, the traditional approaches to transmission planning are not suitable for the competitive market environment and new arrangements are necessary.

Who should be responsible for transmission system planning, when should new transmission invests be made, where should they be installed, for what purpose, who will provide the funds to finance the additions, and how should investment recovery and return be implemented? These questions do not necessarily have the same answers for every market (or deregulated power systems after restructuring), but they must have answers if reliability of power supply is to be assured in the long run.

The restructuring of power industry resulted in two approaches to the organization of transmission services which depended broadly on the degree of unbundling: 1) The independent system operator (ISO) approach in which the ownership and operation of transmission assets are *separated*, and the operation responsibility is transferred to the ISO. 2) Transmission company that both owns and operates the transmission network (often called *integrated* Transmission System Operator (TSO) approach).

- **ISO Approach:** A competitive electricity market necessitates an independent operational control of the grid. The control of the grid cannot be guaranteed without establishing an ISO. The ISO administers transmission tariffs, maintains the system security, coordinates maintenance scheduling, and has a role in coordinating long-term planning. The ISO should function independent of any market participants, such as transmission owners, generators, distribution companies, and end-users, and should provide nondiscriminatory open access to all transmission system users.

The ISO has the authority to commit and dispatch some or all system resources and to curtail loads for maintaining the system security (i.e., remove transmission violations, balance supply and demand, and maintain the acceptable system frequency). Also, the ISO ensures that proper economic signals are sent to all market participants, which in turn, should encourage efficient use and motivate investment in resources capable of alleviating constraints.

Developing an effective ISO governance structure requires striking a delicate balance among three overlapping goals: ensuring neutrality (non-discriminatory access), protecting the interest of stakeholders including transmission owners, and providing incentives for an efficient ISO management [31]. The ISO approach could allow a certain degree of joint ownership of generation and transmission assets. It has been entailed in countries like USA, where the ownership of transmission assets was initially allocated to private parties. The ISO approach could facilitate a *market-based* transmission investment [10]. Market prices can provide signals to transmission system investors on where and when investment is needed. For example in PJM market of USA and Nordic pool, which run a spot market based on locational marginal prices (LMP), the market prices that are higher at congested nodes encourage transmission customers to develop cheaper alternatives, notably additional transmission and/or generating capacity [3].

- **TSO Approach:** In the TSO approach, which is applied in most of European countries, most network-related activities (planning, investment, operation and maintenance) are conducted within an *integrated* framework. In other words, TSOs are both owner and the operator of the system, and independent system operation is already among responsibilities of the TSOs. This approach is common in countries where the electricity sector development is based on solely monopoly utility in the history, like many countries worldwide including Turkey. Essentially, the TSOs are state-owned associations and their activities are subjected to regulations.

The integration of ownership and operation of transmission system facilitates proper management of tradeoffs between costs of network expansion and costs of system operation. In this approach, open access to the transmission network and fair and cost reflective pricing of transmission services are ensured by an independent regulatory authority. TSOs recover their investment and operating costs of transmission facilities using transmission tariffs (i.e., pricing) paid by all market participants, as discussed in Section 2.6.

2.5. Regulation of Transmission Services

Regulation became a crucial activity in the electricity industry as a way to set targets, to induce improvements on technical and economic behaviors, to impose rules on activities still conducted on a monopoly basis, and to defend consumers. Transmission activities are most widely provided in a monopoly basis, and therefore, they require being regulated from a technical and an economic point of view. In several countries, as in Turkey and many European countries, the integrated organization of the transmission system provider (i.e., the TSO) must provide its service according to a number of indices specified by the regulatory agency for several security criteria. This ensures the adequate levels of quality of service while inducing expansion and reinforcement investments. TSOs are then usually obliged to prepare and submit expansion plans to the regulatory agency to guarantee those indices. If approved, those plans will be remunerated by tariffs for the use of transmission networks. This mechanism shows some interesting aspects.

- The link between technical issues and economic aspects becomes clear. Technical security or supply indices determine investments to be remunerated by transmission *tariffs*.

- Once an expansion is approved, it represents a commitment of the regulatory agency to an evolution of those tariffs along the planning horizon.

- Given the impact of investments in tariffs, it becomes clear that expansion plans have to be built carefully, namely, to defend consumers. If available and ensuring the same technical results, a less costly investment plan will have to be selected. This requirement suppresses the transmission planner to optimize the network expansion considering the uncertainties in demand and generation. This is indeed a formidable task given the uncontrollability of the generation expansion after deregulation of the power industry which might essentially result in suboptimal transmission expansion, and therefore, the transmission service provider should not be held solely responsible. The regulatory authority has to shoulder responsibility as well in planning the network expansion, by developing market mechanisms to direct the non-utility investors when necessary in the sense of system security and electricity prices. This is among the main idea of this research study as discussed in Chapter 4.

Open access to the transmission system and fair, cost reflective pricing of transmission services are very important for healthy competition in the power sector. To ensure fair and non-discriminatory transmission access and pricing, system operators (ISO or TSO) are responsible for the operation and pricing of the transmission system. The charges for transmission services introduced in countries that have restructured their power sectors are usually separated into three components as described in the following Section.

2.6. Transmission Costs and Pricing

In restructured power systems, transmission function should facilitate a competitive electricity market by impartially providing energy transportation while recovering the cost of such services. For the cost recovery, market participants should be charged a *fair* price for enticing economic and engineering decisions on upgrading and expanding generation, transmission and distribution facilities [32]. That is, pricing is an important tool to ensure that the transmission system is used competitively and expanded efficiently.

Despite the fact that transmission charges represent a small percentage of operating expenses in utilities, the transmission network is a vital mechanism in competitive electricity markets. In a restructured power system, the transmission network is where generators compete to supply large users and distribution companies. Thus, transmission pricing should be a reasonable *economic indicator* used by the market to make decisions on resource allocation, system expansion, and reinforcement.

The competitive environment of electricity markets necessitates wide access to transmission and distribution networks that connect dispersed customers and suppliers. Moreover, as power flows influence transmission charges, transmission pricing may not only determine the right of entry but also encourage efficiencies in power markets. For example, transmission constraints could prevent an efficient generating unit from being utilized. A proper transmission pricing scheme that considers transmission constraints or congestion could motivate private investors and monopoly transmission companies to build new transmission and/or generating capacity for improving the efficiency. In a competitive environment, proper transmission pricing could meet revenue expectations, promote an efficient operation of electricity markets, encourage investment in optimal locations of generation and transmission lines, and adequately reimburse owners of transmission assets. Most important, the pricing scheme should implement fairness and be practical.

However, it is difficult to achieve an efficient transmission pricing scheme that could fit all market structures in different locations. The ongoing research on transmission pricing indicates that there is no generalized agreement on pricing methodology. In practice, each country or each restructuring model has chosen a method that is based on the particular characteristics of its network. Measuring whether or not a certain transmission pricing scheme is technically and economically adequate would require additional standards. Nevertheless, an efficient transmission pricing mechanism should recover transmission costs by allocating the costs to transmission network users in a proper way.

The charges for transmission services introduced in countries that have restructured their power sectors are usually separated into three components [33]:

- **Connection charge:** This charge covers the cost of network reinforcements required to provide service to a transmission customer. It is characterized as ‘deep’ or ‘shallow’, depending on how far from the customer site the customer’s liability extends.

- **Transmission use-of-system charge (capacity charge):** Transmission use-of-system (TUoS) charge compensates the transmission owner for the *sunk* costs of the existing transmission system assets, as well as the transmission system operating and maintenance costs. Costs of ongoing investment for future expansion and costs of reinforcement associated with load growth are also included in the TUoS charges. TUoS charge constitutes the largest part of transmission service charges.

- **Transmission operating charge (energy charge):** This charge covers the costs incurred in the electricity market due to the existence of a ‘non-perfect’ transmission system. These are the costs of transmission losses and transmission limitations (congestion). The revenues collected from energy charges are used to compensate the providers of the corresponding services (generation adjustment to cover losses, generation or demand adjustment to relieve congestion) [33].

During the last few years, different transmission pricing schemes have been proposed and implemented in various markets to recover the sunk costs (i.e., TUoS charge) [3]. The most common and unsophisticated approach to transmission pricing is the *postage-stamp* method. In this method, regardless of the distance that the energy travels, an entity pays a rate equal to a fixed charge per unit of the energy transmitted within a particular utility system. Postage-stamp rates are based on average system costs. In addition, the rates often include separate charges for peak and off-peak periods, which are functions of season, day, and holiday usage.

As an alternative to the postage-stamp method, locational tariff methods that differentiate charges according to customer locations within the grid, have been developed [33]. Long-run marginal cost (LRMC) based approaches associated with sunk costs of transmission network have been utilized in many countries. The intension of applying a LRMC-based pricing mechanism is to send long-term signals for the positioning of new generators and loads in the grid so as to postpone transmission network reinforcements as far as possible.

MW-mile method is a common LRMC based pricing approach, introduced as a flow-based pricing scheme. In this scheme, power flow and the distance between injection and withdrawal locations reflect transmission charges. MW-mile method is being applied in Turkey to determine the TUoS tariffs, although its efficiency is questionable as discussed in the following Sections.

MW-Mile Method: A Common Embedded-Cost Based Pricing Mechanism

MW-mile method is an embedded cost approach that is also known as a line-by-line method because it considers, in its calculations, changes in MW transmission flows and transmission line lengths in miles. The method requires *dc power flow* calculations [3]. The MW-mile method is the first pricing strategy proposed for the recovery of fixed transmission costs based on the actual use of transmission network. The method guarantees the full recovery of fixed transmission costs like all embedded cost methods and reasonably reflects the actual usage of transmission systems.

It is a locational-tariff method which differentiates the TUoS tariff according to the customers' location within the grid. Usually, the entire network is separated into different zones of charge with a uniform tariff within each zone. The intention behind the design is to send long-term signals for the positioning of new generators and new loads in the grid, so as to avoid network reinforcements as far as possible. MW-mile based approaches are divided based on assumptions made during construction of the optimum network. Investment cost-related pricing (ICRP) was the first proposal developed by British National Grid Company (NGC), which ignores Kirchhoff's voltage law for simplicity [33].

In Turkey, the state-owned transmission company (TEIAS) has a monopoly to operate and expand transmission network to meet the needs of market participants (i.e., TSO of the grid including the ownership). In order to carry out its duties, the company is required to prepare detailed investment plans and a capital expenditure budget. The plans and the corresponding budget are reviewed by the market regulatory, EPDK. The proposed investment cost is recovered through TUoS charges according to the location of customers within the grid based on the ICRP approach described in [33]. Table 2.1 presents a set of zonal TUoS tariffs applied in Turkey.

Table 2.1. TUoS Tariffs applied by Turkey.

Zone	GENERATION		LOAD	
	TUoS tariff	System operation tariff	TUoS tariff	System operation tariff
	YTL/MW-year	YTL/MW-year	YTL/MW-year	YTL/MW-year
1	14.903,57	293,16	5.263,74	293,16
2	9.457,14	293,16	12.042,21	293,16
3	6.654,52	293,16	13.719,29	293,16
4	1.435,68	293,16	17.957,37	293,16
5	10.319,47	293,16	7.894,52	293,16
6	17.531,41	293,16	1.668,17	293,16
7	68,36	293,16	23.905,79	293,16
8	1.698,93	293,16	15.853,27	293,16
9	4.740,52	293,16	13.774,80	293,16
10	68,36	293,16	16.594,38	293,16
11	4.495,45	293,16	11.306,83	293,16
12	6.222,68	293,16	17.473,25	293,16
13	9.615,64	293,16	12.756,10	293,16
14	68,36	293,16	34.941,66	293,16
15	68,36	293,16	24.695,20	293,16
16	9.569,12	293,16	12.933,39	293,16
17	8.542,11	293,16	12.232,30	293,16
18	68,36	293,16	24.155,44	293,16
19	68,36	293,16	15.287,98	293,16
20	68,36	293,16	20.771,32	293,16
21	5.857,50	293,16	14.551,70	293,16
22	6.019,73	293,16	9.574,12	293,16
23	10.383,98	293,16	5.191,98	293,16

Although the approach is proposed to send long-term positioning signals to new market participants, according to the regulatory figures [8], it has not provided sufficient incentive for generator investments in Turkey. The main drawbacks of embedded cost based pricing mechanisms including MW-mile method are summarized below:

Drawbacks of the Embedded-Cost Based Pricing Mechanisms

The embedded cost methods do not take into account of new transmission expansions or of generation production cost effects. They suffer from a lack of technical robustness and they fail in transmitting economic signals to network users. For example, the TUoS pricing mechanism envisaged Turkey (i.e., ICRP methodology) is based on the current topology of the network. That is, marginal increase of demands on the current topology of the power system determines the price differentials between buses. Indeed, the prices should be updated in case of any significant topological changes in the system such as transmission enforcements and generator investments. However, the determination of the price update period is a challenge in this approach given the possible significant effect of price upgrade on the existing transmission users [1]. In addition, ignoring the possible effects of potential generator investments' together with the transmission investment decisions in the planning horizon, the method does not provide the effective marginal prices [14].

Another main drawback of the embedded approaches is that they do not consider transmission constraints. The scarcity of transmission capacity and the demand for power generation from less expensive sources usually lead to transmission system congestion. When congestion occurs, generation (and/or load) has to be re-scheduled to ensure the system security. Essentially, re-scheduling could cause operating costs to increase. Transmission congestion issue is discussed in details in Section 2.7.5.

Since the embedded cost transmission pricing mechanisms fail in transmitting economic signals to network users, there is a clear need for providing more efficient signals to the market participants, even beyond the transmission pricing mechanisms. Under the lack of such market signals to direct non-utility investments, the restructured power systems may suffer supply deficiency particularly during the development phase of the market. The uncertainties in the sector including forecasted energy prices, the role of monopoly institutions, and market power status of the state-owned generation are among the main risk factors of non-utility investors that could result in delay of their generator investment decisions, and this might essentially threat the power system security, as discussed in the next chapters.

2.7. Formulation of the TEP Problem

Power system planning is a complex process that requires a significant amount of work, involving major stages such as system reliability assessment, forecasting of demand and fuel prices, and security assessment. Long-term power transmission network expansion planning problem consists of choosing expansion plans, from a predefined set of candidate circuits, those that should be built in order to minimize the investment and operational costs, and to supply the forecasted demand along the planning horizon. It involves a series of studies whose purpose is to determine *when* and *where* to install new equipments/lines. The initial candidate pool for expansion is generally formulated based on both the characteristics of the given system, such as the generation and transmission capacity, load and energy price forecasts, transmission tariff and its diversity, etc, and the human knowledge based on practical engineering, such financial limits, estimated construction periods, environmental factors, etc.

According to the procedure that was followed to obtain the expansion plan, the synthesis planning models can be classified into two types: *heuristic* and *mathematical optimization* [21].

2.7.1. Mathematical Optimization Methods

The mathematical optimization models find an optimum expansion plan by using a calculation procedure that solves a mathematical formulation of the problem. Due to the impossibility of considering all aspects of the transmission planning problem, the plan obtained is the optimum only under some simplifications and assumptions, and should be technically, financially, and environmentally verified, among other examinations, before the planner makes a decision.

In the formulation of these models, the transmission planning is posed like an optimization problem with an objective function (a criterion to measure in the same way the goodness of each expansion option), subject to a set of constraints. These constraints try to model great part of the technical, economic, and reliability criteria imposed to the power system expansion. Several methods have been proposed to obtain the optimum solution for the transmission expansion problem, mostly using classical optimization techniques like linear programming, dynamic programming, nonlinear programming, and mixed integer programming (MIP) problem.

Usually, big practical obstacles appear to obtain the 'optimal' solution when mathematical optimization techniques are used for solving the transmission planning problem, which is *nonlinear* and *nonconvex* in nature. This is mostly due to the intrinsic limitation of the optimization process itself, for example, convergence problems, unreasonably large computational times when discrete variables are used for modeling the investments, and when stochastic modeling is used for planning under uncertainty.

Because of combinational nature of the TEP problem, solving it is very hard task. Among all combinatorial optimization techniques used, Benders decomposition [15] have been used with success since its first application to this problem. In the classic Benders approach, the original network design problem is broken into two subproblems, the *master* subproblem, which models only investment variables and proposes network expansion plans; and the *slave* subproblem, which implements the expansion plans suggested by *master* subproblem and checks its network feasibility. The iteration between both subproblems is characterized by Benders cut, which are evaluated from the *slave*'s solution and added to the *master* subproblem.

In this thesis, Benders decomposition methodology is utilized in optimizing the multi-year mixed-integer programming TEP problem as presented in Chapter 3 and 4. It is shown with numerical examples that how could Benders decomposition technique be utilized successfully in solving such a complex problem. The theory of utilizing Benders decomposition technique in optimization of MIP problems is given in Appendix A.

2.7.2. Heuristic Methods

The heuristic methods are the current alternative to the mathematical optimization models. The term 'heuristic' (to invent, to create) is used to describe all those techniques that, instead of using a classical optimization approach, go step-by-step generating, evaluating, and selecting expansion options, with or without the user's help (interactive or non-interactive). To do this, the heuristic models perform local searches with the guidance of logical or empirical rules and/or sensitivities heuristic rules). These rules are used to generate and classify the options during the search. The heuristic process is carried out until the plan generation algorithm is not able to find anymore a better plan considering the assessment criteria that were settled down. These criteria usually include investment-operation costs, overloads, and unserved power. The use of heuristic algorithms is attractive in the sense that good feasible solutions can be found with a small computational effort. However, they cannot guarantee in an absolute way, mathematically speaking, the 'optimal' transmission expansion [21].

Computer developments in the area of parallel processing have originated a lot of interest in the researchers that work with optimization algorithms to solve large scale problems. Parallel processing allows solving complex problems in smaller computational times.

2.7.3. Static vs. Dynamic (Multi-year) Planning Approach

Broadly, network expansion planning can be classified as *static* and *dynamic* according to the treatment of the study period. The planning is static if the planner seeks the optimal circuit additional set for a single year on the planning horizon, that is, the planner is not interested in determining when the circuits should be installed but in finding the final optimal network state for a future single definite situation (static situation). On the other hand, if multiple years are considered, and an optimal expansion strategy is outlined along the whole planning period, the planning is classified as dynamic (i.e. year by year expansion plan). In this case the coupling among the interior years makes the problem more complex. In fact, an investment scheduled for a particular year can have a positive impact in years afterward and can also contribute to solve problems elsewhere in the system, given the interconnected nature of transmission networks.

The dynamic models are currently in an underdeveloped status and they have excessive limitations concerning the system size and the system modeling complexity level. The dynamic planning problem is very complex and very large because it must take into accounts not only sizing and placement, but also timing considerations. This results in a large number of variables and restrictions to consider, and requires an enormous computational effort to get the optimal solution, especially in real power systems. Few works about dynamic models for real world transmission planning problems can be found in the technical literature [21].

In Turkey, a static planning approach has been utilized in TEP based on scenario analysis. Essentially, transmission planning is more difficult after restructuring under the strong uncertainty in generation investments after opening the generation market. The following example illustrates how transmission planning problem has challenged after decentralization of the generation investment decisions. Currently, the company has been dealing with the planning of the southwest region of the country's power system. According to demand projections based on current high demand increase rate with about 7% per year, some measures should be taken to ensure the supply reliability at the region within a foreseeable future. Single line diagram of the system (380 kV network only) of the region is given in Fig. 2.1. The solid lines correspond to existing transmission lines, and the dashed lines correspond to candidate reinforcements foreseen by the transmission company. Dashed circles correspond to *potential* non-utility investments by the IPPs. (H: hydro, NG: natural gas combined cycle, and T: thermal power plant.) The long-term transmission plan should define the optimum investment schedule along the planning horizon, which depends strongly on the generation investment decisions as well as the load demand forecast. The uncertainty of those generator investments considerably increases the scenarios to be investigated in a static planning problem, although there is no guarantee that the investments will be made by the corresponding agents. This problem is investigated in this thesis study within a multi-year (i.e., dynamic) TEP model proposed in Chapter 3.

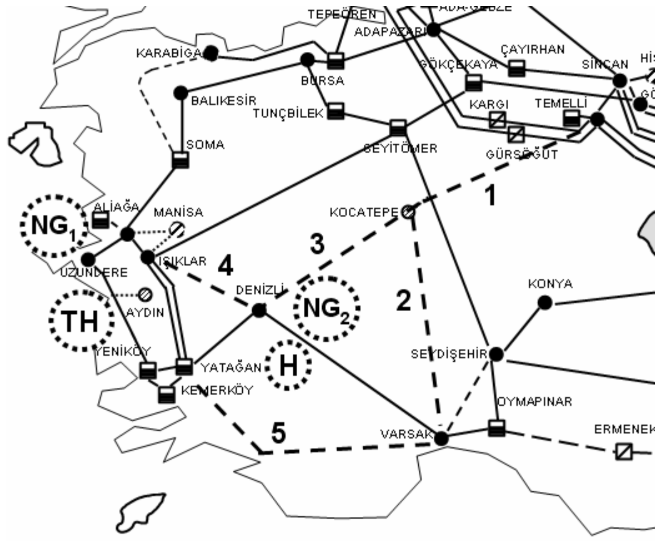

Fig. 2.1. Southwest region of the Turkish Power System (380 kV).

The simple two-bus system depicted in Fig. 2.2 enables easy understanding of the importance of the multi-year planning approach. In this example, the generator at Bus 1 is supplying the load at Bus 2 through a transmission line. The solid line corresponds to the existing transmission line, and the dashed line corresponds to the candidate reinforcement along the planning horizon. Multi-year coordinated planning approach assesses the investment of the second transmission line taking into account the possible generation investment at Bus 2 (the dashed generator).

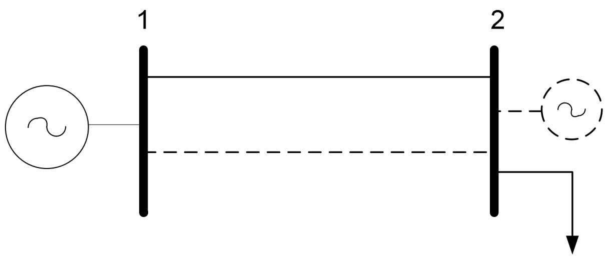

Fig. 2.2. Two-bus system.

The followings are among the main considerations which the investment decision (i.e., timing) of the second transmission line depends on; peak demand increase, load duration curve, planning horizon, capital costs of both transmission line and candidate generator, and energy (operational) cost of the local generation under decision. For example, if it is known that the candidate generator will provide energy in a reasonable price, and its investment will be made before any load shedding is necessary (i.e., the existing line is sufficient until the investment of the candidate generator), then the transmission investment could be deferred some years depending on the capacity of the candidate generator. This will essentially optimize the network planning problem since the transmission system is utilized efficiently. However, depending on the energy price of the candidate generator, the transmission enforcement might be necessary even if the generator investment takes place, in order not to suffer market power. Consequently, the transmission planning problem can not provide the optimum investment schedule unless a multi-year planning approach is considered, which should concern with predefined technical and financial criteria to maximize the social-welfare.

2.7.4. Costs involved in Transmission Planning Problem

Although the deregulation has changed the planning paradigm by separating the transmission and generation planning decisions, the maximization of social-welfare is still (or at least should be) the fundamental aim of the regulatory and the system operators. In this regard, transmission planning problem should consider both the system security/reliability and cost of planning solution suffered by consumers. From the consumer point of view, the main cost includes the transmission sunk costs discussed above and operational costs (i.e., cost of energy). Essentially, a TEP problem which optimizes the transmission investment cost and operational cost expected in the forecasted horizon is the desired issue regardless of the market structure.

The literature regarding TEP problem includes many studies that take the energy cost of the generators as the operational cost [21]. The following Section illustrates this approach.

Investment and Energy (Operational) Cost within a TEP Problem

The energy cost (also referred as operational cost) is proportional with the area under the load duration curves (which is the consumed energy indeed) that show variation of the demand for a definite time period (e.g., daily, weekly, seasonally, yearly, etc.) Strictly speaking, in order to be evaluated within a planning problem, the operational cost needs to be forecasted for each hour throughout the years along the planning horizon. In addition to the computational problems, this requires representation of all supply energy costs for each individual hour. This is obviously a huge burden. This requirement may, however, be softened by taking advantage of possible hourly and seasonal patterns. It may be possible to estimate the whole year for planning purposes. The load can be represented by an average value in each year in calculating the operational cost. This is illustrated in Fig. 2.3 which presents a typical daily load curve. Considering the peak demand as the base load (i.e., 1 p.u.), the area under the 0.7 p.u. line is equal to the area under the daily load curve. In other words, the daily energy consumption of this typical load can be represented by an average load of 0.7 p.u.

The load periods should be splitted in sufficient amounts to represent the operation cost accurately within a TEP problem. On the other hand, in *security* analysis which verify the proposed TEP solution in the sense of technical requirements (i.e., reliability criteria), the loads should be represented with their *peak demand* values in each year along the horizon. That is, the security analysis within the planning problems, such as power flow analysis, should consider the peak demand to assess the transmission and/or generator investment requirement. Consequently, the TEP problems which concern with technical and economical issues should consider the peak demand forecast for security analysis and average demand forecast for operational cost determination. The years along the horizon should be separated into reasonable patterns (e.g., seasonal pattern) to represent the load consumption more accurately. The literature includes many studies that consider the investment and operational costs together within a traditional integrated resource planning (IRP) problem [21].

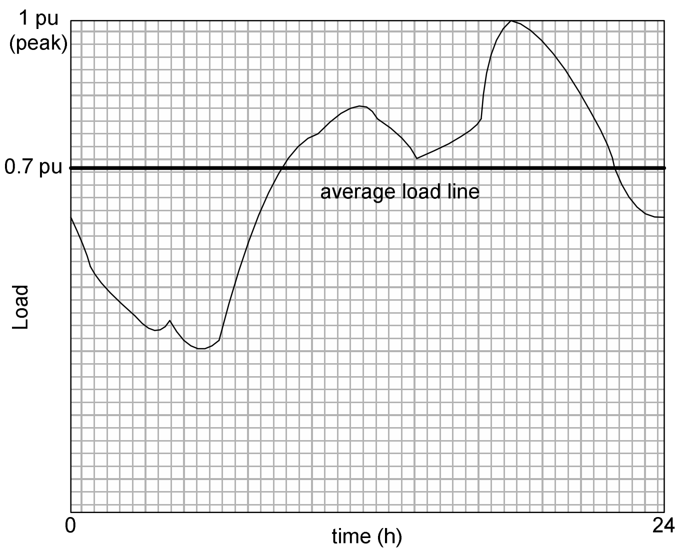

Fig. 2.3. A typical daily load curve.

The traditional transmission planning models are being challenged by considering the congestion-cost approach within the TEP problem instead of the operational cost, with the target of social-cost minimization. Indeed, in competitive markets, the network congestion becomes an important yardstick to evaluate the network adequacy in the sense of both security and economy. Congestion cost provides vital signals for network expansion algorithms in many developed markets [9]. Next section presents the transmission congestion concept and discusses how it could be considered within a TEP problem of a developing market.

2.7.5. Transmission Congestion

The scarcity of transmission capacity and the demand for power generation from less expensive sources usually lead to transmission system congestion. When congestion occurs, generation (and/or load) has to be re-scheduled to ensure the system security. Essentially, re-scheduling could cause operating costs to increase. Congestion can also be relieved in long-term by transmission capacity expansion. In either solution, congestion management involves both economical and technical issues that require analyses of system conditions at present, as well as conditions that could occur due to the future growth in the system.

Congestion costs provide economic information concerning the need for and the location of transmission enhancements. When the transmission becomes congested, meaning that no additional power can be transferred from a point of injection to a point of extraction, more expensive generating units may have to be brought on-line on one side of the transmission system. In a competitive market, such an occurrence would cause different locational marginal prices (LMPs) between the two locations [34].

If transmission losses are ignored, a difference in LMPs would appear when lines are congested. Conversely, if flows are within limits (no congestion), LMPs will be the same at all buses and no congestion charges would apply. The difference in LMPs between the two ends of a congested line is related to the extent of congestion and MW losses on this line. Since LMP acts as a price indicator for both losses and congestion, it should be an elementary part of transmission pricing in competitive markets [3]. This is the case in USA markets (e.g., PJM, NYM, etc.) and Nordic Pool [35]-[36]. In the Turkish bilateral-contract based market, the congestion cost is considered within a *day-ahead* and *real-time balancing markets* [37]. Solving the congestion in short-term balancing markets could result in excessive energy prices as experienced in Turkey during peak demand conditions in 2007 [38].

Figure 2.4 shows a possible congestion period during a typical day. The average demand during the congestion period is very close to the peak demand as illustrated in the figure, which is generally the case in reality. Given that congestions usually occur during peak demand conditions, the congestion cost can be determined by utilizing the average demand value during peak demand conditions. Indeed, the average demand value during congestion periods is generally very close to the peak demand, as in the example given in Fig. 2.4, which enables more realistic estimation of the congestion cost within a planning problem. This will obviously facilitate the transmission planning problem. For example, in the case of southwest region of Turkey (see Fig. 2.1), which encloses the most touristy region of the country during long summer season, the forecasted peak demand duration can be assumed to be roughly four months per year with almost constant demand.

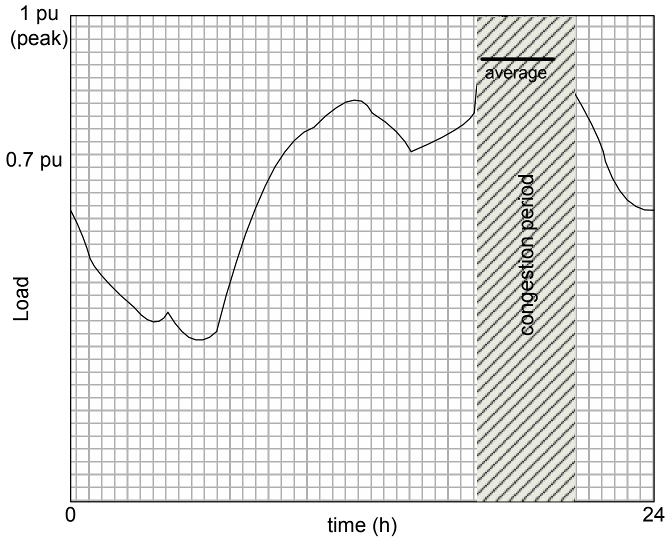

Fig. 2.4. Representation of the congestion period in a typical day.

To address the problem of transmission congestion, the U.S. Secretary of Energy chartered an Electricity Advisory Board that established a Transmission Grid Solution Subcommittee. The report from this subcommittee defines transmission congestion or *bottlenecks* as follows: "Bottlenecks occur when the system is constrained such that it cannot accommodate the flow of electricity and systematically inhibits transactions. Thus, a bottleneck has economic and/or reliability impacts" [7]. Consequently, transmission congestions clearly affect system reliability, and therefore, should be considered in planning decisions. Indeed, balancing of congestion level against network expansion investment cost to alleviate such congestion is becoming more topical issue today than before [9].

Consequently, it is desirable that transmission facilities be adequate enough to support all the demanded power flow. However in practice the presences of congestion are frequent in peak hours, which also cause high price volatiles over the network. In the market environment transmission constraints may even help generation companies to make strategic biddings. Thus it is very meaningful to formulate the congestion level in the network expansion planning model under market environment [39].

In Chapter 3 and 4 the concept of *additional operation cost due to congestion* (AOCC) is proposed to be utilized within the TEP problem. Considering the total AOCC in the planning objective function instead of the operation cost enables to assess the annual cost of investments (or annual gain by deferral of investments) against the annual congestion level, as illustrated by numerical examples.

2.8. Summary and Discussion

This chapter emphasizes the following points which necessitate development of the traditional TEP approaches after restructuring of power systems:

- Power systems are undergoing a significant change of introducing competitions. The unbundling of the generation and transmission functions is fundamentally changing the power system planning paradigm, introducing new challenges to be dealt with the system planners.

- Under a competitive environment, transmission network not only serves as physical route to deliver electrical power, but also causes a strong externality which may prevent perfect competitions among market participants. Therefore, it is very important to make effective operation and expansion plan of the transmission system.

- Although the close linkage between the transmission and generation planning is broken after deregulation of power systems, transmission planning should still consider the expected changes in the generation patterns.

- The optimum investment schedule along the planning horizon can only be determined by a *dynamic* (i.e., multi-year) planning approach which concerns with predefined technical and financial criteria to maximize the social-welfare.

- In addition to the network operation criteria used in traditional grid planning approaches, network congestion becomes an important yardstick to evaluate the network adequacy in competitive markets.

In response, a novel multi-year TEP model is developed in this thesis study as presented in Chapter 3, which takes into account transmission congestion level and the impact of generation expansions in the planning horizon. The proposed planning model is improved in Chapter 4 to consider incentive payments to non-utility generator investments within the planning problem.

CHAPTER 3

CONGESTION-DRIVEN TEP CONSIDERING THE IMPACT OF GENERATION EXPANSION

3.1. Introduction

This Chapter presents a novel approach for considering transmission system security and congestion level in the long-term multi-year transmission expansion planning (TEP) problem. A planning framework is proposed which evaluates the impact of potential generation investments on the optimum TEP. The proposed planning approach gauges the level of congestion and security with respect to transmission and generator investments. Concerning with the expansion of the transmission network for maximizing energy trade opportunities while providing the reliability/security criterion, the proposed model considers congestion cost within the problem. The motivation for developing such a planning framework is the necessity for improving the traditional transmission planning approaches after restructuring of power systems, as discussed in Chapter 2.

It is shown with numerical examples that if the potential generation investment alternatives are ignored, the TEP might result in either over-investment in transmission network or non-optimal generation investments, both of which could increase the total social-cost in the planning horizon. The assessment of potential generation investment decisions in the planning for transmission network security addresses incentive mechanisms for reaching social optimum in the long-term. Inclusion of such incentive mechanisms to the TEP problem to trigger decentralized generator investments is the subject of Chapter 4.

This chapter is organized as follows. After an introduction in Section 3.1, the proposed long-term multi-year TEP model and solution methodology are described in Section 3.2. The formulation of the problem is provided in Section 3.3. Section 3.4 presents and discusses both the case studies of a hypothetical four-bus system which enables easy understanding of the contribution of this study, and application of the approach to southwest region of Turkish transmission network. Summary and discussion of the results are provided in Section 3.5.

3.2. Network Planning Model

Fig. 3.1 shows the framework of the proposed planning model. As shown in the figure, an initial set of investment candidates is assumed to be identified in a preliminary study. In practice, a set of investment candidates is formed based on the integration of analytical approaches with human knowledge. Feasibility studies for this aim include *power flow* and *stability* analysis that could be performed by means of sophisticated simulation tools that available to almost all planners nowadays. Transmission lines which are already overloaded are definite candidates for the investment pool. In addition, the candidate generator investment decisions of non-utility investors give an important feedback about how to enforce the transmission grid along the planning horizon.

After restructuring of power systems and opening market to generation, the generation facilities are due to a licensing mechanism through an electricty market regulatory authority (EMRA). License applications of independent power producers (IPPs) to make a generator investments give an important feedback to the transmission company in the long-term planning process. Although in many electricity markets, including Turkey, those license applications provide information to the transmission companies about the location and the capacity of candidate generator investments, the most critical question for the transmission system planner is the *realization* of those generation investment projects by the IPPs. To mitigate the problem in some degree, it is possible to promote IPPs to trigger those candidate generator investments for the optimum grid planning. This topic is discussed in Chapter 4.

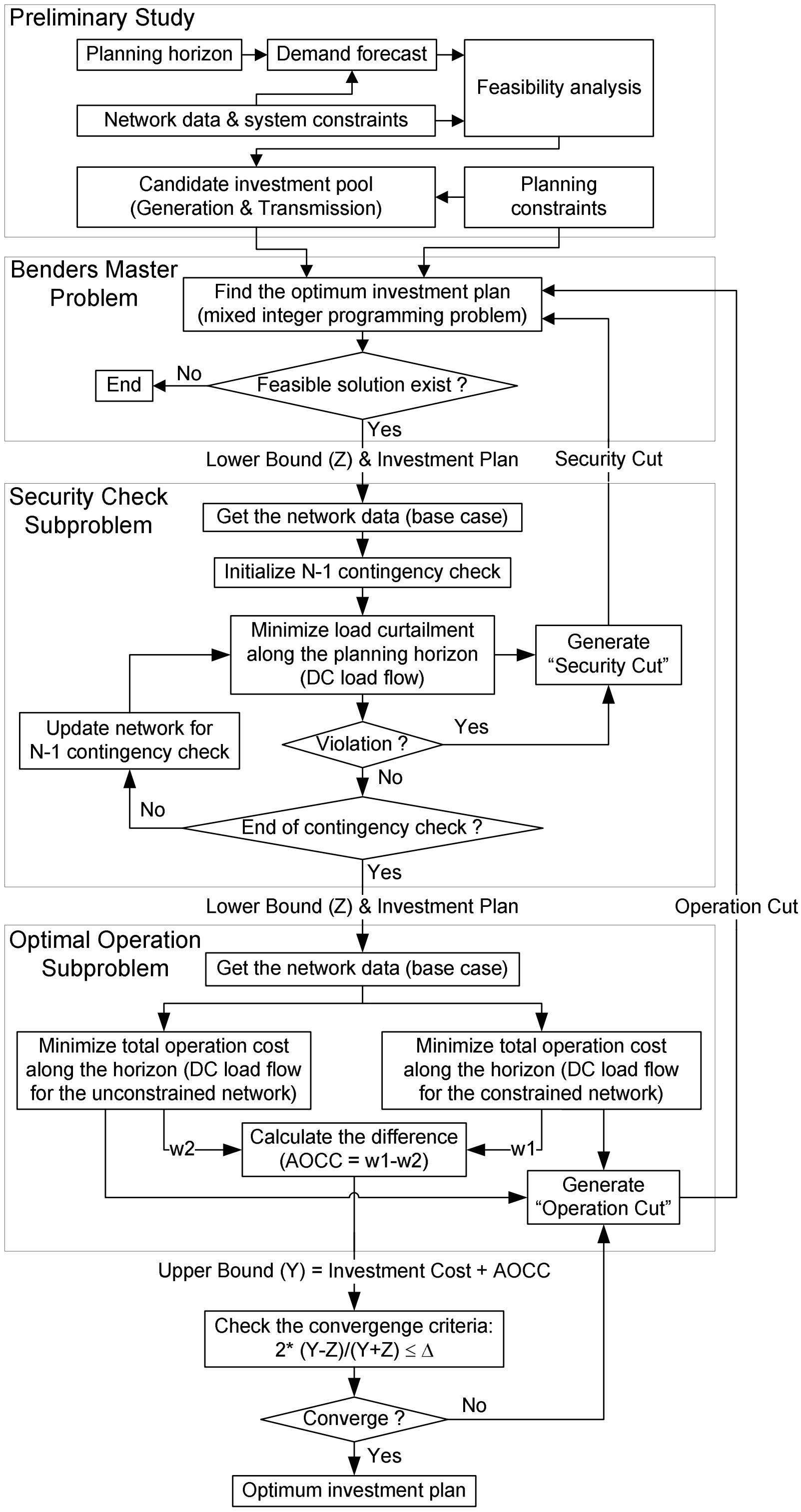

Fig. 3.1. Proposed planning framework.

The candidate generator investment pool should not be necessarily restricted with the IPPs' investment decisions. As proposed in this chapter, the transmission company may include any potential generator investments as well, which deserve evaluation within the TEP problem. It is important to note that, the non-utility investors may not foresee every potential generator investments, in particular during the initial years of the market development period. In the sense of supply deficiency concern, to leave all the generator planning decisions completely to the competitive investors is risky during this transition phase given the fact that market has not matured yet. This is unfortunately the case in Turkey where the generator investment by IPPs has not occurred as expected since opening of the market. This is indeed among the main motivations of this thesis research study which concerns with directing the market participants in making investments and promoting them when necessary in the sense of both system security and economy (i.e., to maximize the social-welfare). Essentially, the proposed planning approaches in this chapter and its improved version described in Chapter 4 address this problem.

In the proposed model, the selection of investment candidates is based on the Benders decomposition technique [15] in which the planning problem is decomposed into a *master* problem and two *subproblems*, representing *security* and *optimal operation*, as illustrated in Fig. 3.1. In the proposed TEP model, the master which is a mixed-integer-programming (MIP) problem, considers an investment plan for generators and transmission lines from the initial candidate pool. Among combinatorial optimization techniques, the Benders decomposition is the one that is applied with success in determining the suitable generation expansion planning [40]-[43]. Appendix-A presents definitions and theorems that point how the "Benders Decomposition Methodology" is utilized in a multi-year MIP problem.

Once the candidate investments are identified by the master problem, the security subproblem will check whether this plan can meet system constraints in the planning horizon. The security subproblem assesses the single-contingency criteria. The single-contingency criteria (also reffered as 'n-1 criteria') requires the transmission system design and configuration to be of a standard adequate to reliably meet peak load demand, even under the outage of any single element in the system. It is a well-known reliability criterion utilized by system planners worldwide. If any violation occurs, a corresponding security cut will be formed by the security subproblem based on the linear programming (LP) duality theory.

The security cuts will be added to the master problem for solving the next iteration of the planning problem in which the lower bound of the problem is updated. Once the violations are removed, the proposed investment schedule is fed to the operation subproblem which calculates the upper bound and forms the corresponding operation cut. The upper bound is the summation of the operation cost and the investment cost of the proposed investment set at corresponding iteration, which satisfies the security criteria.

The iterative process between the master problem and subproblems will continue until a converged optimal solution is found through upper and lower bounds, which are modified in each iteration. The iterative process between the master problem and subproblems can be observed more clearly in Fig. 3.2.

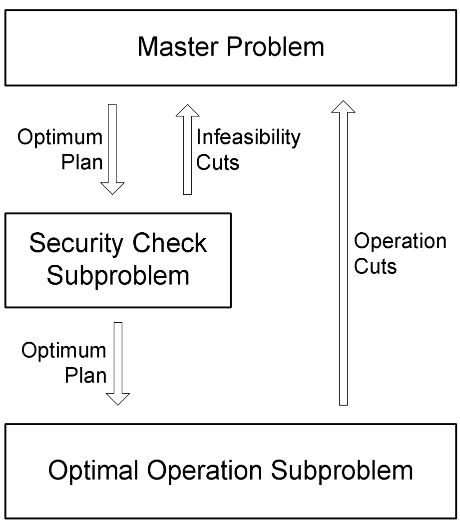

Fig. 3.2. Iterative process between the master problem and subproblems.

The operation subproblem in the proposed approach considers the minimization of the operation cost with and without transmission constraints. This difference is defined in the paper as the total *additional operation cost due to congestion* (AOCC). The motivation behind utilizing AOCC concept is explained below.

In many countries around the world, restructuring process starts with unbundling the generation segment and introducing a wholesale electricity market based on bilateral contracts that match the generation companies and large scale consumers through wholesale trading companies, as in the case of Turkey. The number of bilateral transactions grows with the addition of new agents as the market matures, and this considerably challenges the system operation. Bilateral contracts should be honored and executed by the transmission company unless the system security is endangered. The success of restructuring efforts depends on the availability of transmission network for developing a competitive market.

In addition to the discussions of Chapter 2, this motivated to evaluate the congestion level in the transmission planning model. Since the single-contingency security criterion is already considered in the approach, the impact of congestion is indeed the inhibition of favorable transactions due to foreseen transmission constraints possible in the planning horizon. The unconstrained network in the algorithm (see Fig. 2.1) represents the case in which no transactions can be inhibited due to transmission congestion, and consequently the cost of such a generation dispatch gives the minimum reference cost for the calculation of the AOCC [18], as discussed in the following section.

3.3. Problem Formulation

The objective of the proposed planning approach is to minimize the total AOCC and investment cost involving new generating units and transmission lines while satisfying system security based on single-contingency along the planning horizon (3.1).

$$Min \quad Y = \sum_{t=1}^{T} \sum_{i=1}^{CG} \left[CI_{it} * (X_{it} - X_{i(t-1)}) \right]$$

$$+ \sum_{t=1}^{T} \sum_{j=1}^{CL} \left[CI_{jt} * (X_{jt} - X_{j(t-1)}) \right]$$

$$+ \sum_{t=1}^{T} \sum_{b=1}^{B} AOCC_{bt} \tag{3.1}$$

The first two terms of the objective function (3.1) represent the investment cost for new generating units and transmission lines. The third item is the total AOCC along the planning horizon. The master problem provides both the optimum investment plan and lower bound (Z) of the planning problem.

The initial coordination between generation and transmission planning (i.e., initial master problem) is formulated as follows:

$$Min \quad Z \tag{3.2}$$

s.t.

$$Z \geq \sum_{t=1}^{T} \sum_{i=1}^{CG} \left[CI_{it} * (X_{it} - X_{i(t-1)}) \right] + \sum_{t=1}^{T} \sum_{j=1}^{CL} \left[CI_{jt} * (X_{jt} - X_{j(t-1)}) \right] \tag{3.3}$$

$$\sum_{j=1}^{CL} CI_{jt} * (X_{jt} - X_{j(t-1)}) \leq CI_t \tag{3.4}$$

$$\sum_{j=1}^{CL} PL_{j,\mathbf{max}} * (X_{jt} - X_{j(t-1)}) \leq UC_t \tag{3.5}$$

$$\sum_{j=1}^{CL} (X_{jt} - X_{j(t-1)}) \leq UN_t \tag{3.6}$$

$$X_{jt} = 0 \quad if \quad t < CT_j \tag{3.7}$$

$$X_{it} = 0 \quad if \quad t < CT_i \ . \tag{3.8}$$

The investment planning problem (3.2) is subject to both planning and operation constraints. The set of planning constraints, as depicted in Fig. 3.1, includes constraints on determining the initial candidate investment pool and those involving the availability of capital investment funds in year t (3.4), projected resource and line capacity for year t (3.5), maximum number of units and lines to be added (3.6), and the construction time of the candidate investments (3.7)-(3.8). Depending on the degree of coordination of generation and transmission planning, constraints such as those associated with generator investment may be extended. On the other hands, the operation constraints of the investment problem are developed by the subproblems iteratively, as described in the following sections.

3.3.1. Security-Check Subproblem

The security concern in the proposed planning approach is to satisfy the nodal power balance while maintaining the transmission security based on single-contingency criteria. Security analyze requires load flow (also referred as 'power flow') analysis for each contingency along the planning horizon. For transmission system operation where reactive power flows and voltage constraints are important, it is imperative that AC power flow model should be used. However, the linearized (i.e., DC) power flow equations are usually used in planning studies of highly meshed networks, providing good approximations for the nonlinear equations of transmission flows [40]-[42]. DC power flow model is composed of Kirchhoff's 1st and 2nd laws, which are linear equations relating bus angles, generations and loads to circuit flows.

The *base case* in Fig. 3.1 corresponds to the transmission network conditions without any contingency. Single-contingency is modeled in the security-check subproblem by repeating all transmission network constraints for each contingency indexed by q. The security-check subproblem for the q^{th} contingency at subperiod b and year t is formulated for the n^{th} investment solution of the master problem (i.e., n^{th} iteration) as follows:

$$Min \quad v_{bt}^{nq} = DT_{bt}^{q} * \sum_{k=1}^{N} PC_{k,bt}^{q} = DT_{bt}^{q} * (1^{T} * r^{q}) \tag{3.9}$$

s.t.

$$\boldsymbol{s}^{q} * \boldsymbol{f}^{q} + \boldsymbol{p}^{q} + \boldsymbol{r}^{q} = \boldsymbol{d} \qquad \forall q \tag{3.10}$$

$$PL_{j,bt}^{q} = \gamma_{mn}^{q} * (\theta_{m,bt}^{q} - \theta_{n,bt}^{q}) \quad j \in (m,n), \forall q \tag{3.11.a}$$

$$PL_{j,bt}^{q} = X_{jt}^{n} * \gamma_{mn}^{q} * (\theta_{m,bt}^{q} - \theta_{n,bt}^{q}) \quad j \in (m,n), \forall q \tag{3.11.b}$$

$$\left| PL_{j,bt}^{q} \right| \le PL_{j,\max} \quad j \in (m,n), \forall q \tag{3.12.a}$$

$$\left| PL_{j,bt}^{q} \right| \le X_{jt}^{n} * PL_{j,\max} \quad j \in (m,n), \forall q \tag{3.12.b}$$

$$PG_{i,\min} \le PG_{i,bt}^{q} \le PG_{i,\max} \quad \forall i, \forall q \tag{3.13.a}$$

$$X_{it}^{n} * PG_{i,\min} \le PG_{i,bt}^{q} \le X_{it}^{n} * PG_{i,\max} \quad \forall i, \forall q \tag{3.13.b}$$

$$\theta_{ref} = 0. \tag{3.14}$$

Note that (3.11.b) and (3.12.b) correspond to the candidate lines, and (3.13.b) corresponds to the candidate generators. The objective (3.9) is to mitigate network violations and minimize the load curtailment by applying a generation dispatch. In the above formulation, generator lower bounds (3.13) represent the 'must-run' generator units that are continuously operated due to security and/or bilateral long-term energy agreements. This approach indeed supports the utilization of DC power flow in security subproblem, given that the initial candidate investments are already determined by the AC power flow analysis. Nevertheless, more detailed representation of transmission network could be implemented in the proposed model to consider voltage constraints and transmission losses within the long-term planning problem.

The equality constraint corresponding to candidate lines (3.11.b) can be expressed as two linear inequalities as:

$$PL_{j,bt}^{q} - \gamma_{mn}^{q} * (\theta_{m,bt}^{q} - \theta_{n,bt}^{q}) \le M_j * (1 - X_{jt}^{n}) \quad j \in (m,n), \forall q, \ \pi_{1j,bt}^{nq} \qquad (3.15.a)$$

$$-\left(PL_{j,bt}^{q} - \gamma_{mn}^{q} * (\theta_{m,bt}^{q} - \theta_{n,bt}^{q}) \right) \le M_j * (1 - X_{jt}^{n}) \quad j \in (m,n), \forall q, \ \pi_{2j,bt}^{nq} \qquad (3.15.b)$$

where M_j is the penalty parameter which ensures the 2nd Kirchhoff's law for the candidate lines, and π_1 and π_2 are the dual variable vectors corresponding to the constraints (3.15.a) and (3.15.b) of the security-check subproblem at the n^{th} iteration and the q^{th} contingency. When a candidate line investment status is set to zero, the corresponding linear inequalities enforce that no flow will go on the line, while if it is set to one the flow on the candidate line will obey the 2nd Kirchhoff's law. Similarly, the inequality constraints corresponding to the candidate lines (3.12.b) and generators (3.13.b) can be rewritten as follows:

$$PL_{j,bt}^{q} \le PL_{j,\max} * X_{jt}^{n} \quad j \in (m,n), \forall q, \ \lambda_{1j,bt}^{nq} \qquad (3.16.a)$$

$$-PL_{j,bt}^{q} \le PL_{j,\max} * X_{jt}^{n} \quad j \in (m,n), \forall q, \ \lambda_{2j,bt}^{nq} \qquad (3.16.b)$$

$$PG_{i,bt}^{q} \le PG_{i,\max} * X_{it}^{n} \quad \forall i, \forall q, \ \delta_{1i,bt}^{nq} \qquad (3.17.a)$$

$$-PG_{i,bt}^{q} \le -PG_{i,\min} * X_{it}^{n} \quad \forall i, \forall q, \ \delta_{2i,bt}^{nq} \qquad (3.17.b)$$

where λ_1, λ_2, δ_1 and δ_2 are dual variable vectors of the constraints (3.16.a)-(3.17.b), respectively.

The corresponding security cut, which will be added to the master problem when the objective function of (3.9) is larger than zero (i.e., in case of load curtailment), is calculated based on the linear programming duality theory as follow [18]:

$$v_{bt}^{nq} + \sum_{i=1}^{CG} \delta_{1i,bt}^{nq} * PG_{i,\max} * (X_{it} - X_{it}^{n})$$

$$- \sum_{i=1}^{CG} \delta_{2i,bt}^{nq} * PG_{i,\min} * (X_{it} - X_{it}^{n})$$

$$+ \sum_{j=1}^{CL} (\lambda_{1j,bt}^{nq} + \lambda_{2j,bt}^{nq}) * PL_{j,\max} * (X_{jt} - X_{jt}^{n})$$

$$- \sum_{j=1}^{CL} (\pi_{1j,bt}^{nq} + \pi_{2j,bt}^{nq}) * M_{j} * (X_{jt} - X_{jt}^{n}) \quad \leq 0. \tag{3.18}$$

The security cut (3.18) indicates that the violation could be mitigated by readjusting the investment solution plan in year *t*. The dual variables in the security cut are interpreted as the incremental decrease in load curtailment violations. These security cuts are added to the master problem cumulatively until an investment plan is found which satisfies the load curtailment criteria while meeting the single-contingency along the planning horizon.

3.3.2. Optimal-Operation Subproblem

In the proposed approach, the DC optimal power flow is applied to realize the transmission AOCC. First, the operation cost for the *base case* (*w1*) is calculated along the planning horizon based on the investment solution provided by the master problem. The optimal-operation subproblem for every subperiod *b* and year *t* for the current investment solution is formulated as follows:

$$Min \quad w1_{bt}^{n} = DT_{bt} * \sum_{i=1}^{NG} (OC_{i,bt} * PG_{i,bt}) \tag{3.19}$$

s.t.

$$\boldsymbol{s} * \boldsymbol{f} + \boldsymbol{p} = \boldsymbol{d} \tag{3.20}$$

$$PL_{j,bt} = \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \quad j \in (m,n) \tag{3.21.a}$$

$$PL_{j,bt} = X_{jt}^{n} * \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \quad j \in (m,n) \tag{3.21.b}$$

$$\left| PL_{j,bt} \right| \leq PL_{j,\max} \quad j \in (m,n) \tag{3.22.a}$$

$$\left| PL_{j,bt} \right| \leq X_{jt}^{n} * PL_{j,\max} \quad j \in (m,n) \tag{3.22.b}$$

$$PG_{i,\min} \leq PG_{i,bt} \leq PG_{i,\max} \quad \forall i \tag{3.23.a}$$

$$X_{it}^{n} * PG_{i,\min} \leq PG_{i,bt} \leq X_{it}^{n} * PG_{i,\max} \quad \forall i \tag{23.b}$$

$$\theta_{ref} = 0 \; . \tag{3.24}$$

Equations (3.21.b), (3.22.b) and (3.23.b) correspond to the candidate investments. Then, the total operation cost is recalculated without considering transmission line constraints (3.22.a) and (3.22.b). The optimal-operation subproblem for the unconstrained case (*w2*) for every subperiod *b* and year *t* is formulated this time as follows:

$$Min \quad w2_{bt}^{n} = DT_{bt} * \sum_{i=1}^{NG} (OC_{i,bt} * PG_{i,bt}) \tag{3.25}$$

s.t.

$$\boldsymbol{s} * \boldsymbol{f} + \boldsymbol{p} = \boldsymbol{d} \tag{3.26}$$

$$PL_{j,bt} = \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \quad j \in (m,n) \tag{3.27.a}$$

$$PL_{j,bt} = X_{jt}^{n} * \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \quad j \in (m,n) \tag{3.27.b}$$

$$PG_{i,\min} \leq PG_{i,bt} \leq PG_{i,\max} \quad \forall i \tag{3.28.a}$$

$$X_{it}^{n} * PG_{i,\min}^{C} \le PG_{i,bt}^{C} \le X_{it}^{n} * PG_{i,\max}^{C} \quad \forall i \tag{3.28.b}$$

$$\theta_{ref} = 0 \;. \tag{29}$$

Similarly, (3.27.b) and (3.28.b) correspond to the candidate investments. The difference between the two objection functions (3.19) and (3.25) gives the AOCC for the n^{th} planning solution at subperiod b and year t:

$$AOCC_{bt}^{n} = w1_{bt}^{n} - w2_{bt}^{n} \;. \tag{3.30}$$

After calculating the AOCC, the upper bound (Y) of the planning problem (3.1) at the current iteration will be updated by adding the total AOCC to the investment cost. The convergence of the planning algorithm depends on the upper and lower bounds (Z) of the planning problem as illustrated in Fig. 3.1. If the algorithm does not converge, an operation cut is generated and added to the master problem for the next iteration. The constraints (3.21.b), (3.22.b), and (3.23.b) corresponding to the candidate lines and generators can be rewritten as follows:

$$PL_{j,bt} - \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \le M_{j} * (1 - X_{jt}^{n}) \quad j \in (m,n) \;\; \beta_{1j,bt}^{n} \tag{3.31.a}$$

$$-\left(PL_{j,bt} - \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt})\right) \le M_{j} * (1 - X_{jt}^{n}) \quad j \in (m,n) \;\; \beta_{2j,bt}^{n} \tag{3.31.b}$$

$$PL_{j,bt} \le PL_{j,\max} * X_{jt}^{n} \quad j \in (m,n) \;\; \alpha_{1j,bt}^{n} \tag{3.32.a}$$

$$-PL_{j,bt} \le PL_{j,\max} * X_{jt}^{n} \quad j \in (m,n) \;\; \alpha_{2j,bt}^{n} \tag{3.32.b}$$

$$PG_{i,bt} \le PG_{i,\max} * X_{it}^{n} \quad \forall i \;\; \sigma_{1i,bt}^{n} \tag{3.33.a}$$

$$-PG_{i,bt} \le -PG_{i,\min} * X_{it}^{n} \quad \forall i \;\; \sigma_{2i,bt}^{n} \,. \tag{3.33.b}$$

where β_1, β_2, α_1, α_2, σ_1 and σ_2 are dual variable vectors corresponding to the constraints (3.31.a)-(3.33.b) of the optimal-operation subproblem. The corresponding operation cut at the n^{th} iteration will be

$$Z \geq \sum_{t=1}^{T} \sum_{i=1}^{CG} \left[CI_{it} * (X_{it} - X_{i(t-1)}) \right]$$

$$+ \sum_{t=1}^{T} \sum_{j=1}^{CL} \left[CI_{jt} * (X_{jt} - X_{j(t-1)}) \right] + \sum_{t=1}^{T} \sum_{b=1}^{B} AOCC_{bt}^{n}$$

$$+ \sum_{t=1}^{T} \sum_{b=1}^{B} \left[\sum_{i=1}^{CG} \left(\sigma_{1i,bt}^{n} * PG_{i,\max} * (X_{it} - X_{it}^{n}) \right) \right]$$

$$- \sum_{t=1}^{T} \sum_{b=1}^{B} \left[\sum_{i=1}^{CG} \left(\sigma_{2i,bt}^{n} * PG_{i,\min} * (X_{it} - X_{it}^{n}) \right) \right]$$

$$+ \sum_{t=1}^{T} \sum_{b=1}^{B} \left[\sum_{j=1}^{CL} (\alpha_{1j,bt}^{n} + \alpha_{2j,bt}^{n}) * PL_{j,\max} * (X_{jt} - X_{jt}^{n}) \right]$$

$$- \sum_{t=1}^{T} \sum_{b=1}^{B} \left[\sum_{j=1}^{CL} (\beta_{1j,bt}^{n} + \beta_{2j,bt}^{n}) * M_{j} * (X_{jt} - X_{jt}^{n}) \right]. \tag{3.34}$$

The operation cut indicates that the objective value of the planning problem (3.1) can be decreased by changing the investment status of the candidate investments along the horizon. The dual variables of the optimal-operation subproblem in (3.34) force the optimization algorithm to search for a better planning solution that would result in better economic dispatch solutions. The consideration of total AOCC in the planning objective function instead of the operation cost enables us to assess the annual cost of investments (or annual gain by deferral of investments) against the annual congestion level.

The important feature of the Benders decomposition utilized in the study is the availability of upper and lower bounds (*Y* and *Z*, respectively in Figure 1) of the optimal solution in each iteration. These bounds are utilized as the convergence criteria as illustrated in the flow chart. In every iteration, the security cut narrows the optimality gap by increasing the lower bound of the objective function, while for every feasible solution (i.e., n-1 secure solution) the operation cut narrows the optimality gap by decreasing the upper bound.

3.4. Case Studies

The proposed approach is applied to a hypothetical four-bus system for analyses and to the Turkish power system for practical studies.

3.4.1. Four-Bus System

The four-bus system depicted in Fig. 3.3 shows two generators that supply loads at two different buses. It is assumed that the generator G1, which is located at a distance from large loads at Bus 4, is cheaper than generator G2 which is closer. The solid lines correspond to existing transmission lines, and the dashed lines correspond to candidate reinforcements. The dashed generator at Bus 4 corresponds to a local generation (LG) whose decision on transmission planning will be investigated. A 5% annual interest rate based on 20-years scheduled loan is utilized to calculate the annual cost of capital required for the investment in the planning horizon.

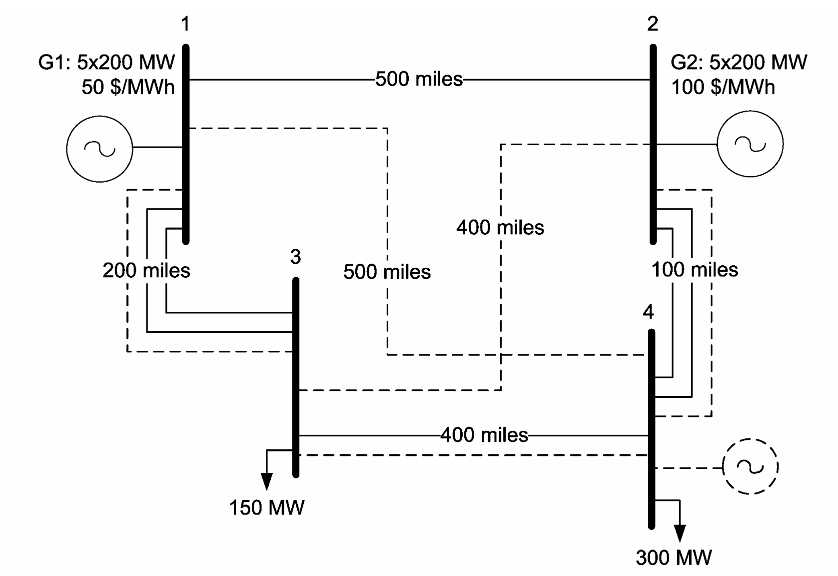

Fig. 3.3. Four-bus system.

The capital cost and energy price of local generators are assumed to depend on their capacity as shown in the Table 3.1. The annual load growth rates are assumed to be 5% at Bus 3 and 10% at Bus 4. The transmission line capacity is 200 MW. Table 3.2 shows the cases that are considered. Two transmission investment costs at 400 \$/MW-mile and 800 \$/MW-mile are assumed. The planning period is assumed to be five and ten-years in separate cases to investigate the results for mid-term and long-term studies respectively.

Table 3.1. Four-Bus System Local Generator Cost Data

Capacity (MW)	Capital cost (M\$/MW)	Energy price (\$/MWh)
< 50	1	10
> 50	0.8	20

Table 3.2. Cases for the Four-Bus System

Case Ti or Ci *	Horizon (years)	Transmission Investment Cost (\$/MW-mile)
T1, C1	5	400
T2, C2		800
T3, C3	10	400
T4, C4		800

* Ti: Transmission only planning, Ci: Coordinated planning.

Five-year horizon

Transmission planning solutions for Cases T1 and T2 are given in Table 3.3. If the proposed enforcement, which is the additional line from Bus 1 to Bus 4, is procured in year 3 (Y3), the system will be single-contingency secure in the planning horizon in both cases. Table 3.4 shows that the investment schedule in Case T1 eliminates the transmission congestion in the planning horizon and the total cost corresponds to transmission line investments only. However, this enforcement is deferred one year in Case T2 at the expense of congestion in year 3, since the annual AOCC is smaller than the annual payment for transmission investment, resulting in a cheaper total cost.

Table 3.3. Candidate Transmission Lines Cases T1/ T2 (1: selected, 0: rejected)

Li-j *	Y1**	Y2	Y3	Y4	Y5
L1-3	0/0	0/0	0/0	0/0	0/0
L1-4	0/0	0/0	1/0	1/1	1/1
L2-3	0/0	0/0	0/0	0/0	0/0
L2-4	0/0	0/0	0/0	0/0	0/0
L3-4	0/0	0/0	0/0	0/0	0/0

* Li-j: Investment on Transmission line from bus i to bus j
** Yi: Years in the planning horizon

In this example, the break-point capacity of LG, which results in the minimum total cost by eliminating the congestion, is calculated as 15 MW with 1 M$/MW capital cost and 10 $/MWh energy price. As shown in Table 3.4, beyond this capacity level, LG does not provide a cheaper solution. In this case, its capital cost, which is proportional to its capacity, exceeds the potential investment gain. Given the generator capacity size, the approach assesses the potential gain from utilizing distributed generation within TEP. In coordinated planning cases, LG might provide a lower planning cost than transmission only planning. This solution depends on several factors including the transmission investment cost, LG capacity, and energy prices. For example, LG does not provide a cheaper planning solution irrespective of its energy price in Case C1. However, it provides cheaper planning solution in Case C2 due to the considerable AOCC which depends on its capacity and energy price.

Ten-year horizon

In transmission only planning cases (i.e., Cases T3 and T4), the AOCC of optimal planning increases to levels that are comparable with investment costs in the ten-year horizon. It is certainly possible to mitigate high congestion levels by increasing transmission investments beyond that of the candidate list. However, the total number of candidate lines is limited in this example to show the effect of generation investment decision. Nevertheless, transmission planning is subject to planning constraints which include the availability of investment funds, projected line capacity, and maximum number of lines to be added, as represented by (3.2)-(3.4).

Table 3.4. Optimum Planning Solutions (Five-Year Planning Horizon)

Case	LG Capacity	IS [*]	AOCC [**] (M$)	IC [***] (M$)	AOCC+IC (M$)
T1, C1	-	See Table 3	0	9.5	9.5
T2			5.59	12.7	18.29
C2	10 MW	L1-4: 00011 LG : 01111	1.6	16.6	18.2
	15 MW	L1-4: 00011 LG : 00111	0	16.2	16.2
	20 MW	L1-4: 00011 LG : 00111	0	17.4	17.4

[*] IS: Investment States
[**] AOCC: Congestion Cost
[***] IC: Investment Cost

Given the high congestion level, the optimal LG capacity which provides minimum total cost along the planning horizon, is expected to be larger if compared to the five-year planning horizon case. In Cases 3 and 4, the break-point capacity of LG is 70 MW and 100 MW, respectively under the assumption of 0.8 M$/MW capital cost and 20 $/MWh energy price. The LG enables not only the mitigation of congestion but also the deferral of transmission investments in both cases as illustrated in Table 3.5. It should be emphasized that an LG bigger than the break-point levels might provide a cheaper transmission investment in the planning horizon due to further deferral of transmission investments. However, the total cost along the horizon, and therefore social-costs, will increase proportionally with the LG investment cost.

The case studies on the four-bus system illustrate the impact of LG on TEP decision. Depending on the technical and financial constraints of the system, LG provides a cheaper solution by either mitigating the congestion in the planning horizon, deferring transmission investments, or both. Planning horizon is an important determinant not only for the main contribution of LG but also for the sequence of investments. The optimal planning will essentially depend on the system characteristics and financial data. In the following section, the proposed model is applied to the Turkish power system.

Table 3.5. Optimal Planning Strategy (Ten-Year Planning Horizon)

Case	LG Capacity	IS	AOCC (M$)	IC (M$)	AOCC+IC (M$)
T3	-	L1-3: 0001111111 L1-4: 0000000111 L2-4: 0000000001 L3-4: 0001111111	39.4	40.6	80
T4	-	L1-3: 0000111111 L1-4: 0000000111 L2-4: 0000000001 L3-4: 0000111111	45	73.5	118.5
C3	70 MW	L1-3: 0000001111 L1-4: 0011111111 L2-4: 0000011111 L3-4: 0000001111 LG : 0000000011	3.13	52.56 (Tr *: 43.7 LG: 8.86)	55.73
C4	100 MW	L1-3: 0000011111 L1-4: 0000000011 L3-4: 0000011111 LG : 0001111111	6.16	95.03 (Tr: 50.68 LG: 44.35)	101.19

* Tr: Transmission

3.4.2. Turkish Power System

The proposed approach is also applied to the Turkish power system according to its configuration in 2006. Opening the market to the generation sector has impacted the transmission planning since the enactment of electricity market law in 2001 [1]. Generation investment decisions were decentralized by the introduction of licensing mechanism for generation facilities through the energy market regulatory authority, EPDK. Although many companies have applied EPDK to get a license, a considerable number of participants have not realized the proposed generation project for various reasons. Nevertheless, those applications should be taken into account in performing planning studies.

The Turkish power system has 807 high voltage buses with the summer peak demand of about 23000 MW by 2006. The transmission system is comprised of two voltage levels: 380 kV and 154 kV. The main demand centers lie in western and northwestern parts of the country, whereas a sizeable installed generating capacity is in the east and southeast.

The state-owned Turkish electricity transmission company, TEIAS, is both the owner and the operator of transmission network. After opening the market to generation segment, the company is subjected to regulation through revenue cap and is required to submit expansion plans to the regulatory authority. If approved, those plans will be remunerated by tariffs for the use of transmission networks.

Currently, the company is dealing with the transmission planning in the southwest region which has projected a load growth of 7% per year and some measures are to be taken to ensure the regional supply reliability within the foreseeable future. The single-line diagram of the system given in Fig 2.1, which represents the southwest region (380 kV network only) of the country, is formed for simulation as illustrated in Fig. 3.4. The remaining parts of the power system, which are connected to the southwest region with strong ties (bold arrow lines in Fig. 3.4), are represented by equivalent systems, in order to reduce the size of the system for the proposed formulation. Load flow simulations are performed and the adequacy of the equivalent network is confirmed before proceeding to planning analysis.

In Fig. 3.4, solid lines correspond to existing 380 kV lines and dashed lines correspond to candidate reinforcements based on feasibility analyses. Dashed circles correspond to potential generation investments (H: hydro, NG: natural gas combined cycle, and TH: thermal). The only official information that the transmission company has about those candidate generators is that a license application has been submitted for NG_1 at the west side. The information on the others is as follows:

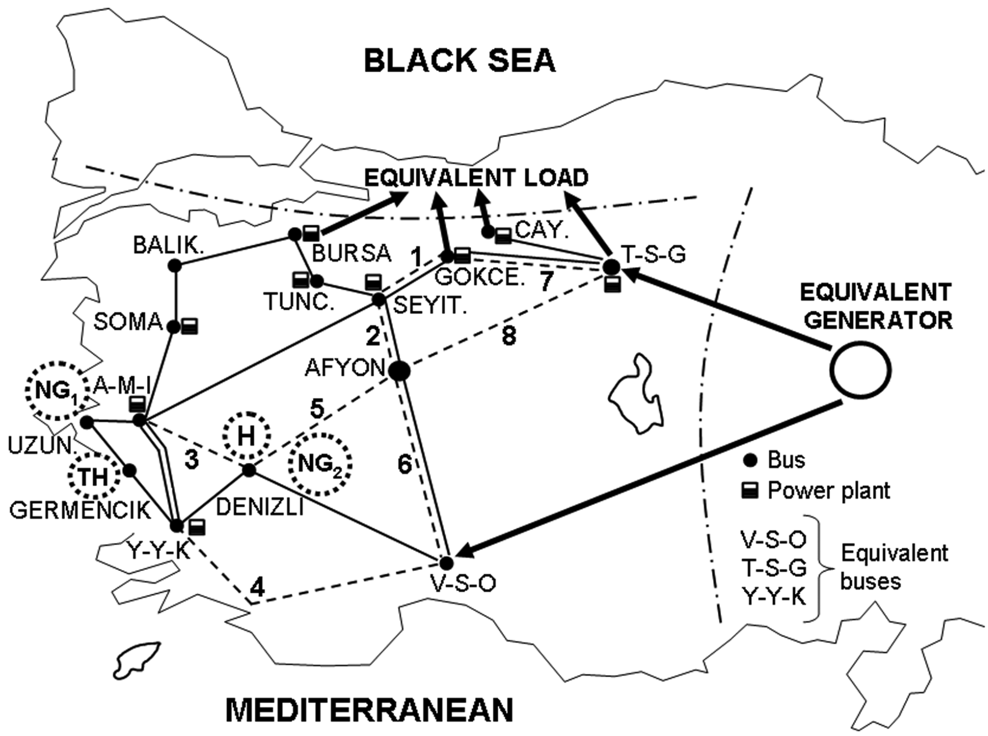

Fig. 3.4. Southwest region of the Turkish Power System (380 kV)

- **TH:** A local private company which intends to make an investment on an import coal-fired power plant near Germencik Bus and is being prepared for licensing.

- **H:** General Directorate for State Hydraulic Works of the country has performed feasibility analysis for a hydraulic power plant at South Denizli close to Mediterranean.

- **NG_2:** Within the near future, natural gas pipelines will be extended to the main demand centers. This may trigger combined cycle power plant investment in Denizli.

Concerning the demand, the following scenarios listed in Table 3.6 are assumed based on projections provided by the Ministry of Energy and Natural Resources of the country and transmission company records:

Table 3.6. Cases for the Turkish Power System

Case	Horizon (years)	Load Duration (month/year)	Annual Load Increment (%)
T1, C1	5	2	5
T2, C2			7
T3, C3		4	5
T4, C4			7
T5, C5	10	2	5
T6, C6			7
T7, C7		4	5
T8, C8			7

- Annual average demand increases between 5% and 7% for optimistic and pessimistic scenarios, respectively.

- Forecasted peak demand duration of the region, which encloses the touristy region of the country during the long summer season, is assumed to be 2 and 4 months per year for the optimistic and pessimistic scenarios, respectively.

- Given that the transmission company has to prepare a five-year plan periodically, five and ten-year planning horizons are investigated separately.

Single-contingency security criterion is applied. System parameters required for DC power flow, energy prices of generators, and up-to-date capital costs of all candidate investments are provided by relevant institutions. Table 3.7 shows the capacity and the cost data of candidate generators and Table 3.8 shows the candidate transmission lines data in the Turkish power system. The annual interest rate of investment loan is 10% and the period of loan is 20 years. Must-run generators are considered based on the initial AC load flows performed in the scope of the preliminary study. Optimum planning solutions are given in Table 3.9.

Table 3.7. Candidate Generators in the Turkish Power System

Generator	Capacity (MW)	Capital cost (M$/MW)	Energy price ($/MWh)
NG_1	1500	0.4	60
NG_2	1000	0.4	60
TH	1000	0.4	20
H	350	0.9	5

Table 3.8. Candidate Transmission Lines in the Turkish Power System

Line	Capacity (MW)	Length (mile)	Capital cost ($/MW-mile)
L1	1116	75	250
L2	1116	115	
L3	1334	125	
L4	1334	188	
L5	1334	134	
L6	1334	144	
L7	1116	105	
L8	1334	140	

According to Table 3.9, in the case of optimistic load increase scenario (i.e., 5% per year), there is no need for any transmission enhancement for the first five years regardless of the load duration factor (Cases T1 and T3). The system is secure in the planning horizon and the congestion that occurs in fourth and fifth years is manageable as the total AOCC is smaller than the cost of any transmission investment for mitigating the congestion. The same result also applies to Case T2. However, in the case of pessimistic load increase with pessimistic load duration (Case T4), the planning algorithm proposes transmission investments to relieve the congestion that has increased proportionally with load duration, although the power system is still secure without any enforcement.

Table 3.9. Optimum Planning Solutions for the Turkish Power System

Case	IS	AOCC (M$)	IC (M$)	AOCC+IC (M$)
T1, T2, T3 C1,C2,C3	No investment	5.91	0	5.91
T4, C4	L1: 00011 [*] L7: 00001	3.03	13.1	16.1
T5, C5	L1: 0000001111 L2: 0000000001 L7: 0000000111	15.6	37.5	53.1
T7, C7	L1: 0000011111 L7: 0000001111 L8: 0000000001	14.6	49.5	64.1
T6, T8	No solution unless load curtailment			
C6	L1: 0000011111 L2: 0000011111 L7: 0000011111 L8: 0000000001 NG_2: 0000000011	58.7	177.2 (Tr: 84.6 NG2: 92.6)	235.9
C8	L1: 0001111111 L2: 0000011111 L3: 0000000011 L5: 0000000001 L7: 0000111111 TH: 0000000011	75.2	205.4 (Tr: 112.8 TH: 92.6)	280.6

[*] Li: Candidate lines in Fig. 3.3.

Since the power system is secure in the next five-years, no generator investment is expected to be proposed unless its investment mitigates the congestion comparatively. In this regard, even the cheapest generator in terms of energy price, the hydraulic plant, does not provide a cheaper solution in the horizon as its capital cost is considerably higher than the potential gain from its investment. Consequently, for the case of five-year horizon, the coordinated planning cases (C1-C4) provide the same result as that of transmission only planning.

Similarly, in the case of ten-year planning horizon, generators are not proposed in the optimistic load increase scenarios regardless of the load. However, for the pessimistic load increase scenarios (i.e., Cases T6 and T8), there is no feasible planning solution by means of transmission investments on candidate lines unless a load curtailment is implemented within the last years. Table 9 shows that the corresponding coordinated planning simulations (i.e., Cases C6 and C8) propose a generator investment to fulfill the security requirement.

The optimal LG depends on the load duration. Although capital costs and sizes are the same, the generator that has the expensive energy price (i.e., NG_2) is proposed in the optimistic load duration scenario (i.e., Case C6). High energy cost of the generator (due to projection of high gas price) is compensated by a considerable gain from the transmission investment deferral in the planning horizon. On the other hand, in the case of pessimistic load duration scenario (i.e., Case C8), the main determining factor for the generator selection is the congestion level. The coal-fired thermal power plant, TH, is proposed to mitigate the congestion that increases to considerable levels particularly in the last years, although it necessitates more transmission investment if compared to Case C6.

Based on the proposed optimal planning solutions, an *indicative* investment plan could be prepared as given in Table 3.10. The investments of transmission lines L1, L7 and L2 in years 4, 5 and 6, respectively, satisfy the security constraints in all cases along the first six years.

Table 3.10. Indicative Investment Plan for the Next Ten Years

Year	Y4	Y5	Y6	…	Y9	Y10
Investment	L1	L7	L2	TH $\Rightarrow$	L3	L5
				$NG_2 \Rightarrow$	-	L8

Although this investment schedule assures the security, it may essentially result in a suboptimal total cost depending on the load scenario. The uniform transmission investment schedule along the six-year period enables to postpone the transmission investment decision within the last years. Transmission investment decision for the last two years depends on the LG decision as illustrated in the table. Given the load uncertainty, such illustrative plans, which might be prepared every five years, can trigger decentralized generation investments as necessary.

3.5. Summary and Discussion of the Results

In this Chapter, a novel multi-year TEP model is proposed which evaluates transmission line and generator investment costs together with the congestion level expected in the planning horizon. The concept of total AOCC is utilized in order to assess the congestion level. The annual evaluation of transmission investments and congestion level along with local generation investment costs enables more realistic assessments of generation and transmission investment decisions. The inclusion of security criteria in the model strengthens the investments planning.

The Benders decomposition technique is utilized successfully to optimize the sum of investment costs of transmission lines and generators, and the total AOCC forecasted along the planning horizon. The results of numerical examples show the effectiveness of the proposed model. Convergence characteristic of the proposed algorithm for a case study is given in Fig. 3.5. The figure illustrates how the iterative process between the master problem and subproblems continues until a converged optimal solution is found through upper and lower bounds.

This kind of *least cost* planning approaches, which consider both transmission and generation planning decisions could be prepared by the state-owned transmission companies (like TEIAS in Turkey) to provide long-term indicative plans for the market participants and authorities. Although the generation investments are decision variables in the objective function, it is not obligatory for independent power producers (IPPs) to follow the regulators' decisions on generation investment. It should be noted that the proposed model does not intend to propose an integrated resource planning under a vertically integrated system. Regulators can use the candidate generation investment pool for the long-term TEP problem.

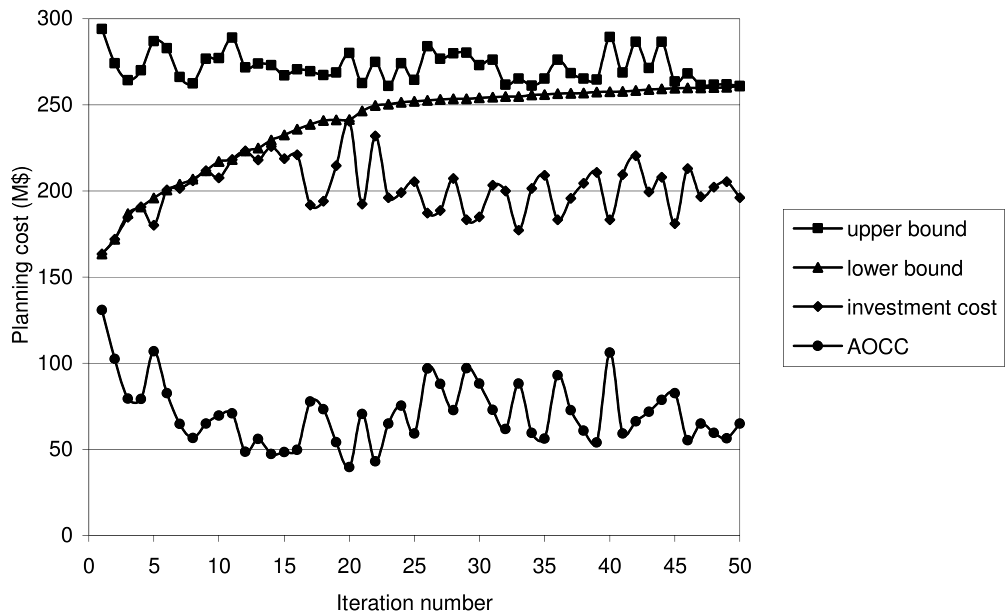

Fig. 3.5. Convergence characteristic of the proposed planning algorithm - An example.

In addition, the transmission company can assure the regulatory authorities that every potential options, including both transmission and generation alternatives, are taken into account in the long term TEP to attain social benefits. Transmission activities are most widely provided in a monopoly basis, and therefore, they require being regulated from a technical and an economic point of view. This ensures the adequate levels of quality of service while inducing expansion and reinforcement investments, as discussed in Chapter 2.

Based on the results of such optimum TEP solutions, the authorities can develop market mechanisms to guide investors for the best planning practices. This may trigger early generation investment as necessary which contribute to social-welfare by mitigating over-investment in transmission network and non-optimal generation investments both of which increase the total cost in the planning horizon. Moreover, if the indicative plan proposes that investment of a generator at a specific bus is critical due to both security and economical concerns, the tendering process can be started without waiting for investors to mitigate the risk of loosing the potential gain.

In competitive markets there is essentially no guarantee that the generation companies (i.e., non-utility investors) will follow those indicative plans prepared with the concern of maximizing social-welfare. Therefore, a method for coordinating *monopoly* transmission planning and *decentralized* generator investment planning might be necessary. Accordingly, the transmission planning method proposed in this chapter is improved in Chapter 4, in a way such that it considers promoting decentralized generator investments through incentive payments within the planning problem.

CHAPTER 4

PROMOTING IPPs TO TRIGGER GENERATOR INVESTMENTS FOR THE OPTIMUM PLANNING

4.1. Introduction

In restructured power markets, until a competitive market has developed sufficiently such that non-utility generation investments are driven solely by competitive forces, the authorities might need to concern ensuring the generation investment projects which are necessary from technical and financial point of view. Otherwise, the deficiency and/or non-optimal placement of new generators under the lack of coordination between transmission and generator investments could result an increase in the total social-cost which might essentially threaten the success of the restructuring efforts.

This Chapter presents a novel model for coordinating *monopoly* transmission and *decentralized* generator investment planning decisions. The proposed approach gauges the level of transmission congestion and security with respect to transmission investments, by decomposing the MIP planning problem with the similar technique proposed in Chapter 3, while considering the promotion of generator investments through incentive payments within the planning problem. It is presented that such incentive payments, which might be utilized to trigger generator investments earlier than the IPPs' projections, could be necessary to satisfy system security and optimum grid expansion. Indeed, this is for nothing but the maximization of social-welfare, which should be the concern of the authorities.

The Chapter is organized as follows. The proposed planning model and the solution methodology are described in Section 4.2. The formulation of the problem is provided in Section 4.3 which presents interaction between the transmission company and IPPs, and incentive mechanism to trigger generation investment. Section 4.4 presents both the case studies of a two-bus system which enables easy understanding of the contribution of this paper, and application of the approach to IEEE 30 bus system. The summary and discussion of the results are given in Section 4.5.

4.2. Modified Network Planning Model

Fig. 4.1 shows the framework of the proposed transmission planning model. The selection of transmission investment candidates is again based on Benders decomposition technique, in which the planning problem is decomposed into a master problem, like presented in Chapter 3, but *three* subproblems this time, representing security and optimal-operation subproblems performed by the transmission company, and investment planning subproblem performed by the IPPs for the candidate generator investments. The master subproblem, which is a MIP problem, considers an investment plan for transmission lines from an initial candidate pool. In addition, it considers incentive payments to IPPs within the transmission expansion planning (TEP) problem, for those investments which contribute to the optimum system planning. The incentive payments, which are determined by each IPP for the corresponding candidate generator investment separately, ensure the investments of those candidate generators which are prioritized in the algorithm in the sense of system security and congestion concern, as described in Section 4.3.3.

Once the candidate investments are identified by the master problem, the security subproblem will check whether this plan can meet the system constraints. The security subproblem assesses the single-contingency criteria along the planning horizon. If any violation occurs, a corresponding security cut will be formed by the security subproblem based on the LP duality theory. Marginal contribution of candidate generators' investments in satisfying security-criteria is considered in the security cuts, which will be added to the master problem for solving the next iteration of the planning problem, by which the lower bound of the problem is updated.

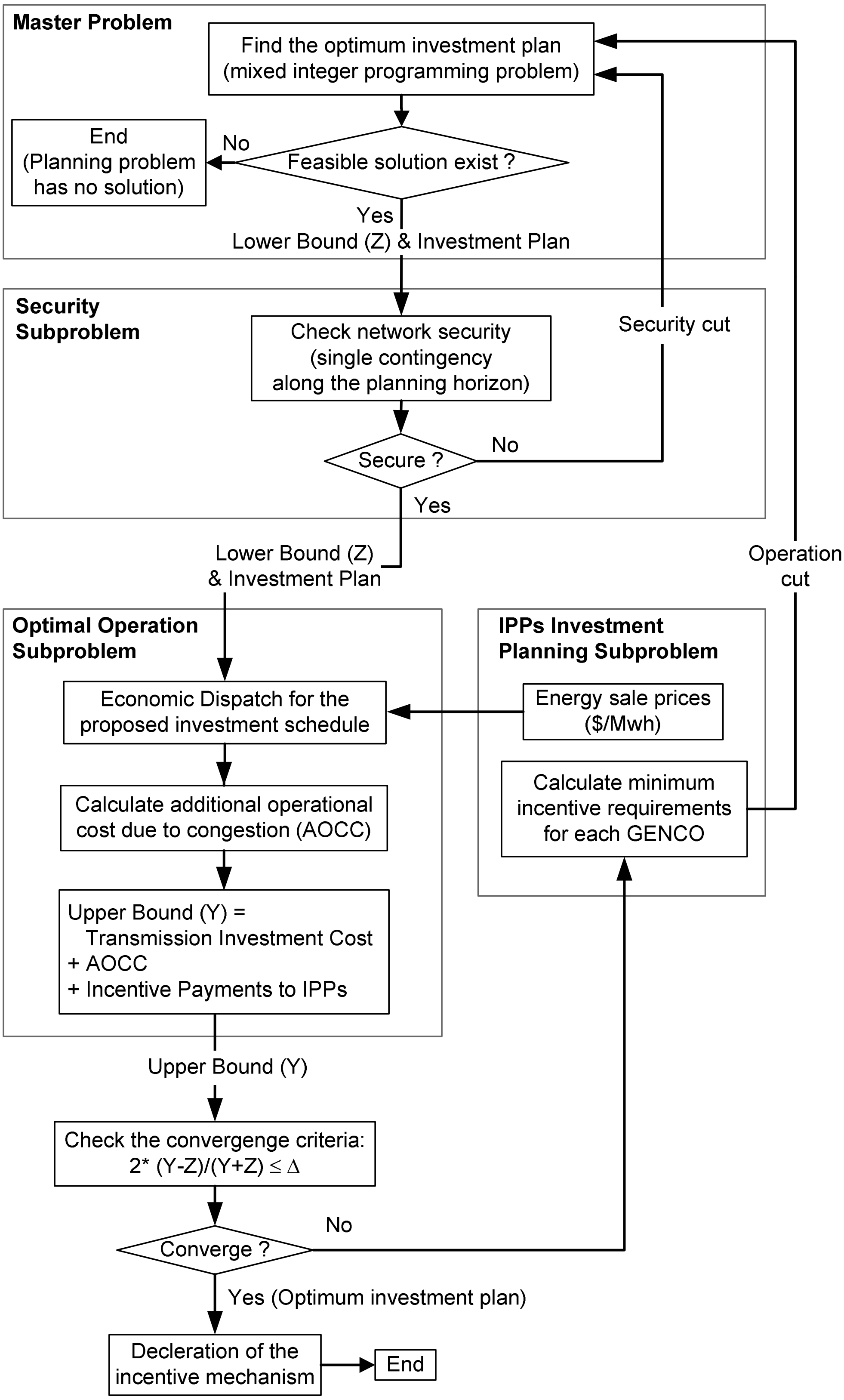

Fig. 4.1. Proposed planning framework.

Once the violations are removed, the proposed investment schedule is fed to the operation subproblem which calculates the upper bound of the planning problem and forms the corresponding operation cut. The operation subproblem requires energy sale prices of both existing and candidate generators as illustrated in Fig. 4.1. The energy sale price of candidate generators are determined by the IPPs individually and independently, taking into account the capital cost of the investment and the expected profit from producing energy, as presented in the following section.

The operation subproblem determines the total additional operation cost due to congestion (AOCC) with comparing the operational costs of constrained and unconstrained networks. It was the conclusion of the Chapter 3 that considering the total AOCC in the planning objective function enables assessing the annual cost of investments (or annual gain by deferral of investments) against the annual congestion level, satisfactorily.

The iterative process between the master problem and subproblems will continue until a converged optimal solution is found through upper and lower bounds. The operation cut includes the incentive payments to IPPs to promote the corresponding investments which contribute to the optimal system expansion from both security and economic point of view.

4.3. Problem Formulation

The objective of the planning problem is to optimize the transmission investment cost, incentive payments to IPPs which contributes to the optimal solution, and the total AOCC, while satisfying the system security along the planning horizon based on the single-contingency criteria. The objective function is formulated as follow:

$$Min \quad Y = \sum_{t=1}^{NT} \sum_{k=1}^{CL} \left[\frac{CI_{kt} * X_{kt}}{(1+d)^{(t-1)}} \right]$$

$$+\sum_{t=1}^{NT}\sum_{i=1}^{NCG}\frac{IP_{it}*X_{it}}{(1+d)^{(t-1)}}$$

$$+\sum_{t=1}^{T}\sum_{b=1}^{NS}\frac{AOCC_{bt}}{(1+d)^{(t-1)}} \tag{4.1}$$

The first two terms of the objective function (4.1) represent the investment cost for new transmission lines and incentive payments to IPPs necessary to trigger corresponding generator investments at the proposed year. The third item is the total AOCC along the planning horizon.

4.3.1. Master Problem

The initial master problem is formulated as follows:

$$Min \quad Z \tag{4.2}$$

s.t.

$$Z \geq \sum_{t=1}^{NT}\sum_{k=1}^{CL}\frac{CI_{kt}*X_{kt}}{(1+d)^{(t-1)}} \tag{4.3}$$

$$\sum_{k=1}^{CL} CI_{kt}*(X_{kt}-X_{k(t-1)}) \leq CI_t \tag{4.4}$$

$$\sum_{k=1}^{CL} PL_k^{\max}*(X_{kt}-X_{k(t-1)}) \leq UC_t \tag{4.5}$$

$$\sum_{k=1}^{CL} (X_{kt}-X_{k(t-1)}) \leq UN_t \tag{4.6}$$

$$X_{kt}=0 \quad if \quad t<CT_k \ . \tag{4.7}$$

The master problem (4.2) is essentially subject to both planning (4.4)-(4.7) and operation constraints. The operation constraints are developed by security-check and optimal-operation subproblems in the form of security and operational cuts, respectively. Note that in the proposed planning model, the generator planning decisions are belong to IPPs, and corresponding planning constraints should be evaluated within the IPP Planning Subproblem.

The initial master problem (4.3) is nothing but the minimization of the transmission investment cost along the planning horizon. Essentially, the first iteration of the master problem will not propose any investment and the objective function is zero. However, in the second and further iterations, transmission and generator investments could be forced by the security and operation cuts as described in the following sections. The master problem provides both the optimum investment plan and lower bound (*Z*) of the planning problem (4.1).

4.3.2. Security-Check Subproblem

The security-check subproblem is again assumed to be satisfying the nodal power balance while maintaining the transmission security based on single-contingency criteria along the planning horizon. The linearized power flow equations (i.e., DC) are utilized based on 1st and 2nd Kirchhoff's laws.

The *base case* corresponds to transmission network conditions without any line contingency. Single-contingency is modeled by repeating all transmission network constraints for each contingency indexed by q. The security-check subproblem for the q^{th} contingency at subperiod b and year t is formulated for the n^{th} solution of the master problem (i.e., n^{th} iteration) as follows:

$$Min \ \ v_{bt}^{nq} = DT_{bt}^{q} * \sum_{j=1}^{ND} P_{C,jbt}^{q} = DT_{bt}^{q} * (1^{T} * r^{q}) \tag{4.8}$$

s.t.

$$\boldsymbol{s}^{q} * \boldsymbol{f}^{q} + \boldsymbol{p}^{q} + \boldsymbol{r}^{q} = \boldsymbol{d} \quad \forall \mathrm{q} \tag{4.9}$$

$$PL_{kbt}^{q} = \gamma_{mn} * (\theta_{m,bt}^{q} - \theta_{n,bt}^{q}) \quad \forall k, \forall q \tag{4.10.a}$$

$$PL_{kbt}^{q} = X_{kt}^{n} * \gamma_{mn} * (\theta_{m,bt}^{q} - \theta_{n,bt}^{q}) \quad \forall k, \forall q \tag{4.10.b}$$

$$\left|PL_{kbt}^{q}\right| \leq PL_{k}^{\max} \quad \forall k, \forall q \tag{4.11.a}$$

$$\left|PL_{kbt}^{q}\right| \leq X_{kt}^{n} * PL_{k}^{\max} \quad \forall k, \forall q \tag{4.11.b}$$

$$P_{G,i}^{\min} \leq P_{G,ibt}^{q} \leq P_{G,i}^{\max} \quad \forall i, \forall q \tag{4.12.a}$$

$$X_{it}^{n} * P_{GC,i}^{\min} \leq P_{GC,ibt}^{q} \leq X_{it}^{n} * P_{GC,i}^{\max} \quad \forall i, \forall q \tag{4.12.b}$$

$$\theta_{ref} = 0. \tag{4.13}$$

where (4.10.b) and (4.11.b) correspond to the candidate lines and (4.12.b) corresponds to the candidate generators. Note that, the candidate generators are considered in the security-check subroblem as well. It is intended to determine the marginal effects of the candidate generators on violation of the security criteria. In case of any security criterion violation along the planning horizon, the security cut corresponding to the proposed investment solution will be calculated as follow:

$$\begin{aligned} & v_{bt}^{nq} + \sum_{i=1}^{NCG} \delta_{1ibt}^{nq} * P_{GC,i}^{\max} * (X_{it} - X_{it}^{n}) \\ & - \sum_{i=1}^{NCG} \delta_{2ibt}^{nq} * P_{GC,i}^{\min} * (X_{it} - X_{it}^{n}) \\ & + \sum_{k=1}^{CL} (\lambda_{1kbt}^{nq} + \lambda_{2kbt}^{nq}) * PL_{k}^{\max} * (X_{kt} - X_{kt}^{n}) \\ & - \sum_{k=1}^{CL} (\pi_{1kbt}^{nq} + \pi_{2kbt}^{nq}) * M_{k} * (X_{kt} - X_{kt}^{n}) \leq 0 . \end{aligned} \tag{4.14}$$

where M_k is the penalty parameter which ensures the 2nd Kirchhoff's law for the candidate lines, and π_1, π_2, λ_1, λ_2, δ_1 and δ_2 are the dual variable vectors corresponding to the constraints which involve candidate investments (4.10)-(4.12).

The dual variables in the security cut are interpreted as the incremental decrease in load curtailment violations. The security cut will be added to the master problem when the objective function of (4.9) is larger than zero which means load curtailment. Security-cut (4.17) indicates that the violation in year t could be mitigated by transmission and/or generator investments. These security cuts are added to the master problem cumulatively until an investment plan is found which satisfies the load curtailment criteria based on the single-contingency criteria along the planning horizon.

4.3.3. IPPs Investment Planning Subproblem

IPPs investment planning subproblem provides information to the network planner about the candidate generator investments, including their location, capacity, energy sale price, and the required incentives to trigger investment, if any. In the proposed planning approach, these incentive requirements will be utilized in forming the operation cut, as will be described below.

The investment planning problem for each candidate generator investment is the maximization of the profit from the corresponding investment along the planning horizon (4.15).

$$Max\ X_i = \sum_{t=1}^{NT} \sum_{b=1}^{NS} \frac{DT_{bt}}{(1+d)^{(t\text{-}1)}} * \begin{pmatrix} R_{C,ibt} * P_{GC,ibt} \\ -OC_{GC,it} * P_{GC,ibt} \end{pmatrix} - \sum_{t=1}^{NT} \frac{CI_{it} * X_{it}}{(1+d)^{(t-1)}} \qquad (4.15)$$

where

$$R_{C,ibt} = \alpha_i * OC_{GC,ibt} \qquad (4.16)$$

The followings are the main assumptions in formulating the IPPs investment planning subproblem:

- There is no coupling between the investment decisions of different IPPs.

- Existing generator(s) of IPPs, *if any*, does not have any influence on their generator investment decisions (i.e., existing and candidate generators are uncoupled in the sense of profit calculation).

Note that the investment decision of an IPP for a specific project depends on the envisaged profit, which is a function of the expected energy production (4.15). For a fixed energy sale price, R_C, the expected profit depends solely on the energy production. Essentially, the expected amount of energy sale is a critical determinant of a candidate generator investment decision.

The correct time for making the investment is when the difference between the expected profit from the energy sale and the annual investment cost is positive. Otherwise, the IPP would not make the investment unless its deficiency is compansated. Considering this, the minimum incentive requirement for a candidate generator investment i for a year t is assumed to be the difference between annual investment cost and the expected profit form the energy sale (4.17).

$$IP_{it} = \frac{CI_{it} * X_{it}}{(1+d)^{(t-1)}} - \sum_{b=1}^{NS} \frac{DT_{bt}}{(1+d)^{(t\text{-}1)}} * \begin{pmatrix} R_{C,ibt} * P_{GC,ibt} \\ -OC_{GC,it} * P_{GC,ibt} \end{pmatrix} \qquad (4.17)$$

When (4.17) is negative, there is no need for promoting the investment as it is already beneficial. Incentive requirement is assumed to be zero in such a case.

In the proposed approach, each IPP provides energy sale price of the corresponding generator investment to the system operator. Then, considering these energy sale prices, the system operator determines the expected economic dispatch along the planning horizon. Based on the dispatch, each IPP determines its annual incentive requirement to make the investment. These incentive requirements are utilized in determining the operation cuts as described in the following section. The information transfer between the transmission company and IPPs continues for every feasible (i.e., secure) planning solution proposed by the master problem as illustrated in Fig. 2, until an optimum planning solution is found.

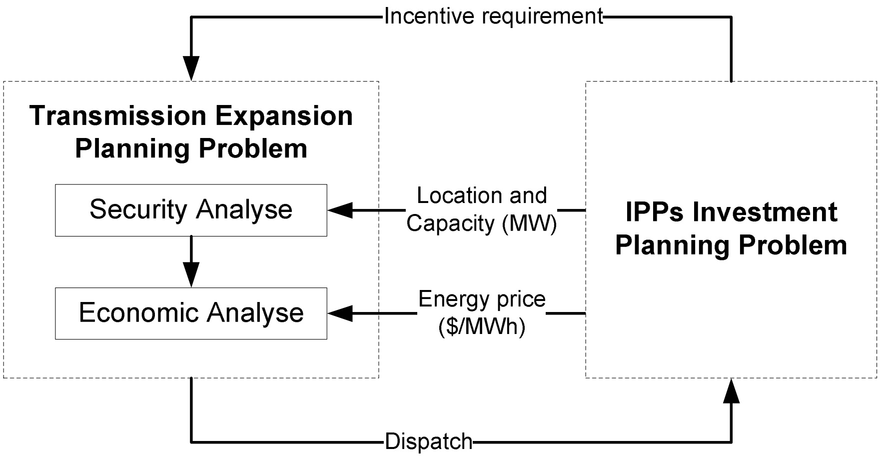

Fig. 4.2. Coordination of the transmission company and IPPs.

4.3.4. Optimal-Operation Subproblem

For each feasible planning solution provided by the security-check subproblem, the optimal-operation subproblem runs economic dispatch along the horizon (see Fig. 4.1). The economic dispatch for every subperiod b and year t for the current investment solution r is formulated as follows:

$$Min \quad w1_{bt}^{n} = DT_{bt} * \left[\sum_{i=1}^{NG} (R_{ibt} * P_{G,ibt}) + \sum_{i=1}^{NCG} (R_{C,ibt} * P_{GC,ibt}) \right] \tag{4.18}$$

s.t.

$$\boldsymbol{s} * \boldsymbol{f} + \boldsymbol{p} = \boldsymbol{d} \tag{4.19}$$

$$PL_{kbt} = \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \quad \forall k \tag{4.20.a}$$

$$PL_{kbt} = X_{kt}^{n} * \gamma_{mn} * (\theta_{m,bt} - \theta_{n,bt}) \quad \forall k \tag{4.20.b}$$

$$\left| PL_{kbt} \right| \le PL_{k}^{\max} \quad \forall k \tag{4.21.a}$$

$$\left|PL_{kbt}\right| \le X_{kt}^{n} * PL_{k}^{\max} \quad \forall k \tag{4.21.b}$$

$$P_{G,i}^{\min} \le P_{G,ibt} \le P_{G,i}^{\max} \quad \forall i \tag{4.22.a}$$

$$X_{it}^{n} * P_{GC,i}^{\min} \le P_{GC,ibt} \le X_{it}^{n} * P_{GC,i}^{\max} \quad \forall i \tag{4.22.b}$$

$$\theta_{ref} = 0\,. \tag{4.23}$$

The economic dispatch solution is utilized in calculating the total AOCC along the horizon. Note that, the economic dispatch is also utilized by the IPPs to determine the required incentives as described above.

In order to calculate the total AOCC, the total operation cost along the horizon is recalculated without considering transmission line constraints (4.21). The difference between the two economic dispatch solutions gives the total AOCC for the n^{th} planning solution at subperiod b and year t, as described in Chapter 3.

The summation of the total AOCC, capital investment cost of candidate transmission lines and the incentive payments to candidate IPPs gives the upper bound (Y) of the planning problem (4.1) for the current iteration n. The convergence of the planning algorithm depends on the upper and lower bounds (Z) of the planning problem as illustrated in Fig. 4.1. If the algorithm does not converge, an operation cut is generated and added to the master problem for the next iteration. The operation cut at the n^{th} iteration is:

$$Z \ge \sum_{t=1}^{NT} \sum_{b=1}^{B} AOCC_{bt}^{n}$$

$$+\sum_{t=1}^{NT} \sum_{k=1}^{CL} \left(CI_{kt} * (X_{kt} - X_{kt}^{n}) \right)$$

$$+\sum_{t=1}^{NT}\sum_{i=1}^{NCG} SP_{it} *(X_{it} - X_{it}^{n})$$

$$+\sum_{t=1}^{NT}\sum_{b=1}^{NS}\left[\sum_{i=1}^{NCG}\left(\sigma 1_{ibt}^{n} * P_{GC,i}^{\max} *(X_{it} - X_{it}^{n})\right)\right]$$

$$-\sum_{t=1}^{NT}\sum_{b=1}^{NS}\left[\sum_{i=1}^{NCG}\left(\sigma 2_{ibt}^{n} * P_{GC,i}^{\min} *(X_{it} - X_{it}^{n})\right)\right]$$

$$+\sum_{t=1}^{NT}\sum_{b=1}^{NS}\left[\sum_{k=1}^{CL}(\alpha_{1kbt}^{n} + \alpha_{2kbt}^{n}) * PL_{k}^{\max} *(X_{kt} - X_{kt}^{n})\right]$$

$$-\sum_{t=1}^{NT}\sum_{b=1}^{NS}\left[\sum_{k=1}^{CL}(\beta_{1kbt}^{n} + \beta_{2kbt}^{n}) * M_{k} *(X_{kt} - X_{kt}^{n})\right]. \tag{4.24}$$

where β_1, β_2, α_1, α_2, σ_1 and σ_2 are dual variable vectors corresponding to the constraints of the optimal-operation subproblem that involve candidate investments (same approach utilized in the security-check subproblem).

The dual variables of the optimal-operation subproblem in (4.24) force the optimization algorithm to search for a better economic dispatch that would essentially result in a better planning solution. The operation cut indicates that depending on the gain/cost ratio, the objective value of the planning problem (4.1) can be decreased by changing the investment status of the candidate investments along the horizon. From the regulatory point of view, the incentive payments to IPPs in the planning problem indeed correspond to cost of generator investments to ensure optimum grid expansion for maximizing the social-welfare.

4.4. Case Studies

Case studies for discussing the effectiveness of the proposed model include a two-bus system and the IEEE 30-bus system.

4.4.1. Two-bus system

The two-bus system depicted in Fig. 4.3 shows two generators that can supply loads at two different buses. It is assumed that the generator G1, which is located at a distance from large loads at Bus 2, is cheaper than generator G2 which is closer. Two additional units will be in operation at Bus 1 in year 3 (i.e., assumed to be under construction). The solid lines correspond to existing transmission lines, and the dashed lines correspond to transmission reinforcement. The dashed generator at Bus 2 corresponds to a candidate investment by an IPP. The annual load growth rates are assumed to be 5% at Bus 1 and 8% at Bus 2.

Transmission investment costs is assumed to be 800 $/MW-mile. A 5% annual interest rate based on 10-years scheduled loan is utilized to calculate the annual cost of capital required for the investment of both transmission line and the generator. Financial figures of the generator investment are given in Table 4.1.

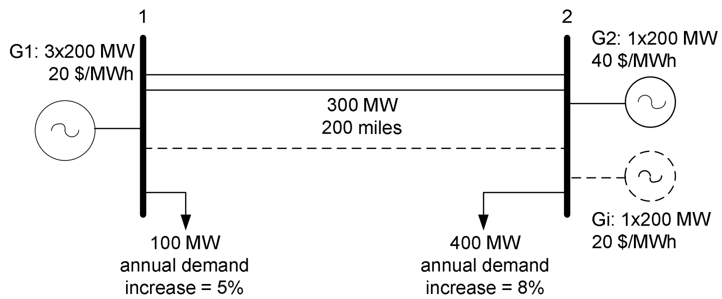

Fig. 4.3. Two-bus system

According to the financial assumptions given in Table 4.1, the discounted value of the annual profit from investment of the candidate generator is approximately 2 M$/year, provided that it is operated full capacity (i.e., 8760*200=1752 GWh production per year). The profit will essentially decrease along the planning horizon if its average operation will occur less than full capacity.

Table 4.1. Two-Bus System Generator Data (G_i)

Capacity (MW)	Capital cost (M$/MW)	Energy price ($/MWh)	Profit in the energy price (%)
200	0.75	20	60

In order to observe the effect of promoting the investment of the candidate generator investment on optimal network expansion, the following two scenarios are investigated.

Case 1: In the first case, optimum TEP problem is solved without considering the candidate generator investment. Given the demand forecasts, the total demand to be supplied in two buses will be approximately 1025 MW after 10 years. The existing generators could not supply this demand unless the transmission line enforcement takes place, since the G2 is not sufficient to supply the load at Bus 2 alone. The planning problem in this case is only to determine optimum timing of the transmission line investment between Buses 1 and 2.

The results of the transmission planning problem are given in Table 4.2. Transmission enforcement takes place in year 7 at the expense of congestion at year 6 as shown. This is obvious since the total AOCC at year 6 is smaller than the annual investment cost of the transmission line. Note that, 25 MW of the total demand is supplied by the expensive generator G2 at year 10, since the G1 is already loaded full capacity. Nevertheless, the total AOCC is zero in year 10 according to definition.

Table 4.2. Two-Bus System Case 1 Results

Transmission line investment	TTIC * (M$)	AOCC (M$)	TC ** (M$)
Year 7	24.44	6.09	30.53

* TTIC: Total transmission investment cost,
** TC: Total cost along the planning horizon.

Case 2: In this case, investment decision of the candidate generator at Bus 2 is considered in the planning problem. The results given in Table 4.3 show that the transmission line enforcement is deferred by 4 years provided that the candidate generator investment is procured in year 7. Although the candidate generator is loaded full capacity in year 10, the transmission line investment mitigates the possible congestion by enabling the dispatch of cheaper generator G1. The AOCC of 6.09 M$ is again due to congestion in year 6, as in Case 1.

Table 4.3. Two-Bus System Case 2 Results

Transmission line investment	Generator investment	TTIC (M$)	IR* (M$)	AOCC (M$)	TC (M$)
Year 10	Year 7	6.11	14.44	6.09	26.64

* IR: Incentive requirement by the IPP.

Annual incentive payments to trigger generator investment are given in Table 4.4. Since no dispatch is proposed, the incentive requirement in years between 1 and 6 is essentially equal to the annual capital cost of the generator. The incentive requirements in years 7 and 8 are to compensate for deficit of the IPP due to low dispatch levels. Note that, the candidate generator is dispatched ≈43% of its full capacity in year 7 and ≈70% of its full capacity in year 8.

Table 4.4. Two-Bus System Case 2 Incentive Payments

Year	1-6	7	8	9	10
Dispatch (MW)	0	85.53	140.37	199.6	200
IR (M$)	19.1	10.1	4.34	0	0
Investment status of Gi *	0	1	1	1	1

* If installed: 1, otherwise: 0.

Even though the energy sale prices of the existing generator G1 and candidate generator Gi are same, dispatch priority is given to G1. It is intended to represent the following fact here. The existing generators, like the G1 in this example, might already have long-term contracts and therefore deserve the dispatch priority, which is common in reality.

Compare of the total planning costs of two cases shows the effectiveness of promoting generator investments in optimum grid planning problem. It is presented that incentive payments might be required to trigger generator investments earlier than envisaged by the IPPs. There is only one candidate generator in this simple two-bus system. In case of more than one candidate, those which contribute to system security and optimum operation more should be given the priority. The security and operational cuts in the proposed planning approach satisfies this criterion involving the marginal effects of the generator investments on system security and optimum operation, respectively. Promoting IPPs among more than one candidate generator investments is investigated in the following Section.

Table 4.5 compares the results of Case 1 and 2 from the consumer point of view. Case 2 provides more economic solution to the consumers as shown. Although the total cost difference between the two cases is 3.89 M$ (compare the TCs of Table 4.2 and 4.3) from the transmission company point of view, it is 8.52 M$ from the consumer viewpoint (see Table 4.5). Total planning cost difference between these two viewpoints can be explained as follows. In Case 1, the dispatch of expensive generator G2 is inevitable in the last year as the G1 is already dispatched full capacity and there is no other generator but the G2. Although the total AOCC is zero in year 10 by definition, the operation of G2 essentially increases the operation cost for the consumers. Indeed, the difference (i.e., 8.52 - 3.89 = 4.63 M$) corresponds to this increase. This example illustrates that the utilization of AOCC approach satisfies the optimum planning solution while enabling us to assess the annual cost of investments (or annual gain by deferral of investments) against the annual congestion level. In the proposed model, the annual cost of candidate generator investments is the corresponding annual incentive payments.

Table 4.5. Two-Bus System Consumer Point of View

Case	IRC * (M$)	TEC ** (M$)	TC (M$)
1	24.44	1426.14	1450.58
2	20.55	1421.51	1442.06

* IRC: Investment related cost (TTIC + Total incentive payments to IPP).
** TEC: Total energy cost.

One of the main concerns in promoting market players is determining an incentive mechanism which is fair to every participant. In the example given above, the corresponding IPP of the existing generator G2 at Bus 2 might consider that the incentive payments will provide unfair advantages to Gi in the sense of contributing system security. Indeed, both G2 and Gi have the same marginal effect on the supply security, although the Gi contributes to the economic dispatch additionally. On the other hand, if the G2 also benefits from the promotion then the cost of planning solution might deviate from the optimum drastically.

Before proposing an incentive method, the results of two-bus example should be elaborated. The Gi in Case 2 deserves incentive payments due to its contribution not only to system security but also optimum operation. Considering this fact, the following incentive mechanism could be proposed. The additional cost of energy due to incentive payment in year 7 is 13.48 $/MWh (i.e., 10.1 M$ / 85.53 MW / 8760 h). Accordingly, 20 + 13.48 = 33.48 $/MWh is the breakpoint energy sale price for the IPP to make the investment of Gi in year 7. In order to be fair, a tender could be opened in the initial year to buy 85.53 MW * 8760 h ≈ 750 GWh energy for 33.48 $/MWh in year 7, and 140.37 MW * 8760 h ≈ 1230 GWh power for 23.53 $/MWh in year 8. If the existing generator G2 agrees to make a contract in advance to sale such amount of energy for those predefined prices, then there is no need for promoting the investment. It should be noted that this amount of energy purchase agreement with G2 in advance will result only delay of transmission enforcement by 2 years unless the investment of G2 takes place in year 9. On the other hand, given no incentive requirement in year 8, the corresponding IPP is expected to make the investment. If not, the G2 will essentially continue to have its market power unless the transmission line enforcement takes place.

Given the feasibility of investing Gi in year 7 with some additional incentives, the existing generator G2 is clearly competitive as its energy sale price (40 $/MWh) is higher than that of Gi even after incentive payment (i.e., 33.48 $/MWh). From this point of view, the proposed approach not only ensures system security in a most economic way but also enables appraisal of the expected energy prices in advance.

Thereby, the regulatory authority would have idea about the competition level and the market power.

4.4.2. IEEE 30 Bus system

The proposed planning approach is applied to IEEE 30 bus system, depicted in Fig. 4.4, to analyze its performance when there are more than one candidate generator investments. The original IEEE 30 bus system is a little bit modified for the purpose of the analysis. The existing transmission grid is enforced in order to satisfy the single-contingency security criteria at the initial year. Those transmission enforcements made on the original data are indicated on the figure. The initial configuration of the grid consists of 50 transmission lines, 15 candidate transmission line investments, 21 demand buses, 7 existing power plants and 8 candidate generator investments. Lengths of each transmission lines (in miles) are indicated on the lines in Fig. 4.4. The load buses which have relatively higher load density are indicated by bold arrows in the figure. For simplicity, capacities of all generator units are assumed to be same. The modified IEEE 30 bus system data which include transmission lines, generators and forecasted load information are given in Appendix C.

The dashed lines in Fig. 4.4 correspond to the candidate transmission investments to be analyzed. The initial set of candidate transmission lines are determined based on preliminary load flow analysis. The lines which are loaded more than 50% in the initial year are selected as candidate investments. For the simplicity of the problem, the required construction time of both transmission lines and generators is assumed to be one year.

Candidate investment pool involves 3 different types of generators as illustrated in Table 4.6. Realistic financial values were utilized as close as possible. For example, although capital investment cost of the hydraulic generator is the highest, its energy sale price is minimum providing the highest profit for the corresponding energy sale price. It is assumed that all candidate generators provide the same amount of annual profit (i.e., $/year) in case of operating full capacity.

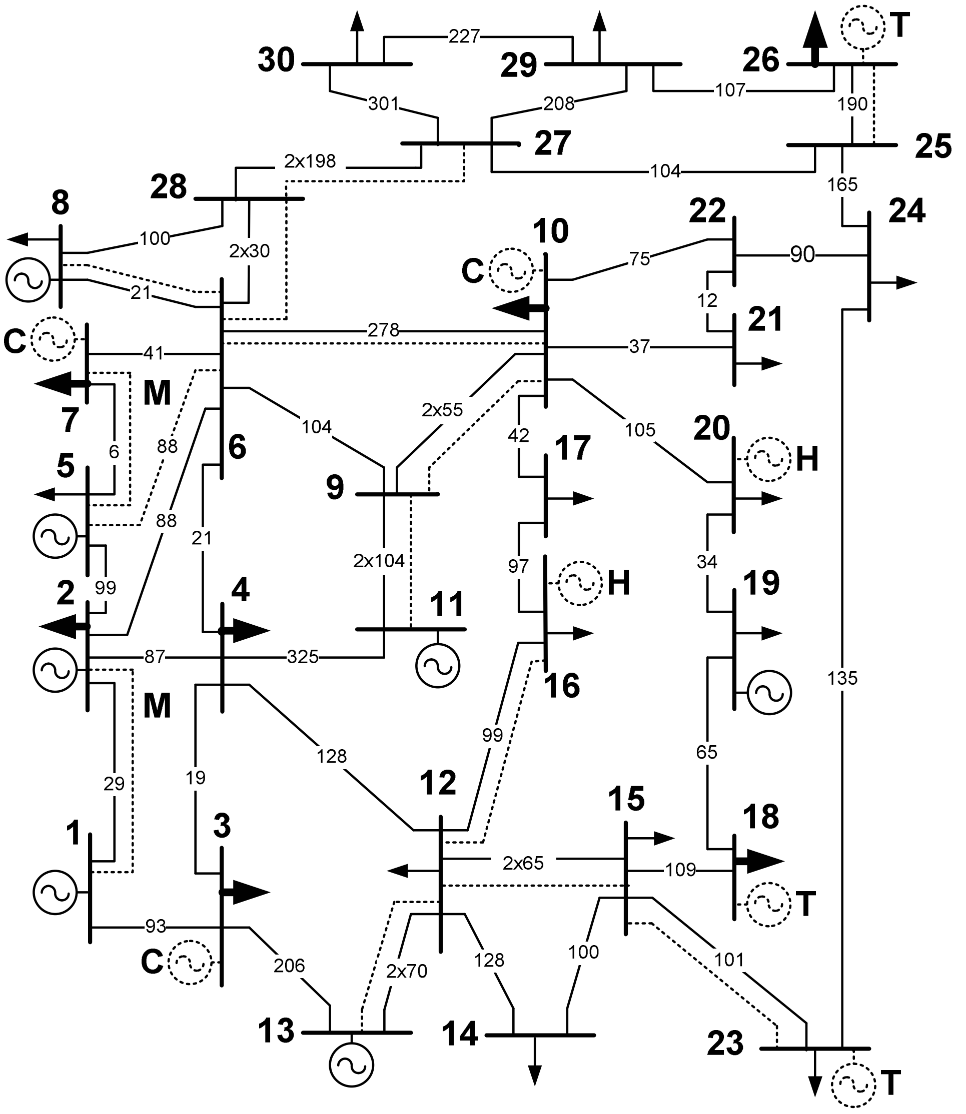

Fig. 4.4. Modified IEEE 30-bus System.

Table 4.6. IEEE-30 Bus System Candidate Generator Types

Type [(1)]	Capacity (MW)	IC [(2)] (M$/MW)	Loan schedule	ESP [(3)] ($/MWh)	Profit [(4)] (%)
H	300 or 100 (see the Case studies)	1	20 years 7%	18	70
T		0.6		20	40
C		0.5		22	30

[(1)] H: Hydraulic power plant (PP); T: Coal fired thermal PP; C: Natural gas combined cycle PP.
[(2)] IC: Overnight investment cost.
[(3)] ESP: Energy sale price.
[(4)] Profit in the energy sale price.

It is also assumed that some buses of the power system, which have high load distribution factors (bold arrows in Fig. 4.4), places in a metropolitan region so that capital investment cost of transmission line enforcement in those regions is higher than the others. Such regions are indicated by 'M' (representing Metropolitan) in Fig. 4.4.

A planning year is divided into 4 subperiods representing seasonal load pattern. The following four different scenarios are considered to analyze the performance of the proposed planning model. Planning horizon is assumed as 10 years in all scenarios. The results are summarized in Table 4.7.

Case 1: It is assumed that annual peak demand increase is 2% in all seasons along the planning horizon. This is the case which the existing generator units are sufficient to supply the forecasted demand. Given the low demand increase ratio, the planning model does not propose any incentive payments to IPPs. Transmission line investments shown in Table 4.7 are already sufficient to satisfy security criteria while optimizing the total investment cost and the transmission congestion level along the planning horizon. In other words, the incentive requirements by IPPs are considerably high if compared to the transmission investment solution.

Case 2: Given the assumption of proportional relation between the capital investment cost and the capacity of the generator (see Table 4.6), the capacity of candidate generators are reduced to a level such that the amount of annual incentive payments are comparable with the transmission investment costs. Capacity of the candidate generators is decreased to 100 MW for this purpose (it was 300 MW in Case 1). The other financial figures in Table 4.6 are remained same. The planning result in Table 4.7 show that, the investment of hydraulic generator at Bus 16 (i.e., GH16) in year 1 defers the transmission line investments proposed in Case 1 while satisfying the security criteria with a reduced AOCC along the horizon.

Table 4.7. 30-Bus System Results Summary

Case	API *	Investment **	TIC (M$)	IR (M$)	AOCC (M$)	TC (M$)
1	2%	L9-10; Y1 L5-7; Y2 L9-11; Y3	31.19	-	24.64	55.83
2	2%	L9-10; Y4 L5-7; Y5 L9-11; Y6 GH16; Y1	20.45	≈ 5	21.40	46.85
3	5%	L5-6; Y1 L5-7; Y1 L9-10; Y6 L9-11; Y9 L12-16; Y10 L15-23; Y10 GH16; Y2 GH20; Y7	53.65	40.56	≈ 0	94.21
4	7%	L5-6; Y1 L5-7; Y1 L9-10; Y8 L9-11; Y7 GT26; Y7 GT23; Y10 GH16; Y5 GH20; Y2	51.52	100.85	≈ 0	152.37

* API: Annual peak demand increase (%)
** Li-j: Investment on Transmission line from bus i to bus j; Yi: Investment in year i; GX,i: Candidate generator at bus i (X: generator type index).

The dispatch proposed for GH16 along the horizon and corresponding annual incentive requirements are given in Table 4.8. Although the generator is dispatched full capacity during peak demand seasons (i.e., S2 and S4) of each year, this is not the case during the off-peak seasons. It is assumed that, for the same energy sale price, dispatch priority is given to the already existing generators considering their possible long-term contracts. Consequently, the incentive requirement in the initial years is due to this underloaded operation of the GH16 during the off-peak seasons. An energy purchase agreement could be made with the corresponding IPP in advance to trigger investment of GH16 in year 1. Financial figures of such an agreement are proposed in Table 4.8 considering the approach described in two-bus example.

Table 4.8. 30-Bus System Case 2 (Dispatch and Incentive Payments for GH16)

Years		Y1*	Y2	Y3	Y4	Y5	Y6	Y7	Y8	Y9-10
Dispatch (MW)	S1**	0	0	0	67	89	79	89	99	100
	S2	100	100	100	100	100	100	100	100	100
	S3	30	100	100	100	100	100	100	100	100
	S4	100	100	100	100	100	100	100	100	100
IR (M$)		2.95	1.03	1.03	0	0	0	0	0	0
Contract in advance	$/MWh	24	19	19	0	0	0	0	0	0
	GWh	500	650	650	0	0	0	0	0	0

* Yi: Year along the planning horizon
** Si: Season of a year

Case 3: Annual peak demand increase is now 5% so that the total capacity of the existing generators is not sufficient to supply the forecasted demand along the planning horizon. Contrary to the previous cases, generator investment is inevitable in this scenario to satisfy the system security criteria. Assuming that the capacity of all candidate generators is 300 MW (like in Case 1), the planning model proposes the combination of transmission and generator investments shown in Table 4.7, which optimizes the grid expansion problem. It is worth to note that, given their lowest energy sale prices, the hydraulic generators are given the priority not only for the security concern but also to optimize congestion level of the grid along the planning horizon. Indeed, the expected AOCC is zero under the proposed investments, as shown in Table 4.7.

Case 4: Owing to their relatively high energy sale prices, investment of the other types of candidate generators can be promoted only if they contribute to system security. In case of 7% annual peak demand increase, investments of the thermal generators at buses 23 and 26 are proposed in addition to the hydraulic generators to compensate for the supply deficiency. The optimum investment combination is shown in Table 4.7.

The 30-bus system example shows how the incentive payments - when necessary - could be prioritized among more than one candidate generator investments to satisfy system security and optimize grid expansion. It is presented that the optimum investment combination which satisfies the system security criteria could already mitigate the congestion along the horizon completely (Cases 3 and 4). On the other hand, in case of sufficient installed capacity, investment of candidate generators could be promoted only when the amount of corresponding incentive payments is comparable with the transmission investment costs (Cases 1 and 2).

4.5. Summary and Discussion of the Results

In this Chapter, a novel multi-year grid expansion planning approach is proposed which considers incentive payments to IPPs within the planning problem. Incentive payments to IPPs are considered to trigger candidate generator investments when necessary from the network security point of view. Benders decomposition technique is utilized successfully to optimize the sum of investment cost of transmission lines, incentive payments to IPPs and the congestion level forecasted along the planning horizon. The results of numerical examples show the effectiveness of the proposed model.

The proposed planning approach coordinates the monopoly transmission and decentralized generation investment decisions in order to get an optimum planning solution in a deregulated market. Such incentive mechanisms might be indispensable during the market development phase after restructuring of power systems. The uncertainties in the sector including energy prices and the role of government and monopoly institutions are among the main risk factors of non-utility investors that could result in delay of decentralized generator investment decisions, and this might threat the power system security during this transient period. This would essentially threat the success of the restructuring and deregulation efforts in electricity markets.

Providing an incentive mechanism which is fair to every market participant is a challenge. Opening a tender based on purchasing some predefined amount of energy in advance for a fixed price could be a solution as proposed in the numerical examples. Nevertheless, developing incentive mechanisms deserves more research to be considered in a future study.

CHAPTER 5

CONCLUSION

The restructuring of electricity industry has led to dramatic changes from monopoly to competitive markets in generation and retailing sectors of power systems while keeping transmission and distribution services, which involve large sunk costs accumulated under this integrated structure, as natural monopolies with strong economies of scale. Therefore, in order to encourage competition in generation and to ensure open access to transmission network on an equitable basis to market participants, generation, transmission, and distribution segments of the power industry have been unbundled in many countries worldwide. The introduction of competition in the generation sector and the assignment of market-based missions to the transmission segment of power industry, including the provision of open access and maximization of energy trade opportunities, have challenged the transmission expansion planning (TEP) paradigm in many respects.

A key to enhancing electricity restructuring is to have an adequate competition in the generation sector of power industry. This requires a sufficient transmission capacity to support trading in electricity markets while maintaining the system reliability. However, TEP for managing adequate transmission capacity is a major challenge which involves uncertainties and risks in restructured electricity environment. The TEP process has become complicated in the restructured electric utility industry because generation investment decisions are now based on market forces rather than a centralized decision process. In electricity markets, the inherent uncertainty over the configuration of power systems is indeed among the major issues which create new challenges for power systems planners.

In electricity markets, which the level of competition is already sufficient to ensure non-utility generator investments, there might be no need for additional measures to mitigate the concern of supply deficiency due to insufficient investments. However, this could be an important concern for those countries which are at the market development phase, like Turkey. The uncertainties in the sector including forecasted energy prices, removal of subsidies, the role of monopoly institutions, and market power status of the state-owned generation and wholesale companies are among the risk factors of non-utility investors that could result in delay of generator investment decisions, and this might threat the power system security during this transient period. Therefore, the authorities supporting the restructuring process in electricity sector should concern the way of mitigating such concerns. They should think as if a non-utility investor when necessary, until the market has developed such that the security of the power system could be ensured by solely competition.

The coordination between the monopoly transmission and decentralized generation planning decisions is very important for the success of restructuring process in the electricity sector. Insufficient and improper placement of transmission lines and generators could be among the main reason for network constraints which might threaten the success of the restructuring efforts in the electric power industry.

Focusing on transmission expansion planning (TEP) problem for restructured power systems and addresses challenges specifically in countries where electricity market is in developing phase after liberalization of power industry for establishing a competitive market, a novel multi-year TEP model is developed in this thesis study which takes into account transmission congestion level and the impact of generation expansions in the planning horizon within the planning problem. The annual evaluation of transmission investments and congestion level along with local generation investment costs enables more realistic assessments of generation and transmission investment decisions if compared to the traditional planning approaches. The inclusion of security criteria in the model strengthens the investments planning.

The utilization of Benders decomposition methodology in optimizing the sum of investment costs of transmission lines and generators, and the total congestion level forecasted along the planning horizon, is proposed for the first time in this study. The Benders decomposition technique is utilized successfully to decompose the TEP, which is a complex mixed-integer programming problem, into a master problem (i.e., minimizing the investment cost; an integer-programming-problem) and two subproblems representing security and optimal operation both of which are continuous-programming-problems. Numerical examples illustrate the convergence characteristic of the proposed algorithm and how the iterative process between the master problem and subproblems continues successfully until a converged optimal solution is found through upper and lower bounds. Given the importance of congestion level particularly for the developing markets, the concept of total additional operation cost due to congestion (AOCC) is introduced in the optimal operation subproblem of the proposed model to represent the congestion level. The study is unique in utilizing the AOCC concept within the TEP problem.

The proposed model could be utilized by monopoly transmission companies to provide indicative plans to the market players and authorities for the long-term system expansion, which might be quite necessary particularly during the development of the market. However, in competitive markets, there is no guarantee that the generation companies will follow those indicative plans prepared with the concern of maximizing social-welfare. Nevertheless, by preparing such long-term plans, the transmission company can assure the regulatory authority that every potential options, including both transmission and generation alternatives, are taken into account in the long term TEP to attain social benefits. The regulatory authorities can develop market mechanisms to guide investors for the best planning practices and this might trigger early generation investment as necessary. Moreover, if the indicative plan proposes that investment of a generator at a specific bus is critical due to both security and economical concerns, the tendering process can be started without waiting for a non-utility investment.

Given the necessity of coordination between the monopoly transmission and decentralized generator investment plannings, the proposed planning method is improved further to consider promoting decentralized generator investments through incentive payments. Such incentives might be necessary to trigger independent power producers to make investments earlier than their projections, as illustrated by numerical examples. The proposed novel approach not only ensures system security in a most economic way but also enables appraisal of the expected energy prices in advance. Thereby, the regulatory authority would have idea about the competition level and the market power. The proposed planning model is applicable to power systems after restructuring, in particular when uncertainties in the sector could result in delay of generator investment decisions by the IPPs. The approach is unique in addressing inherently the concern of whether the market participants would follow the optimum grid plans or not.

Combining the discussions made regarding challenges with the TEP problem in deregulated electricity environment and results of the proposed planning approaches, the following general remarks could be given for countries which have restructured their power industry for establishing a competitive market:

- Generation investment decisions, either centralized or decentralized, are concerned with many issues including the primary energy sources of the country, geographical placement of loads, long-term energy contracts with neighboring countries (e.g., gas pipe lines contracts), energy policy of the government (e.g., incentives for green energy), budgetary constraints of state-owned companies (generation and transmission), etc. The optimum transmission enforcement schedule may be altered considerably depending on several factors including generation investment decisions, load duration, annual load increment rate, planning horizon, and certainly financial constraints. Regulatory agencies and transmission service providers should consider these factors and indispensable interdependency between transmission and generation planning to optimize the long-term social benefits. The authorities have to shoulder the responsibility in network planning and develop mechanisms to direct the non-utility investors when necessary in the sense of supply security.

- The unbundling process in restructuring of power systems necessitates an independent institution for the long-term planning of power systems. Such an institution should be non-discriminatory to transmission companies as well as to other institutions and market players, given the mandate for the coordination among institutions to achieve a social solution as illustrated in the study.

In addition to those general conclusive remarks, the following remarks could be given specific to Turkey where the liberalization of the electric power industry is underway for establishing a competitive market. These conclusive remarks are applicable to other countries as well, particularly for those which are in the similar condition in the sense of historical developments of the electricity sector.

- Turkey is one of the countries that have been liberalizing its power industry. The ongoing efforts to unbundle and restructure the power industry and to establish prospective interconnection projects to take advantage of cross-border electricity trading with neighboring countries are among the main factors that point out the urgent necessity for transmission capacity enhancement in Turkey.

- According to the current regulations, the transmission company of Turkey has to submit a document of ‘connection opportunities’ for each planning horizon to inform the market players about the transmission system condition and give signals to direct investments. This document should be prepared in the context of a multi-year planning considering the impacts of generator investments, like proposed in this thesis study. Given the fact that the success of restructuring efforts depends on the ‘availability’ of the transmission network that permits development of the competitive market, transmission congestions possible in the future should necessarily be considered within the planning problem.

- The integration of transmission network ownership and system operation in a single framework (i.e., state-owned transmission company, TEIAS) could facilitate high operational and planning efficiencies to be achieved in Turkey, by using the same entity to control, operate, maintain, and expand the grid. Essentially, the key point is to regulate the monopoly state-owned transmission company in the most effective manner. In this sense, the transmission company could take some responsibility of the direct and indirect transmission costs in addition to its planning duty. Under the concept of 'regulated revenue' approach, which many regulators have been inclined to use worldwide to regulate the monopoly transmission company (including Turkey), there is no incentive to reduce the congestion, given that the income granted to the transmission provider is constant irrespective of the performance of the transmission system. Such incentive-based regulatory mechanisms, which have been successfully applied in some developed countries, may motivate the state-owned company to expand the transmission network in an optimal manner, beyond its responsibility to comply with minimum standards of network design, operation, and maintenance.

- The utilization of local generation as an alternative way to delay the need for capital expenditures to upgrade a congested transmission network is a very topical issue that is being discussed worldwide. The considerable renewable potential of the country including the hydraulic and wind energy points out the importance of local generation utilization in the restructured Turkish power industry within the near future. The regulatory authority in Turkey should consider the interests of IPPs in such investments that are highly associated with the transmission planning.

- Some sort of location-based transmission pricing mechanism that takes into account the transmission constraints should be designed in accordance with the envisaged market model in the country. Such market-based mechanism should provide locational signals to the market participants, and contribute to the transmission planning decisions. A proper transmission pricing scheme that considers transmission constraints could motivate new transmission and/or generating capacity investments for improving the electricity market efficiency and perhaps prevent gaming in day-ahead and real-time balancing markets.

- The implementation of cost-based electricity prices and the dominant role of a state-owned trading company (TETAS) are among the key issues for the development of a competitive electricity market in Turkey. Therefore, a well-designed electricity tariff balancing strategy that considers the social, economic, and political issues of the country is quite important. Determining subsidies and defining a phase-out plan for subsidies are among the critical issues for a transition phase in restructuring and are essential for introducing incremental steps in adjusting electricity prices. The development of a competitive electricity market depends on the success of this transition phase in Turkey.

Finally, the current situation of electricity sector in Turkey shows that, the restructuring efforts unfortunately have not reached the key goal: to have an adequate competition in the generation sector of power industry and reduce the net cost through increased competition. Moreover, a supply deficiency is expected in 2008 summer peak demand conditions and so on, and therefore, the authorities are trying to find urgent solutions to trigger generator investments by the IPPs. Draft proposals on the authorities' desk include the authorization of the system operator and state-owned wholesale company, to make long-term energy and capacity contracts with the generator companies in advance, in order not to suffer supply deficiency and market power.

The intervention of transmission company to the market to mitigate supply security concern matches up with the main idea of this thesis research. That is, the coordination of monopoly transmission and decentralized generation planning decisions is essential in optimum system operation and planning to maximize the social-welfare. This is indeed among the main responsibilities of the state-owned transmission company which is subjected to regulation. However, the continuous involvement of the state-owned wholesale company in the market is a handicap in front of the development of the liberalized market structure, conflicting with the main target of the restructuring efforts. The government and authorities supporting the restructuring process in electricity sector should concern the way of developing non-utility generator participation in the market in a competitive manner instead of enforcing the monopolistic structure.

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APPENDIX - A

BENDERS DECOMPOSITION METHODOLOGY - DEFINITIONS AND THEOREMS -

Benders decomposition is a popular optimization technique. J. F. Benders initially introduced the Benders decomposition algorithm for solving large-scale Mixed Integer Programming (MIP) problems [15]. The basic idea is to separate integer variables and real variables and treat larger optimization problem via decomposition in order to speed up the calculation speed. The Benders decomposition algorithm has been successfully used in a different way to take advantage of underlying problem structures for various optimization problems, such as network design, optimal transportation problem, plant location and stochastic optimization. What is more, in a restructured power system, Benders decomposition also has some applications for a series of independent entities (e.g., GENCOs, IPPs, ISO and TRANSCOs), which include security-constrained unit commitment, generation and transmission maintenance scheduling, generation resource planning, and so on.

In applying the Benders decomposition algorithm, the original problem will be decomposed into a master problem and several subproblems, based on the linear programming duality theory. Generally, the master-program is an integer problem and subproblems are the linear programs. The process of solution of the master problem begins with only a few or no constraints. The subproblems are used to see if optimal solutions the remaining constraints based on this solution of the master problem. If subproblems are feasible, an upper bound solution of the original problem is obtained, while forming a new objective function for the next optimal calculation of the master problem. If any of the subproblems is infeasible, a corresponding infeasibility cut representing the least satisfies constraint will be introduced to the master problem. Then, a lower bound solution of the original problem is obtained by re-calculating the master problem with more constraints. The final solution based on the Benders algorithm may require iterations between the master problem and subproblems. When the upper bound and the lower bound are sufficiently close, the optimal solution of the original problem is achieved.

Benders decomposition is a very useful tool of solving the large-scale optimization problem. The interactions between master problem and subproblems are represented by the corresponding Benders cuts. Meanwhile, Benders decomposition makes it possible to speed up the solution to the large-scale optimization problem by using the parallel calculation.

The following definitions and theorems are reviewed for analyzing the Benders decomposition algorithm.

Polyhedron: A nonempty polyhedron is represented as $P = \left\{ x \in R^n \middle| Ax \le b \right\}$ shown in Figure A-1. Where $\mathbf{A}$ is an $m \times n$ matrix, $\mathbf{x}$ is a n-vector, $\mathbf{b}$ is an m-vector. Assume $rank\,(\mathbf{A}) = n$ and $\mathbf{P} \neq \mathbf{\Phi}$.

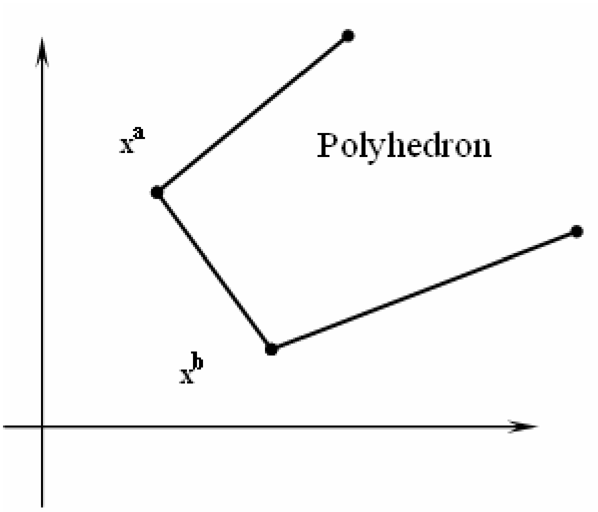

Fig. A-1. Polyhedron

Extreme Points: A point $\mathbf{x} \in \mathbf{P}$ is an extreme point of $\mathbf{P}$ if there do not exist points $\mathbf{x^1}$ and $\mathbf{x^2}$ in $\mathbf{P}$ and a scalar λ (with $\mathbf{x^1} \neq \mathbf{x^2}$ and $0 < \lambda < 1$) such that

$x = \lambda x^1 + (1-\lambda)x^2$. For example, extreme points $\mathbf{x^a}$ and $\mathbf{x^b}$ are shown in Figure A-1.

Polyhedral Cone: A polyhedron of the form $P^0 = \left\{ x \in R^n \,\middle|\, Ax \le 0 \right\}$ is called a polyhedral cone. Note that the origin is a member of every polyhedral cone and $\mathbf{P^0}$ does not contain a line.

Recession Cone: Consider a nonempty polyhedron $P = \left\{ x \in R^n \,\middle|\, Ax \le b \right\}$ and fix a point $y \in \mathbf{P}$. The recession cone at y is the set of all directions along which can be moved indefinitely from y and still be in $\mathbf{P}$, i.e., $\left\{ r \in R^n \,\middle|\, A(y + \lambda r) \le b \ \forall \lambda \ge 0 \right\}$. This set turns out to be $\left\{ r \in R^n \,\middle|\, Ar \le 0 \right\}$ and is hence a polyhedral cone $\mathbf{P^0}$ independent of y shown in Figure A-2, $\mathbf{r}$ in recession cone are called rays of polyhedron $\mathbf{P}$.

Extreme Rays: A point $\mathbf{r} \in \mathbf{R^n}$ is an extreme ray of $\mathbf{P^0}$ if there do not exist rays $\mathbf{r^1}$ and $\mathbf{r^2}$ in $\mathbf{P^0}$ and a scalar μ (with $\mathbf{r^1} \ne \mathbf{r^2}$ and $0 < \mu < 1$) such that $\mathbf{r} = \boldsymbol{\mu}\mathbf{r^1} + (\mathbf{1} - \boldsymbol{\mu})\mathbf{r^2}$. For example, extreme rays $\mathbf{r^a}$ and $\mathbf{r^b}$ are shown in Figure A-2. Note that two extreme rays are equivalent if one is a multiple of the other and that a polyhedral cone has a finite number of "non-equivalent extreme rays". In addition, every ray of a polyhedral cone $\mathbf{P^0}$ is expressed as a nonnegative linear combination of extreme rays.

Theorem A.1: If linear programming (LP) has a feasible region $\mathbf{Ax} \le \mathbf{b}$ with at least one extreme point and the objective function $Max\, \mathbf{c^T x}$ is bounded, then there is an optimal solution that is an extreme point in $\mathbf{P}$.

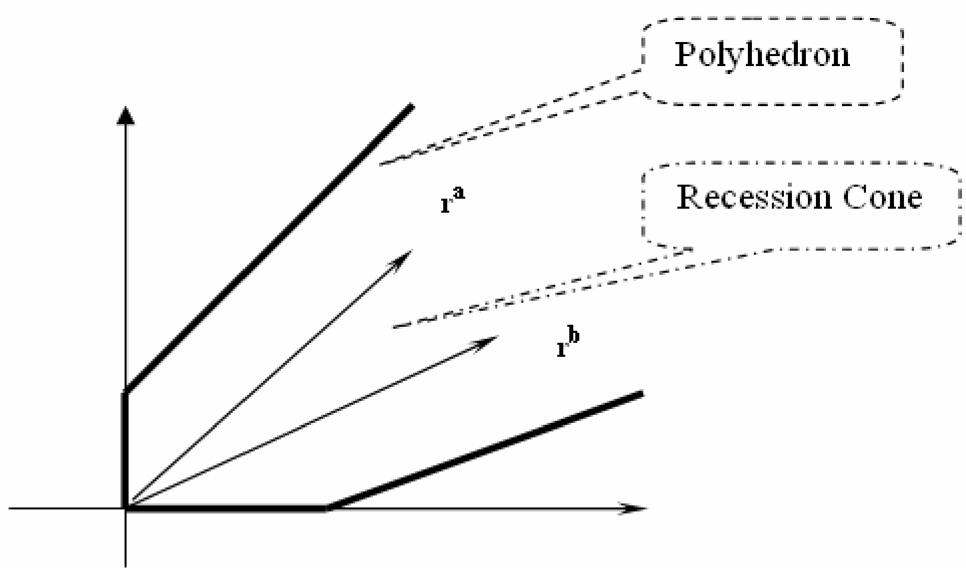

Fig. A-2. Polyhedron and Recession Cone.

Theorem A.2: $Max\left\{c^T x \mid Ax \le b\right\}$ is an unbounded LP if and only if some extreme rays $\mathbf{r}$ satisfy $\mathbf{c^T r} \ge \mathbf{0}$.

Theorem A.3: If LP cannot meet $\mathbf{Ax \le b}$ (no feasible region), then there is no optimal solution.

Theorem A.4: A nonempty polyhedron $P = \left\{x \in R^n \mid Ax \le b\right\}$ can be represented as

$$P = \left\{ x \in R^n \,\middle|\, x = \sum_{i \in k} \lambda_k x^k + \sum_{j \in J} \mu_j r^j \right\} \tag{A-1}$$

s.t.

$$\sum_{i \in k} \lambda_k = 1, \lambda_k \ge 0, \forall k \in K, \mu_j \ge 0, \forall j \in J \tag{A-2}$$

where $\mathbf{x^1}, \Lambda, \mathbf{x^k}$ are the extreme points and $\mathbf{r^1}, \Lambda, \mathbf{r^j}$ are the extreme rays. Note that a nonempty polyhedral $\mathbf{P}$ is bounded if and only if it has no extreme rays. This theorem is the basis for decomposition algorithms of LP.

Primal Problem and Dual Problem

In this section, the relationship between primal and dual problems and the related duality theorems are discussed. Every LP called the ***primal problem*** can be equivalently expressed in another LP form called the ***dual problem***. The primal problem can be expressed in matrix notation as follows:

$$\begin{aligned} &\textit{Minimize } z = \mathrm{c}^{\mathrm{T}}\mathrm{x} \\ &s.t. \qquad \mathrm{Ax} \geq \mathrm{b} \qquad\qquad \text{Primal} \qquad\qquad \text{(A-3)} \\ &\qquad\qquad \mathrm{x} \geq 0 \end{aligned}$$

Where $\mathbf{c}$ and $\mathbf{x}$ are n-vector, $\mathbf{b}$ is an m-vector and $\mathbf{A}$ is an *m x n* matrix. The linear function $\mathbf{c}^{\mathbf{T}}\mathbf{x}$ is called *objective function*. The linear inequalities are called *constraints* and they form a *feasible region* for minimize the objective function. The elements in the feasible region are called the *feasible point* written as $\left\{ \mathrm{x} \in \mathrm{R}^{\mathrm{n}} \,\middle|\, \mathrm{Ax} \geq \mathrm{b},\, \mathrm{x} \geq 0 \right\}$. The vector $\mathbf{x}$ is the solution of the primal problem.

Its corresponding dual problem is defined as:

$$\begin{aligned} &\textit{Maximize } z = \mathrm{b}^{\mathrm{T}}\mathrm{y} \\ &s.t. \qquad \mathrm{A}^{\mathrm{T}}\mathrm{y} \leq \mathrm{c} \qquad\qquad \text{Dual} \qquad\qquad \text{(A-4)} \\ &\qquad\qquad \mathrm{y} \geq 0 \end{aligned}$$

The number of inequalities in the primal problem becomes the number of variables in the dual problem. Correspondingly, the number of variables in the primal problem becomes the number of inequalities in the dual problem. Hence the dual problem differs in dimensions from the primal problem.

LP Solution Method:

Generally, the “simplex method” can be to solve LP. Note that it is typically easier to solve numerically an LP with fewer constraints. Since the primal problem has m constraints while the dual problem has n constraints, this generates the following rule of thumb: Solve the problem that has the fewer number of constraints. For instance, solve the primal problem if m<n, but solve the dual problem if m>n.

Switching Rules:

The relationship between primal and dual problems is listed in Table 3.1.

Table A-1. Switching Rules.

Primal (or Dual)		**Dual (or Primal)**	
Objective	*Max z*	*Min w*	Objective
Variable (n)	≥ 0	$\geq$	Constraints (n)
	≤ 0	$\leq$	
	Unlimited	$=$	
Constraints (m)	$\leq$	≥ 0	Variable (m)
	$\geq$	≤ 0	
	$=$	Unlimited	
Right-side vector of constraints		Coefficient vector of variables in objective function	
Coefficient vector of variables in objective function		Right-side vector of constraints	

Example A.1:

Primal problem

$$Max\ z = 5x_1 + 4x_2 + 6x_3$$

$$S.t.\quad x_1 + 2x_2 \geq 2$$

$$x_1 + x_3 \leq 3$$

$$-3x_1 + 2x_2 + x_3 \leq -5$$

$$x_1 - x_2 + x_3 = 1$$

$$x_1 \geq 0,\ x_2 \leq 0,\ x_3\ unlimited$$

$\longrightarrow$

Dual problem

$$Min\ w = 2y_1 + 3y_2 - 5y_3 + y_4$$

$$S.t.\quad y_1 + y_2 - 3y_3 + y_4 \geq 5$$

$$2y_1 + 2y_3 - y_4 \leq 4$$

$$y_2 + y_3 + y_4 = 6$$

$$y_1 \leq 0,\ y_2, y_3 \geq 0,\ y_4\ unlimited$$

Weak duality property: If **x** is a feasible solution of the primal problem and **y** is a feasible solution of the dual problem, then $\mathbf{c}^{\mathbf{T}}\mathbf{x} \geq \mathbf{b}^{\mathbf{T}}\mathbf{y}$.

Strong duality property: If $\mathbf{x}^*$ is an optimal solution of the primal problem and $\mathbf{y}^*$ is an optimal solution of the dual problem, then $\mathbf{c}^{\mathbf{T}}\mathbf{x}^* = \mathbf{b}^{\mathbf{T}}\mathbf{y}^*$. Thus, solving one of the two problems is equivalent to solving the other.

Symmetry property: The dual of the dual is the primal.

Duality Theorems:

- **Theorem A.5:** If the feasible solution exists and objective function is bounded for one, then the same is true for other problem.

- **Theorem A.6:** If the feasible solution exists and objective function is unbounded for one, then the other problem is infeasible.

- **Theorem A.7:** If no feasible solutions exist for one, then the other problem is either infeasible or has an unbounded objective function.

Basic Model of Benders Decomposition

A mixed-integer program has the following form:

$$\begin{aligned} &\textit{Minimize } z = \mathrm{c}^{\mathrm{T}}\mathrm{x} + \mathrm{d}^{\mathrm{T}}\mathrm{y} \\ &s.t. \qquad \mathrm{Ay} \geq \mathrm{b} \\ &\qquad \mathrm{Ex} + \mathrm{Fy} \geq \mathrm{h} \\ &\qquad \mathrm{x} \geq 0,\ \mathrm{y} \in \mathrm{S} \end{aligned} \qquad \text{P1} \qquad \text{(A-5)}$$

where,

$\boldsymbol{A}$: $m \times n$ matrix,

E: q× p matrix,

F: q× n matrix,

x, c : p vectors,

y, **d** : n integer vector,

b : m vector,

h : q vector,

S : an arbitrary subset of E^p with integral-valued components

Since ***x*** is continuous and ***y*** is integer, (P1) is a mixed-integer problem. If ***y*** values are fixed, (P1) is linear in ***x***. Hence, (A-5) is written as:

$$\underset{y \in R}{\boldsymbol{Minimize}} \left\{ d^T y \middle| Ay \ge b + Min\left\{ c^T x \mid Ex \ge h - Fy, x \ge 0 \right\} \right\} \tag{A-6}$$

where,

$$\mathbf{R} = \left\{ \mathbf{y} \,\middle|\, \text{ there exists } \mathbf{x} \ge \mathbf{0} \text{ such that } \mathbf{Ex} \ge \mathbf{h} - \mathbf{Fy}, \mathbf{Ay} \ge \mathbf{b}, \mathbf{y} \in \mathbf{S} \right\} \tag{A-7}$$

So, the original problem can be decoupled into a master problem and a subproblem.

Initial master problem (MP1)

Begin with solving the following MP1 (A-8):

$$\begin{aligned} & \textit{Minimize } z_{lower} \\ & s.t. \quad z_{lower} \ge d^T y \\ & \qquad Ay \ge b \\ & \qquad y \in S \end{aligned} \qquad \text{MP1} \tag{A-8}$$

Here, z is used instead of $\mathbf{d^T y}$ as the objective function. Meanwhile, the inner part of minimization (A-6) is a subproblem rewritten as follows:

Primal subproblem (SP1)

$$\begin{aligned} &\textit{Minimize} \quad \mathrm{c^T x} \\ &\textit{\textbf{s.t.}} \quad \mathrm{Ex \geq h - F\hat{y}} \\ &\qquad\quad \mathrm{x \geq 0} \end{aligned} \qquad \text{SP1} \qquad \text{(A-9)}$$

Dual subproblem (SP2)

$$\begin{aligned} &\textit{Maximize} \quad \mathrm{(h - F\hat{y})^T\ u} \\ &\textit{\textbf{s.t.}} \quad \mathrm{E^T u \leq c} \\ &\qquad\quad \mathrm{u \geq 0} \end{aligned} \qquad \text{SP2} \qquad \text{(A-10)}$$

where $\hat{\mathbf{y}}$ is the solution of the master problem.

Based on the duality theory, three possible cases will arise when solving SP2.

1. **SP2 has a feasible solution and its objective function is bounded**. So, an optimal solution is obtained that is an extreme point ($\mathbf{u^1}, \mathbf{u^2}$,…, or $\mathbf{u^p}$) in the dual feasible region shown in Figure A-3. Note that the dual feasible region doesn't depend on vector $\mathbf{y}$. So, the minimum value of the objective function in SP1 is equal to the maximum value of the objective function in SP2;

$$\mathbf{(h - F\hat{y})^T\ u_i^p}, 1, \mathrm{K}\ , n_p, \qquad \text{(A-11)}$$

where n_p is number of extreme points of the nonempty polyhedron:

$$\mathbf{P} = \left\{\mathbf{u} \middle| \mathbf{E^T u \leq c, u \geq 0}\right\}. \qquad \text{(A-12)}$$

2. **SP2 has a feasible solution but unbounded solution.** When SP2 is unbounded then SP1 is infeasible (according to Theorem A.6). Based on Theorem A.5, the extreme rays of SP2 given as $\mathbf{u}_i^{\mathbf{r}}$ $(i = 1, \ldots, n_r)$, where n_r is number of extreme rays of the polyhedral cone $\mathrm{P}^0 = \left\{ \mathrm{u} \middle| \mathrm{E}^{\mathrm{T}}\mathrm{u} \le 0, \mathrm{u} \ge 0 \right\}$, satisfy $(\mathbf{h} - \mathbf{F}\hat{\mathbf{y}})^{\mathbf{T}} \mathbf{u}_i^{\mathbf{r}} \ge \mathbf{0}$. In order to obtain a feasible and bounded solution in SP2, $(\mathbf{h} - \mathbf{F}\hat{\mathbf{y}})^{\mathbf{T}} \mathbf{u}_i^{\mathbf{r}} \le \mathbf{0}$ must be satisfied. So, $(\mathbf{h} - \mathbf{F}\mathbf{y})^{\mathbf{T}} \mathbf{u}_i^{\mathbf{r}} \le \mathbf{0}$ will be added as additional constraints (Benders cuts) into MP2 for the next iterative calculation. However, first an extreme ray $\mathbf{u}^{\mathbf{r}}$ needs to be calculated for the above constraint by introducing slack variables into SP1. Thus, SP1 is rewritten as follows:

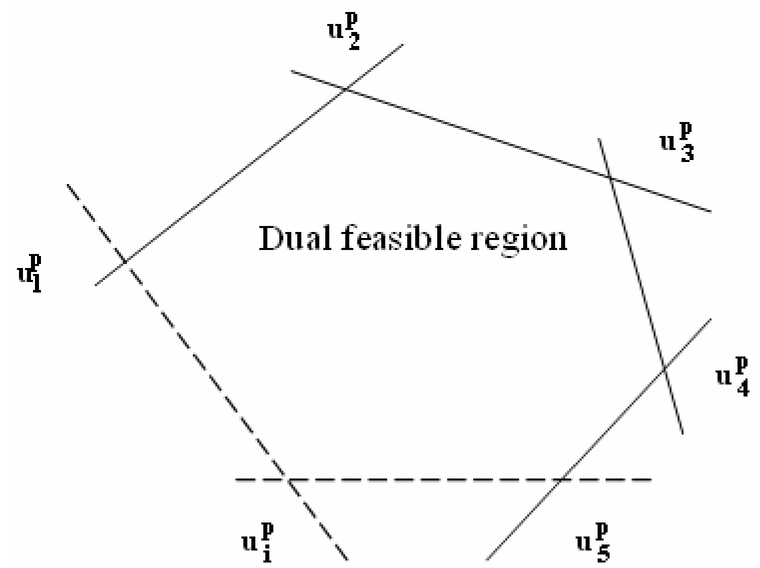

Fig. A-3. Dual feasible region.

1

$$\textbf{\textit{Minimize}} \quad \mathrm{c}^{\mathrm{T}}\mathrm{x} + \mathrm{m}^{\mathrm{T}}\mathrm{s}$$

$$\textbf{\textit{St.}} \quad \mathrm{Ex} + \mathrm{Is} \ge \mathrm{h} - \mathrm{F}\hat{\mathrm{y}} \qquad \rightarrow \quad \mathrm{u}^{\mathrm{r}} \tag{A-13}$$

$$\mathrm{x} \ge 0, \mathrm{s} \ge 0$$

where,

I Identity matrix

m	q	penalty cost vector of violation on constraints in SP1
s	q	slack vector on constraints in SP1

Since the elements of **m** are infinitely large (e.g., 10^6), an approximately equivalent extreme ray $\mathbf{u^r}$ is obtained. A new SP1 (A-14) can also be used (feasibility check subproblem), to get an exact extreme ray $\mathbf{u^r}$ in SP2. Note that two extreme rays are equivalent if one is a multiple of the other.

$$\textbf{\textit{Minimize}}\ 1^T s$$

$$\textbf{\textit{St.}}\quad Ex + Is \geq h - F\hat{y} \qquad \rightarrow \quad u^r \qquad\qquad \text{(A-14)}$$

$$x \geq 0, s \geq 0$$

where $\mathbf{1}$ is the unit vector.

3. **SP2 is infeasible.** Then the original problem (P1) is either infeasible or has an unbounded objective function. Stop the process.

The resulting algorithm involves iterations between MP2 and SP2. The first is the modified master problem MP2 to which additional constraints from the subproblem are successively added. The second is the LP subproblem (SP1 or SP2), which tests the optimality of a solution for the modified problem and, if necessary, provides a new constraint for the next iteration.

Solution Steps for the Benders Cut Algorithm.

The flowchart for the Benders decomposition is as shown in Figure A-4.

1. Solve MP1 in (4-8) and obtain an initial lower bound solution given as $\hat{z}$ and $\hat{\mathbf{y}}$. If MP1 is infeasible so will be the original problem P1. If MP1 is unbounded, set $\hat{z} = \infty$ in (A-8) for $\hat{\mathbf{y}}$ (an arbitrary element of S), and go to step 2.

2. Solve SP2 in (A-10) or SP1 in (A-9). An upper bound solution of the original problem P1 is $\hat{z}_{upper} = \mathbf{d}^{\mathbf{T}}\hat{\mathbf{y}} + (\mathbf{h} - \mathbf{F}\hat{\mathbf{y}})^{\mathbf{T}}\hat{\mathbf{u}}^{\mathbf{p}}$ for the optimal objective of $(\mathbf{h} - \mathbf{F}\hat{\mathbf{y}})^{\mathbf{T}}\hat{\mathbf{u}}^{\mathbf{p}}$ or the upper bound solution of the original problem P1 is $\mathbf{c}^{\mathbf{T}}\hat{\mathbf{x}}$ for $\hat{\mathbf{y}}$ and $\hat{\mathbf{x}}$.

- If $\left|\hat{z}_{upper} - \hat{z}_{lower}\right| \le \varepsilon$ for P1, then stop the process. Otherwise, generate a new constraint $z_{lower} \ge \mathbf{d}^{\mathbf{T}}\mathbf{y} + (\mathbf{h} - \mathbf{F}\mathbf{y})^{\mathbf{T}}\hat{\mathbf{u}}^{\mathbf{p}}$ **(feasibility cut)** for MP2 (A-15) and go to step 3.
- If SP2 is unbounded, which means that SP1 is infeasible, then introduce a new cut $(\mathbf{h} - \mathbf{F}\mathbf{y})^{\mathbf{T}}\hat{\mathbf{u}}^{\mathbf{r}} \le \mathbf{0}$ **(infeasibility cut)** into MP2 (A-15). In this case, first $\mathbf{u}^{\mathbf{r}}$ will be calculated from (A-14) to form the infeasibility cut and then go to step 3.
- If SP2 is infeasible, the original problem P1 will either have no feasible solution or have an unbounded solution.

3. Solve MP2 to obtain a new lower bound solution $\hat{z}_{lower}$ with respect to $\hat{\mathbf{y}}$ for the original problem P1.

In the following formulation, <u>either</u> feasibility cut (first constraint) <u>or</u> the infeasibility cut (third constraint) is utilized.

$$\begin{aligned} &\textit{Minimize } z_{lower} \\ &s.t. \quad z_{lower} \ge \mathrm{d}^{\mathrm{T}}\mathrm{y} + (\mathrm{h} - \mathrm{F}\mathrm{y})^{\mathrm{T}}\mathrm{u}_{\mathrm{i}}^{\mathrm{p}}, i = 1, \ldots, n_p \\ &\qquad \mathrm{A}\mathrm{y} \ge \mathrm{b} \\ &\qquad (\mathrm{h} - \mathrm{F}\mathrm{y})^{\mathrm{T}}\mathrm{u}_{i}^{\mathrm{r}} \le 0, i = 1, \ldots, n_r \\ &\qquad \mathrm{y} \in \mathrm{S} \end{aligned} \qquad \text{MP2} \qquad \text{(A-15)}$$

- Then go back to step 2 for solving the subproblem again.
- If MP2 is unbounded, specify $\hat{z}_{lower} = \infty$ in (A-15) with $\hat{\mathbf{y}}$ as an arbitrary element of $\mathbf{S}$. Return to step 2.

If the solution of MP2 (A-15) is infeasible, so will be the original problem P1. Stop the process.

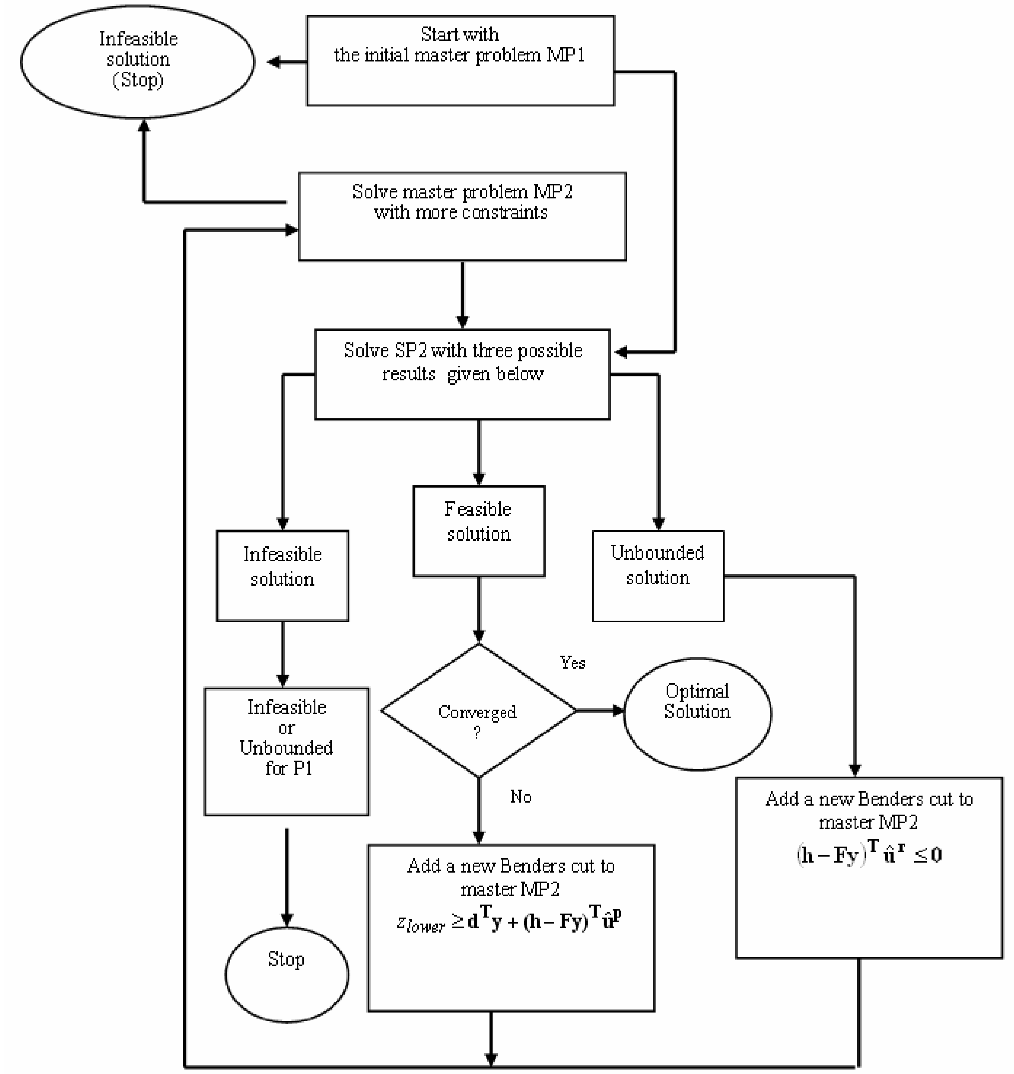

Fig. A-4. Flowchart.

Two Different Forms of Benders Cuts

Form 1.

As discussed above, Benders cuts are typically expressed as

$$
\begin{aligned}
& z \geq \mathrm{d}^{\mathrm{T}}\mathrm{y} + (\mathrm{h}-\mathrm{Fy})^{\mathrm{T}}\mathrm{u}_{\mathrm{i}}^{\mathrm{p}}, i = 1, \ldots, n_p \\
& \left(\mathrm{h}-\mathrm{Fy}\right)^{\mathrm{T}}\mathrm{u}_{i}^{\mathrm{r}} \leq 0, i = 1, \ldots, n_r
\end{aligned}
\qquad \text{(A-16)}
$$

Form 2.

Let us consider the optimal problem with the standard Benders decomposition form as follows.

$$
\begin{aligned}
& \textit{Minimize } z = \mathrm{c}^{\mathrm{T}}\mathrm{x} + \mathrm{d}^{\mathrm{T}}\mathrm{y} \\
& s.t. \quad \mathrm{Ay} \geq \mathrm{b} \\
& \qquad \mathrm{Ex} + \mathrm{Fy} \geq \mathrm{h} \\
& \qquad \mathrm{x} \geq 0,\ \mathrm{y} \in \mathrm{S}
\end{aligned}
\tag{A-17}
$$

The initial master problem (MP1) is

$$
\begin{aligned}
& \textit{Minimize } z \\
& s.t. \quad z \geq \mathrm{d}^{\mathrm{T}}\mathrm{y} \\
& \qquad \mathrm{Ay} \geq \mathrm{b} \\
& \qquad \mathrm{y} \in \mathrm{S}
\end{aligned}
\tag{A-18}
$$

After solving the master problem, the subproblem based on $\hat{\mathbf{y}}$ is calculated. If $\mathbf{y}$ is still regarded as a variable vector in SP1, it is formed as follows.

$$
\begin{aligned}
& \textbf{\textit{Minimize}} \ \mathrm{c}^{\mathrm{T}}\mathrm{x} \\
& \textbf{\textit{St.}} \quad \mathrm{Ex} + \mathrm{Fy} \geq \mathrm{h} && \lambda \\
& \qquad \mathrm{I\,y} = \hat{\mathrm{y}} && \pi \\
& \qquad \mathrm{x} \geq 0
\end{aligned}
\tag{A-19}
$$

Where $\boldsymbol{\lambda}$ and $\boldsymbol{\pi}$ are dual multiplier vectors associated with the constraints in (A-19).

Then SP2 is

$$\begin{aligned}
&\textit{Maximize} \;\; \mathrm{h}^{\mathrm{T}}\lambda + \hat{\mathrm{y}}^{\mathrm{T}}\pi \\
&\textit{St.} \qquad \mathrm{E}^{\mathrm{T}}\lambda \le \mathrm{c} \\
&\qquad \mathrm{F}^{\mathrm{T}}\lambda + \mathrm{I}\,\pi = 0 \\
&\qquad \lambda \ge 0, \pi \; \textit{unlimited}
\end{aligned} \tag{A-20}$$

If (A-20) has a bounded solution $\mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{p}} + \hat{\mathbf{y}}^{\mathbf{T}}\hat{\boldsymbol{\pi}}_{\mathbf{p}}$ at the extreme point $(\hat{\boldsymbol{\lambda}}_{\mathbf{p}}^{\mathbf{T}} \;\; \hat{\boldsymbol{\pi}}_{\mathbf{p}}^{\mathbf{T}})$ of the dual feasible region, according to the discussion above, a new constraint $z \ge \mathbf{d}^{\mathbf{T}}\mathbf{y} + \mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{p}} + \hat{\boldsymbol{\pi}}_{\mathbf{p}}^{\mathbf{T}}\mathbf{y}$, which is equivalent to $z \ge \mathbf{d}^{\mathbf{T}}\mathbf{y} + (\mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{p}} + \hat{\mathbf{y}}^{\mathbf{T}}\hat{\boldsymbol{\pi}}_{\mathbf{p}}) + \hat{\boldsymbol{\pi}}_{\mathbf{p}}^{\mathbf{T}}(\mathbf{y} - \hat{\mathbf{y}})$, is formed. Here $\mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{p}} + \hat{\mathbf{y}}^{\mathbf{T}}\hat{\boldsymbol{\pi}}_{\mathbf{p}}$ in the added constraint is the optimal solution of SP1, $w(\hat{\mathbf{y}})$. So, the constraint is $z_{lower} \ge \mathbf{d}^{\mathbf{T}}\mathbf{y} + w(\hat{\mathbf{y}}) + \boldsymbol{\pi}_{\mathbf{p}}^{\mathbf{T}}(\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}}$.

However, if (A-20) has an unbounded solution, the feasibility check subproblem (A-21) will be used in SP1 (A-19) to get an extreme ray $(\hat{\boldsymbol{\lambda}}_{\mathbf{r}}^{\mathbf{T}} \; \hat{\boldsymbol{\pi}}_{\mathbf{r}}^{\mathbf{T}})^{\mathbf{T}}$ of its dual subproblem.

$$\begin{aligned}
&\textbf{\textit{Minimize}} \;\; 1^{\mathrm{T}}\mathrm{s} \\
&\textbf{\textit{St.}} \qquad \mathrm{Ex} + \mathrm{Fy} + \mathrm{Is} \ge \mathrm{h} \qquad\qquad \lambda \\
&\qquad\qquad \mathrm{I}\,\mathrm{y} = \hat{\mathrm{y}} \qquad\qquad\qquad \pi \\
&\qquad\qquad \mathrm{x} \ge 0, \mathrm{s} \ge 0
\end{aligned} \tag{A-21}$$

where,

I	Identity matrix
1	Unit vector
s	Slack vector on constraints in the optimal problem

Thus, $\mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{r}} + \hat{\boldsymbol{\pi}}_{\mathbf{r}}^{\mathbf{T}}\mathbf{y} \le \mathbf{0}$ is the new constraint for the master problem. Similarly, it is equal to $(\mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{r}} + \hat{\mathbf{y}}^{\mathbf{T}}\hat{\boldsymbol{\pi}}_{\mathbf{r}}) + \hat{\boldsymbol{\pi}}_{\mathbf{r}}^{\mathbf{T}}(\mathbf{y} - \hat{\mathbf{y}}) \le \mathbf{0}$. Because of the term $\mathbf{h}^{\mathbf{T}}\hat{\boldsymbol{\lambda}}_{\mathbf{r}} + \hat{\mathbf{y}}^{\mathbf{T}}\hat{\boldsymbol{\pi}}_{\mathbf{r}}$ in the constraint is the optimal solution of (A-21), $v(\hat{\mathbf{y}})$, the constraint is also rewritten as $v(\hat{\mathbf{y}}) + \boldsymbol{\pi}_{\mathbf{r}}^{\mathbf{T}}(\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}} \le \mathbf{0}$.

Accordingly the cuts are as follows: the first one is the feasibility cut and the second one is the infeasibility cut.

$$
\begin{aligned}
& z \ge \mathrm{d}^{\mathrm{T}}\mathrm{y} + w(\hat{\mathrm{y}})_i + \pi_{\mathrm{pi}}^{\mathrm{T}}(\mathrm{y} - \hat{\mathrm{y}}), i = 1, \ldots, n_p^{'} \\
& v(\hat{\mathrm{y}})_i + \pi_{\mathrm{ri}}^{\mathrm{T}}(\mathrm{y} - \hat{\mathrm{y}}) \le 0, i = 1, \ldots, n_r^{'}
\end{aligned}
\tag{A-22}
$$

where,

$w(\hat{\mathbf{y}})$ Optimal solution of SP1

$v(\hat{\mathbf{y}})$ Optimal solution of feasibility check subproblem

$\hat{\mathbf{y}}$ Solution for the master problem

$\boldsymbol{\pi}$ Dual multiplier vector for $\mathbf{y} = \hat{\mathbf{y}}$ in SP1

Based on the above analysis, Form 2 of Benders cut is equivalent to the standard Benders cuts Form 1. The Benders cut $z \ge \mathbf{d}^{\mathbf{T}}\mathbf{y} + w(\hat{\mathbf{y}}) + \boldsymbol{\pi}_{\mathbf{p}}^{\mathbf{T}}(\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}}$ indicates that the objective value of the original problem can be decreased by changing $\mathbf{y}$ from $\hat{\mathbf{y}}$ to a new value. The dual multiplier vector $\boldsymbol{\pi}_{\mathbf{p}}$ represents the incremental change in the optimal objective. Similarly, the Benders cut $v(\hat{\mathbf{y}}) + \boldsymbol{\pi}_{\mathbf{r}}^{\mathbf{T}}(\mathbf{y} - \hat{\mathbf{y}})^{\mathbf{T}} \le \mathbf{0}$ indicates that one can switch $\hat{\mathbf{y}}$ to a new value to eliminate the total violation on constraints in SP1 based on a given $\hat{\mathbf{y}}$ in the previous master problem. The dual multiplier vector $\boldsymbol{\pi}_{\mathbf{r}}$ represents the incremental change in the total violation.

Expanded Model of Benders Decomposition

The basic model of Benders decomposition involving a master problem and one subproblem is introduced above. However, in practice, a master problem and several subproblems could be considered. If the original optimization problem is decomposed into a master problem and n subproblems satisfying the following form.

$$
\begin{aligned}
&\textit{Minimize } z = c_1^T x_1 + c_2^T x_2 + \cdots + c_n^T x_n + d^T y \\
&s.t. \qquad Ay \geq b \\
&\qquad E_1 x_1 + F_1 y \geq h_1 \\
&\qquad E_2 x_2 + F_2 y \geq h_2 \\
&\qquad \vdots \\
&\qquad E_n x_n + F_n y \geq h_n \\
&\qquad x_1,\ x_2, \ldots, x_n \geq 0,\ y \in S
\end{aligned}
\tag{A-23}
$$

Initial master problem

$$
\begin{aligned}
&\textit{Minimize } z \\
&s.t. \quad z \geq d^T y \\
&\qquad Ay \geq b \\
&\qquad y \in S
\end{aligned}
\tag{A-24}
$$

Primal subproblem i

$$\begin{aligned} & \textit{Minimize} \;\; \mathrm{c_i^T x_i} \\ & \textit{s.t.} \quad \mathrm{E_i x_i \geq h_i - F\hat{y}} \qquad \text{(A-25)} \\ & \qquad \mathrm{x}_i \geq 0 \end{aligned}$$

Master problem with Benders cuts

The feasibility and infeasibility cuts, which are used according to the SP1 solution are listed below:

$$\textit{Minimize } z$$

$$\textit{s.t.} \quad z \geq \mathrm{d^T y} + (\mathrm{h_1 - F_1 y})^{\mathrm{T}} \mathrm{u_{1i}^p} + (\mathrm{h_2 - F_2 y})^{\mathrm{T}} \mathrm{u_{2i}^p} + \cdots + (\mathrm{h_n - F_n y})^{\mathrm{T}} \mathrm{u_{ni}^p}, \; i = 1, \ldots, n_p$$

$$\mathrm{Ay \geq b}$$

$$\left(\mathrm{h_1 - F_1 y}\right)^{\mathrm{T}} \mathrm{u_{1i}^r} \leq 0, \; i = 1, \ldots, n_r$$

$$\left(\mathrm{h_2 - F_2 y}\right)^{\mathrm{T}} \mathrm{u_{2i}^r} \leq 0, \; i = 1, \ldots, n_r$$

$$\vdots$$

$$\left(\mathrm{h_n - F_n y}\right)^{\mathrm{T}} \mathrm{u_{ni}^r} \leq 0, \; i = 1, \ldots, n_r$$

$$\mathrm{y \in S}$$

(A.26)

APPENDIX - B

TURKISH SYSTEM DATA

Table B-1. Transmission System Data

FROM	TO	CAPACITY IN SUMMER (MW)	LENGTH (KM)
BURSA	BALIKESIR	889	109,3
BURSA	TUNCBILEK	889	87.8
BALIKESIR	SOMA	889	65
SEYITOMER	TUNCBILEK	889	42
SEYITOMER	A-M-I	889	284.3
SEYITOMER	GOKCEKAYA	1116	119
SEYITOMER	GOKCEKAYA	1116	119
SEYITOMER	AFYON	1116	184
SEYITOMER	AFYON	1116	184
A-M-I	UZUNDERE	1334	69
A-M-I	SOMA	889	82.3
A-M-I	Y-Y-K	889	146.4
A-M-I	Y-Y-K	1334	147
A-M-I	DENIZLI	1334	200
UZUNDERE	GERMENCIK	1334	72
Y-Y-K	DENIZLI	1334	119.6
Y-Y-K	GERMENCIK	1334	111.6
Y-Y-K	V-S-O	1334	300
DENIZLI	V-S-O	1334	170
DENIZLI	AFYON	1334	215
V-S-O	AFYON	1334	230
V-S-O	AFYON	1116	114.5
CAYIRHAN	T-S-G	1116	78.1
CAYIRHAN	T-S-G	1116	78.1
GOKCEKAYA	T-S-G	1116	167.4
GOKCEKAYA	T-S-G	1116	167.4
T-S-G	AFYON	1334	222.5

Table B-2. Demand Data (Summer Peak)

BUS NAME	DEMAND (MW)
BURSA	380
BALIKESIR	45
SEYITOMER	58
TUNCBILEK	43
A-M-I	1086
UZUNDERE	350
SOMA	169
Y-Y-K	543
DENIZLI	351
GERMENCIK	330
V-S-O	1120
CAYIRHAN	504
GOKCEKAYA	28
T-S-G	1295
AFYON	231

Table B-3. Existing Generators' Data

GENERATOR	P_{MAX} (MW)	P_{MIN} * (MW)	ENERGY PRICE ($/MWh)
BURSA	717	0	58
SEYITOMER	160	160	16
TUNCBILEK	160	0	16
ALIAGA	750	500	64
SOMA	165	110	14
YATAGAN	500	250	23
VARSAK	135	70	5
CAYIRHAN	160	110	15
GOKCEKAYA	93	0	5
TEMELLI	818	570	60
ATATURK	7500	0	10
SEYITOMER	320	160	16
ALIAGA	750	500	64
SOMA	825	550	14
YATAGAN	1260	1050	23
VARSAK	405	210	5
CAYIRHAN	640	480	15
GOKCEKAYA	186	186	5

* Pmax = Pmin ⇒ "Must run" generator.

APPENDIX - C

IEEE 30-BUS SYSTEM DATA

Table C-1. Transmission System Data

From-Bus	To-Bus	Maximum Capacity (MW)	Line impedance (ohm)
1	2	300	0.0575
1	3		0.1852
2	4		0.1737
2	5		0.1983
2	6		0.1763
3	4		0.0379
3	13		0.412
4	6		0.0414
4	11		0.649
4	12		0.256
5	6		0.0116
5	7		0.0116
6	7		0.082
6	8		0.042
6	9		0.208
6	10		0.556
6	28		0.0599
8	28		0.2
9	10		0.11
9	11		0.208
9	11		0.208
10	17		0.0845
10	20		0.209
10	21		0.0749
10	22		0.1499
12	13		0.14
12	14		0.2559
12	15		0.1304
12	16		0.1987
14	15		0.1997
15	18		0.2185
15	23		0.202

Table C-1 (cont'd)

16	17	300	0.1932
18	19		0.1292
19	20		0.068
21	22		0.0236
22	24		0.179
23	24		0.27
24	25		0.3292
25	26		0.38
25	27		0.2087
26	29		0.2144
27	28		0.396
27	29		0.4153
27	30		0.6027
29	30		0.4533

Table B-2. Demand Data

Bus No	**Demand (MW)**			
	Spring	**Winter**	**Fall**	**Summer**
1	0,00	0,00	0,00	0,00
2	28,77	61,42	35,30	114,29
3	28,77	61,42	35,30	114,29
4	33,56	71,65	41,18	133,33
5	23,97	51,18	29,41	95,24
6	0,00	0,00	0,00	0,00
7	28,77	61,42	35,30	114,29
8	23,97	51,18	29,41	95,24
9	0,00	0,00	0,00	0,00
10	38,35	81,89	47,06	152,38
11	0,00	0,00	0,00	0,00
12	23,97	51,18	29,41	95,24
13	0,00	0,00	0,00	0,00
14	14,38	30,71	17,65	57,14
15	19,18	40,94	23,53	76,19
16	14,38	30,71	17,65	57,14
17	19,18	40,94	23,53	76,19
18	28,77	61,42	35,30	114,29
19	23,97	51,18	29,41	95,24
20	19,18	40,94	23,53	76,19
21	19,18	40,94	23,53	76,19
22	0,00	0,00	0,00	0,00
23	23,97	51,18	29,41	95,24
24	19,18	40,94	23,53	76,19
25	0,00	0,00	0,00	0,00

Table B-2 (cont'd)

26	38,35	81,89	47,06	152,38
27	0,00	0,00	0,00	0,00
28	0,00	0,00	0,00	0,00
29	14,38	30,71	17,65	57,14
30	19,18	40,94	23,53	76,19

Table B-3. Existing Generators' Energy Price.

Generator	**Energy price ($/MWh)**
G_1	20
G_2	22
$G_{5,1}$	18
$G_{5,2}$	18
G_8	18
$G_{11,1}$	20
$G_{11,2}$	20
$G_{11,3}$	20
G_{13}	18
G_{19}	20

APPENDIX - D

OPTIMUM SOLUTIONS OF THE CASE STUDIES (CHAPTER 4)

Table D-1. 2-Bus System (Case 1- DC Load Flow Results and Planning Solution)

Power flows (MW)		**Years along the planning horizon**										
from-bus	**to-bus**	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9	Y_{10}
1	2	200	216	233	252	272	294	300	229	247	267	279
1	2	200	216	233	252	272	294	300	229	247	267	279
1	2	0	0	0	0	0	0	0	229	247	267	279
Bus no		**Bus-angles (radian)**										
1		0	0	0	0	0	0	0	0	0	0	0
2		-40	-43	-47	-50	-54	-59	-60	-46	-49	-53	-56
Generator no		**Generation dispatch (MW)**										
$G_{1,1}$		200	200	200	200	200	200	200	200	200	200	200
$G_{1,2}$		200	200	200	200	200	200	200	200	200	200	200
$G_{1,3}$		100	137	177	200	200	200	200	200	200	200	200
$G_{1,4}$		0	0	0	20	66	115	134	200	200	200	200
$G_{1,5}$		0	0	0	0	0	0	0	26	88	155	200
$G_{2,1}$		0	0	0	0	0	0	35	0	0	0	26
AOCC (M$/year)		0	0	0	0	0	0	6,09	0	0	0	0
TIC (M$/year)		0	0	0	0	0	0	0	6,11	6,11	6,11	6,11
IR (M$/year)		**0**	**0**	**0**	**0**	**0**	**0**	**6,09**	**6,11**	**6,11**	**6,11**	**6,11**
TPC (M$)		**30,53**										

Table D-2. 2-Bus System (Case 2- DC Load Flow Results and Planning Solution)

Power flows (MW)		**Years along the planning horizon**										
from-bus	**to-bus**	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9	Y_{10}
1	2	200	216	233	252	272	294	300	300	300	300	221
1	2	200	216	233	252	272	294	300	300	300	300	221
1	2	0	0	0	0	0	0	0	0	0	0	221
Bus no		**Bus-angles (radian)**										
1		0	0	0	0	0	0	0	0	0	0	0
2		-40	-43	-47	-50	-54	-59	-60	-60	-60	-60	-44
Generator no		**Generation dispatch (MW)**										
$G_{1,1}$		200	200	200	200	200	200	200	200	200	200	200
$G_{1,2}$		200	200	200	200	200	200	200	200	200	200	200
$G_{1,3}$		100	137	177	200	200	200	200	200	200	200	200
$G_{1,4}$		0	0	0	19,6	65,7	115	134	140,71	148	155	200
$G_{1,5}$		0	0	0	0	0	0	0	0	0	0	26,5
$G_{2,1}$		0	0	0	0	0	0	34,8	0	0	0	0
G_i		0	0	0	0	0	0	0	85,53	140	200	200
AOCC (M$/year)		0	0	0	0	0	0	6,09	0	0	0	0
TIC (M$/year)		0	0	0	0	0	0	0	0	0	0	6,11
IR (M$/year)		0	0	0	0	0	0	0	10,10	4,34	0	0
TC (M$/year)		**0**	**0**	**0**	**0**	**0**	**0**	**6,09**	**10,10**	**4,34**	**0**	**6,11**
TPC (M$)		**26,64**										

Table D-3. IEEE 30-Bus System (Case 1- DC Load Flow Results and Planning Solution (Peak-Demand Season))

Power flows (MW)		**Years along the planning horizon**										
from-bus	**to-bus**	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9	Y_{10}
1	2	9,43	48,17	69,71	-6,32	-5,98	15,70	48,19	81,33	115,14	149,62	184,79
1	3	11,89	30,78	42,51	6,32	5,98	17,03	33,85	51,01	68,51	86,36	104,56
2	4	-6,60	4,04	10,65	-9,99	-10,69	-4,72	4,63	14,16	23,88	33,80	43,91
2	5	-64,69	-52,54	-46,60	-73,79	-74,44	-68,21	-58,50	-48,60	-38,49	-28,19	-17,68
2	6	-33,28	-19,62	-12,94	-43,52	-44,25	-37,24	-26,32	-15,18	-3,82	7,77	19,59
3	4	-74,04	-58,77	-53,18	-86,26	-87,27	-81,02	-71,09	-60,96	-50,63	-40,10	-29,35
3	13	-28,07	-26,73	-22,92	-28,40	-30,15	-27,82	-23,45	-18,98	-14,43	-9,79	-5,05
4	6	-114,02	-100,50	-99,77	-143,45	-143,60	-138,80	-131,50	-124,05	-116,46	-108,71	-100,81
4	11	-139,76	-130,28	-127,89	-135,27	-136,52	-135,42	-133,16	-130,84	-128,48	-126,08	-123,62
4	12	40,14	40,40	46,76	41,33	38,19	41,65	48,41	55,32	62,36	69,54	76,86
5	7	174,23	176,23	95,02	96,13	97,26	98,41	99,59	100,79	102,01	103,26	104,53
5	7	0,00	0,00	95,02	96,13	97,26	98,41	99,59	100,79	102,01	103,26	104,53
6	7	-60,23	-59,95	-71,44	-71,28	-71,12	-70,96	-70,79	-70,62	-70,45	-70,27	-70,09
6	8	-148,49	-146,63	-144,28	-142,80	-140,74	-138,40	-135,90	-133,35	-130,74	-128,09	-125,38
6	9	-113,39	-86,51	-79,20	-138,59	-142,88	-140,06	-133,68	-127,18	-120,54	-113,77	-106,86
6	10	5,72	1,50	4,72	-10,56	-12,52	-11,21	-8,26	-5,24	-2,16	0,97	4,17
6	28	84,55	85,74	88,75	88,13	89,71	92,30	95,40	98,58	101,81	105,11	108,47
6	28	84,55	85,74	88,75	88,13	89,71	92,30	95,40	98,58	101,81	105,11	108,47
8	28	56,51	56,47	56,88	56,38	56,43	56,71	57,11	57,53	57,95	58,38	58,82
9	10	243,30	171,16	173,60	208,71	206,87	208,17	211,05	213,99	216,99	220,05	223,17
9	10	243,30	171,16	173,60	208,71	206,87	208,17	211,05	213,99	216,99	220,05	223,17
9	10	0,00	171,16	173,60	208,71	206,87	208,17	211,05	213,99	216,99	220,05	223,17
9	11	-300,00	-300,00	-300,00	-254,91	-254,49	-254,86	-255,61	-256,39	-257,17	-257,97	-258,79
9	11	-300,00	-300,00	-300,00	-254,91	-254,49	-254,86	-255,61	-256,39	-257,17	-257,97	-258,79

Table D-3 (cont'd)

9	11	0,00	0,00	0,00	-254,91	-254,49	-254,86	-255,61	-256,39	-257,17	-257,97	-258,79
10	17	111,10	116,71	118,07	138,57	141,02	142,80	144,26	145,74	147,26	148,81	150,38
10	20	10,80	16,83	20,03	65,36	47,34	43,70	47,16	50,69	54,30	57,97	61,72
10	21	139,03	143,99	145,87	158,74	161,81	164,26	166,43	168,64	170,89	173,19	175,54
10	22	79,39	82,42	83,41	91,61	93,38	94,73	95,89	97,07	98,28	99,51	100,76
12	13	-135,96	-136,63	-138,54	-135,80	-134,93	-136,09	-138,28	-140,51	-142,78	-145,11	-147,47
12	13	-135,96	-136,63	-138,54	-135,80	-134,93	-136,09	-138,28	-140,51	-142,78	-145,11	-147,47
12	14	46,29	47,06	48,37	49,43	48,98	49,78	51,21	52,67	54,16	55,68	57,22
12	15	74,44	75,38	78,17	80,06	76,65	77,56	80,62	83,75	86,95	90,20	93,52
12	15	74,44	75,38	78,17	80,06	76,65	77,56	80,62	83,75	86,95	90,20	93,52
12	16	21,90	18,95	20,30	2,57	2,94	4,04	5,52	7,03	8,57	10,14	11,74
14	15	-10,71	-11,08	-10,94	-11,06	-12,72	-13,15	-12,98	-12,80	-12,63	-12,45	-12,26
15	18	-25,80	-26,13	-23,51	-13,16	-26,51	-29,03	-26,20	-23,32	-20,37	-17,37	-14,31
15	23	87,97	88,28	89,84	81,57	84,82	87,08	88,88	90,72	92,59	94,50	96,44
16	17	-35,10	-39,19	-39,00	-57,92	-58,76	-58,89	-58,67	-58,44	-58,21	-57,98	-57,74
18	19	-139,80	-142,41	-142,12	-134,14	-149,91	-154,90	-154,59	-154,27	-153,94	-153,61	-153,27
19	20	65,20	60,69	59,04	15,29	34,93	40,21	38,43	36,61	34,75	32,86	30,93
21	22	63,03	66,47	66,80	78,09	79,55	80,35	80,84	81,34	81,85	82,37	82,90
22	24	142,42	148,89	150,21	169,70	172,92	175,08	176,73	178,41	180,12	181,87	183,66
23	24	-7,03	-8,62	-9,00	-19,25	-18,01	-17,80	-18,10	-18,41	-18,72	-19,04	-19,36
24	25	59,39	62,75	62,14	69,80	72,65	73,37	73,04	72,70	72,36	72,01	71,65
25	26	109,17	111,76	113,64	117,13	119,75	122,00	124,10	126,25	128,43	130,66	132,93
25	27	-49,78	-49,01	-51,50	-47,33	-47,10	-48,64	-51,07	-53,55	-56,07	-58,65	-61,28
26	29	-42,83	-43,28	-44,50	-44,17	-44,78	-45,82	-47,07	-48,35	-49,66	-51,00	-52,36
27	28	-112,81	-113,97	-117,19	-116,32	-117,92	-120,65	-123,96	-127,34	-130,78	-134,30	-137,88
27	28	-112,81	-113,97	-117,19	-116,32	-117,92	-120,65	-123,96	-127,34	-130,78	-134,30	-137,88
27	29	102,79	104,55	106,89	108,16	110,12	112,42	114,92	117,46	120,05	122,70	125,40

Table D-3 (cont’d)

27	30	73,05	74,39	75,98	77,16	78,62	80,23	81,93	83,67	85,44	87,24	89,08
29	30	2,95	3,13	3,09	3,50	3,64	3,68	3,65	3,63	3,61	3,58	3,56
Bus no		**Bus-angles (radian)**										
1		0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
2		-0,54	-2,77	-4,01	0,36	0,34	-0,90	-2,77	-4,68	-6,62	-8,60	-10,63
3		-2,20	-5,70	-7,87	-1,17	-1,11	-3,15	-6,27	-9,45	-12,69	-15,99	-19,37
4		0,60	-3,47	-5,86	2,10	2,20	-0,08	-3,57	-7,14	-10,77	-14,47	-18,25
5		12,29	7,65	5,23	15,00	15,11	12,62	8,83	4,96	1,01	-3,01	-7,12
6		5,32	0,69	-1,73	8,04	8,15	5,66	1,87	-2,00	-5,95	-9,97	-14,08
7		10,26	5,60	4,13	13,88	13,98	11,48	7,67	3,79	-0,17	-4,21	-8,33
8		11,56	6,85	4,33	14,03	14,06	11,48	7,58	3,60	-0,46	-4,59	-8,81
9		28,91	18,68	14,75	36,86	37,86	34,80	29,68	24,45	19,13	13,69	8,15
10		2,15	-0,15	-4,35	13,91	15,11	11,90	6,46	0,91	-4,74	-10,52	-16,40
11		91,31	81,08	77,15	89,89	90,80	87,81	82,84	77,78	72,62	67,35	61,98
12		-9,67	-13,81	-17,83	-8,48	-7,58	-10,74	-15,97	-21,30	-26,73	-32,28	-37,93
13		9,36	5,31	1,57	10,53	11,31	8,31	3,39	-1,63	-6,74	-11,96	-17,28
14		-21,52	-25,86	-30,21	-21,13	-20,11	-23,48	-29,07	-34,78	-40,59	-46,52	-52,57
15		-19,38	-23,64	-28,02	-18,92	-17,57	-20,86	-26,48	-32,22	-38,07	-44,04	-50,13
16		-14,02	-17,58	-21,86	-8,99	-8,16	-11,55	-17,07	-22,69	-28,44	-34,29	-40,26
17		-7,24	-10,01	-14,33	2,20	3,19	-0,17	-5,73	-11,40	-17,19	-23,09	-29,11
18		-13,74	-17,94	-22,88	-16,05	-11,78	-14,51	-20,76	-27,12	-33,62	-40,24	-47,00
19		4,32	0,46	-4,52	1,28	7,59	5,50	-0,78	-7,19	-13,73	-20,40	-27,20
20		-0,11	-3,66	-8,54	0,24	5,21	2,76	-3,40	-9,68	-16,09	-22,63	-29,30
21		-8,27	-10,93	-15,28	2,02	2,99	-0,41	-6,01	-11,72	-17,54	-23,49	-29,55
22		-9,75	-12,50	-16,85	0,17	1,11	-2,30	-7,91	-13,64	-19,48	-25,43	-31,51
23		-37,15	-41,48	-46,17	-35,40	-34,71	-38,45	-44,44	-50,54	-56,77	-63,13	-69,61

Table D-3 (cont'd)

24	-35,25	-39,15	-43,74	-30,20	-29,84	-33,64	-39,55	-45,57	-51,72	-57,99	-64,38
25	-54,80	-59,81	-64,20	-53,18	-53,76	-57,79	-63,59	-69,51	-75,54	-81,69	-87,97
26	-96,28	-102,28	-107,38	-97,69	-99,26	-104,16	-110,75	-117,48	-124,34	-131,34	-138,48
27	-44,41	-49,58	-53,45	-43,31	-43,93	-47,64	-52,93	-58,33	-63,84	-69,45	-75,18
28	0,26	-4,45	-7,04	2,76	2,77	0,13	-3,85	-7,90	-12,05	-16,27	-20,58
29	-87,10	-93,00	-97,84	-88,22	-89,66	-94,33	-100,66	-107,11	-113,69	-120,41	-127,26
30	-88,44	-94,42	-99,24	-89,81	-91,31	-96,00	-102,32	-108,76	-115,33	-122,03	-128,87
Generator no	**Generation dispatch (MW)**										
G_1	21,32	78,95	112,22	0,00	0,00	32,72	82,04	132,34	183,64	235,97	289,35
$G_{5,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{5,2}$	33,92	25,67	35,48	66,87	71,79	69,92	64,66	59,29	53,82	48,24	42,54
G_8	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,2}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,3}$	139,76	130,28	127,89	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{13}	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{19}	300,00	300,00	300,00	250,25	287,67	300,00	300,00	300,00	300,00	300,00	300,00
AOCC (M$/year)	0,00	2,35	2,36	2,30	2,37	2,47	2,54	2,55	2,56	2,57	2,58
TIC (M$/year)	0,00	1,15	1,40	3,58	3,58	3,58	3,58	3,58	3,58	3,58	3,58
TC (M$/year)	0,00	3,50	3,76	5,88	5,95	6,04	6,12	6,13	6,14	6,15	6,16
TPC (M$)	**55,83**										

Table D-4. IEEE 30-Bus System (Case 2- DC Load Flow Results and Planning Solution (Peak-Demand Season))

Power flows (MW)		**Years along the planning horizon**										
from-bus	**to-bus**	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9	Y_{10}
1	2	9,43	-3,37	-3,04	17,21	57,80	80,93	-4,50	0,10	33,91	68,39	103,56
1	3	11,89	3,37	3,04	13,33	33,19	45,77	4,50	6,40	23,90	41,75	59,96
2	4	-6,60	-12,25	-12,92	-7,38	3,81	10,88	-12,76	-12,18	-2,45	7,46	17,58
2	5	-64,69	-69,13	-69,75	-63,94	-51,25	-44,85	-75,11	-74,43	-64,33	-54,03	-43,52
2	6	-33,28	-38,28	-38,98	-32,45	-18,16	-10,97	-45,01	-44,24	-32,88	-21,29	-9,47
3	4	-74,04	-77,70	-78,72	-72,85	-57,04	-51,00	-87,27	-86,90	-76,57	-66,03	-55,29
3	13	-28,07	-35,21	-36,84	-34,80	-33,16	-29,10	-36,61	-37,65	-33,10	-28,46	-23,72
4	6	-114,02	-111,62	-111,76	-107,19	-93,31	-92,36	-138,14	-137,32	-129,72	-121,97	-114,07
4	11	-139,76	-141,22	-142,56	-141,47	-131,93	-129,38	-137,68	-138,54	-136,18	-133,77	-131,32
4	12	40,14	27,24	24,32	27,30	28,03	34,79	26,01	24,00	31,04	38,23	45,55
5	7	174,23	176,23	178,27	180,34	182,46	98,41	99,59	100,79	102,01	103,26	104,53
5	7	0,00	0,00	0,00	0,00	0,00	98,41	99,59	100,79	102,01	103,26	104,53
6	7	-60,23	-59,95	-59,66	-59,37	-59,07	-70,96	-70,79	-70,62	-70,45	-70,27	-70,09
6	8	-148,49	-146,60	-144,62	-142,38	-140,37	-137,88	-136,39	-134,16	-131,55	-128,90	-126,19
6	9	-113,39	-118,42	-122,58	-120,09	-93,07	-85,32	-147,99	-151,11	-144,47	-137,70	-130,80
6	10	5,72	3,34	1,37	2,55	-1,39	2,03	-14,85	-16,28	-13,20	-10,07	-6,86
6	28	84,55	85,86	87,38	89,82	91,21	94,40	93,43	95,30	98,54	101,84	105,20
6	28	84,55	85,86	87,38	89,82	91,21	94,40	93,43	95,30	98,54	101,84	105,20
8	28	56,51	56,50	56,54	56,80	56,80	57,23	56,63	56,72	57,14	57,57	58,01
9	10	243,30	240,79	238,71	239,96	168,98	171,56	204,78	203,45	206,45	209,51	212,63
9	10	243,30	240,79	238,71	239,96	168,98	171,56	204,78	203,45	206,45	209,51	212,63
9	10	0,00	0,00	0,00	0,00	168,98	171,56	204,78	203,45	206,45	209,51	212,63
9	11	-300,00	-300,00	-300,00	-300,00	-300,00	-300,00	-254,11	-253,82	-254,61	-255,41	-256,23

Table D-4 (cont'd)

9	11	-300,00	-300,00	-300,00	-300,00	-300,00	-300,00	-254,11	-253,82	-254,61	-255,41	-256,23
9	11	0,00	0,00	0,00	0,00	0,00	0,00	-254,11	-253,82	-254,61	-255,41	-256,23
10	17	111,10	66,75	69,25	70,88	76,49	77,92	98,79	101,25	102,76	104,31	105,88
10	20	10,80	40,16	23,65	18,94	25,10	28,49	65,27	49,07	52,67	56,35	60,10
10	21	139,03	141,92	144,95	147,27	152,30	154,30	167,60	170,72	172,98	175,28	177,62
10	22	79,39	81,05	82,80	84,08	87,13	88,18	96,66	98,44	99,65	100,88	102,13
12	13	-135,96	-132,39	-131,58	-132,60	-133,42	-135,45	-131,69	-131,17	-133,45	-135,77	-138,14
12	13	-135,96	-132,39	-131,58	-132,60	-133,42	-135,45	-131,69	-131,17	-133,45	-135,77	-138,14
12	14	46,29	50,61	50,22	50,91	51,77	53,16	53,59	53,36	54,85	56,37	57,91
12	15	74,44	87,80	84,65	85,25	86,40	89,36	88,92	86,17	89,36	92,61	95,93
12	15	74,44	87,80	84,65	85,25	86,40	89,36	88,92	86,17	89,36	92,61	95,93
12	16	21,90	-31,09	-30,88	-29,73	-32,53	-31,08	-49,01	-48,47	-46,93	-45,36	-43,76
14	15	-10,71	-7,53	-9,08	-9,58	-9,93	-9,77	-10,61	-12,11	-11,94	-11,75	-11,57
15	18	-25,80	-0,89	-13,32	-16,49	-16,61	-13,83	-9,73	-21,69	-18,75	-15,75	-12,68
15	23	87,97	91,44	94,46	96,76	97,21	98,87	91,37	94,61	96,48	98,39	100,34
16	17	-35,10	10,77	9,82	9,78	5,78	5,99	-13,20	-13,95	-13,72	-13,48	-13,24
18	19	-139,80	-117,17	-131,92	-137,47	-140,00	-139,69	-138,11	-152,64	-152,32	-151,99	-151,65
19	20	65,20	37,36	55,42	61,72	57,17	55,42	20,32	38,23	36,38	34,48	32,55
21	22	63,03	64,40	65,88	66,62	70,04	70,39	82,01	83,42	83,93	84,45	84,98
22	24	142,42	145,45	148,68	150,70	157,17	158,56	178,67	181,86	183,58	185,33	187,11
23	24	-7,03	-5,46	-4,38	-4,05	-5,62	-6,02	-15,61	-14,51	-14,83	-15,14	-15,47
24	25	59,39	62,47	65,22	65,99	69,28	68,63	77,47	80,05	79,71	79,36	79,00
25	26	109,17	111,71	114,23	116,41	119,11	121,11	124,94	127,64	129,82	132,05	134,32
25	27	-49,78	-49,24	-49,00	-50,42	-49,83	-52,48	-47,48	-47,59	-50,12	-52,69	-55,32
26	29	-42,83	-43,33	-43,91	-44,89	-45,42	-46,71	-46,23	-46,96	-48,27	-49,60	-50,96
27	28	-112,81	-114,11	-115,65	-118,23	-119,61	-123,02	-121,75	-123,66	-127,11	-130,62	-134,21

Table D-4 (cont'd)

27	28	-112,81	-114,11	-115,65	-118,23	-119,61	-123,02	-121,75	-123,66	-127,11	-130,62	-134,21
27	29	102,79	104,58	106,47	108,67	110,58	113,07	114,32	116,46	119,05	121,70	124,40
27	30	73,05	74,41	75,82	77,36	78,80	80,49	81,70	83,28	85,05	86,85	88,69
29	30	2,95	3,11	3,26	3,29	3,46	3,42	3,89	4,02	4,00	3,98	3,95
Bus no		**Bus-angles (radian)**										
1		0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
2		-0,54	0,19	0,18	-0,99	-3,32	-4,65	0,26	-0,01	-1,95	-3,93	-5,95
3		-2,20	-0,62	-0,56	-2,47	-6,15	-8,48	-0,83	-1,18	-4,43	-7,73	-11,10
4		0,60	2,32	2,42	0,29	-3,98	-6,54	2,47	2,11	-1,52	-5,23	-9,01
5		12,29	13,90	14,01	11,69	6,84	4,24	15,15	14,75	10,81	6,78	2,67
6		5,32	6,94	7,05	4,73	-0,12	-2,72	8,19	7,79	3,85	-0,18	-4,29
7		10,26	11,86	11,94	9,60	4,72	3,10	14,00	13,59	9,62	5,58	1,46
8		11,56	13,10	13,12	10,71	5,77	3,07	13,92	13,43	9,37	5,23	1,01
9		28,91	31,57	32,54	29,71	19,24	15,03	38,98	39,22	33,90	28,46	22,92
10		2,15	5,09	6,29	3,31	0,65	-3,85	16,45	16,84	11,19	5,42	-0,47
11		91,31	93,97	94,94	92,11	81,64	77,43	91,83	92,02	86,86	81,59	76,22
12		-9,67	-4,65	-3,81	-6,69	-11,16	-15,45	-4,18	-4,04	-9,47	-15,02	-20,67
13		9,36	13,88	14,62	11,87	7,52	3,51	14,25	14,33	9,21	3,99	-1,33
14		-21,52	-17,60	-16,66	-19,72	-24,41	-29,05	-17,90	-17,69	-23,51	-29,44	-35,49
15		-19,38	-16,10	-14,84	-17,81	-22,43	-27,10	-15,78	-15,27	-21,12	-27,09	-33,18
16		-14,02	1,53	2,33	-0,79	-4,70	-9,27	5,55	5,60	-0,15	-6,00	-11,98
17		-7,24	-0,56	0,43	-2,68	-5,81	-10,43	8,10	8,29	2,50	-3,40	-9,42
18		-13,74	-15,91	-11,93	-14,21	-18,80	-24,08	-13,65	-10,53	-17,03	-23,65	-30,41
19		4,32	-0,77	5,11	3,55	-0,71	-6,03	4,19	9,19	2,65	-4,01	-10,82
20		-0,11	-3,31	1,34	-0,64	-4,60	-9,80	2,81	6,59	0,18	-6,36	-13,03

Table D-4 (cont'd)

21	-8,27	-5,54	-4,57	-7,72	-10,76	-15,40	3,90	4,06	-1,77	-7,71	-13,77
22	-9,75	-7,06	-6,13	-9,29	-12,41	-17,06	1,96	2,09	-3,75	-9,70	-15,78
23	-37,15	-34,57	-33,92	-37,36	-42,06	-47,07	-34,24	-34,38	-40,61	-46,97	-53,45
24	-35,25	-33,10	-32,74	-36,26	-40,54	-45,45	-30,02	-30,47	-36,61	-42,88	-49,27
25	-54,80	-53,67	-54,21	-57,99	-63,35	-68,04	-55,52	-56,82	-62,85	-69,00	-75,28
26	-96,28	-96,12	-97,62	-102,22	-108,61	-114,06	-103,00	-105,32	-112,18	-119,18	-126,32
27	-44,41	-43,39	-43,98	-47,47	-52,95	-57,09	-45,61	-46,89	-52,39	-58,01	-63,73
28	0,26	1,80	1,81	-0,65	-5,59	-8,37	2,60	2,08	-2,06	-6,28	-10,59
29	-87,10	-86,82	-88,20	-92,60	-98,87	-104,05	-93,09	-95,25	-101,83	-108,55	-115,40
30	-88,44	-88,24	-89,68	-94,09	-100,44	-105,60	-94,85	-97,08	-103,65	-110,35	-117,19
Generator no	**Generation dispatch (MW)**										
G_1	21,32	0,00	0,00	30,54	90,99	126,70	0,00	6,50	57,81	110,14	163,52
$G_{5,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{5,2}$	33,92	42,26	46,86	45,10	36,54	46,56	81,27	85,13	79,65	74,07	68,38
G_8	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,2}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,3}$	139,76	141,22	142,56	141,47	131,93	129,38	300,00	300,00	300,00	300,00	300,00
G_{13}	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{19}	300,00	251,42	286,18	300,00	300,00	300,00	265,42	300,00	300,00	300,00	300,00
G_{16}	0,00	100,00	100,00	100,00	100,00	100,00	100,00	100,00	100,00	100,00	100,00
AOCC (M$/year)	0,00	1,85	1,91	2,01	2,13	2,14	2,08	2,15	2,27	2,39	2,47
TIC (M$/year)	0,00	0,00	0,00	0,00	1,15	1,40	3,58	3,58	3,58	3,58	3,58

Table D-4 (cont'd)

IR (M$/year)	0,00	2,95	1,03	1,03	0,00	0,00	0,00	0,00	0,00	0,00	0,00
TC (M$/year)	0,00	4,79	2,94	3,03	3,28	3,54	5,65	5,73	5,85	5,97	6,05
TPC (M$)	**46,85**										

Table D-5. IEEE 30-Bus System (Case 3- DC Load Flow Results and Planning Solution (Peak-Demand Season))

Power flows (MW)		**Years along the planning horizon**										
from-bus	**to-bus**	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9	Y_{10}
1	2	9,43	48,85	78,94	119,91	165,98	189,81	96,00	196,75	69,79	196,57	197,05
1	3	11,89	44,65	47,23	68,69	98,53	110,19	53,91	103,25	35,19	103,43	102,95
2	4	-6,60	13,15	14,78	25,87	40,56	45,59	10,00	39,29	-5,05	35,33	32,42
2	5	-64,69	-48,82	-38,25	-27,14	-15,48	-9,71	-39,37	-9,78	-50,92	-14,81	-16,89
2	6	-33,28	-35,18	-23,28	-10,79	2,33	8,44	-27,40	6,83	-42,67	-0,81	-4,18
3	4	-74,04	-83,80	-43,28	-35,21	-43,78	-41,53	-71,95	-25,95	-89,20	-45,23	-55,52
3	13	-28,07	8,75	-35,18	-28,07	3,74	6,22	-26,90	-31,21	-44,04	-28,19	-27,23
4	6	-114,02	-204,97	-161,14	-154,45	-160,24	-155,37	-158,64	-135,74	-160,52	-151,68	-153,81
4	11	-139,76	-116,24	-36,19	-43,25	-100,19	-110,20	-123,57	-65,17	-142,54	-100,19	-124,92
4	12	40,14	110,91	22,20	34,39	95,55	99,89	42,03	27,10	12,32	35,65	38,99
5	6	0,00	300,00	300,00	300,00	300,00	294,27	256,72	270,94	222,07	240,83	225,19
5	7	174,23	75,71	78,51	81,44	84,53	87,38	88,30	92,81	93,32	98,49	101,59
5	7	0,00	75,71	78,51	81,44	84,53	87,38	88,30	92,81	93,32	98,49	101,59
6	7	-60,23	-31,73	-31,33	-30,92	-30,48	-29,27	-23,83	-25,20	-18,21	-20,14	-17,49
6	8	-148,49	-140,17	-136,13	-130,14	-122,71	-116,45	-112,39	-105,54	-99,79	-91,27	-84,11
6	9	-113,39	-21,90	37,73	34,61	-0,61	-12,93	-54,00	-5,32	-112,81	-84,18	-117,60
6	10	5,72	48,99	41,31	43,83	55,13	53,24	15,81	20,22	-10,07	2,18	-3,96

Table D-5 (cont'd)

6	28	84,55	102,33	102,00	108,69	120,38	126,37	122,54	128,94	129,89	140,87	145,18
6	28	84,55	102,33	102,00	108,69	120,38	126,37	122,54	128,94	129,89	140,87	145,18
8	28	56,51	60,08	59,14	59,88	61,82	62,30	60,30	60,78	59,86	61,36	61,14
9	10	243,30	289,05	137,43	156,11	279,81	293,54	182,00	112,23	162,40	170,18	202,37
9	10	243,30	289,05	137,43	156,11	279,81	293,54	182,00	112,23	162,40	170,18	202,37
9	10	0,00	0,00	0,00	0,00	0,00	0,00	182,00	112,23	162,40	170,18	202,37
9	11	-300,00	-300,00	-118,57	-138,81	-280,12	-300,00	-300,00	-171,00	-300,00	-198,24	-241,57
9	11	-300,00	-300,00	-118,57	-138,81	-280,12	-300,00	-300,00	-171,00	-300,00	-198,24	-241,57
9	11	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	-198,24	-241,57
10	17	111,10	110,84	-52,26	-44,49	-19,30	-9,95	8,44	-0,93	34,69	38,54	90,66
10	20	10,80	142,79	-2,59	8,81	208,93	200,82	64,74	-141,01	-109,28	-98,40	-76,95
10	21	139,03	136,64	130,73	138,57	153,83	163,37	181,63	182,12	208,08	214,42	218,06
10	22	79,39	77,22	72,71	77,20	86,54	92,08	103,31	102,84	119,05	122,34	123,80
12	13	-135,96	-154,37	-132,41	-135,96	-151,87	-153,11	-136,55	-134,39	-127,98	-135,90	-136,39
12	13	-135,96	-154,37	-132,41	-135,96	-151,87	-153,11	-136,55	-134,39	-127,98	-135,90	-136,39
12	14	46,29	59,39	59,58	62,60	77,00	78,62	69,10	65,07	65,61	70,50	77,05
12	15	74,44	115,85	111,91	117,65	162,93	163,28	124,46	104,53	100,25	110,90	127,00
12	15	74,44	115,85	111,91	117,65	162,93	163,28	124,46	104,53	100,25	110,90	127,00
12	16	21,90	28,81	-101,10	-101,55	-119,03	-120,31	-130,21	-111,92	-138,19	-132,21	-87,01
12	16	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	-87,01
14	15	-10,71	-0,46	-3,27	-3,39	7,72	5,87	-7,28	-15,13	-18,61	-17,93	-15,80
15	18	-25,80	71,46	16,80	21,11	137,49	126,94	17,19	-57,97	-69,65	-59,48	-58,82
15	23	87,97	80,00	119,95	122,82	103,70	108,49	122,60	144,96	139,25	145,44	86,61
15	23	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	86,61
16	17	-35,10	-31,04	136,05	132,46	111,68	106,94	93,41	107,87	77,59	79,36	33,13
18	19	-139,80	-48,24	-108,88	-110,86	-1,08	-18,56	-135,58	-218,38	-238,08	-236,33	-244,51
19	20	65,20	-62,99	86,38	79,17	-116,55	-103,83	37,11	-52,05	-78,44	-83,70	-99,26

Table D-5 (cont'd)

21	22	63,03	56,84	46,94	50,59	61,45	66,37	79,78	75,18	95,79	96,52	94,27
22	24	142,42	134,06	119,66	127,79	147,98	158,45	183,09	178,02	214,84	218,86	218,07
23	24	-7,03	-19,76	15,21	12,85	-11,77	-12,76	-4,71	11,29	-1,11	-1,93	18,47
24	25	59,39	34,50	51,08	52,66	43,84	48,69	76,54	82,37	101,45	99,02	112,74
25	26	109,17	109,34	117,63	123,32	127,32	134,19	145,71	153,38	163,88	170,66	180,85
25	27	-49,78	-74,84	-66,55	-70,66	-83,48	-85,50	-69,18	-71,01	-62,44	-71,63	-68,11
26	29	-42,83	-50,26	-49,95	-52,64	-57,44	-59,81	-57,98	-60,50	-60,69	-65,14	-66,74
27	28	-112,81	-132,37	-131,57	-138,63	-151,29	-157,53	-152,70	-159,33	-159,81	-171,55	-175,75
27	28	-112,81	-132,37	-131,57	-138,63	-151,29	-157,53	-152,70	-159,33	-159,81	-171,55	-175,75
27	29	102,79	111,72	115,28	121,18	128,79	134,87	138,16	144,79	150,00	158,52	165,25
27	30	73,05	78,19	81,31	85,42	90,31	94,68	98,05	102,85	107,19	112,95	118,13
29	30	2,95	1,61	2,48	2,56	2,07	2,32	3,79	4,09	5,10	4,95	5,67
Bus no		**Bus-angles (radian)**										
1		0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
2		-0,54	-2,81	-4,54	-6,89	-9,54	-10,91	-5,52	-11,31	-4,01	-11,30	-11,33
3		-2,20	-8,27	-8,75	-12,72	-18,25	-20,41	-9,98	-19,12	-6,52	-19,16	-19,07
4		0,60	-5,09	-7,11	-11,39	-16,59	-18,83	-7,26	-18,14	-3,14	-17,44	-16,96
5		12,29	6,87	3,04	-1,51	-6,47	-8,99	2,29	-9,37	6,09	-8,37	-7,98
6		5,32	3,39	-0,44	-4,99	-9,95	-12,40	-0,69	-12,52	3,51	-11,16	-10,59
7		10,26	5,99	2,13	-2,46	-7,46	-10,00	1,26	-10,45	5,00	-9,51	-9,16
8		11,56	9,28	5,28	0,47	-4,80	-7,51	4,03	-8,09	7,70	-7,33	-7,06
9		28,91	7,95	-8,28	-12,19	-9,83	-9,71	10,54	-11,41	26,97	6,35	13,87
10		2,15	-23,85	-23,40	-29,37	-40,61	-42,00	-9,48	-23,76	9,11	-12,37	-8,40
11		91,31	70,35	16,38	16,68	48,44	52,69	72,94	24,16	89,37	47,58	64,11
12		-9,67	-33,49	-12,79	-20,19	-41,05	-44,41	-18,02	-25,08	-6,29	-26,57	-26,94
13		9,36	-11,87	5,75	-1,16	-19,79	-22,97	1,10	-6,26	11,63	-7,54	-7,85

Table D-5 (cont'd)

14	-21,52	-48,69	-28,04	-36,21	-60,76	-64,52	-35,70	-41,73	-23,08	-44,61	-46,66
15	-19,38	-48,59	-27,38	-35,53	-62,30	-65,70	-34,25	-38,71	-19,36	-41,03	-43,50
16	-14,02	-39,21	7,30	-0,01	-17,40	-20,50	7,85	-2,84	21,17	-0,30	-9,65
17	-7,24	-33,21	-18,99	-25,61	-38,98	-41,16	-10,19	-23,68	6,18	-15,63	-16,06
18	-13,74	-64,21	-31,05	-40,15	-92,34	-93,43	-38,00	-26,04	-4,14	-28,03	-30,65
19	4,32	-57,97	-16,99	-25,82	-92,20	-91,03	-20,49	2,17	26,62	2,50	0,94
20	-0,11	-53,69	-22,86	-31,21	-84,27	-83,97	-23,01	5,71	31,95	8,19	7,69
21	-8,27	-34,08	-33,19	-39,74	-52,13	-54,24	-23,08	-37,40	-6,47	-28,43	-24,73
22	-9,75	-35,42	-34,30	-40,94	-53,58	-55,80	-24,97	-39,17	-8,74	-30,71	-26,95
23	-37,15	-64,75	-51,61	-60,34	-83,25	-87,61	-59,01	-67,99	-47,49	-70,41	-61,00
24	-35,25	-59,42	-55,72	-63,81	-80,07	-84,17	-57,74	-71,04	-47,19	-69,89	-65,99
25	-54,80	-70,78	-72,53	-81,15	-94,50	-100,19	-82,94	-98,15	-80,59	-102,48	-103,10
26	-96,28	-112,33	-117,23	-128,01	-142,88	-151,19	-138,31	-156,44	-142,86	-167,33	-171,82
27	-44,41	-55,16	-58,65	-66,40	-77,08	-82,35	-68,50	-83,34	-67,56	-87,53	-88,89
28	0,26	-2,74	-6,55	-11,50	-17,17	-19,97	-8,03	-20,24	-4,27	-19,60	-19,29
29	-87,10	-101,55	-106,52	-116,73	-130,56	-138,36	-125,88	-143,47	-129,85	-153,37	-157,52
30	-88,44	-102,28	-107,65	-117,89	-131,50	-139,41	-127,60	-145,32	-132,16	-155,61	-160,08
Generator no	**Generation dispatch (MW)**										
G_1	21,32	93,50	126,17	188,60	264,51	300,00	149,92	300,00	104,98	300,00	300,00
$G_{5,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{5,2}$	33,92	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_8	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,1}$	300,00	300,00	273,32	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,2}$	300,00	300,00	0,00	20,86	300,00	300,00	300,00	107,17	300,00	300,00	300,00

Table D-5 (cont'd)

$G_{11,3}$	139,76	116,24	0,00	0,00	60,43	110,20	123,57	0,00	142,54	94,90	249,64
G_{13}	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{19}	300,00	85,00	300,00	300,00	0,00	35,98	300,00	300,00	300,00	300,00	300,00
G_{16}	0,00	0,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{20}	0,00	0,00	0,00	0,00	0,00	0,00	0,00	300,00	300,00	300,00	300,00
AOCC (M$/year)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
TIC (M$/year)	0,00	3,94	3,94	3,94	3,94	3,94	5,09	5,09	5,09	7,26	11,45
IR (M$/year)	0,00	0,00	3,08	3,08	0,00	0,00	9,84	5,19	3,08	11,35	4,95
TC (M$/year)	0,00	3,94	7,01	7,01	3,94	3,94	14,92	10,28	8,16	18,62	16,40
TPC (M$)	**94,21**										

Table D-6. IEEE 30-Bus System (Case 4- DC Load Flow Results and Planning Solution (Peak-Demand Season))

Power flows (MW)		**Years along the planning horizon**										
from-bus	**to-bus**	Y_0	Y_1	Y_2	Y_3	Y_4	Y_5	Y_6	Y_7	Y_8	Y_9	Y_{10}
1	2	9,43	63,53	118,73	175,24	41,44	-0,39	194,89	187,88	79,90	180,41	193,90
1	3	11,89	51,99	78,62	102,52	31,08	0,39	105,11	112,12	47,88	119,59	106,10
2	4	-6,60	16,99	31,59	44,65	-2,35	-23,86	36,24	41,69	-0,35	50,63	31,49
2	5	-64,69	-44,79	-29,70	-13,56	-57,34	-70,95	-13,62	-24,25	-59,73	-11,65	-22,54
2	6	-33,28	-30,64	-13,67	4,49	-48,30	-65,48	1,19	-12,62	-55,90	-0,43	-14,83
3	4	-74,04	-79,83	-59,27	-30,50	-99,79	-111,85	-51,87	-71,80	-114,33	-78,60	-79,94
3	13	-28,07	9,84	7,37	-6,64	-18,56	-47,65	-14,11	0,87	-33,67	-11,40	-38,22
4	6	-114,02	-201,75	-190,74	-168,20	-195,83	-178,75	-146,99	-228,63	-236,59	-214,26	-195,28
4	11	-139,76	-115,77	-93,90	-54,63	-142,51	-152,37	-131,38	-109,35	-142,17	-130,43	-136,71

Table D-6 (cont'd)

4	12	40,14	112,38	104,68	74,05	61,87	8,87	63,15	94,29	35,57	72,21	21,91
5	6	0,00	300,00	300,00	300,00	246,07	217,71	250,88	222,80	171,46	192,53	160,00
5	7	174,23	76,78	80,77	85,03	86,04	89,05	96,46	100,20	102,79	110,59	115,29
5	7	0,00	76,78	80,77	85,03	86,04	89,05	96,46	100,20	102,79	110,59	115,29
6	7	-60,23	-31,58	-31,01	-30,41	-22,64	-18,20	-21,85	-17,34	-9,71	-11,59	-6,32
6	8	-148,49	-138,07	-130,67	-123,13	-115,73	-107,40	-95,25	-104,24	-95,53	-81,84	-72,42
6	9	-113,39	-21,08	-8,60	18,81	-105,69	-139,84	-80,68	-71,76	-143,89	-107,78	-133,28
6	10	5,72	49,38	44,68	39,72	9,36	-6,80	21,19	32,51	-13,34	3,32	-8,31
6	28	84,55	104,47	110,59	115,65	118,32	122,87	140,84	71,19	70,73	87,86	85,11
6	28	84,55	104,47	110,59	115,65	118,32	122,87	140,84	71,19	70,73	87,86	85,11
8	28	56,51	60,28	60,56	60,50	59,74	59,35	62,18	43,21	41,24	43,50	40,70
9	10	243,30	289,46	242,11	165,19	247,16	230,08	259,66	300,00	204,65	220,60	210,00
9	10	243,30	289,46	242,11	165,19	247,16	230,08	259,66	300,00	204,65	220,60	210,00
9	10	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	204,65	220,60	210,00
9	11	-300,00	-300,00	-246,41	-155,79	-300,00	-300,00	-300,00	-223,92	-252,61	-256,52	-254,43
9	11	-300,00	-300,00	-246,41	-155,79	-300,00	-300,00	-300,00	-223,92	-252,61	-256,52	-254,43
9	11	0,00	0,00	0,00	0,00	0,00	0,00	0,00	-223,92	-252,61	-256,52	-254,43
10	17	111,10	112,62	119,48	113,77	152,45	24,14	26,36	46,04	78,39	87,06	83,07
10	20	10,80	135,42	2,31	-169,25	-133,75	-92,80	-31,27	73,47	-55,80	-36,47	-39,92
10	21	139,03	139,05	148,93	153,29	181,89	196,50	202,32	173,88	203,61	215,48	182,90
10	22	79,39	78,57	84,16	86,07	103,84	112,34	114,99	95,04	113,24	119,59	96,64
12	13	-135,96	-154,92	-153,69	-146,68	-140,72	-126,18	-142,95	-150,43	-133,17	-144,30	-130,89
12	13	-135,96	-154,92	-153,69	-146,68	-140,72	-126,18	-142,95	-150,43	-133,17	-144,30	-130,89
12	14	46,29	59,80	58,89	52,05	53,30	63,90	74,52	82,05	73,68	81,33	70,32
12	15	74,44	115,54	105,80	74,91	71,80	100,84	129,36	146,51	107,43	123,68	73,97
12	15	74,44	115,54	105,80	74,91	71,80	100,84	129,36	146,51	107,43	123,68	73,97
12	16	21,90	29,69	32,79	49,16	21,88	-137,60	-126,76	-132,47	-149,87	-142,55	-121,44

Table D-6 (cont'd)

14	15	-10,71	-1,19	-6,37	-17,78	-21,42	-16,04	-11,02	-9,48	-24,26	-23,46	-41,81
15	18	-25,80	66,18	23,98	-81,61	-92,67	-53,20	-3,60	61,75	-54,52	-39,57	0,55
15	23	87,97	82,39	94,24	120,55	115,24	132,24	137,23	99,77	114,53	123,76	-43,94
16	17	-35,10	-31,30	-32,47	-20,67	-52,83	82,46	87,70	76,00	52,20	52,66	66,44
18	19	-139,80	-55,80	-106,54	-221,27	-242,10	-213,09	-174,68	-121,31	-250,39	-249,16	-223,70
19	20	65,20	-54,10	-215,30	-37,65	-66,63	-100,61	-154,68	-251,43	-113,62	-123,81	-110,58
21	22	63,03	57,73	61,92	60,19	82,27	89,90	88,26	51,84	73,03	75,75	33,39
22	24	142,42	136,30	146,08	146,26	186,10	202,24	203,25	146,88	186,27	195,35	130,04
23	24	-7,03	-19,26	-14,52	4,17	-9,28	-1,01	-5,34	-52,78	-48,69	-50,89	69,18
24	25	59,39	35,72	44,54	57,33	77,20	94,64	83,85	-27,95	6,99	4,73	49,72
25	26	109,17	111,53	120,54	130,81	142,97	155,26	162,83	12,31	29,94	41,28	62,41
25	27	-49,78	-75,82	-76,00	-73,48	-65,77	-60,62	-78,98	-40,25	-22,95	-36,55	-12,69
26	29	-42,83	-51,11	-53,49	-55,40	-56,27	-57,93	-65,28	68,23	68,77	61,84	63,40
27	28	-112,81	-134,62	-140,88	-145,90	-148,19	-152,54	-171,93	-92,80	-91,35	-109,61	-105,46
27	28	-112,81	-134,62	-140,88	-145,90	-148,19	-152,54	-171,93	-92,80	-91,35	-109,61	-105,46
27	29	102,79	113,77	120,87	128,02	134,82	142,62	154,97	66,72	74,43	88,07	96,21
27	30	73,05	79,65	84,89	90,31	95,79	101,85	109,91	78,62	85,32	94,61	102,01
29	30	2,95	1,67	2,13	2,79	3,84	4,75	4,15	43,42	45,26	45,11	47,49
Bus no		**Bus-angles (radian)**										
1		0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
2		-0,54	-3,65	-6,83	-10,08	-2,38	0,02	-11,21	-10,80	-4,59	-10,37	-11,15
3		-2,20	-9,63	-14,56	-18,99	-5,76	-0,07	-19,47	-20,77	-8,87	-22,15	-19,65
4		0,60	-6,60	-12,31	-17,83	-1,97	4,17	-17,50	-18,04	-4,53	-19,17	-16,62
5		12,29	5,23	-0,94	-7,39	8,99	14,09	-8,51	-5,99	7,25	-8,06	-6,68
6		5,32	1,75	-4,42	-10,87	6,13	11,57	-11,42	-8,58	5,26	-10,30	-8,53
7		10,26	4,34	-1,87	-8,37	7,99	13,06	-9,62	-7,16	6,06	-9,35	-8,02
8		11,56	7,55	1,07	-5,70	10,99	16,08	-7,42	-4,20	9,27	-6,86	-5,49

Table D-6 (cont'd)

9	28,91	6,13	-2,63	-14,78	28,12	40,65	5,37	6,35	35,19	12,12	19,19
10	2,15	-25,71	-29,26	-32,95	0,93	15,35	-23,20	-26,65	12,68	-12,15	-3,91
11	91,31	68,53	48,63	17,62	90,52	103,05	67,77	52,92	87,73	65,48	72,11
12	-9,67	-35,37	-39,11	-36,79	-17,81	1,89	-33,67	-42,18	-13,64	-37,65	-22,23
13	9,36	-13,68	-17,60	-16,25	1,89	19,56	-13,65	-21,12	5,00	-17,45	-3,90
14	-21,52	-50,68	-54,18	-50,11	-31,45	-14,46	-52,74	-63,18	-32,49	-58,47	-40,22
15	-19,38	-50,44	-52,91	-46,56	-27,18	-11,26	-50,53	-61,29	-27,65	-53,78	-31,87
16	-14,02	-41,27	-45,63	-46,56	-22,16	29,24	-8,48	-15,86	16,14	-9,33	1,90
17	-7,24	-35,22	-39,36	-42,56	-11,95	13,31	-25,42	-30,54	6,06	-19,50	-10,93
18	-13,74	-64,90	-58,15	-28,72	-6,93	0,37	-49,75	-74,78	-15,74	-45,13	-31,99
19	4,32	-57,69	-44,39	-0,14	24,35	27,90	-27,18	-59,11	16,62	-12,94	-3,09
20	-0,11	-54,01	-29,75	2,42	28,88	34,74	-16,66	-42,01	24,34	-4,52	4,43
21	-8,27	-36,12	-40,42	-44,43	-12,69	0,63	-38,35	-39,68	-2,57	-28,28	-17,61
22	-9,75	-37,48	-41,88	-45,85	-14,64	-1,49	-40,43	-40,90	-4,30	-30,07	-18,40
23	-37,15	-67,08	-71,95	-70,91	-50,46	-37,97	-78,26	-81,44	-50,78	-78,78	-23,00
24	-35,25	-61,88	-68,03	-72,03	-47,95	-37,70	-76,81	-67,19	-37,64	-65,04	-41,68
25	-54,80	-73,64	-82,69	-90,91	-73,36	-68,85	-104,42	-57,99	-39,94	-66,60	-58,04
26	-96,28	-116,02	-128,49	-140,62	-127,69	-127,85	-166,29	-62,67	-51,31	-82,28	-81,76
27	-44,41	-57,82	-66,83	-75,57	-59,64	-56,20	-87,94	-49,59	-35,15	-58,97	-55,40
28	0,26	-4,51	-11,04	-17,80	-0,95	4,21	-19,85	-12,84	1,02	-15,56	-13,63
29	-87,10	-105,06	-117,03	-128,74	-115,63	-115,43	-152,30	-77,30	-66,06	-95,54	-95,35
30	-88,44	-105,82	-117,99	-130,00	-117,37	-117,58	-154,18	-96,98	-86,57	-115,99	-116,88
Generator no	**Generation dispatch (MW)**										
G_1	21,32	115,52	197,35	277,76	72,53	0,00	300,00	300,00	127,78	300,00	300,00
G_2	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	67,73	24,47

Table D-6 (cont'd)

$G_{5,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{5,2}$	33,92	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{8}	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,1}$	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,2}$	300,00	300,00	286,72	66,20	300,00	300,00	300,00	300,00	300,00	300,00	300,00
$G_{11,3}$	139,76	115,77	0,00	0,00	142,51	152,37	131,38	181,10	300,00	300,00	300,00
G_{13}	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{19}	300,00	103,35	0,00	300,00	300,00	245,72	162,57	22,43	300,00	300,00	300,00
G_{26}	0,00	0,00	0,00	0,00	0,00	0,00	0,00	300,00	300,00	300,00	300,00
G_{23}	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	300,00
G_{16}	0,00	0,00	0,00	0,00	0,00	300,00	300,00	300,00	300,00	300,00	300,00
G_{20}	0,00	0,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00	300,00
AOCC (M$/year)	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00	0,00
TIC (M$/year)	0,00	3,94	3,94	3,94	3,94	3,94	3,94	6,11	7,26	7,26	7,26
IR (M$/year)	0,00	0,00	3,08	6,05	2,75	14,43	14,26	20,42	13,50	8,63	17,72
TC (M$/year)	0,00	3,94	7,01	9,99	6,69	18,37	18,19	26,53	20,77	15,89	24,99
TPC (M$)	**152,37**										

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WORK EXPERIENCE

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2000- Present	TÜBİTAK-UZAY	Chief Researcher
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FOREIGN LANGUAGES

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PUBLICATIONS

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