

2011

Long-term power system capacity expansion planning considering reliability and economic criteria

Yang Gu
Iowa State University

Follow this and additional works at: <https://lib.dr.iastate.edu/etd>

 Part of the [Electrical and Computer Engineering Commons](#)

Recommended Citation

Gu, Yang, "Long-term power system capacity expansion planning considering reliability and economic criteria" (2011). *Graduate Theses and Dissertations*. 10163.
<https://lib.dr.iastate.edu/etd/10163>

This Dissertation is brought to you for free and open access by the Iowa State University Capstones, Theses and Dissertations at Iowa State University Digital Repository. It has been accepted for inclusion in Graduate Theses and Dissertations by an authorized administrator of Iowa State University Digital Repository. For more information, please contact digirep@iastate.edu.

Long-term power system capacity expansion planning considering reliability and economic criteria

by

Yang Gu

A dissertation submitted to the graduate faculty
in partial fulfillment of the requirements for the degree of

DOCTOR OF PHILOSOPHY

Major: Electrical Engineering

Program of Study Committee:
James D. McCalley, Major Professor
Dionysios Aliprantis
Lizhi Wang
Sarah Ryan
Arka Ghosh

Iowa State University

Ames, Iowa

2011

Copyright © Yang Gu, 2011. All rights reserved

Table of Contents

NOMENCLATURE	vii
LIST OF FIGURES	x
LIST OF TABLES	xiii
ACKNOWLEDGEMENTS	xiv
CHAPTER 1 INTRODUCTION	1
CHAPTER 2 LITERATURE REVIEW	6
2.1 SYSTEM CAPACITY EXPANSION PLANNING ALGORITHMS	6
2.1.1 Generation Expansion Planning Algorithms	6
2.1.2 Transmission Expansion Planning Algorithms	9
2.2 SYSTEM CAPACITY EXPANSION PLANNING TOOLS.....	14
2.2.1 Introduction	14
2.2.2 Production Cost Simulation Tools.....	17
2.2.3 Resource Planning Tools	19
2.2.4 Reliability Assessment Tools	20
2.2.5 National Planning Tools	22
CHAPTER 3 MODELING THE INTEGRATED ENERGY SYSTEM	25

3.1 GENERALIZED NETWORK FLOW MODEL	27
3.2 COMBINING DC POWER FLOW MODEL WITH GNF MODEL	30
3.2.1 System Formulation.....	30
3.2.2 Nodal Prices.....	31
3.3 NUMERICAL EXAMPLE	33
CHAPTER 4 RELIABILITY-BASED AND MARKET-BASED PLANNING	44
4.1 RELIABILITY-BASED TRANSMISSION EXPANSION PLANNING	47
4.1.1 Overall Formulation	47
4.1.2 Master Problem.....	48
4.1.3 Slave Problem.....	49
4.1.4 Iteration Procedures	51
4.2 MARKET-BASED TRANSMISSION EXPANSION PLANNING	52
4.2.1 Overall Problem.....	52
4.2.2 Market Structure and Operation	53
4.2.3 Master Problem.....	57
4.2.4 Slave Problem.....	58
4.2.5 Iteration Procedures	60
4.3 NUMERICAL EXAMPLE	61
4.3.1 5-bus System.....	61
4.3.2 A 30-bus System.....	65

3.4.3 Scalability of The Market-based Planning Algorithm.....	67
4.4 TRANSMISSION PLANNING CONSIDERING BOTH RELIABILITY AND ECONOMIC CRITERIA.....	70
CHAPTER 5 MODELING UNCERTAINTIES.....	74
5.1 MONTE CARLO SIMULATION METHOD.....	76
5.2 BENDERS DECOMPOSITION ITERATION PROCEDURES.....	79
5.3 ROBUSTNESS TESTING AND MULTIPLE FUTURES.....	82
5.4 NUMERICAL EXAMPLE.....	86
CHAPTER 6 TRANSMISSION PLANNING CONSIDERING LARGE-SCALE INTEGRATION OF RENEWABLE ENERGY.....	89
6.1 INTRODUCTION.....	89
6.2 WIND FORMULATION.....	92
6.3 GENERATION EXPANSION PLANNING MODEL.....	93
6.3.1. Unit Commitment Problem Formulation.....	97
6.3.2. Economic Dispatch Problem Formulation.....	101
6.3.3. GEP Master Problem Formulation.....	103
6.4 TRANSMISSION EXPANSION PLANNING MODEL.....	104
6.5 COORDINATING GEP AND TEP.....	106
6.6 NUMERICAL EXAMPLE.....	107

CHAPTER 7 EVALUATING ENERGY STORAGE SYSTEM AS AN ALTERNATIVE TO TRANSMISSION EXPANSIONS.....	115
7.1 INTRODUCTION.....	115
7.2 STORAGE MODEL	117
7.3 CASE STUDY.....	122
7.4 COMPARING THE ECONOMIC PERFORMANCE OF CAES AND TRANSMISSION LINE ADDITIONS	131
CHAPTER 8 THE MARKET-BASED TRANSMISSION PLANNING TOOL	133
8.1 INTRODUCTION.....	133
8.2 INPUT DATA	136
8.3 PREPROCESSOR.....	138
8.3 MPS FILE GENERATION	139
8.4 OPTIMIZATION MODEL.....	141
8.4.1 Benders Decomposition and Monte Carlo Simulation	141
8.4.2 System Long-term Performance Evaluation.....	144
CHAPTER 9 CONCLUSIONS.....	146
9.1 CONTRIBUTIONS	146
9.2 FURTHER RESEARCH DIRECTIONS	147
APPENDIX: DETAILS OF THE TEST SYSTEMS	152

BIBLIOGRAPHY 154

NOMENCLATURE

A. Sets

T	Set of time periods
M	Set of arcs in the existing electric transmission network
M_f	Set of arcs in the fuel transportation network
M_t	Set of arcs that represent electric transmission system
Mn'	Arcs that represent potential lines
Mg	Set of arcs that represent power generation processes for generators (excluding wind farms)
Md	Set of arcs that represent LSEs' bidding curves
N	Set of nodes
N_f	Set of nodes in the fuel transportation network
Ng	Set of generators (excluding wind farms)
Nt	Set of transmission buses
Nw	Set of wind farms
Ns	Set of compressed air energy storage systems
L_{ij}	Set of linearization segments of the energy bidding from node i to node j
S_{ij}	Set of linearization segments of the spinning reserve bidding from node i to node j

NS_{ij} Set of linearization segments of the non-spinning reserve bidding from node i to node j

B_i Set of nodes adjacent to node i

G_i Set of generator nodes connected to node i

B. Variables

$e_{ij}(l,t)$ Energy flow segment l from node i to node j during period t

$en_{ij}(l,t)$ Energy flowing segment l from node i to node j through potential line during period t

$f_{ij}(s,t)$ Spinning reserve bidding segment s from node i to node j during period t

$g_{ij}(ns,t)$ Non-spinning reserve bidding segment ns from node i to node j during period t

U_{ij} Unit commitment decision variable for generator ij

$r_i(t)$ Load curtailment at node i during time t

C. Parameters

$Ce_{ij}(l,t)$ Per-unit cost of the energy flow segment l from node i to node j during period t

$Cs_{ij}(s,t)$ Per-unit cost of the spinning reserve bidding segment s from node i to node j during period t

$Cn_{ij}(ns,t)$ Per-unit cost of the energy flowing from node i to node j during period t

$\overline{e_{ij}(l,t)}$ Upper bound on the energy flowing from node i to node j , also expressed as

$e_{ij,\max}$

$\underline{e_{ij}(l,t)}$	Lower bound on the energy flowing from node i to node j , also expressed as $e_{ij,\min}$
η_{ij}	Efficiency parameter associated with the arc connecting node i to node j
η_{ii}	Efficiency parameter associated with the arc connecting CAES i from one time step to the next
lol	Load curtailment penalty factor
b_{ij}	Susceptance of the arc between node i and node j , also expressed as B_{ij}
t	The t_{th} time period
$\delta w(t)$	System wind penetration level at time t
σw_{ij}	Capacity factor for wind farm ij
$w o_{ij}(t)$	Nominal 1-MW wind power time series ij at time t
$w c_{ij}$	The steps of wind power capacity expansion
D_{avg}	Average system power demand level
$d_j(t)$	Supply (if positive) or negative of the demand (if negative) at node j , during time t
$r u_{ij}$	Generator ij 's up-ramp rate limit
$r d_{ij}$	Generator ij 's down-ramp rate limit
u_{ij}	Unit commitment decision for generator ij
λ_i	Locational marginal price at node i
a	Load time in generation investments

LIST OF FIGURES

Fig. 2.1. Generation Expansion Planning Procedure.....	7
Fig. 2.2. Transmission expansion planning procedure	10
Fig. 2.3. Classification of system capacity expansion planning tools	15
Fig. 2.4. A simplified diagram of system model.....	16
Fig. 2.5. A simplified diagram of modular packages.....	16
Fig. 2.6. A simplified diagram of integrated models	17
Fig. 3.1. A typical network flow diagram.....	28
Fig. 3.2. Representing a generator's marginal cost curve.....	29
Fig. 3.3. The interactions between fuel transportation system and electric transmission system	30
Fig. 3.4. Five-node system with fuel suppliers.....	34
Fig. 3.5. Fuel transportation and storage system.....	35
Fig. 3.6. Oil and natural gas prices	37
Fig. 3.7. Oil Storage level.....	37
Fig. 3.8. Generation levels	38
Fig. 3.9. Locational marginal prices	38
Fig. 3.10. Branch flows (with DC power flow)	39
Fig. 3.11. Branch flow (no DC power flow).....	40

Fig. 4.1. An example two-bus system.....	44
Fig. 4.2. Iterations between master and slave problems in the reliability-based planning	52
Fig. 4.3. Generator marginal cost curve.....	55
Fig. 4.4. Supply- and Demand-side bidding curves.....	56
Fig. 4.5. Iterations between master and slave problems in the market-based planning.....	61
Fig. 4.6. Five-bus system with four fuel suppliers.....	61
Fig. 4.7. The thirty-bus system (six regions with seven interregional interconnections)	66
Fig. 4.8. Transmission planning considering both economic benefits and reliability requirement	71
Fig. 5.1. The flow chart of Benders decomposition iteration procedures.....	82
Fig. 6.1. Wind generation expansion planning model	95
Fig. 6.2. Transmission expansion planning model	105
Fig. 6.3. Coordinate the two planning processes	107
Fig. 6.4. IEEE 24-bus reliability test system	108
Fig. 6.5. GEP results from the original system.....	111
Fig. 6.6. GEP results from the fifth iteration	112
Fig. 7.1. Fields of application of the different storage techniques according to energy stored and power output.....	116
Fig. 7.2. Storage system model.....	119
Fig. 7.3. IEEE 24-bus reliability test system	122

Fig. 7.4. CAES average charge/discharge pattern and LMPs at bus 21 under scenario 1	125
Fig. 7.5. CAES average charge/discharge pattern and LMPs at bus 21 under scenario 2	126
Fig. 7.6. CAES average charge/discharge pattern and LMPs at bus 2 under scenario 3	127
Fig. 7.7. CAES average charge/discharge pattern and LMPs at bus 2 under scenario 4	128
Fig. 8.1. The structure of the MBTEP tool	135
Fig. 8.2. The structure of the preprocessor	139
Fig. 8.3. The MPS file format	141
Fig. 8.4. The same optimization problem written in equation-oriented format	141
Fig. 8.5. The flow chart of the Benders decomposition and Monte Carlo simulation processes	143
Fig. 8.6. The economic and reliability assessment functions of the MBTEP tool.....	145

LIST OF TABLES

Table 2.1 Production Simulation and Costing tools.....	18
Table 2.2 Resource Planning tools	19
Table 2.3 Reliability assessment tools	21
Table 2.4 National Planning tools	23
Table 3.1 Optimal results of five scenarios	36
Table 3.2 Generators' real power output and branch flows (week 2 low demand hours).	40
Table 4.1. Investment plans made by the two planning methods.....	62
Table 4.2. Comparison of the results of the two planning methods.....	63
Table 4.3. Economic benefits generated by the market-based planning method	64
Table 4.4. Detailed information about the results of the 5-bus system	69
Table 4.5. Detailed information of the results of the 30-bus system	70
Table 4.6. Comparison of the results of the three planning methods	72
Table 5.1. The weights of the four Futures	86
Table 5.2. Four investment plans.....	86
Table 5.3. The social surplus increases of the four plans.....	87
Table 5.4. Benefit/cost ratios of the four plans.....	87
Table 5.5. Final scores of the four plans.....	88
Table 6.1 Capacity factors for candidate wind sites.....	108
Table 6.2 Results from the Copper sheet method.....	109

Table 6.3 Average LMP of each bus.....	110
Table 6.4 TEP results from the original system.....	111
Table 6.5 TEP results from the fifth iteration.....	112
Table 6.6 Results from the two cases.....	113
Table 7.1. Annual Profits of the CAES.....	128
Table 7.2. CAES's Annual Profits and System Total Production Costs V.S. CAES Capacity	130
Table A.1. Generator Data.....	152
Table A.2. Transmission Line Data	152
Table A.3. Fuel Characteristics.....	152
Table A.4. Interregional Interconnection Data	152
Table A.5. Generators' O&M cost curves and demand bidding curves	153

ACKNOWLEDGEMENTS

It would not have been possible to write this dissertation without the help and support of the kind people around me, to only some of whom it is possible to give particular mention here.

First and foremost I offer my sincerest gratitude to my supervisor, Dr. James McCalley, who has supported me throughout my Ph.D. study with his patience and knowledge whilst allowing me the room to work in my own way. I appreciate all his contributions of time, ideas, and funding to make my Ph.D. experience productive and stimulating. The joy and enthusiasm he has for research was contagious and motivational for me throughout my Ph.D. study. For me, he is not only a teacher, but also a lifetime friend and advisor.

I would like to acknowledge my committee members, Dr. Lizhi Wang, Dr. Sarah Ryan, Dr. Dionysios Aliprantis, Dr. Alicia L. Carriquiry and Dr. Arka Ghosh for their encouragements, insightful comments and all the contributions to this work.

I am grateful to all my friends in Iowa State University and Midwest ISO for helping me get through the difficult time, and for all the emotional support, entertainment, and caring they provided.

Finally, I want to express my appreciation to my parents, Chuanguang Gu and Xinghua Yu, and my sister Lin Gu, for their love, understanding, patience, endless support, and never failing faith in me. To them I dedicate this dissertation.

CHAPTER 1 INTRODUCTION

Before the deregulation of the electric industry, a vertically integrated utility made planning decisions for both the generation system and the transmission system according to reliability criteria with incurred expenditures recovered via rate structures. Interconnections between neighboring systems were developed primarily for reliability reasons. The advent of electricity markets together with organizational restructuring have resulted in an unbundling of the long-term planning function for generation and transmission systems. In the deregulated world, transmission planning is different from that in the regulated environment. On the one hand there are more uncertainties under the restructured market; on the other hand the objectives of the two transmission planning approach are different as planning and decision making for generation and transmission are carried out by different organizations now [1].

There are significant transmission bottlenecks in the United States' Independent System Operator/Regional Transmission Organization (ISO/RTO) control areas now as the result of growths in certain generation technologies, lack of transmission investment, and increased regional interchange [2]. Congestions in transmission system will impair the physical security of the electric system, reduce grid reliability and prevent the efficient operation of the electric market [3]. Congestions not only reduce the reliability of the system, but also cause losses in economic value. Inexpensive energy won't be transferred to locations where energy prices are higher because of bottlenecks in the transmission system. What is more,

congestions will also enhance opportunities for suppliers to exploit market power so the competition in the market is impaired. In reliability-based transmission planning, the economic benefits of new lines and the economic effects of congestions are usually ignored.

As the congestion level increases, economic transmission expansion planning becomes necessary to alleviate the excess cost of it, see [4], [5], [6], [7], [8]. In FERC order 890 issued in 2008, transmission economic study is required in each transmission provider's planning process. Unlike traditional planning approach which seeks to find the least-cost way to expand the system while satisfying the reliability constraints during peak-load times, economic transmission planning models try to find the optimum expansion plan for economic justification of network investment costs with the economic benefits that network expansions incur. In this paper, we present a market-based transmission planning model, which considers a wholesale electricity market with double-sided auctions. The fundamental economic impacts of a transmission upgrade are that it promotes competition and enables the system operator to dispatch the generation resources in a more efficient and economic way. Based on economic theory, social surplus is a good indicator of how efficiently the market is working. Thus, it can be used to quantify the economic benefits of transmission expansions. Market-based transmission planning model needs to calculate the sum of the social surplus at each hour of the planning horizon and find a trade-off between investment costs and an increase in social surplus incurred by network expansions. The traditional reliability-based planning approach and market-based approach are also compared in the dissertation.

There is no clear distinction between reliability-based transmission projects and value-based transmission projects as most transmission additions can bring reliability and economic benefits to the system. Although market-based transmission planning method can identify the optimal investment plan to maximize the economic benefits, the reliability criterion is not considered in the planning model. A new transmission planning method which considers both the reliability and economic performance of the electric system is proposed. Traditional reliability-based planning and the new market-based planning methods are combined to collect the advantages of both planning methodologies. The transmission investment plan generated by this planning model maximizes the economic benefits of new projects while satisfying the reliability criterion.

The market-based transmission expansion planning problem is a large-scale mixed-integer non-linear optimization problem that requires large computation efforts. In this dissertation, Benders decomposition is employed to reduce the computation time. Benders decomposition was first introduced by J. F. Benders in 1962 to solve mixed-integer programming (MIP) problems [9]. A. M. Geoffrion later generalized this method so it can be applied to solve mixed-integer nonlinear planning (MINLP) problems under some convex and regularity assumptions [10]. The Benders decomposition method, as well as the combination of decomposition techniques with other approaches, has been used in transmission planning with success [1], [7], [11], [12]. In this model, the overall optimization problem is decomposed into a master problem, which makes investment decisions; and a

slave problem (or multiple slave problems when conducting reliability-based planning), which implements the expansion plans suggested by the master problem and gives feedbacks to the master problem about the system's operating conditions.

The planning process has all kinds of uncertainties. Uncertainty is defined as “a state of having limited knowledge where it is impossible to exactly describe existing state or future outcome” [13]. The numerous uncertainties in the operation and planning of power system which need to be identified and taken care of can be classified into two categories: random and nonrandom [7]. Random uncertainties are those that occur repeatedly and their patterns can be captured by fitting probability distribution functions to their values based on the analysis of historical data. The future outcome of these uncertainties can be predicted by using their probability distribution functions. Uncertainties in fuel prices and outages of power plants or transmission lines fall into this category. Nonrandom uncertainties, on the other hand, either had never happened before or do not happen repeatedly, so we cannot forecast them mathematically. In other words, their statistical behaviors cannot be derived from past observations, if there are any. Market rules and national energy policies are typical nonrandom uncertainties. In the proposed model, random uncertainties are simulated by assigning probability density functions (pdfs) to random parameters and then using Monte Carlo method to simulate their effects on the system. Nonrandom uncertainties are considered by building multiple futures and analyzing transmission projects across all futures and to find the project which consistently provides the highest economic benefits [14].

The objective of this dissertation is to propose, design, and implement a market-based system capacity expansion planning model that can: 1) Identify transmission and generation investments based on economic benefits and/or reliability criteria; 2) handle various uncertainties in the planning problem; 3) evaluate alternatives to transmission expansion; 4) integrate generation expansion planning and transmission expansion planning in a computationally tractable way.

The remaining sections are organized as follows. Chapter II presents the literature review on transmission and generation expansion planning and the classification of commercial planning software. Section III presents the formulation of the integrated energy system and the way to combine generalized network flow method with DC power flow method. Section IV describes the reliability-based transmission expansion planning and market-based transmission planning methods and compares them side by side. A new transmission planning method that considers both reliability and economic performance of the electric system is also illustrated in chapter IV. Chapter V describes how to incorporate uncertainties in the planning model. Chapter VI shows the way to consider the interactions between large-scale wind integration and transmission expansion planning. Chapter VII discusses the economic performance of compressed-air energy storage (CAES) system and the possibility of building CAES to defer or substitute transmission investments. The description of the market-based transmission expansion planning tool is provided in section VIII. Sections IX summarizes the contributions of the dissertation and identifies further research direction

CHAPTER 2 LITERATURE REVIEW

2.1 System Capacity Expansion Planning Algorithms

2.1.1 Generation Expansion Planning Algorithms

Generation expansion planning (GEP) problem is defined as a problem of determining the best size, timing and type of generation units to be built over the long term planning horizon, to satisfy the expected demand. Since the emerge of the electric power system, significant efforts have been made to optimize the generation asset investment.

Before the deregulation of the power industry, the generation expansion planning is conducted together with the transmission expansion planning by a centralized decision make. The investment criteria are normally minimization of sum of capital investment and operation cost or maximization of system long-term reliability with various constraints.

A generic form of GEP problem is:

$$\text{Min } \sum (\text{investment cost}_{jk} + \text{Operating cost}_{jk})$$

Subject to:

$$\text{Demand}_k \geq \text{constraint}$$

$$\text{LOLP}_k \geq \text{constraint}$$

$$\text{Fuel Price}_k = \text{Price path}$$

Technological parameters_j = assumed or calculated values;

where j and k represent technology and time period.

This simplified formulation addresses the major questions of cost, fuel choice, technology and system reliability.

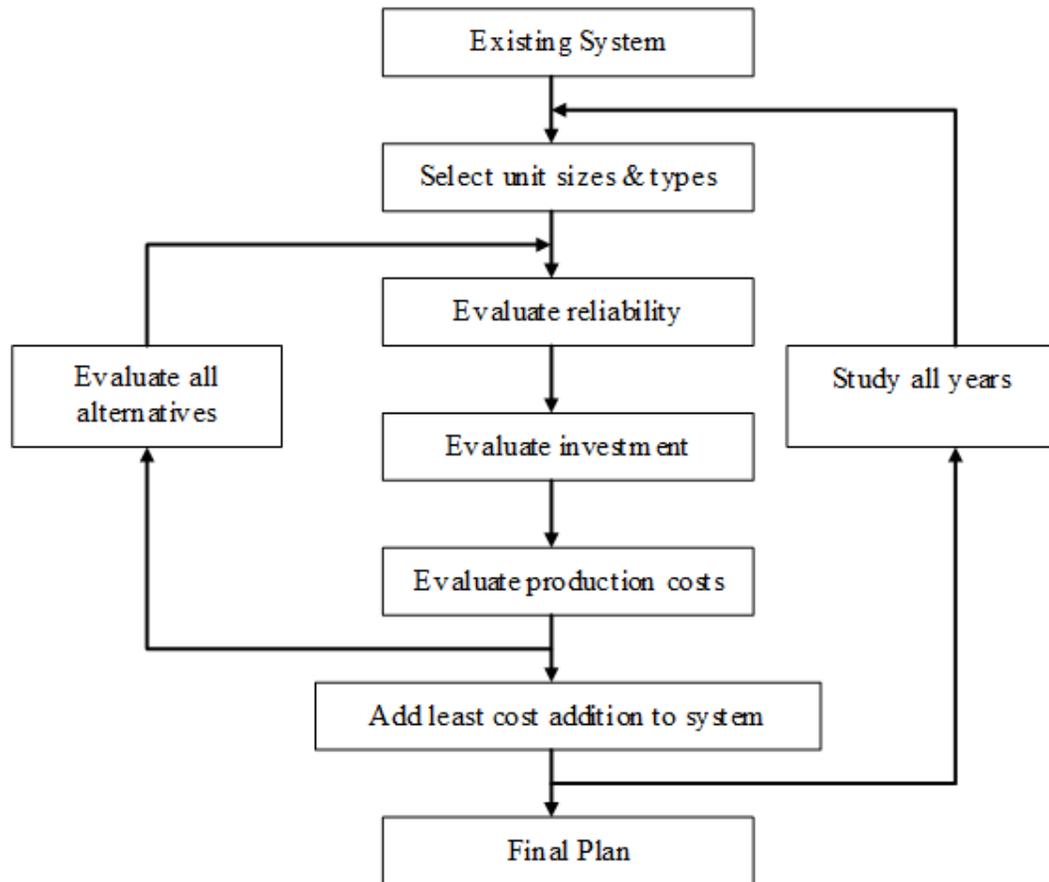


Fig. 2.1. Generation Expansion Planning Procedure from [15].

The high level description of the generation expansion procedure is illustrated in Fig. 2.1. Since that time, the traditional way of generation expansion planning has been totally changed as the result of the competition and the deregulation of electricity market. Compared to the generation planning problem in the regulated world, the planning models in the deregulated industry generally have higher complexity. First, the planning problem is

exposed to much more uncertainties via the input data, such as load forecasting, price and availability of fuels, construction lead time, economic and technical characteristics of new generating techniques, governmental regulations, and transmission. For example, not only the future load level is uncertain, utilities nowadays cannot take their market share for granted as the result of the competition with other utilities as well as other independent power suppliers. Second, in the planning process several conflicting objectives must be fulfilled. For example, such objectives could be maximizing the system's profit, maximizing the system's reliability, minimizing the emission of greenhouse gases, or minimize the investment risks. These objectives are difficult to coordinate or even conflicting with each other. Third, the large scale integration of renewable energy has a profound impact on the reliability and economic performance in the future operations of the system, which requires new tools for production cost simulation and reliability evaluation. Fourth, as the result of increasing competition, there are increased interactions between neighboring regions. The frequent inter-regional transactions need to be represented in the planning model [16]. Fifth, the change of market structure incurs the change in the way that utilities secure their investment. In the deregulated system, vertically integrated utilities can get a pre-determined rate of return on the authorized rate base. In the electric market, the generation owner (GenCos) bear a larger share of the risk associated with the investment as they need to secure their investment via sell electric power or ancillary services in the electric market. So the objective of the generation

expansion planning might shift from minimization of (production cost + investment cost) to maximization of (generator profit – investment cost).

Generation expansion planning problem is a challenging problem because of the large-scale, long-term, non-linear, and discrete nature of generation investment. Various optimization techniques have been applied to solve the generation planning problem, such as dynamic programming [17], decomposition methods [18], network flow [19], expert system [20], neural networks [21], genetic algorithm [22], and stochastic optimization method [23].

2.1.2 Transmission Expansion Planning Algorithms

The primary purpose of Transmission expansion planning (TEP) is to determine, on the least-cost basis, the best transmission additions to provide the load with sufficient energy and facilitate wholesale power marketing with a given criteria. Most new lines can help improve local voltage quality and improve system reliability, as well as enabling new generation units to served area load and increasing capability for longer-distance transaction. The benefits of a transmission upgrade changes over time as the result of the changes of loads, generation and grid topology. In the regulated environment, the vertically integrated utilities operate the whole electric system and make investment decision for both generation and transmission additions. Transmission expansions can be justified if there is a need to build new lines to connect cheaper generators to meet the current and forecasted demand or new additions are required to enhance the system reliability so some reliability criteria can be fulfilled, or both. In the traditional transmission planning model, the capital investments are often justified by

fulfilling the reliability requirements to serve the current and forecasted load. As costs is often used as a criterion to select the alternative investment plan and various reliability criteria are used to constrain the decision making problem, the traditional transmission planning problem normally formulated as cost minimization problem with reliability as a constraint [24].

A simplified transmission planning procedure is shown in Fig. 2.2.

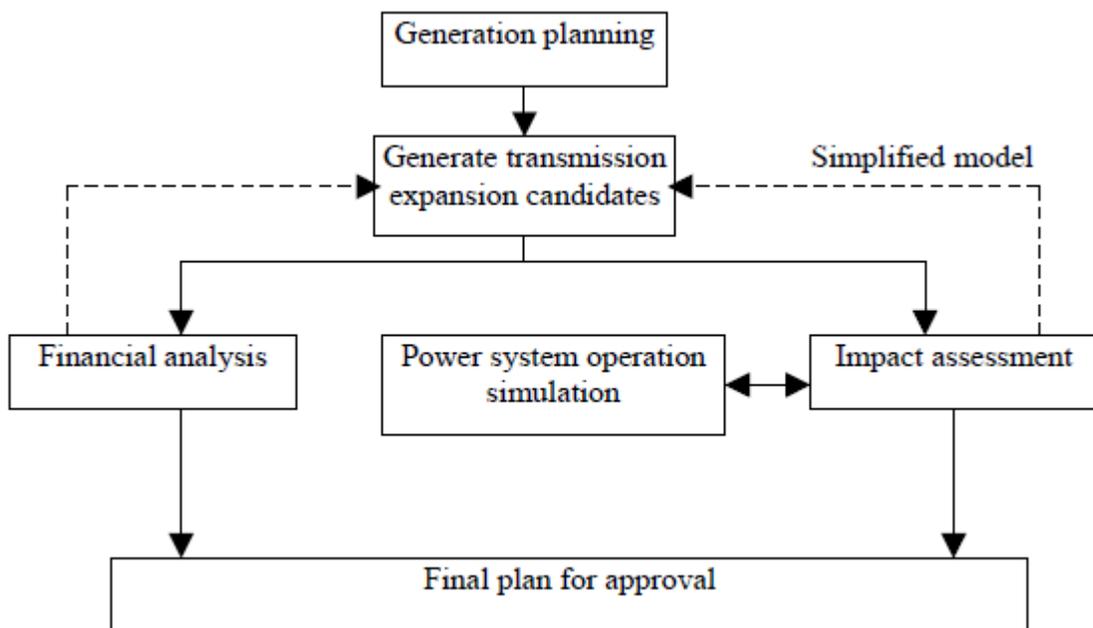


Fig. 2.2. Transmission expansion planning procedure from [24]

In the restructured power industry, transmission expansion planning encompasses many economic and engineering issues. As the results of the issues arising in the new system structure, many aspects of the planning problem are under re-evaluation and numerous attempts have been made to explore the right way to solve them.

(1) The objective of the transmission expansion planning problem

As the paradigm of the traditional least-cost expansion criteria is not valid in the new market environment, there has been a debate on what criteria shall guide the transmission expansion decision making. Based on the decision maker's concerns, the objective function could be minimization of (production cost + investment cost), minimization of (congestion cost + investment), maximization of (Social surplus – investment cost), maximization of (TransCo's expected revenue – investment cost), minimization of investment risk, minimization of greenhouse gas emissions, or evaluating multiple objectives at the same time. These various kinds of objective are a reflection of the interests that different parties want to gain from the planning problem. From the government agencies such as Federal Energy Regulatory Commission (FERC) and North American Electric Reliability Corporation (NERC)'s perspective, they want to ensure enough transmission lines are built to maintain the system reliability. From the TransCos' perspective, they want the transmission investment to be returned via cost allocation plan and revenues from FTR market, energy market, and bilateral contracts. For TransCos, they also want their financial risk to be minimized. From ISO/RTO's perspective, they want to ensure that the electric system will be operating reliably. What's more, they also want to stimulate enough transmission investment to relieve the transmission system bottlenecks, reduce the congestion cost, transfer the economical generation resources from remote areas, promote the competition in the electric market, and lower the system production cost and customer payment. From GenCos' perspective, they want a transmission investment plan that can facilitate the transportation of

their generation resources. It is very difficult to satisfy all the above needs, which causes problem with deciding the objective function of the planning problem.

(2) Coordination with generation and load

As the planning for both generation and transmission planning is carried out by a single decision maker in the regulated industry, the transmission planner can obtain near-perfect information on generation expansion schedule and load information. In the restructured environment, however, the authority that is making transmission planning does not own the generation companies so it is difficult to get the detailed information on the generation and load information. For example, when the Midwest ISO is conducting transmission planning, the first step is to forecast the generation resource additions within the planning horizon. The imperfect information might produce imperfect expansion plans. Moreover, as generally generation projects have much shorter lead time than that of the transmission expansions, new generation projects might be built after a transmission plan is finalized but before the line is ready to be operated. As the initial transmission plan did not take those generation projects into consideration, the transmission investment might not be able to be justified in terms of economic value or reliability requirements. Just like the impacts of GEP on TEP, transmission additions might affect the economic or reliability justification of the generation investment plan. For example, in U.S. eastern interconnection, most of the wind-rich areas are located in the Midwest and Texas, which are far away from load centers. If there are no high capacity transmission lines to connect the wind resource centers to the load center, it

might not be economic to build numerous wind farms in the Midwest and Texas as the existing generation fleets in those areas are large enough to support the regional energy demand. However, if there is not enough low-cost clean energy flowing through the inter-regional transmission lines to the load center, the transmission expansions might not be profitable to invest. The interactions between generation, transmission and demand are worth exploring.

(3) Cost allocation

In the regulated industry, the transmission investment plan often needs to be approved by state public service commissions, and the cost associated with it can be reimbursed via a surcharge in customers' utility bills. In the deregulated industry, however, there is more uncertainty associated with the return on investment. The transmission investments are classified into several categories according to their main purpose, each having a unique cost allocation plan. For example, in the Midwest ISO, the new transmission projects are classified as baseline reliability projects, which are required to fulfill the NERC standards; generation interconnection projects, which are network upgrades required to ensure the system reliability when new generation connects to the grid; transmission service delivery projects, which are projects needed to connect new generators to the system; market efficiency projects, which are those system expansions that relieves the congestions; and multi-value projects, which provides both reliability enhancement and economic benefits. Each of these categories has a different cost allocation plan. Although each cost allocation

plan needs to be discussed and approved by all the stakeholders, there have always been debates about whether the existing cost allocation plan is fair for all the parties or not. One practical problem associated with deciding the cost allocation plan is whether the investment cost should be allocated based on the cost incurred or usage of the new transmission lines/benefits gain from the transmission lines. While it seems more reasonable to adopt the usage-based or benefit-based cost allocation mechanism, it is hard to decide the actual usage/benefits of each market participant because of the ever-changing market conditions.

Just like generation expansion planning, transmission expansion planning problem is a large-scale non-linear mixed-integer programming problem. Many optimization techniques have been employed in the transmission planning processes, such as dynamic programming [25], game theory [26], fuzzy set theory [27], objected-oriented model [28], expert system [29], decomposition method [30,31,32], heuristic method [33], non-linear programming [34], and mixed-integer programming algorithm [35].

2.2 System Capacity Expansion Planning Tools

2.2.1 Introduction

There has already been a lot of commercial-grade system planning tools with different features like model types, modeling granularities and so on in the market. Some of them are mainly employed by Utilities, GENCOs, TRANSCO, and ISOs, while others are national

planning tools which are used by government and other organizations to facilitate the decision/policy making.

There are three main types of planning tools for electric infrastructure: reliability, production costing, and resource optimization, as shown in Fig. 2.3.

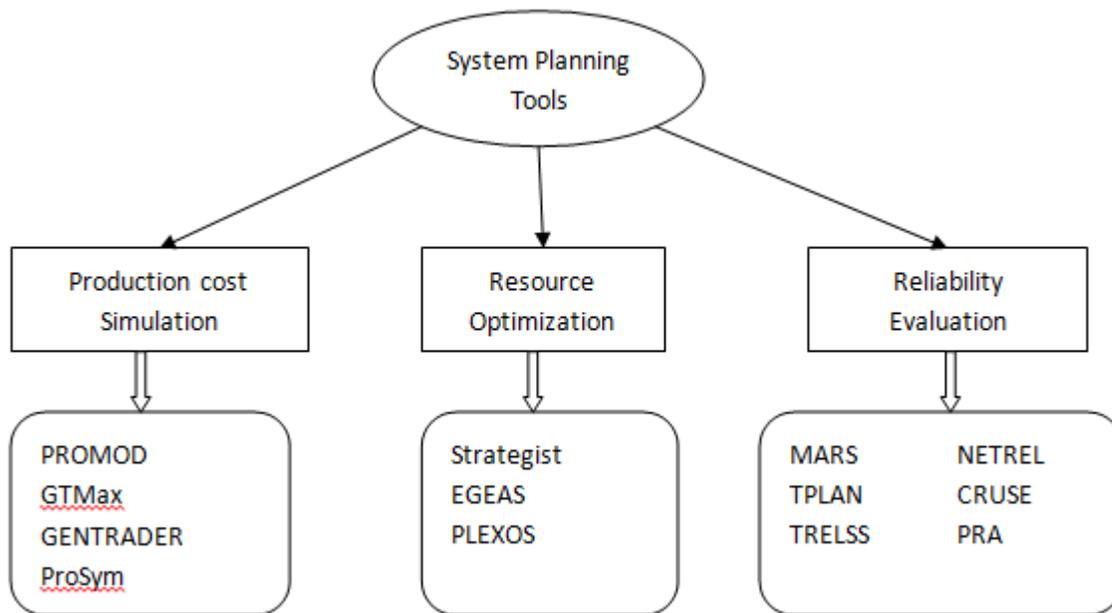


Fig. 2.3. Classification of system capacity expansion planning tools

The tools can be sub-divided into three categories: System models, Modular packages and integrated models [36]. Their differences are illustrated below:

System models normally have only a database and some means to organize and/or analyze data. Such tools are generally not as comprehensive in scope as Modular packages.

Fig. 2.4 is a simplified system model.

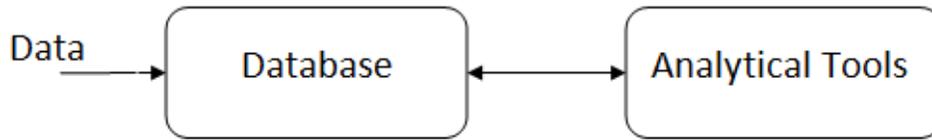


Fig. 2.4. A simplified diagram of system model

Modular packages are integrated software packages for economic/reliability analysis, for estimating the growth of system load level, or for balancing energy supply and demand. In the planning process, the users do not need to use all of the modules. They can select to use any module according to their need and nature of the problem. A simplified diagram of Modular packages is shown below in Fig. 2.5.

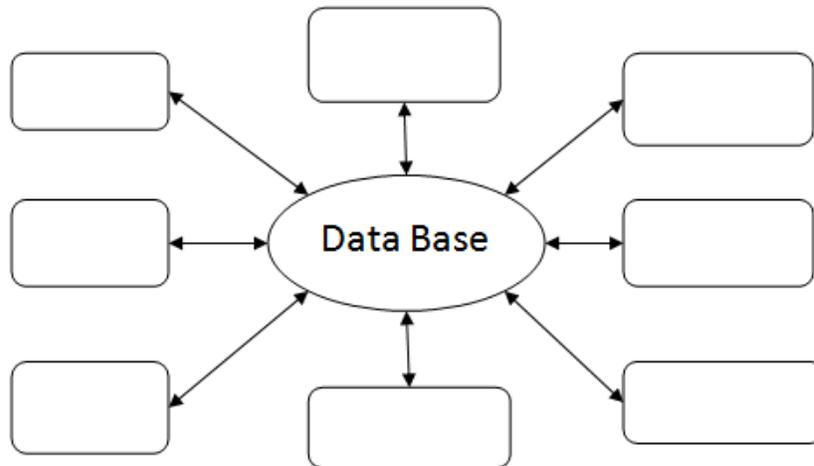


Fig. 2.5. A simplified diagram of modular packages

Integrated models solve different aspects of the planning problem simultaneously. They usually cover the energy-economic-environment interaction. Following is a simplified diagram of integrated models.

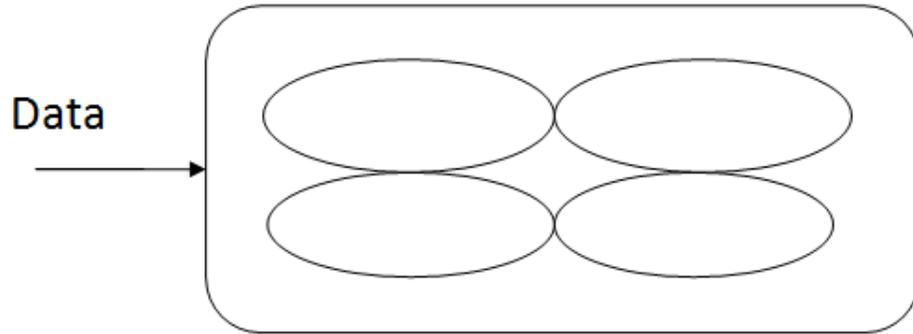


Fig. 2.6. A simplified diagram of integrated models

However, the comparison and classification of different tools is not straightforward as each tool is designed for a specific purpose and they normally have different target audiences. For example, the underlying economic structure varies from model to model and it's difficult to compare which one is better.

2.2.2 Production Cost Simulation Tools

Production cost programs have become the workhorse of long-term planning. These programs perform chronological optimizations, often hour-by-hour, of the electric system operation, where the optimization simulates the electricity markets, providing an annual cost of producing energy. Although production cost models make use of optimization, it is for performing dispatch, and not for selection of infrastructure investments. Therefore, production cost models are equilibrium/evaluation models. A representative list of commercial grade production cost models include GenTrader [37], MAPS [38], GTMax [39], ProMod [40], and ProSym [41]. Production cost programs usually incorporate one or more reliability evaluation methods.

Table 2.1 Production Simulation and Costing tools

	Production cost simulation tools			
Features	ProMod	GTMax	GENTRADER	ProSym
Model category	Integrated model	Integrated model	Modular package	Integrated model
Function (Generation or transmission planning or both)	Both	Both	G	Both
Modeling granularity	Regional	Regional and national	Regional	Regional
Economic/ Reliability	Both	Economic	Both	Economic
Reliability simulation methods	Baleriaux-Booth		Monte-Carlo	
Methods to represent system load	Hourly chronological load	Hourly chronological load	Hourly Chronological load	Hourly Chronological load
Capital cost	√	√	√	√
Investment cost	√	√	√	√
Estimated operating cost	√	√	√	√
Unit-commitment	√	?		√
Operations in market	√	√		√

2.2.3 Resource Planning Tools

Resource optimization models select a minimum cost set of generation investments from a range of technologies and sizes to satisfy constraints on load, reserve, environmental concerns, and reliability levels. These models, as optimization models, identify the best generation investment subject to the constraints. However, at this point in time, these models generally do not represent transmission, or they represent it but do not consider transmission investments. A representative list of resource optimization models includes EGEAS [42], PLEXOS [43], Strategist [44], and WASP-IV [45]. Resource optimization models usually incorporate a production cost evaluation, which may also include a reliability evaluation. Fig. 2.3 classifies common commercial system capacity planning software.

Table 2.2 Resource Planning tools

	Resource planning tools			
Features	PLEXOS	GEM	EGEAS	Strategist
Model category	System model	Integrated model	Modular packages	Modular packages
Function (Generation or transmission planning or both)	Both	G	G	G
Modeling granularity	Regional	Regional	Regional	Regional

Algorithm	Mixed integer linear programming	Mixed integer linear programming	Generalized benders decomposition and Dynamic Programming	Dynamic programming
Economic / Reliability	Both	Both	Both	Both
Objective	Maximize portfolio profit or least cost	Least cost	Least cost	10 different objective functions
Methods to represent system load	load duration curve	load duration curve	load duration curve	chronological load in twelve typical weeks per year
Plant retirement decision	√		√	√
Transmission Loss	DC OPF	only losses on HVDC	?	quadratic loss function
Competition/ transaction modeling	√	√		
Reliability evaluation/simulation methods	Monte-Carlo	N-1	Monte-Carlo	Monte-Carlo

2.2.4 Reliability Assessment Tools

Reliability assessment tools are evaluative only, i.e., they do not identify solutions but just evaluate them. Both deterministic and probabilistic tools exist and are heavily used in the planning process. Deterministic tools include power flow, stability, and short-circuit programs, providing yes/no answers for specified conditions. Probabilistic tools compute indices such as loss-of-load probability, loss of load expectation, or expected unserved energy, associated with a particular investment plan. A representative list of commercial-grade reliability evaluation models include CRUSE [46], MARS [47], TPLAN [48], and TRELSS [49].

Table 2.3 Reliability assessment tools

	Reliability assessment tools				
Features	MARS	TRELSS	TPLAN	PRA	TRANSREL
Hierarchical levels	level 1	level 2	level 2	level 2	level 2
Modeling granularity	Regional	Regional	Regional	Regional	Regional
Operating Conditions	Sequential	Non-sequential	Non-sequential	Sequential ?	?
Contingency selection	Monte-Carlo	Enumeration	Monte-Carlo	Monte-Carlo	Enumeration
Single-area/ Multi-area	Multi-area	Multi-area	Multi-area	?	Single-area

2.2.5 National Planning Tools

While above-mentioned planning tools are powerful to perform regional system capacity planning, other tools are needed when the national electric system or even wider geographic area are studied. National planning tools can be used by governments and other entities to help them evaluate the system conditions and design national energy policies. In considering the differences between the two sets of planning tools, some major factors must be considered.

1) Level of regional aggregation

In national planning tools, the regional aggregation is highly aggregated. For example, in some studies using MARKAL, all of Europe has been aggregated as a single node. However, in many regional planning tools, the regional aggregation can be specified by the users. Normally, regional planning tools can have multiple aggregation levels. For example, PLEXOS can aggregate at 3 types of geographical units: regional, zonal, or nodal.

2) Perspective user

National planning tools are mainly used by regulatory bodies and governments, while regional planning tools are widely used among electric power utilities, ISOs, and many consulting firms.

3) Function

National planning tools normally cover all of the three aspects of system planning or they are designed to combine with other software to enhance their capabilities. For example,

WASP can be combined with dispatch and IPP-oriented models, such as GTMax, to improve the accuracy of results and identify interactions between generation and transmission and transmission bottlenecks. Regional planning tools, on the other hand, are focused on performing one or two duties of system planning only.

Table 2.4 National Planning tools [50]

		NEMS	MARKAL/TIMES	WASP-IV
Output		Alternative energy assessment	Optimal investment plan	Optimal investment plan
Optimization model	Objective function	Single objective	Single objective	Single objective
	Stochastic events	√	√	√
	Formulation	Modular	Generalized network	Generalized network, modular
Forecast horizon		20-25 years	Unconstrained	30 years
Sustainability	GHG	√	√	√
	Other emissions	√	√	√
	Depletability			
Resiliency				Loss of load
Energy represented	Primary energy sources	√	√	
	Electricity	√	√	√
	Liquid fuels	√		

Table 2.4 Continued

		NEMS	MARKAL/TIMES	WASP-IV
Transportation	Freight	√ ?	Only fuel demand	
	Passenger	?	?	

CHAPTER 3 MODELING THE INTEGRATED ENERGY SYSTEM

In recent years, there have been many studies on the operation and planning of electric power systems. However, there has been little effort on analyzing the economic and physical interdependencies between the electric energy system and other energy subsystems, such as the fuel production system, fuel transportation system, and storage system. Due to difficulties in collecting data and modeling complex dynamics of highly interacted subsystems, most energy systems described in the literature either deal with systems in a smaller geographic area or focus mainly on one aspect of the integrated energy system. Quelhas et al. [1] formulated a model that connected fuel supply and electric demand nodes via a transportation network and validated it with year 2002 data. The model can help decision makers to have a more comprehensive understanding of the whole energy sector. However, in that model power flowing in the transmission system only follows the Kirchhoff current law (KCL), ignoring Kirchhoff voltage law (KVL). Thus, the transmission system is not well represented.

A multiperiod generalized network flow model in conjunction with DC power flow is formed to analyze the integrated energy system, which includes fuel production, fuel transportation, storage, electric generation, and transmission system. The model focuses on the physical and economic interdependencies among various subsystems. Some linear constraints are added to the existing network flow formulation to generate optimal flows in

the transmission system that follow both KCL and KVL. Besides model flexibility, one of the key advantages with the network flow formulation is that the network simplex method can be employed to reduce the computation time. Due to the special structure of the coefficient matrix of the network flow model, specialized simplex-based software can solve these problems in from one to two orders of magnitude faster than general linear programming software. Although adding some linear constraints (also called side constraints) will change the structure of the coefficient matrix, the computational results in [10] suggest that the simplex method can still maintain a high efficiency if the number of side constraints is much smaller than the number of nodes of the network.

The advantages of the proposed model are: (1) Network flow formulation that enables the use of the network simplex algorithm, which is generally much faster than the general linear or nonlinear algorithm; (2) Extra linear constraints are added to the network flow model to incorporate the DC power flow algorithm; (3) In the multiperiod model, different subsystems can be modeled using different time steps, considering the dynamics of each subsystem; (4) Different parts of the electric system can be aggregated at different levels. This enables one part of the electric system to optimize its operation while considering the interaction with other parts of the electric system as well as the other energy subsystem.

In general, the model can foster a better understanding of how the fuel production, transportation, and storage industry interact with the electric energy sector of the U.S. economy facilitate decision makers from ISOs, utilities, and government agencies with their

analysis of the operational and planning issues with regard to the electric power system while considering the integrated dynamics of fuel markets and infrastructures.

3.1 Generalized Network Flow Model

The energy system is modeled using the generalized network flow method [51]. The basic generalized network flow problem can be described as follows. Given a network consisting of a number of nodes and capacitated arcs, we want to find the optimal routing plan to transfer flows from the source nodes (supply nodes) to the destination nodes (demand nodes) at minimum cost without violating the capacity limits. The concept of the network simplex algorithm was developed by Dantzig [2] in 1947. Since then, a series of papers has been published using network flow model approaches for solving various problems in a power system, such as fuel scheduling [3], hydrothermal scheduling [4], economic dispatch [5], and reliability analysis [6].

There have been many attempts to model active power flow based on the network flow algorithm. Although the network flow algorithm is unable to satisfy Kirchhoff's voltage law directly [7], this major drawback can be overcome by considering KVL as a least-effort criterion that has a quadratic cost function associated with each arc [8]. However, it can be shown that this model is equivalent with DC power flow only when the power flow limits are not binding [9]. The more accurate model [9] represents the second Kirchhoff law by adding some linear constraints to set up the basic loop equations where the sum of voltage around the loops equals zero. This method assures total equivalence with DC power flow. The

advantage of this algorithm, regarding DC power flow algorithms, is explicit representation of branch flows. Consequently, transmission limits can be promptly imposed and transmission losses can be expressed in the objective function. The proposed model represents KVL in a similar way by adding some variables and linear constraints.

Fig. 3.1 is an example of a typical network, which is composed of supply and demand nodes together with directed arcs connecting them. There are four properties associated with each arc: cost coefficient c , flow efficiency η , lower bound e_{\min} , and upper bound e_{\max} . Piecewise linearization can be performed to deal with the convex quadratic cost function of the arc flow. Then a single arc can be substituted by multiple arcs, each representing one segment of the piecewise linear function. For nodes that represent facilities that add cost or losses to the flow, such as fuel production facilities and power plants, one node is split into a pair of nodes with arcs connecting them. The cost and/or loss generated by these facilities can be expressed in the arc.

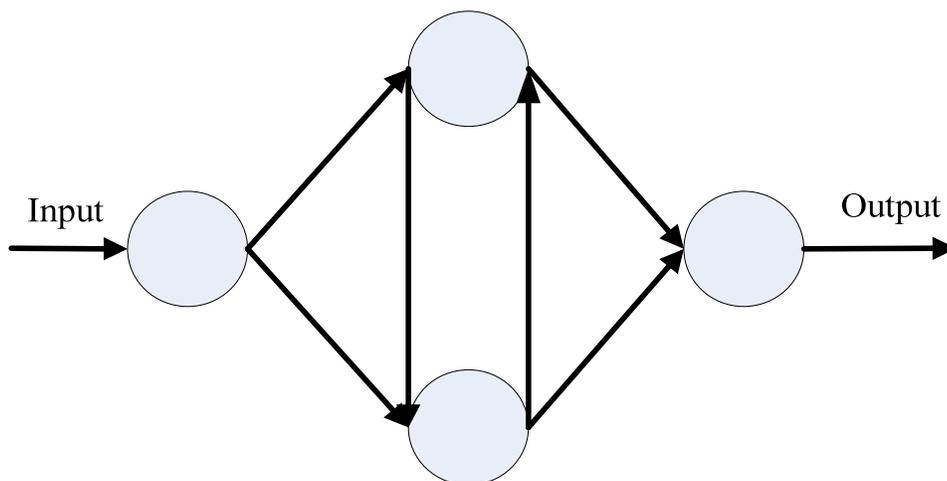


Fig. 3.1. A typical network flow diagram.

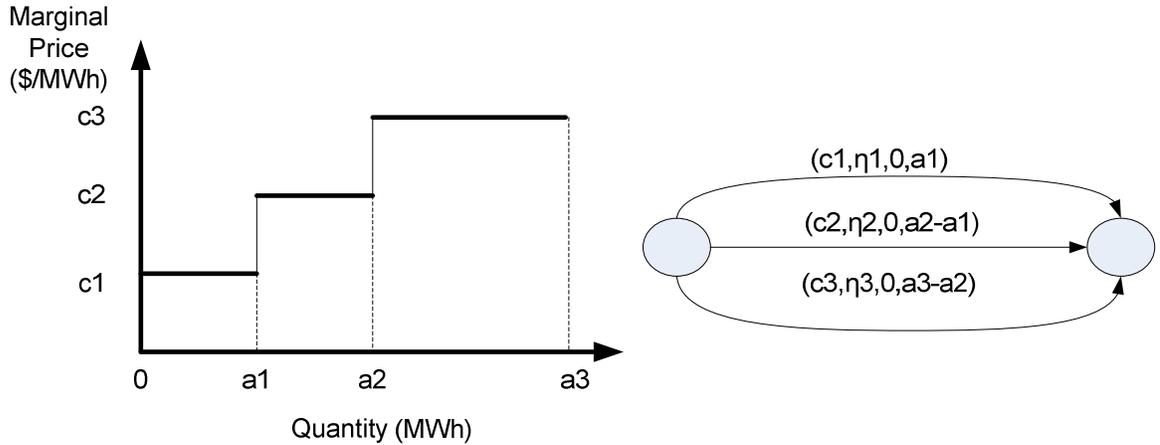


Fig. 3.2. Representing a generator's marginal cost curve

In Fig. 3.2, when the generator is bidding at its marginal costs, the three arcs represent the generator's energy bidding curves. As the objective of the production cost simulation problem is the minimization of total production cost, arc 1 will first be used to transfer the energy flow due to its low cost. When the demand goes higher and flow in arc 1 reaches its limit, arc 2 will then be used, followed by arc 3. In the same manner, the cost/efficiency associated with transmission lines and the generating units can be captured.

In the proposed model, both the electric system and fuel system are considered in order to capture the fuel cost of generators directly. In the proposed model, one generator node is split into a pair of generator nodes so that operating constraints and operation and maintenance (O&M) costs can be expressed as the properties of the arc connecting the two nodes. Generator maximum and minimum output limits are enforced by constraining the energy flow between the paired generator nodes.

3.2 Combining DC Power Flow Model with GNF Model

3.2.1 System Formulation

In this minimal cost network flow model, the interest is to optimize the flows of fuel and electric energy in an integrated network in the most economical way. Fuel production, transportation and storage costs and losses, generation costs, and transmission costs and losses are included in the model.

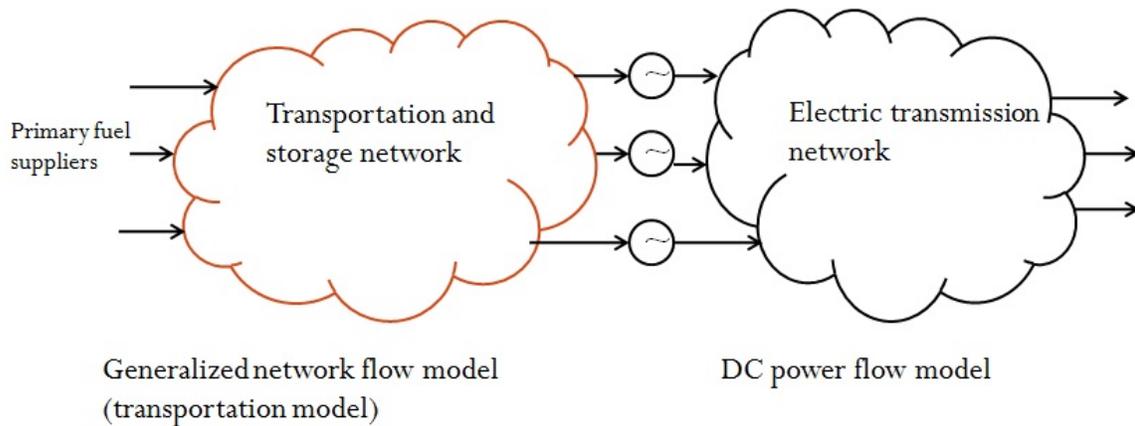


Fig. 3.3. The interactions between fuel transportation system and electric transmission system

The objective function, which is to be minimized, is the sum of the costs associated with all kinds of flows in the network. The prices of different kinds of fuels at the fuel production side, such as wellhead natural gas prices and spot price of coal in different coal-producing regions, are included in the cost property of transportation arcs. Equation (3.2) represents that for each node, the sum of flows into the node minus the flows out of the node equals the demand (or supply if negative) of the node. For the electric transmission system, Kirchhoff's first and second laws are fulfilled by Equations (3.3) and (3.4). Arc flows and power angles

must be within constraints, as is shown in Equations (3.5) and (3.6). For the fuel transportation network, arc flows should be larger than or equal to zero, whereas in the transmission network, arc flow can be negative to account for the bidirectional nature of the power flow. Each generation nodes is split into a pair of nodes and an arc linking them in order to account for the operation and maintenance (O&M) cost of the power plant as well as its generation capacity.

$$\text{Minimize } Z = \sum_{t \in T} \sum_{(i,j) \in Mt \cup Mf} c_{ij}(t) e_{ij}(t) \quad (3.1)$$

Subject to

$$\sum_{\forall i} \eta_{ij} e_{ij}(t) - \sum_{\forall k} e_{kj}(t) = d_j(t), \quad \forall j \in Nf, \forall t \in T \quad (3.2)$$

$$e_{ij}(t) - b_{ij}(\theta_i(t) - \theta_j(t)) = 0, \quad \forall (i, j) \in Mt \quad (3.3)$$

$$\sum_{j \in G_i} \eta_{ji} e_{ji}(t) - \sum_{j \in B_i} b_{ij}(\theta_i(t) - \theta_j(t)) = d_i(t), \quad \forall i \in Nt, \forall (i, j) \in Mt \quad (3.4)$$

$$e_{ij.\min} \leq e_{ij}(t) \leq e_{ij.\max}, \quad \forall (i, j) \in (Mt \cup Mf) \quad (3.5)$$

$$-\pi \leq \theta_i \leq \pi, \quad \forall i \in Nt \quad (3.6)$$

3.2.2 Nodal Prices

As a byproduct of the model, marginal prices of nodes in both the fuel transportation and storage network and the electric network can be calculated. The term nodal price is defined as the change in total cost that arises when the quantity produces changes by one unit. The objective function and equation (3.1)--(3.5) can be combined to form the Lagrange function L using Lagrangian multipliers (which are interpreted as dual prices or shadow prices). The

Lagrangian multiplier is the rate of change in objective value as a function of constraint variable. In the production cost model, when optimal solutions are obtained, Lagrangian multipliers are indicators of the costs of supplying/consuming one more unit of energy. In electric system, this means the cost of serving the next MW of load at a specific node. In fuel system, Lagrangian multiplier is the cost of transporting/storing the next unit of fuel at a specific location. We use the term nodal prices for these marginal costs in both systems.

$$\begin{aligned}
L = & \sum_{t \in T} \sum_{(i,j) \in Mf \cup Mf} c_{ij}(t) e_{ij}(t) + \sum_{t \in T} \sum_{j \in Nf} \lambda_j(t) \left[-\sum_{\forall i} \eta_{ij} e_{ij}(t) + \sum_{\forall k} e_{jk}(t) + d_j(t) \right] \\
& + \sum_{t \in T} \sum_{(i,j) \in Mt} \gamma_i(t) \left[-\sum_{j \in G_i} \eta_{ji} e_{ji}(t) + \sum_{j \in B_i} b_{ij}(\theta_i(t) - \theta_j(t)) + d_i(t) \right] + \sum_{t \in T} \sum_{(i,j) \in Mt} \alpha_{ij}(t) \\
& \left[e_{ij}(t) - b_{ij}(\theta_i(t) - \theta_j(t)) \right] + \sum_{t \in T} \sum_{(i,j) \in Mf \cup Mf} \delta_{ij}(t) \left[e_{ij,\min} - e_{ij}(t) \right] + \\
& \sum_{t \in T} \sum_{(i,j) \in Mf \cup Mf} \mu_{ij}(t) \left[e_{ij}(t) - e_{ij,\max} \right] + \sum_{t \in T} \sum_{i \in Nt} \beta_{ij}(t) \left[-\pi - \theta_i(t) \right] + \sum_{t \in T} \sum_{i \in Nt} \omega_{ij}(t) \left[\theta_i(t) - \pi \right] \quad (3.7)
\end{aligned}$$

The relationship between linked nodes can be derived by applying Karush-Kuhn-Tucker(KKT) first-order optimal conditions to the above Lagrangian function. When an optimal solution to the optimization problem is obtained, the first-order derivatives of Lagrange function L with respect to each decision variable $e_{ij}(t)$ should be zero. Thus, the relationship between nodal prices of nodes that are connected by $e_{ij}(t)$ can be shown.

When $(ij) \in Mf$, the nodal prices between two linked nodes i and j are given in the following equation:

$$\frac{\partial L}{\partial e_{ij}(t)} = c_{ij}(t) + \lambda_i(t) - \eta_{ij} \lambda_j(t) - \delta_{ij}(t) + \mu_{ij}(t) = 0 \quad (3.7)$$

If the arc flow constraints are not binding, $\delta_{ij}(t)$ and $\mu_{ij}(t)$ are both zero. If we assume the energy flow is costless and lossless, then $\lambda_i(t) = \lambda_j(t)$. Under normal conditions, the difference between nodal prices of two connected nodes is decided by whether the arc flow is congested, the cost of transferring the energy and the efficiency of energy flow. The nodal prices of fuel production nodes are given as the prices of raw fuel resources at wellhead/coal mines. Then according to equation (3.7), nodal prices of other nodes in fuel system can also be obtained. The connections between fuel system and electric system are arcs that connect pseudo generator nodes to generator nodes. Equation (3.7) also applies to energy flows in these arcs, so we can get nodal prices of generator nodes.

When $(ij) \in Mt$, the nodal prices between two linked nodes i and j are given in the following equation:

$$\frac{\partial L}{\partial e_{ij}(t)} = \lambda_i(t) - \gamma_j(t) + \alpha_{ij}(t) - \delta_{ij}(t) + \mu_{ij}(t) = 0 \quad (3.8)$$

In this model, in electric system, neither line losses nor transmission costs is considered. So transmission line congestion is the only factor for nodal prices differences between two connected nodes. The presence of difference between nodal prices means the generation at lower-priced locations cannot be transferred to high-priced locations due to flow constraints.

3.3 Numerical Example

To evaluate the methodology presented before, a five-node system has been considered.

In the system shown in Fig. 3.4, there are two suppliers of coal, one supplier of natural gas,

and one supplier of oil. Three of the five generators burn coal; the other two burn natural gas and oil separately. An oil storage facility with a capacity of 20,000 barrels is included. The properties associated with the fuel transportation and storage system are shown in Fig. 3.5.

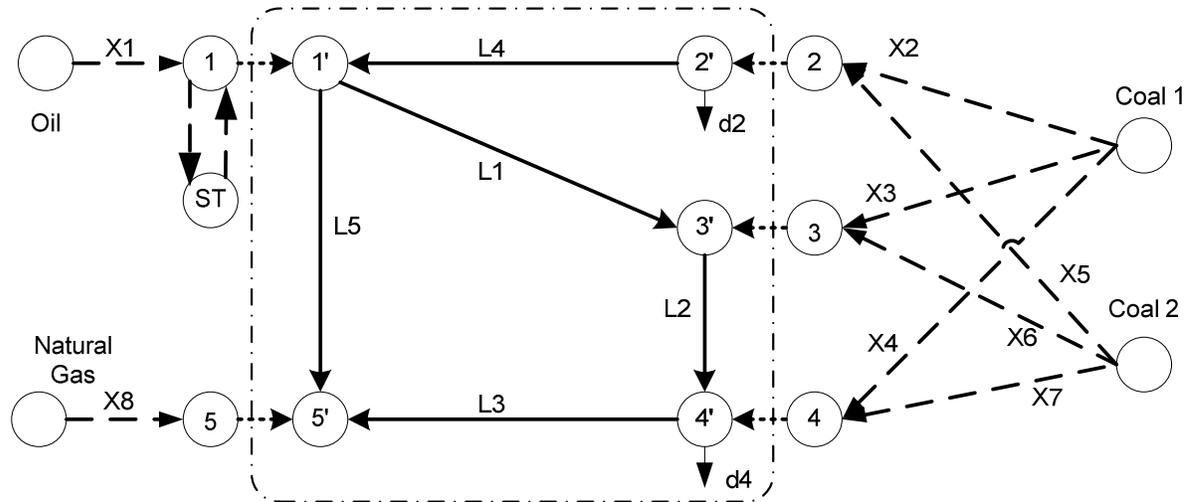


Fig. 3.4. Five-node system with fuel suppliers.

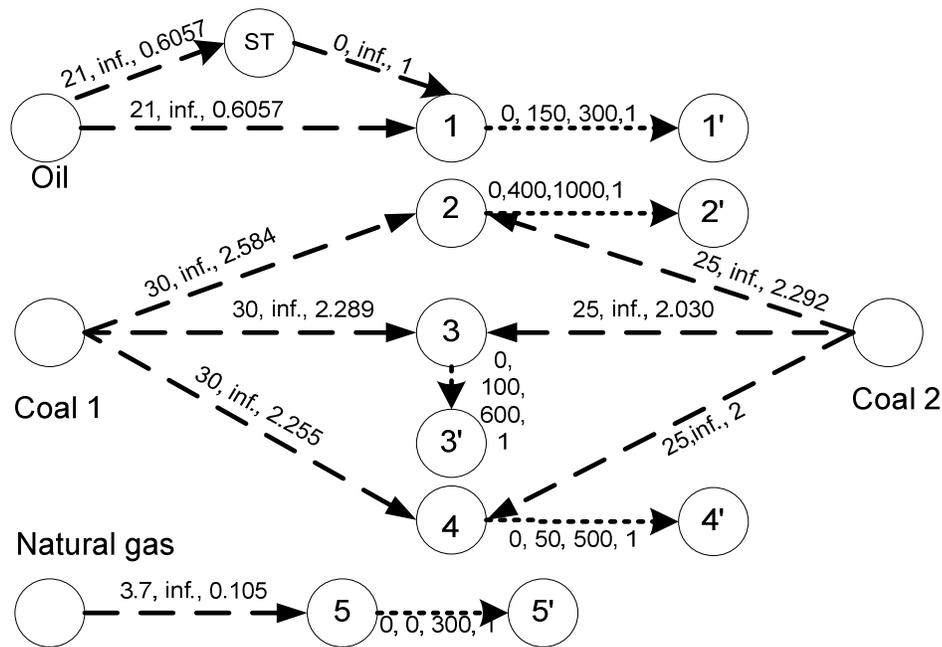


Fig. 3.5. Fuel transportation and storage system.

The five-bus system is tested for a period of 52 weeks to analyze the mid-term operation characteristics. In order to encapsulate the load duration characteristics of the demand in the algorithm, load is represented as weekly load duration curves (LDCs). An LDC plots the number of hours (percentage of hours per year) that the load equals or exceeds a given level of demand. In order to reduce the computation time, the LDC is simplified to have three levels of load that represent high, medium and low demand. There are variations with wellhead oil and natural gas prices, with peak price appearing in the middle of the year (see Figure 5). Coal price is determined mainly by long-term contracts and coal supply is less dependent on import than oil and natural gas, so coal price tends to be stable. This estimation is in line with historical data of coal prices from EIA.

The flows of the test system under five scenarios were calculated, as shown in table 1. The “No DC OPF” scenario uses the original generalized network flow model and one set of the multiple solution sets is shown. The “Base case” scenario considers a transmission system without any flow constraints. In scenario “Case 1”, a 100 MW flow constraint is applied on line L4. In scenarios “Case 2”, load on node 4 was increased to 1600 MW. In scenario “Case 3”, the flow limit in line X5 is 200 ton (per hour).

Table 3.1 Optimal results of five scenarios

Energy flow	Optimal solution				
	No DC OPF	Base case	Test case 1	Test case 2	Test case 3
X1(barrel)	247.65	247.65	247.65	495.29	247.65
X2(ton)	0	0	0	0	209.59
X3(ton)	0	0	0	0	0
X4(ton)	0	0	0	0	0
X5(ton)	436.3	436.3	392.67	436.3	200
X6(ton)	295.57	295.57	295.57	295.57	295.57
X7(ton)	125	125	175	250	125
X8(Mcf)	0	0	0	0	0
V1(MWh)	150	150	150	300	150
V2(MWh)	1000	1000	900	1000	1000
V3(MWh)	600	600	600	600	600
V4(MWh)	250	250	350	500	250
V5(MWh)	0	0	0	0	0
L1(MWh)	350	25	-25	100	25
L2(MWh)	950	625	575	700	625
L3(MWh)	0	-325	-275	-400	-325
L4(MWh)	200	200	100	200	200
L5(MWh)	0	325	275	400	325
D2(MWh)	800	800	800	800	800
D4(MWh)	1200	1200	1200	1600	1200
Cost(\$)	26622.3	26622.3	26781.5	34947.9	27002.7

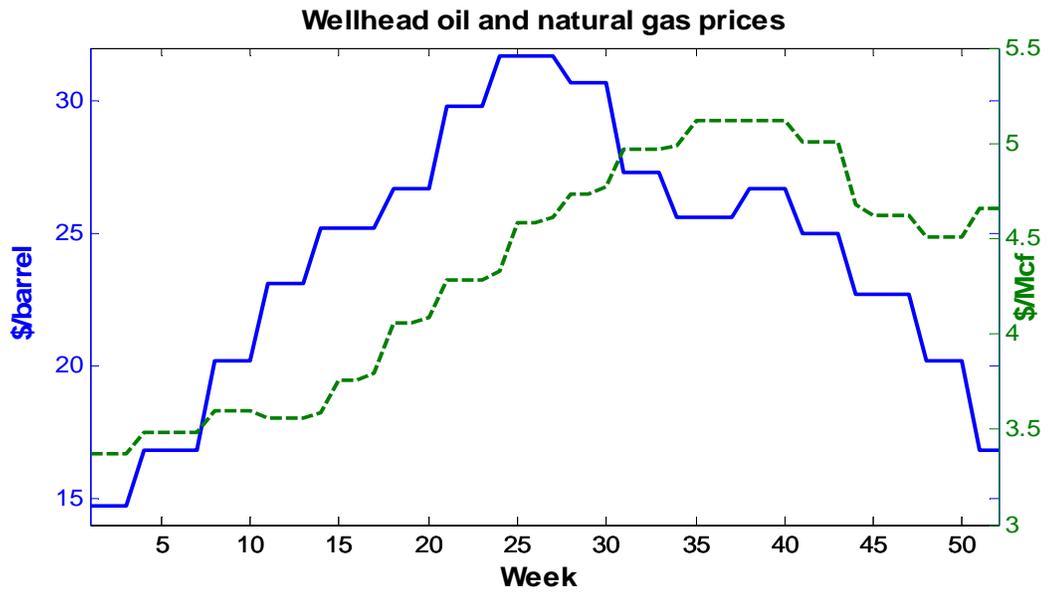


Fig. 3.6. Oil and natural gas prices

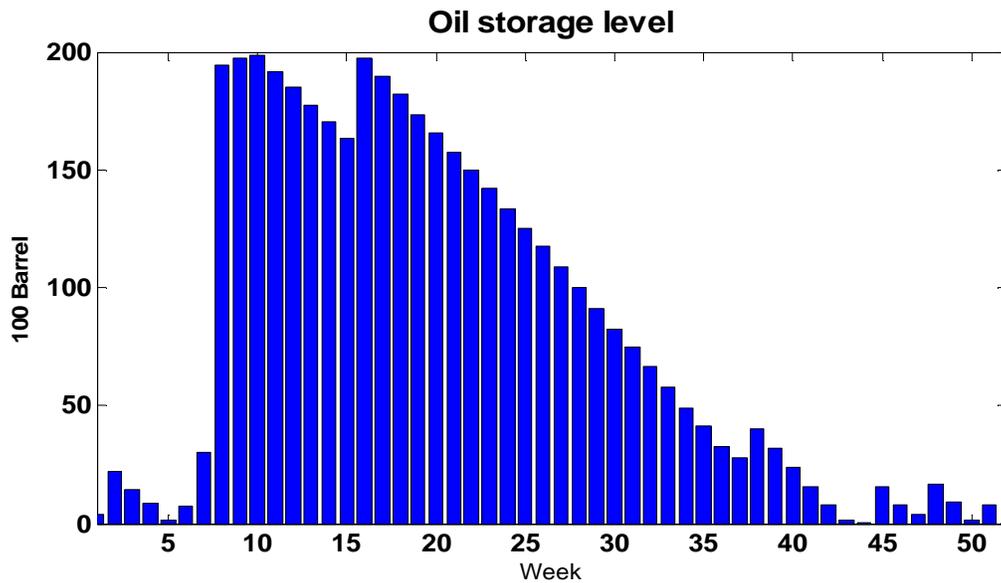


Fig. 3.7. Oil Storage level

Fig. 3.6 shows the oil storage level for the 52-week term. The storage level is very high in the beginning, when oil price is in a low level; whereas when oil price increases, the storage level drops accordingly.

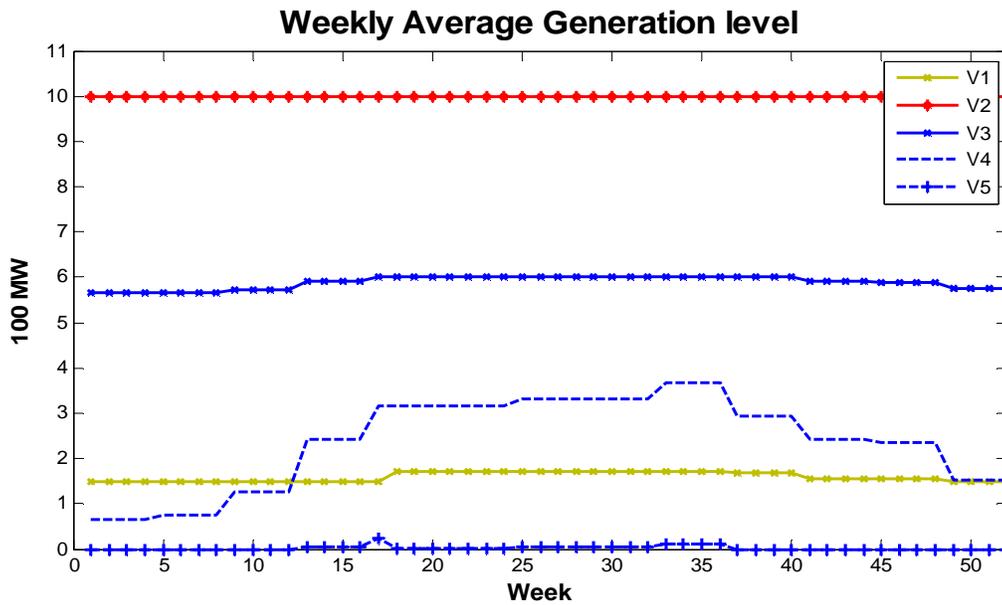


Fig. 3.8. Generation levels

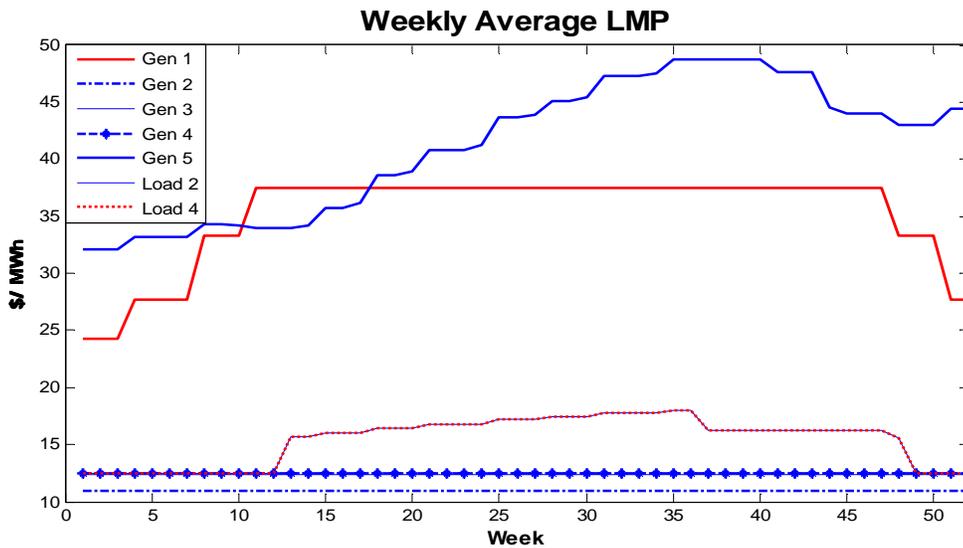


Fig. 3.9. Locational marginal prices

Fig. 3.8 shows the weekly average generation levels of generators over 52 weeks. Coal-fired power plants generally have higher fixed costs and lower operating cost than gas-fired and oil-fired plants, so they run all the time (base-load plants). Gas-fired power plants, on the contrary, have higher operating costs and lower fixed costs, so they only run

when load is very high. Fig. 3.9 presents the weekly average LMPs of each bus and load. Although LMPs of oil-fired and gas-fired plants are higher, they only operate for a short time each week, so the average LMPs of two demands are only a little higher than the highest coal-fired power plant. What is more, the storage facility helps to reduce the oil price by saving the cheaper oil in the beginning of the year for later use.

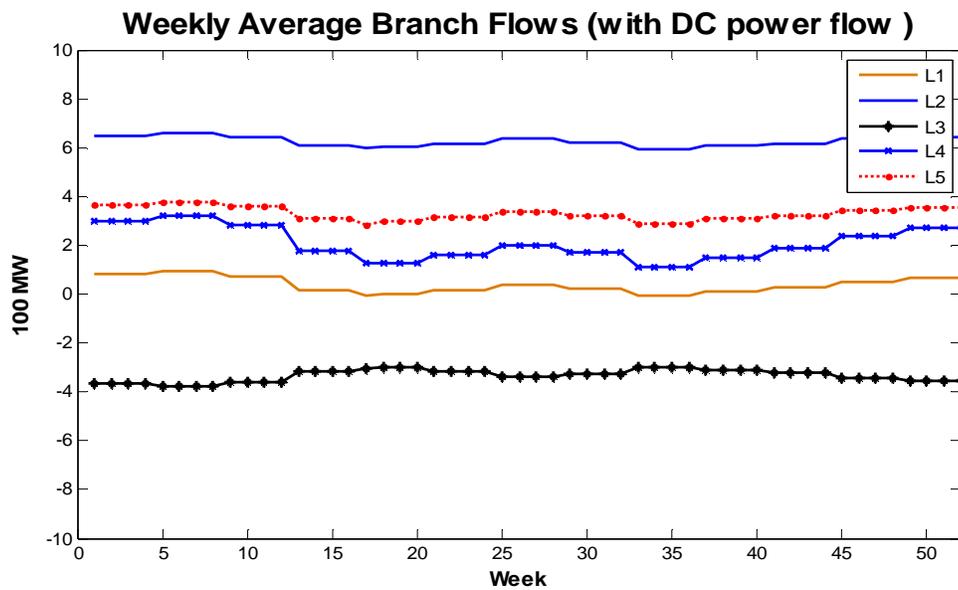


Fig. 3.10. Branch flows (with DC power flow)

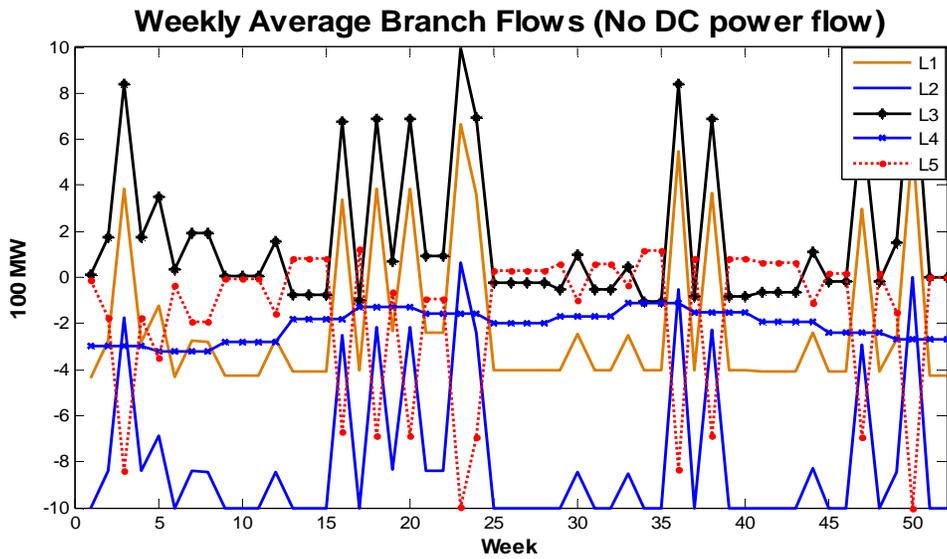


Fig. 3.11. Branch flow (no DC power flow)

A comparison of branch flows optimized by models with and without DC power flow is shown in Fig. 3.10 and Fig. 3.11. There is a 1,000 Mw constraint on each transmission line in both cases. Fig. 3.11 shows the extreme condition where no loss or cost is considered. The reason for differences between the two cases is that in the first case, DC power flow function is not incorporated, so the flows in the transmission system only comply with KCL, but not KVL.

Table 3.2 Generators’ real power output and branch flows (week 2 low demand hours).

	Bus					Line					Load	
	1	2	3	4	5	2-1	1-5	1-3	3-4	4-5	d2	d4
With DC power flow	150	1000	363	0	0	405	368.25	186.75	549.75	-368.25	595	918
Without DC power flow	150	1000	363	0	0	405	1000	-445	-82	-1000		

Table 3.2 shows the optimal solutions generated by the models with and without DC power flow. We can see that when DC power flow is not incorporated, active power flows in the direction of 1→5→4→3→1, which violates KVL in that the sum of price drop in one

loop is not zero. Consequently, the flow generated in this model won't happen in the real system.

Let's take a look at network flow model without DC power flow. There is no cost or loss associated with the branch flows, so for the overall optimization problem, as long as branch flows can satisfy KCL for buses 1–5, the value won't affect the optimal value of the objective function and other variables. So we can assume that the generators' active power output is given, and the following equations can be made to get branch flow.

$$\underline{A} \underline{P}_B = \underline{P} \quad (3.9)$$

$$\begin{bmatrix} Lmin \\ Lmin \\ Lmin \\ Lmin \\ Lmin \end{bmatrix} \leq \begin{bmatrix} L1 \\ L2 \\ L3 \\ L4 \\ L5 \end{bmatrix} \leq \begin{bmatrix} Lmax \\ Lmax \\ Lmax \\ Lmax \\ Lmax \end{bmatrix} \quad (3.10)$$

$$\text{Where } \underline{A} = \begin{bmatrix} 1 & 0 & 0 & 0 & 1 \\ 0 & 0 & 0 & 1 & 0 \\ -1 & 1 & 0 & 0 & 0 \\ 0 & -1 & 1 & 0 & 0 \\ 0 & 0 & -1 & 0 & -1 \end{bmatrix}, \underline{P}_B = \begin{bmatrix} L1 \\ L2 \\ L3 \\ L4 \\ L5 \end{bmatrix}, \text{ and } \underline{P} = \begin{bmatrix} V1 \\ V2 - d2 \\ V3 \\ V4 - d4 \\ V5 \end{bmatrix}.$$

V1–V5 are the generators' real power output. d2 and d4 are loads in buses 2 and 4, which are known. The determinant of \underline{A} is zero. According to Cramer's rule, if the right-hand side of the equation is not zero and the determinant of coefficient matrix is zero, the system has no unique solution. So there will be multiple solutions to the same equation and the branch flows generated from the model can be any one of the multiple solutions, which explains why the branch flows change so violently over time. For example, in Table 3.2, the branch flows in both cases satisfy Equation 3.9, yet they are totally different. In larger transmission

systems, the coefficient matrices tend to be sparse, so their determinants are usually zero. Consequently, for a given level of the generators' real power output, there might be multiple sets of branch flows that can satisfy equation (3.9) and the solution generated by the model can be either one of them.

For the network model with DC power, we can also form equations to get branch flows.

$$\underline{P}_B = (\underline{D} \times \underline{A})[\underline{B}]^{-1} \underline{P} \quad (3.11)$$

\underline{P}_B is a vector of branch flows. \underline{D} is a diagonal matrix with the diagonal elements in row k , column k contains the negative of susceptance of the k_{th} branch. \underline{A} is the $M \times (N-1)$ node-arc incidence matrix. \underline{B} is of dimension $(N-1) \times (N-1)$. \underline{P} is the vector of nodal injections for buses $2, \dots, N$. Apparently, given a certain \underline{P} , there will be a unique \underline{P}_B .

If costs or losses are associated with branch flows, the branch flows in the second case (without DC power flow) are included in the objective function, and then the optimal solution would be the one that minimizes the overall cost of the system. However, there is no guarantee that the branch flow solution will comply with KVL. When modeling larger systems, e.g., western interconnection, the difference with branch flow solutions will still occur in that, after all, KVL is not represented by the model without DC power flow. The solution derived from this model might be optimal the least-cost way but physically impossible. The differences with branch flows will in turn affect the optimal solutions of the other variables and the overall objective function if cost or losses is considered. For decision makers, accurate active power flow solutions will give them a better idea of transmission line

congestion level so that they can arrange their operation plans accordingly. What is more, LMP will not be right if it's based on inaccurate branch flows.

CHAPTER 4 RELIABILITY-BASED AND MARKET-BASED PLANNING

The differences between the proposed market-based transmission planning method and the traditional reliability-based transmission expansion planning method can be illustrated using

Fig. 4.1.

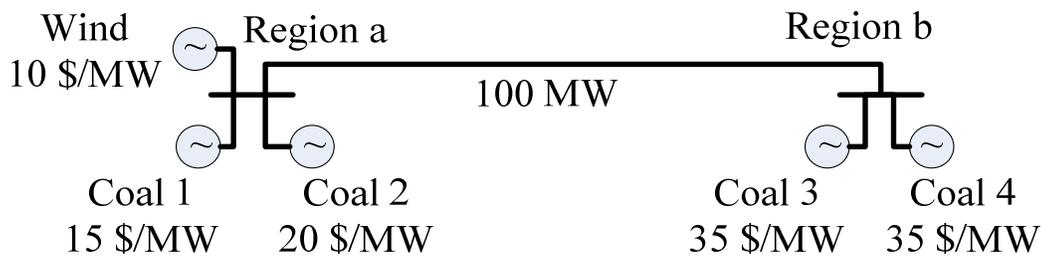


Fig. 4.1. An example two-bus system

Region a and region b are weakly connected by a long distance transmission line with a flow limit of 100 MW. The two regions have two 500 MW coal generators each. Region A also has a 600 MW wind farm with a 30% capacity factor. The peak loads in the two regions are both 500 MW. As we assume a simplified ISO-managed electric market, the bilateral contract between the two utilities is not considered here. In the central-dispatched electric market, ISO oversees the energy market and ensures the efficient and reliable operation of the electric system. In the day-ahead and real-time markets, ISO will conduct security-constrained unit commitment (SCUC) and security-constrained economic dispatch (SCED). The results of the SCUC and SCED are the optimal commitment and dispatch schedules to maximize the social surplus of the market.

If there were no transmission limit on the transmission line, the low-cost generators in region a will substitute the high-cost generators in region b so that the total production costs in the system are minimized at all hours. There will be a 500 MW flow in the transmission system during the peak hours. However, due to transmission line thermal limit and other reliability reasons, ISO needs to make sure that the flow limits will not be violated. Thus, a rather than allowing 500MW flow during the peak hours, the maximum flow on the transmission line is 100MW. Apparently, the test system has a much higher production cost now than that of the case with no transmission limits.

In the electric system, there are generally two ways to maintain the transmission flow within the defined set limit. When there is an overload in the transmission network, system operator can conduct TLR (through curtailment of scheduled transactions), market re-dispatch (by means of binding elements), or both, to maintain system reliability. While congestions as the result of contingencies and dispatches need to be taken care of immediately, most of the congestions only reflect proper system management with reliability regions and do not mean requirement for system expansion. There are generally two categories of transmission congestions:

1) Most of the time, when congestion occurs, there are plenty of other generation resources and mitigation options available. Simply shifting the generation supply among the available generator and reducing the demand via demand-side management can solve the

congestions. In this kind of situation, the system is operating in a less-economical way compared to the non-congested system.

2) Alternatively, in some rare cases, transmission thermal limits are reached and there is either no generation resources readily available for dispatch or generation resources are sufficient system-wide but limited by transmission bottlenecks. As the result of this kind of congestions, system operators have limited mitigation plans except for curtailing the load.

The former category of congestions might not justify the needs for transmission system expansion from reliability point of view, the later, however, violates system reliability criteria set by FERC and is a clear indicator for system expansion needs.

In the test system, reliability-based transmission planning will not expand transmission system because there is no load curtailment during peak hours under N-1 contingency conditions. However, as the inter-regional transmission line is heavily congested, LMP in region b is much higher than region a. Although region a has excess low-cost energy, it cannot be transferred to region b because of transmission bottleneck. The consumers in region b need to pay a much higher price for electricity. Due to the congestion, the total load payments in the two regions are higher than the total amount of money that generators receive. The difference between the revenues collected and costs incurred is called merchandising surplus or congestion cost. The appearance of large merchandising surplus means there is social surplus loss in the whole market, which indicates that the system is operating inefficiently [52]. Unlike reliability-based transmission planning method, the

market-based transmission planning model will consider investing new transmission lines between the two regions to relieve the congestions, promote competition and enhance the efficiency of the market. Similarly, reliability-based planning would not build HVDC transmission from the US Midwest, where energy prices are low, to the US East Coast, where energy prices are high, but market-based planning would.

4.1 Reliability-Based Transmission Expansion Planning

4.1.1 Overall Formulation

The objective of traditional transmission expansion planning is to find the least-cost alternative to serve the load demand of all existing and future customers reliably. Capital investments are justified on the grounds of reliability requirements. In reliability-based transmission planning, the investment decision is made based on the operating conditions during the system's peak-load hours and under various contingencies. Such a planning effort is based upon load/generation forecasts and the lead times required to implement resource and transmission investment decisions. In today's ISO/RTO markets, such planning processes are conducted both by regional transmission organizations and/or by transmission companies. When ISO/RTOs are conducting reliability-based planning, the planning are done at a regional level with the active participation from generation and transmission companies, load serving entities, state regulators, and many other market participants. Based on various reliability criteria (power flow, power transfer limits, contingency analysis for steady-state,

dynamic, voltage, and small-signal stability) and economic assessment of investment costs, a set of transmission investment plans are created. In this paper, an N-1 contingency reliability criterion is adopted. The N-1 contingency criterion means that the system should withstand an outage of one major element, such as a line, generator or transformer. In this paper, we only consider transmission line outages. This is a reasonable assumption considering that most major blackouts are transmission based, and that transmission lines are vulnerable to various disturbances.

4.1.2 Master Problem

The master problem is the decision making problem. The objective function is the minimization of the present value of investment costs. Constraint (4.2) is the cut from the slave problem, which indicates that there are violations (loss of load) in iteration k under wth contingency. Constraint (4.3) updates the total number of each line at time t considering the lead time of investments. Both the number of lines to be built each year and the total number of lines are subject to constraints, as shown in constraints (4.4) and (4.5).

$$\text{Min} \quad \sum_{t \in T} \sum_{(ij) \in Mn'} (1+r)^{-t} I_{ij} m_{ij}(t) \quad (4.1)$$

subject to

$$\sum_{t \in T} \sum_{(ij) \in Mn'} \delta_{ij}^{kw}(t) (n_{ij}^k(t) - n_{ij}(t)) + Z^{kw} \leq 0 \quad (4.2)$$

$$n_{ij}(t) = n_{ij}(t-1) + m_{ij}(t-a) \quad (4.3)$$

$$0 \leq m_{ij}(t) \leq \overline{m_{ij}} \quad (4.4)$$

$$0 \leq n_{ij}(t) \leq \overline{n_{ij}} \quad (4.5)$$

where δ_{ij} is the sensitivity of the optimum value Z with respect to the decision variable n_{ij}

given by Romero and Monticelli [53]:

$$\delta_{ij}(t) = -B_{ij}(\theta_i(t) - \theta_j(t))(\lambda_i(t) - \lambda_j(t)) \quad (4.6)$$

4.1.3 Slave Problem

In the slave problem, the impact of the transmission expansion plan is assessed under worse-case scenarios to ensure the system is designed and operated to a certain level of reliability. As the N-1 contingency criterion is adopted, the transmission investment must ensure that, under the loss of any single equipment, the system won't have any load curtailment during peak hours throughout the planning horizon. Thus, each slave problem is a feasibility check problem, which checks the reliability of the system under an N-1 contingency. In each iteration, there are w sub-problems, each representing the outage of one major element in the system. $r_j(t)$ is the slack variable in constraint (4.2), which balances the total energy input and total energy output for node j at time t . If $r_j(t) > 0$, it means that there is not enough power to supply the electric demand. In this case, a portion of the demand is not satisfied, which, in other words, means a violation occurs. Z_w is the sum of all slack variables, and if $Z_w > 0$, it means that violations occur during w_{th} contingency and the load cannot be satisfied at some time. Thus, a feasibility cut is added to the master problem in

order to eliminate the violations. If $Z^w = 0$, then there are no violations and there is no feedback to the master problem.

$$\text{Min } Z^w = \sum_{t \in T} \sum_{j \in N \cup N'} r_j(t) \quad (4.7)$$

subject to

$$\sum_{\forall i} \eta_{ij} e_{ij}(t) - \sum_{\forall k} (e_{jk}(t) + en_{jk}(t)) + r_j(t) = d_j(t), \quad \forall j \in Nf \cup Nt, \quad \forall (ij) \in Mf \cup Mt \cup Mn' \quad (4.8)$$

$$e_{ij}(t) - b_{ij} h_{ij}^w (\theta_i(t) - \theta_j(t)) = 0 \quad \forall (ij) \in Mt \quad (4.9)$$

$$en_{ij}(t) - n_{ij}^k h_{ij}^w b_{ij} (\theta_i(t) - \theta_j(t)) = 0 \quad \forall (ij) \in Mn' \quad (4.10)$$

$$e_{ij.\min} \leq e_{ij}(t) \leq e_{ij.\max} \quad \forall (ij) \in Mf \cup Mt \quad (4.11)$$

$$n_{ij}^k e_{ij.\min} \leq en_{ij}(t) \leq n_{ij}^k e_{ij.\max} \quad \forall (ij) \in Mn' \quad (4.12)$$

$$-\pi \leq \theta_i \leq \pi \quad \forall i \in Nt \quad (4.13)$$

where h_{ij}^w is 0 if (i, j) is the w_{th} line; otherwise it's 1.

The operation sub-problem is modeled using the generalized network flow method. The electric power generation/ transfer are considered as energy flows in the system. The prices of different kinds of fuels at the fuel production side, such as wellhead natural gas prices and spot prices of coal in different coal-producing regions, are included in the cost properties of transportation arcs. Equation (4.8) shows that for each node, the sum of flows into the node minus the flows out of the node equals the demand (or supply if negative) of the node. For

the electric transmission system, Kirchhoff's first and second laws are fulfilled by constraints (4.9), (4.10) and (4.11). Arc flows and power angles must be within constraints, as shown in constraints (4.11), (4.12) and (4.13). Constraint (4.11) exerts constraints on flows in the existing network; Constraint (4.12) exerts constraints on flows in the potential lines. If no new line is installed in time t , $n_{ij}(t)$ is 0, then $en_{ij}(t)$ is also 0. For the fuel transportation network, arc flows should be larger than or equal to zero, whereas in the transmission network, arc flow can be negative to account for the bidirectional nature of the power flow.

4.1.4 Iteration Procedures

Fig. 5 shows the iteration procedures for the reliability-based transmission planning model. At the beginning of the planning process, the master problem is solved without any cut (constraint (4.2)). Then the investment decisions about when, where and which lines should be built are sent to the slave problems. The slave problems check the adequacy of the electric supply under various contingencies for the whole planning horizon. If there is a violation in any slave problem, a feasibility cut is generated and added to the master problem. The iterations between the master problem and slave problem continue until there are no violations in all of the slave problems.

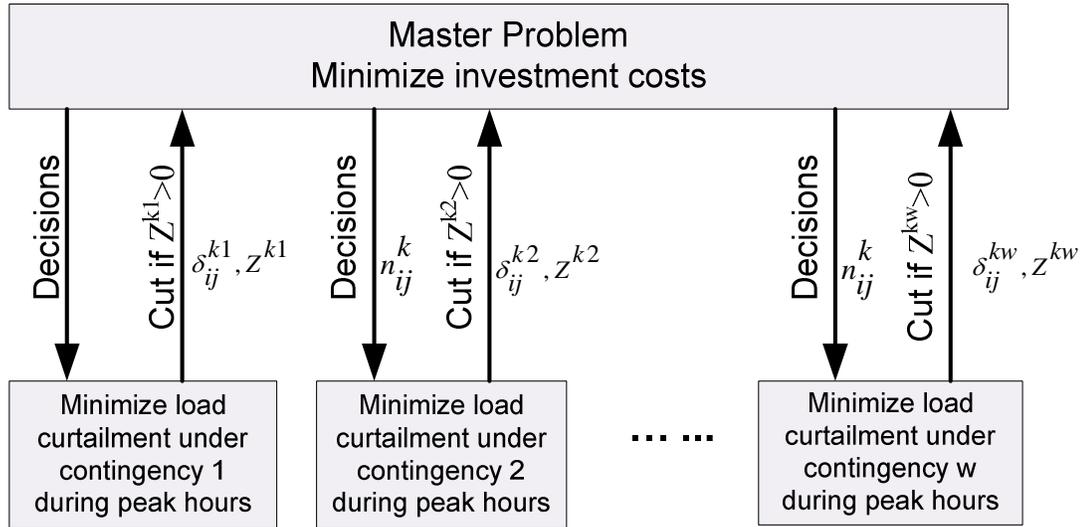


Fig. 4.2. Iterations between master and slave problems in the reliability-based planning

4.2 Market-Based Transmission Expansion Planning

4.2.1 Overall Problem

Market-based transmission investment assumes that an efficient investment might bring sufficient economic benefit when the transmission system has a high level of congestion. In this paper, we assume ISOs will conduct the market-based transmission planning study for the whole system in order to find the profitable investment opportunities for companies or individual investors that are interested. By doing so, ISOs ensure the efficient operation of the whole electric market.

According to economic theories, social surplus is a good indicator of how well the market is working. Thus, social surplus should be used to quantify the economic benefits that network expansions bring. From the social welfare perspective, a market-based transmission investment is justified if the total social surplus increase caused by the investment is higher

than the cost of the investment itself. However, the two values are hard to compare in that while investment cost is incurred at a certain time and can be considered as present value at the beginning of the planning horizon, social surplus occurs at every time step. So in the slave problem, social surplus must be calculated at every hour throughout the planning horizon or a way to approximate this process must be found.

4.2.2 Market Structure and Operation

In this paper, the ISO-managed day-ahead market is considered. In the ISO-managed day-ahead market, all transactions are carried out by an ISO which clears the market for both the generation companies (GenCos) and load-serving entities (LSEs) [54]. The responsibility of an ISO is to ensure the reliable and efficient operation of the wholesale electricity market. The objective of the LSEs (buyers) is to ensure the highest possible net earning each day by buying electric power from the day-ahead market and selling it in the retail electric market. The objective of GenCos (sellers) is to acquire the highest possible net earning each day by selling electric power in the day-ahead market.

At the beginning of each day, each GenCo submits to the operator an incremental cost and the amount of energy it is willing to sell and each LSE submits to the operator a decremental cost and the amount of energy it is willing to buy. After receiving offers and bids for the next day, the ISO then conducts an optimal power flow based on offers/bids and determines the hourly dispatch schedules and locational marginal prices (LMPs). Each GenCo gets paid by the LMP it receives and each LSE pays the LMP for the electric power it

purchases. In this paper, all generators are bidding according to their marginal cost curves, so strategic bidding is not considered.

The generator's cost is generally comprised of two parts: the fuel cost and the O&M cost. The fuel cost is decided by the price of fuel at its production site, e.g., coal mines, gas well, etc., and the costs to transport and store the fuel. In our generalized network flow model, fuel cost can be expressed as the cost of transferring the flows (fuel) from the supply nodes to the generator. The O&M cost is generalized to have not only the regular maintenance, repair, and spare parts costs, but also fixed costs such as insurance, return to stockholders, administration costs, etc. The marginal cost of generators normally grows with the increase of power output. The marginal cost curves can usually be adequately approximated using piecewise linear functions. Fig. 4.3 shows the generator marginal cost curve as well as incremental fuel cost curve and incremental O&M cost curve. The marginal fuel cost can be described using a step function, while the incremental O&M cost increases linearly as generation output increases. As can be seen in the figure, when the generator output is x MW, the production cost is the sum of areas S1 and S2, which are the total fuel cost and total O&M cost respectively.

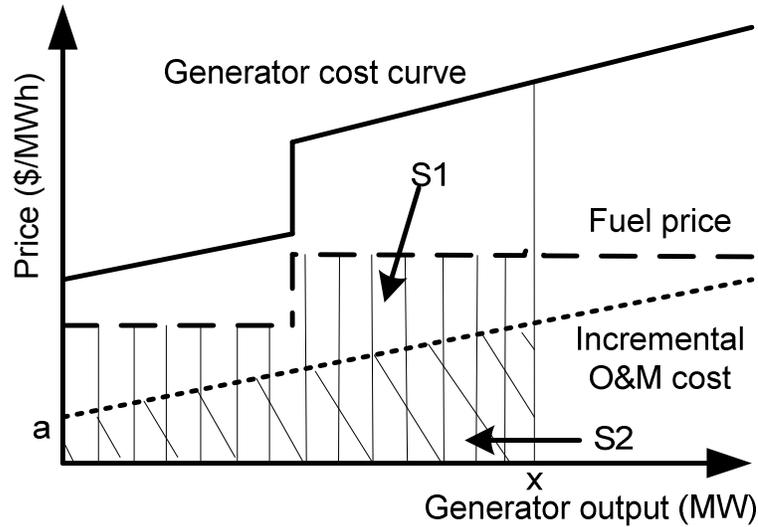


Fig. 4.3. Generator marginal cost curve

Fig. 4.4 shows the case where there is only one seller and one buyer in the market. L1 is the demand curve for the consumer, while L2 is the marginal cost curve for the generator. The elasticity of electric demand is considered, which means that customers are sensitive to the price at which electric power is sold and will not buy it if the price rises what they consider too much. In other words, consumers will pay a certain price, or a certain range of prices, for electric power. In Fig. 4.4, the market reached an economic equilibrium at quantity x and price y , which means that the GenCo sells x MW (for an hour) to the LSE at the price of y \$/MWh. In economics theory, consumer surplus is the area above the price level and below the demand curve, since the price that consumers pay is equal to the value of the last unit of energy (the marginal value). In other words, consumers get more than what they pay for. In contrast, producer surplus is the area below the price level and above the supply curve, since producers get paid more than their total production cost. The social

surplus is the sum of consumer surplus and producer surplus, which is essentially area $S3$ ($S4-S1-S2$). For a market that has multiple participants, we can get the total social surplus on the figure of the cumulative demand curve and cumulative supply curve.

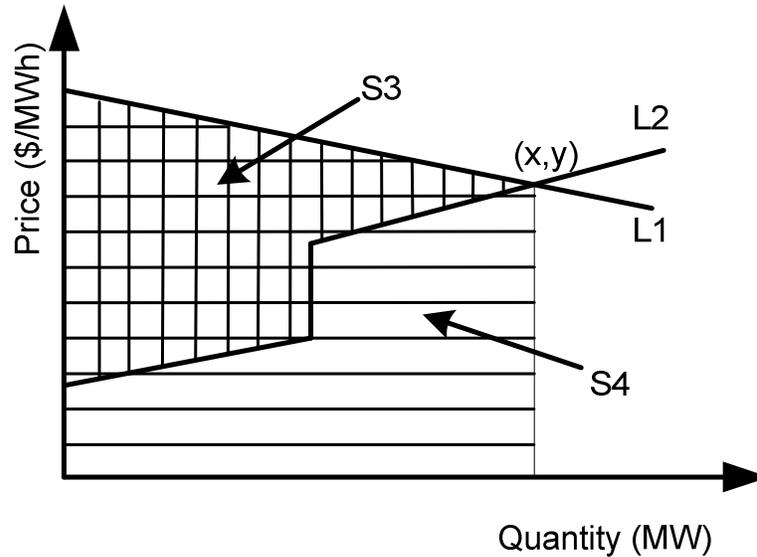


Fig. 4.4. Supply- and Demand-side bidding curves

In many economic planning models, in order to capture the fundamental economic benefits of circuit installations, various expansion criteria are defined, such as production costs [5], flatness of price profile [1], congestion rent [4], redispatch cost, etc. In this paper, a day-ahead bulk electric market is considered. According to [8], the objectives of the electric market framework are promoting market efficiency, lowering energy delivery cost, securing system reliability, mitigating significant market power and increasing the choices offered to market participants. Thus, social surplus is used as the market-based expansion criterion as it is the primal measure of the efficiency of a market. When there are congestions in the

transmission grid, less expensive energy cannot be freely transferred in the market, which causes some valuable resource to remain unused. What is more, the congestions in the system will hamper the full extract of all possible surpluses as price-sensitive demand might be curtailed as the result of an insufficient supply of less expensive energy. In order to enhance market efficiency, we need to invest in new transmission lines to eliminate or reduce the level of congestion in the system. The idea of market-based transmission expansion planning is based on the trade-off between the investment costs and the induced increase in social surplus.

4.2.3 Master Problem

In the planning problem, while generally more circuit expansions will promote the efficient operation of the electric market and increase the social surplus, they also means more investment cost. The master problem tries to find a trade-off between high investment cost and increase in social surplus. The objective function is the minimization of social costs (investment costs minus social surplus), which is the same as maximization of social surplus minus investment costs.

$$\text{Min} \quad \sum_{t \in T} \sum_{(ij) \in Mn'} (1+r)^{-t} I_{ij}^{m'}(t) + Z^* \quad (4.14)$$

Subject to

$$Z^* \leq 0 \quad (4.15)$$

$$Z^* \geq \sum_{t \in T} \sum_{(ij) \in Mn'} \delta_{ij}^k(t) (n_{ij}^k(t) - n_{ij}^k(t)) + Z^k \quad (4.16)$$

$$n_{ij}(t) = n_{ij}(t-1) + m_{ij}(t-a) \quad (4.17)$$

$$0 \leq m_{ij}(t) \leq \overline{m_{ij}} \quad (4.18)$$

$$0 \leq n_{ij}(t) \leq \overline{n_{ij}} \quad (4.19)$$

where Z^k is the optimal value of the slave problem in the k_{th} iteration and δ_j can also be expressed as (4.6).

4.2.4 Slave Problem

The slave problem tries to minimize the social cost plus loss of load penalties. The major differences between the slave problem in market-based transmission planning and that of reliability-based transmission planning are that: (1) The former tries to minimize the social costs by conducting optimal power flow (OPF), while the latter tries to check if there is any load curtailment; (2) The former needs to calculate the economic value introduced by circuit additions throughout the planning horizon, which means it needs to optimize the operations of system either chronologically or under a set of typical conditions that can approximate the hour-by-hour load levels, while the latter only needs to check violations during peak-load hours of each year; (3) The former is a quadratic programming problem as the double-sided bidding is considered, while the latter is a linear programming problem; (4) There is only one slave problem in market-based planning, while there are w slave problems in reliability-based planning, each representing a contingency in the system; and (5) The slave problem in market-based planning will generate an optimality cut to the master problem,

while one slave problem in reliability-based planning will generate a feasibility cut only when its optimal objective value is higher than zero.

$$\begin{aligned} \text{Min } Z = & \sum_{t \in T} (1+r)^{-t} \left(\sum_{(i,j) \in Mf \cup Mt} c_{ij}(t) e_{ij}(t) + \sum_{\forall j \in Nf \cup Nt} lol(t) r_j(t) \right) \\ & + \sum_{(i,j) \in Mg} S_{ij}(e_{ij}(t)) - \sum_{(i,j) \in Md} D_{ij}(e_{ij}(t)) \end{aligned} \quad (4.20)$$

Subject to

$$e_{ij}(t) - b_{ij}(\theta_i(t) - \theta_j(t)) = 0 \quad \forall (ij) \in Mt \quad (4.21)$$

$$en_{ij}(t) - n_{ij}^k(t) b_{ij}(\theta_i(t) - \theta_j(t)) = 0 \quad \forall (ij) \in Mn' \quad (4.22)$$

$$n_{ij}^k(t) \underline{e}_{ij} \leq en_{ij}(t) \leq n_{ij}^k(t) \overline{e}_{ij} \quad \forall (ij) \in Mn' \quad (4.23)$$

$$\begin{aligned} \sum_i \eta_{ij} e_{ij}(t) - \sum_{\forall k} (e_{jk}(t) + en_{jk}(t)) + r_j(t) = 0 \quad \forall j \in Nf \cup Nt, \\ \forall (ij) \in Mf \cup Mt \cup Mn', \forall (jk) \in Mf \cup Mt \cup Mn' \end{aligned} \quad (4.24)$$

$$e_{ij, \min} \leq e_{ij}(t) \leq e_{ij, \max} \quad \forall (ij) \in Mf \cup Mt \quad (4.25)$$

$$-\pi \leq \theta_i \leq \pi \quad \forall i \in Nt \quad (4.26)$$

As shown in Fig. 4.3, if we assume the intercept and slope of the incremental O&M cost curve for $(i, j) \in Mg$ are a_{ij} and s_{ij} respectively, the total O&M cost $S_{ij}(e_{ij}(t))$ is:

$$S_{ij}(e_{ij}(t)) = a_{ij} e_{ij}(t) + s_{ij} e_{ij}^2(t) / 2 \quad (4.27)$$

In the same way, if we assume the intercept and slope of consumer bidding curve for $(i, j) \in Md$ are p_{ij} and q_{ij} respectively, the total consumer benefit $D_{ij}(e_{ij}(t))$ is:

$$D_{ij}(e_{ij}(t)) = p_{ij}e_{ij}(t) + q_{ij}e_{ij}^2(t)/2 \quad (4.28)$$

In order to encapsulate the load duration characteristics of the demand, load is represented as yearly load duration curves (LDCs). An LDC plots the number of hours (percentage of hours per year) that the load equals or exceeds a given level of demand. Compared to simulating the system chronologically, LDC helps to reduce the computation time.

4.2.5 Iteration Procedures

The overall problem is solved by iterating between the master and the slave problem, as shown in Fig. 4.5. In each iteration, the master problem generates a set of investment decisions and passes them to the slave problem. The slave problem simulates the operation of the market and gets new values of Z and δ_{ij} using the solution obtained in the master problem. Then the Benders optimality rule is used to check whether the optimal solution is achieved. If not, a cut will be added to the master problem and the next iteration gets started.

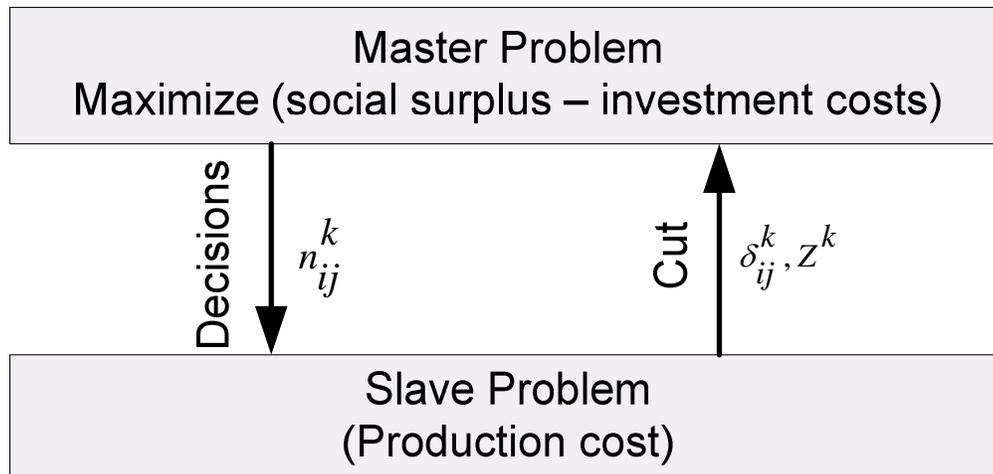


Fig. 4.5. Iterations between master and slave problems in the market-based planning

4.3 Numerical Example

4.3.1 5-bus System

To evaluate the methodology presented before, a 5-bus system has been considered. Fig. 4.6 shows the network diagram of the integrated energy system, which has three integrated gasification combined cycle (IGCC) power plants, one natural gas combined cycle (NGCC) power plant and an oil-fueled power plant. The fuel subsystem which includes four fuel suppliers and eight fuel transportation lines is also considered. Fuel transportation arcs X5 and X6 do not exist at the beginning of the planning horizon. They will come into use at year 2 and year 5, respectively.

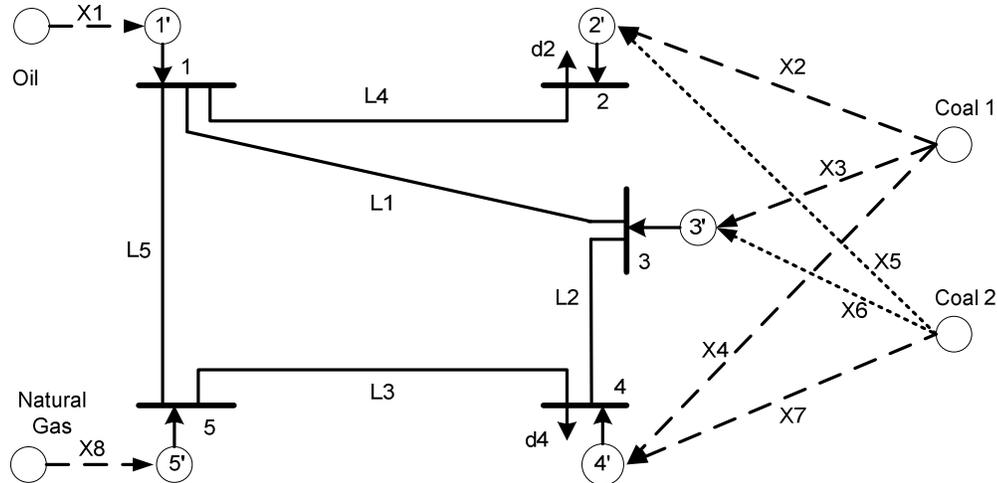


Fig. 4.6. Five-bus system with four fuel suppliers

The expected values of the natural gas price and oil price increases at a rate of 4% per year, while the coal price has a growth rate of 2% per year. The coal price is determined mainly by long-term contracts, and coal supply is less dependent on import than oil and

natural gas, so the coal price tends to be stable. This estimation is consistent with historical data of coal prices from the Energy Information Administration (EIA).

The market-based transmission expansion planning is carried out on this system for a planning horizon of 10 years. In order to reduce the computation time, yearly LDCs are used. Investment decisions are made at the beginning of each year.

Reliability-based transmission expansion planning considers the N-1 contingencies and generates investment decisions to ensure the system has no loss of load even in peak hours. The reliability-based planning method is also carried in this system with the same load conditions.

Table 4.1. Investment plans made by the two planning methods

Year	Reliability-based	Market-based
1	4-5	3-4, 2*1-2
2	4-5	
3		1-2
4		
5	3-4	
6		
7		
8		
9	1-5	
10		

A comparison between the results of the two planning methods is shown in Table 4.1. In order to reduce the investment cost, reliability-based planning will not invest new lines until they are needed. Because of the discount rate, the later the investment is made, the smaller the present value of the investment is. Market-based planning, however, tries to find the

opportunities to invest new circuits that can bring more social surplus than their costs. The test system is highly congested, so market-based planning tends to build new lines at the beginning of the planning horizon in order to get more economic benefits. Line 4-5 and line 3-4 are the only two lines connecting load 4 with the rest of the system. As the capacity of the generator in bus 4 is much lower than the demand, a lot of electric power needs to be transferred from the other buses. So the two lines become congested as the load grows over time and new lines need to be installed in order to supply the demand in bus 4. The LMP in bus 2 is the lowest in the system. However, the low-cost energy from generator 2 cannot be transferred to bus 4 in that line 1-2 and line 3-4 are highly congested. Thus, the market-based transmission planning made decisions to invest new lines on arcs 1-2 and 3-4 in order to relieve congestion, reduce congestion cost and increase social surplus.

Table 4.2. Comparison of the results of the two planning methods

Present value (\$)	Investment cost	Social surplus before investment	Social surplus after investment	Social surplus - investment cost
Reliability-based	3.40E+07	1.99E+09	2.06E+09	2.03E+09
Market-based	3.15E+07	1.99E+09	2.16E+09	2.13E+09

As shown in Table 4.2, both of the planning methods helped to increase the social surplus. Market-based transmission planning had a smaller investment cost, yet it generated a higher social surplus.

If transmission lines are congested during a dispatch, LMPs vary across the system. Congestion rent, which is also called merchandising cost or congestion cost, is used to

measure the congestion. The congestion rent refers to the difference between the total load payments and total revenues that generators receive. One of the goals of market-based planning is to relieve congestion, so congestion rent is a good indicator of how well market-based planning is working. In Table 4.3, market-based planning reduced congestion rent from 929 million dollars to 378 million dollars. Moreover, consumer payment was also reduced as less expensive energy can be freely transferred to where it is needed. Producer revenues decreased a little bit, showing that producers in total don't benefit much from transmission investments. However, as system expansion helps to relieve congestions and promote market efficiency, low-cost generators generally produce more power than before and take a larger portion from the overall producer revenues.

Table 4.3. Economic benefits generated by the market-based planning method

Present value (\$)	Consumer Payment	Producer Revenue	Congestion rent
Business as Usual (BAU)	5.61E+09	4.68E+09	9.28E+08
Market-based planning	5.02E+09	4.68E+09	3.78E+08

The test system is highly congested, so there are many investment opportunities for market-based planning. In a less congested system, the two planning methods might make fewer investments. However, in both cases market-based planning will outperform reliability-based planning in terms of economic benefits generated by investments.

While intensive studies have been done on expanding the electric transmission system, few efforts have been made to understand how bottlenecks in the fuel delivery system

interact with those in the transmission system to affect the operating efficiency of the whole energy sector [55]. Just like congestions in the electric system, congestions in the fuel transportation lines will also cause differences in nodal prices and prevent the efficient transportation of fuel resources. Because of economic interdependencies between the fuel system and electric system, investments in the fuel system will have a profound impact on the electric system. So it makes sense to include fuel transportation network investments as decision variables in the overall planning problem. In the 5-bus system, when investments on X5 and X6 are included in the market-based planning as decision variables, the investment decisions on the transmission system are different than earlier, which shows that the planning of the electric system is directly affected by the planning of the fuel system and vice versa. Although there are a lot of problems that need to be solved, such as cost allocation, data collection, and coordinating authorities and investors from both systems, this model can help decision makers carry out an analysis on this issue and get a better understanding of it.

4.3.2 A 30-bus System

The market-based transmission expansion planning model is applied on a 30-bus system, as shown in Fig. 4.7. The 30-bus system is composed of six weakly interconnected regions, each of which is a 5-bus system used in section A. All of the six regions are the same except that in each region, the fuel prices, marginal O&M costs for each generator, and consumer bidding curves are scaled by a factor. We assume each interconnection connects bus 3 of two regions.

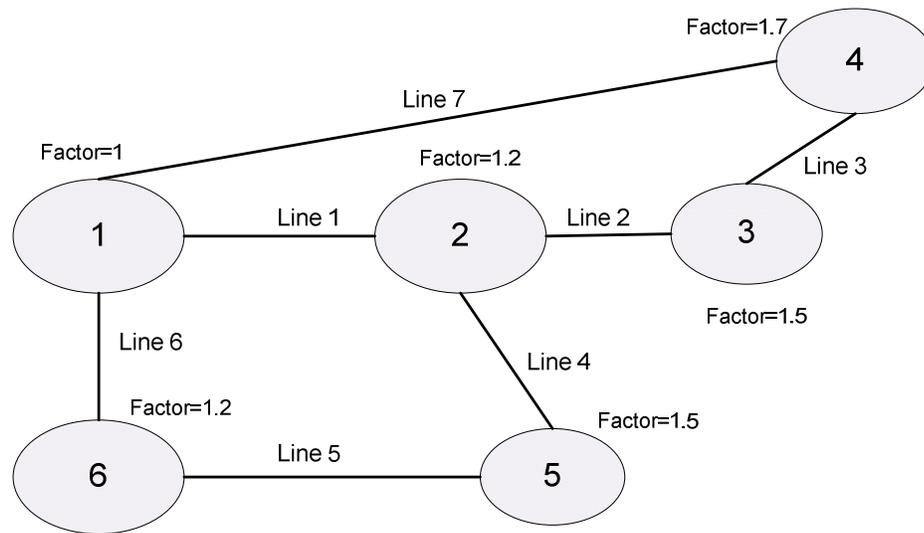


Fig. 4.7. The thirty-bus system (six regions with seven interregional interconnections)

In the 30-bus system, although candidate interconnections have very high investment costs compared to those of intra-regional transmission lines, the final solution of the planning problem suggests that one new interconnection between region 5 and 6 and three new interconnections between regions 1 and 4 should be built at the beginning of the planning horizon. This means that significant economic benefits can be obtained by transferring a large amount of energy from regions that have low energy prices and sufficient supply to regions that have higher energy price and high demand. In the U.S. eastern interconnection system, where several ISO/RTOs have long distances between each other and high differences in energy prices (e.g., Midwest ISO and ISO NE), the market-based transmission planning model can analyze the economic value of connecting these regions using HVAC or HVDC and make investment decisions accordingly.

When each region optimizes their own transmission investments and no candidate interconnections are considered, the optimal objective value is \$1.76e10. On the other hand, when all six regions are considered as one big market and candidate interconnections are included, the optimal objective value is \$1.78e10. This shows that inter-regional energy transference helps to enhance the market efficiency. The small difference between the optimal values is because regions with low energy prices don't have too much spare energy to supply the other regions. Should these regions have more generation capacities, there would be a higher difference between the optimal objective values of the two cases.

3.4.3 Scalability of The Market-based Planning Algorithm

All results illustrated in this section were taken from a PC with 32 GB of RAM and 3.16 GHz of CPU frequency running Microsoft windows server 2003. The mathematical programs are built in MATLAB and TOMLAB and solved using CPLEX. The tolerance for convergence is set to be 1%. For the five-bus system, seven iterations were performed for the market-based planning model to find the optimal solution. The total CPU time is about 1.39 seconds. When the same market-based planning approach is applied on a thirty-bus system, convergence to the optimal solution takes about 45 iterations and 0.2 hour. Tables 4 and 5 illustrate parts of the convergence report, where iteration number, lower and upper bounds, gaps for convergence, and CPU time for each master and slave problems are included.

The total computation time is decided by three factors: the number of iterations, computation time of the master problem in each iteration and computation time of the slave problem in each iteration. The iteration number is directly related to the number of candidate lines in the master problem. The master problem is an integer programming problem with all decision variables being the investment decision on candidate lines at each year. Thus, the computation time of the master problem is decided only by the number of candidate lines and the number of constraints, rather than the system size. It takes a longer time to solve the master problem as the number of iterations increases (more cuts added to the master system). According to reference [56], an integer programming problem with a fixed number of constraints can be solved by a pseudopolynomial-time algorithm, that is, an algorithm with running time polynomial in the numeric value of the input. Cobham's thesis [57] states that polynomial time is a synonym for “tractable”, “feasible”, “efficient”, or “fast”. In transmission planning of large systems, such as the joint coordinated system plan (JCSP) carried out by several ISO/RTOs in the Eastern Interconnection, there are a small number of candidate lines compared to system size [58], so the total computation time of the master problem is tractable.

The computation time for slave problems is generally the same in each iteration. The slave problem is a quadratic programming problem that optimizes a quadratic function of some variables subject to linear constraints of these variables. As s_{ij} in constraint (3.8) are all positive and q_{ij} in constraint (3.9) are all negative, all of the quadratic terms in the objective

function have a positive coefficient, which means that the slave problem is a convex problem and can be solved in polynomial time [59]. The slave problem is essentially running OPF at every time step and adding the social surplus together. For larger systems, slave problems will take up most of the computation time as there will be a huge number of decision variables and constraints. In order to reduce the computation time, the slave problem can be broken into multiple small problems that run the OPFs for each year. For example, for the 30-bus system, if we divide the slave problem into 10 small problems (one for each year), the total computation time for the 10 problems is 0.114 second, much smaller than the computation time for the single slave problem. What is more, the parallel computing technique can be used to improve the performance of the algorithm and reduce the execution time.

As shown in Tables 4 and 5, the gap in the second iteration is already very small, so if the tolerance for convergence is higher, the optimal solution can be reached in a much shorter time. For larger systems, we can reduce the computation time by setting a larger tolerance for convergence or further decomposing the system over time (e.g. one master problem and one slave problem each year).

Table 4.4. Detailed information about the results of the 5-bus system

Iteration #	Lower bound	Upper bound 10 ⁸ S	Gap	CPU time	
				Master (s)	Slave (s)
1	13.025	100.506	87.481	0.0043	0.0148
2	20.382	21.539	1.157	0.0107	0.0097
		...			
6	21.045	21.406	0.361	0.0439	0.0093
7	21.209	21.388	0.180	0.0594	0.0093

Table 4.5. Detailed information of the results of the 30-bus system

Iteration #	Lower bound	Upper bound 10 ⁸ S	Gap	CPU time	
				Master (s)	Slave (s)
1	111.371	776.066	664.696	0.1503	0.2513
2	159.470	179.245	19.776	0.2595	0.2329
		...			
27	173.803	178.337	4.534	7.5560	0.2290
28	173.615	178.310	4.695	10.7410	0.2317
		...			
44	175.508	177.981	2.473	32.4380	0.2336
45	176.359	177.970	1.611	38.5467	0.2321

4.4 Transmission Planning considering Both Reliability and Economic Criteria

Most of the transmission expansion projects are justified on the ground of enhanced system reliability level or induced economic benefits. For example, many transmission additions at the low voltage or distribution levels are mainly for reliability purpose, while most HVAC and HVDC inter-regional interconnections are designed to bring economic benefits to multi-regional electric system. However, there is no clear distinction between economic projects and reliability project since transmission expansions inevitable enhance

the economic and reliability performance to some extent. While many transmission investments focus on one aspect of system performance improvement, studies have been made to assess a new class of transmission expansion projects that not only enhances the system reliability level, but also brings significant economic value to the system as well. For instance, Midwest ISO has implemented a new Multi-Value Project (MVP) Cost Allocation methodology to address the appropriate match of beneficiaries and costs over time. The MVP projects are transmission additions that provide regional benefits in response to energy policies, and/or by providing multiple regional-level benefits such as increased reliability level and/or economic value [60]. In this section, a new transmission planning method which considers both the reliability and economic performance of the electric system is proposed. Traditional reliability-based planning and the new market-based planning methods are combined to include the advantages of both planning methodologies, as shown in Fig. 4.8.

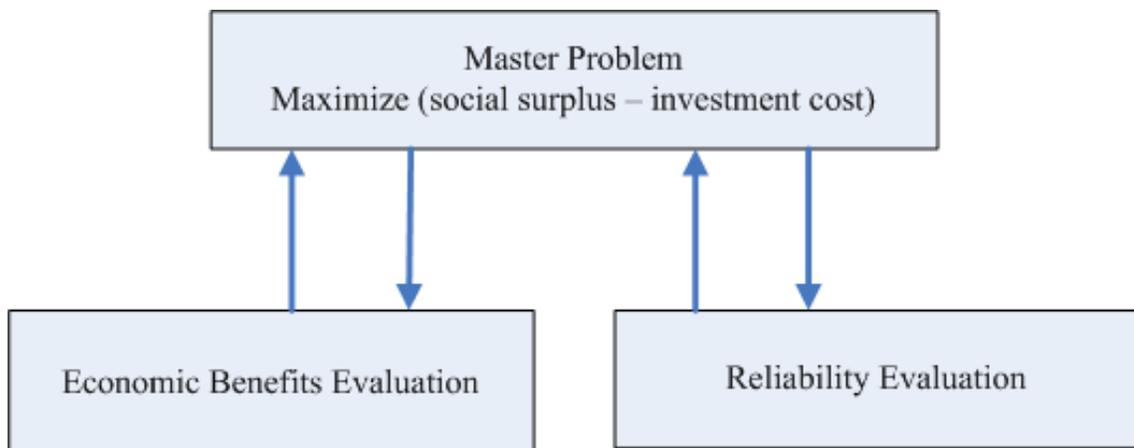


Fig. 4.8. Transmission planning considering both economic benefits and reliability requirement

The iteration procedures of the new planning model are:

1. The master problem is solved based on the existing system conditions. A transmission investment plan is identified.
2. The economic benefits evaluation sub-problem is updated based on the transmission investment plan proposed by the master problem. Then the slave problem is solved.
3. A benders optimality check is conducted to check if the current investment plan is optimal (in terms of economic benefits) or not. If not, an optimality cut will be added to the master problem.
4. The reliability evaluation sub-problems are also updated based on the transmission investment plan proposed by the master problem.
5. For each reliability evaluation sub-problem, if the objective function is greater than 0, the load curtailment is made during a contingency. So a benders feasibility cut is added to the master problem.
6. If no optimality cut or feasibility cut is added to the master problem, the current investment plan is optimal and the program stops, otherwise the iteration continues.

Table 4.6. Comparison of the results of the three planning methods

Present value (\$)	Investment cost	Social surplus before investment	Social surplus after investment	Social surplus - investment cost
Reliability-based	3.40E+07	1.99E+09	2.06E+09	2.03E+09
Market-based	3.15E+07	1.99E+09	2.16E+09	2.13E+09
Market and reliability	4.65E+07	1.99E+09	2.15E+09	2.10E+09

The new transmission planning method is applied on the 5-bus test system and the results are shown in table 4.6. The market & reliability transmission planning incurs a higher investment cost than applying reliability-based planning or market-based planning only because the investment plan need to take into consideration both economic and reliability criteria. Although market & reliability transmission planning has a higher investment cost, the present value of long-term (social surplus – investment cost) of the market & reliability transmission plan is higher than that of the reliability-based planning and lower than market-based planning. In general, as most reliability-based transmission projects are not the most economical ones, market & reliability transmission planning is a trade-off between economic performance and reliability criteria.

CHAPTER 5 MODELING UNCERTAINTIES

Significant uncertainties occur in the planning model in the deregulated world. Numerous studies have been made to analyze the effects of uncertainties on the reliability-based planning model, see [61], [62], and [63]. However, in the deregulated world, uncertainties have more impacts on transmission expansion planning than on traditional transmission planning because: 1) Many uncertainties in market-based planning are not considered in reliability-based planning, e.g. uncertainties in fuel prices. 2) In market-based planning, uncertainties affect the long-term hourly operations of the electric market. Whereas in the reliability-based planning, uncertainties' impacts on the supply-demand balance during the are peak hours are analyzed. 3) The effects of uncertainties in the market-based model can be quantified in momentary terms. In the reliability-based planning, however, the effects of uncertainties are captured by changes in values of reliability indices

In this chapter, the uncertainties that occur in the long-term transmission planning problem are classified into two categories: random uncertainties (also known as high-frequency uncertainties), and non-random uncertainties (also known as low-frequency uncertainties). The two categories of uncertainties are considered in the planning model using different methods. In order to capture the random uncertainties in the market-based planning model, Monte Carlo simulation method and Benders decomposition method are combined to simulate the uncertainties on the operations of the system. The Confidence Interval (CI) technique is used to check the optimality of the Benders decomposition problem. For

non-random variables in the planning model, the robustness testing method is used to identify one optimal investment plan which works well under all major planning scenarios.

Some studies have been conducted to incorporate uncertainties to the planning models in the deregulated world, see [1], [7], [64]. Reference [1] uses Monte Carlo simulation technique to obtain the probability distribution functions of the LMPs during the peak loading conditions in the planning horizon. Transmission investment decisions are then made based on several market-based criteria, such as flatness of the price profile, average congestion cost, average load payment, etc. The minimax regret approach is also used to minimize the worst-case regret in the planning model [1]. Monte Carlo simulation method is used to evaluate the system's operating condition. The decision making problem is separated from this. Reference [7] also employed Monte Carlo simulation method in the planning model. In this model, the calculated expected values of LMPs are used in the decision making problem. However, there are two limitations of the planning model used in [7]: 1) in the transmission investment problem, there is no iteration mechanism between the master problem (decision making problem) and slave problem (optimal operation problem) and no Benders cut in the master problem. So the transmission investment plan generated by the master problem is solely based on the average LMPs of the original system. The investment obtained in this way might not be the optimal one as it normal takes several iterations between the master and the slave problem to get the optimal solution for the whole optimization problem. For example, tables 4.4 and 4.5 illustrate the gaps between the upper

and the lower bounds of the whole optimization problem at different numbers of iterations. One iteration between master and slave problem might generate big gap which indicate huge difference between current solution and optimal solution for the whole system. 2) In the master problem, average LMPs are used to calculate expected production cost. The variance (risk) of the Monte Carlo simulation results is not considered.

Compared with existing studies on incorporating uncertainties to transmission planning, the major different features of the model proposed in this chapter are: 1) systematic way to deals with two categories of uncertainties by combining Monte Carlo simulation with Benders Decomposition and employing the robustness testing method, 2) ensures optimal solution for the whole planning problem, 3) variance of the production cost results generated by the Monte Carlo simulation is captured via building CI, 4) different planning objective.

5.1 Monte Carlo Simulation Method

Monte Carlo method is computational simulation algorithm that generates random trials to obtain a solution [65]. Monte Carlo method is employed to capture the effects of random uncertainties in the planning of transmission system. Given the probability density function of random uncertainties, the deterministic integrated energy system model is then evaluated iteratively using the values of uncertain parameters which are generated randomly using their specific probability densities.

The random uncertainties considered in this article are as follows:

i) Uncertainties in fuel prices

In the long term planning model, coal price is considered to be constant while natural gas prices and oil prices are considered to be uncertain. The natural gas prices and oil prices follow normal distributions and have increasing variances. Essentially, the expected value of uncertain fuel prices are the same as the forecasted values used in the deterministic case, however, standard deviations of fuels prices increase over time in order to reflect the accumulated errors in forecasts.

$$c_{ij,s}(t) = c_{ij}(t)(1 + RC_s(t)) \quad (5.1)$$

ii) Uncertainties in availability of generation and transmission facilities

We use $ut_{ij,s}(t)$ and $ug_{i,s}(t)$ in the Monte Carlo simulation to represent transmission line and generating unit availability. $ut_{ij,s}(t)=0$ means that the transmission line between node i and j has a major outage at time step t while $ut_{ij,s}(t)=1$ indicates otherwise; $ug_{i,s}(t)=0$ means that generating unit i is not available at time step t while $ug_{i,s}(t)=1$ indicates it is in service. $ut_{ij,s}(t)$ can also be a value between 0 and 1 to indicate that the rating of transmission line is reduced because of outage or maintenance. At the beginning of each iteration of Monte Carlo simulation, a random number which follows uniform distribution on [0, 1] is sampled for each generation unit and transmission line and is compared to the forced outage rate of that facility. If the random variable is higher than the forced outage rate, then the unit is available and $ug_{i,s}(t)$ or $ut_{ij,s}(t)$ is set to be 1. Otherwise it is on outage and $ug_{i,s}(t)$ is set to be 0 if it is a generating unit or $ut_{ij,s}(t)$ is set to be 0.6 if it is a transmission line. In the proposed model, one generator node is split into a pair of generator nodes so that operating constraints and

O&M costs can be expressed as the properties of the arc connecting the two nodes. Generator maximum and minimum output limits are enforced by constraining the energy flow between the paired generator nodes. In (5.3), when $ug_{i,s}(t)$ is 0, the maximum and minimum constraints for flow in that arc are both zero, hence the arc flow is zero.

$$e_{ij.\min}^{ut} ut_{ij.s}(t) \leq e_{ij.s}(t) \leq e_{ij.\max}^{ut} ut_{ij.s}(t) \quad \forall (i, j) \in Mt \quad (5.2)$$

$$e_{ij.\min}^{ug} ug_{ij.s}(t) \leq e_{ij.s}(t) \leq e_{ij.\max}^{ug} ug_{ij.s}(t) \quad \forall (i, j) \in Mg \quad (5.3)$$

The process to analyze the operation of electric market using Monte Carlo simulation method is given below:

Step 1) Determine the forecasts of prices of each kind of fuel resources and the load levels.

Step 2) Determine the probability density functions for all of the random uncertainties mentioned above. For each time step, we need to determine:

- The variances of natural gas and oil prices
- The forced outage rates of generating units and transmission lines

Step 3) Generate a number from the probability density functions of each random variable and compute the value of its corresponding parameter. For parameter associated with fuel prices, $c_{ij,s}(t)$ is updated for each time t ; for parameter about availability of generating units or transmission lines, the number generated by the standard uniform distribution is compared with forced outage rate of one unit and then $ut_{ij,s}(t)$ or $ug_{i,s}(t)$ is decided.

Step 4) Run the slave problem using the inputs and parameters generated in steps 1, 2 and 3 and the decisions made in the master problem.

Step 5) Repeat steps 3 and 4 a large number of times until the results converge.

5.2 Benders Decomposition Iteration Procedures

The combination of Benders decomposition and Monte Carlo simulation method is employed in the market-based planning approach. Unlike traditional benders decomposition process, the slave problems are repeated for a large number of times in order to account for various random uncertainties. Then the program checks the convergence of the results from slave problems. If the results converge, a statistical test will be carried out to check the null hypothesis that the population mean is equal to a specified value, otherwise the Monte Carlo simulation process will increase the number of simulation until the results converge [66].

In each Benders iteration, the master problem generates a set of decisions and an optimal objective value, which is an upper bound of the real optimal value of the whole planning problem. Each slave problem can also generate a lower bound of the real optimal value of the whole planning problem.

In order to check whether the lower bound and the upper bound converge, the confidence interval of the mean of the whole population of the lower bounds is calculated at each iteration. Confidence interval is a statistical method to estimate the interval that the true value of system parameter can lie in. Conference interval method is based on the premise that if the statistical model is right, large number of observations can help to construct an interval

within which the true value of system parameter lies with a specified probability [67]. Although theoretically the confidence interval requires the random variables to be normally distributed, the confidence interval can be approximated according to central limit theorem. According to central limit theorem, for n independently and identically distributed random variables, if the sample size n is large enough, the distribution of sample average \bar{x} ($\bar{x} = (x_1 + \dots + x_n)/n$) is approximately normal with mean μ and variance σ^2/n , where μ and σ^2 are mean and variance of the random variable, respectively [67]. In our study, the mean and variance of the Monte Carlo simulation results are unknown. In this case, the standard deviation σ is replaced by the standard error s . s can be expressed in the following equation:

$$s^2 = \frac{1}{n-1} \sum_{i=1}^n (x_i - \bar{x})^2 \quad (5.4)$$

Then given a confidence level α , the confidence interval for the lower bounds calculated in the Monte Carlo simulation can be expressed as $\left[\bar{x} - \frac{cs}{\sqrt{n}}, \bar{x} + \frac{cs}{\sqrt{n}} \right]$, where c is the 100 α percentile of the standard normal distribution. For example, when a 95% confidence level is considered, c is 1.96.

During each iteration, the upper bound is compared with the confidence interval of the lower bound using (5.5):

$$B_{upper} (1 - \varepsilon) \leq \bar{x} - \frac{cs}{\sqrt{n}} \quad (5.5)$$

where ε is a very small value. When (5.5) is fulfilled, the upper bound and lower bound are converged and the optimal solution of the whole transmission planning problem is obtained.

Otherwise the iteration continues and an optimality cut is added to the master problem. The optimality cut is given in (4.16) where Z^k is the mean of optimal objective values of all slave problems.

The employment of confidence interval ensures that not only the mean of the Monte Carlo simulation results are considered in the planning problem, the variance of the lower bounds are also used to check the convergence of the whole planning problem. The variance of the Monte Carlo simulation results (lower bounds) quantifies how sensitive the electric system is to the random uncertainties considered in the Monte Carlo simulation process. For example, if the long-term production cost of the system is very sensitive to the oil prices. If the variation of the results cannot be captured, the transmission plan generated might not be satisfactory when oil prices are very volatile in the future.

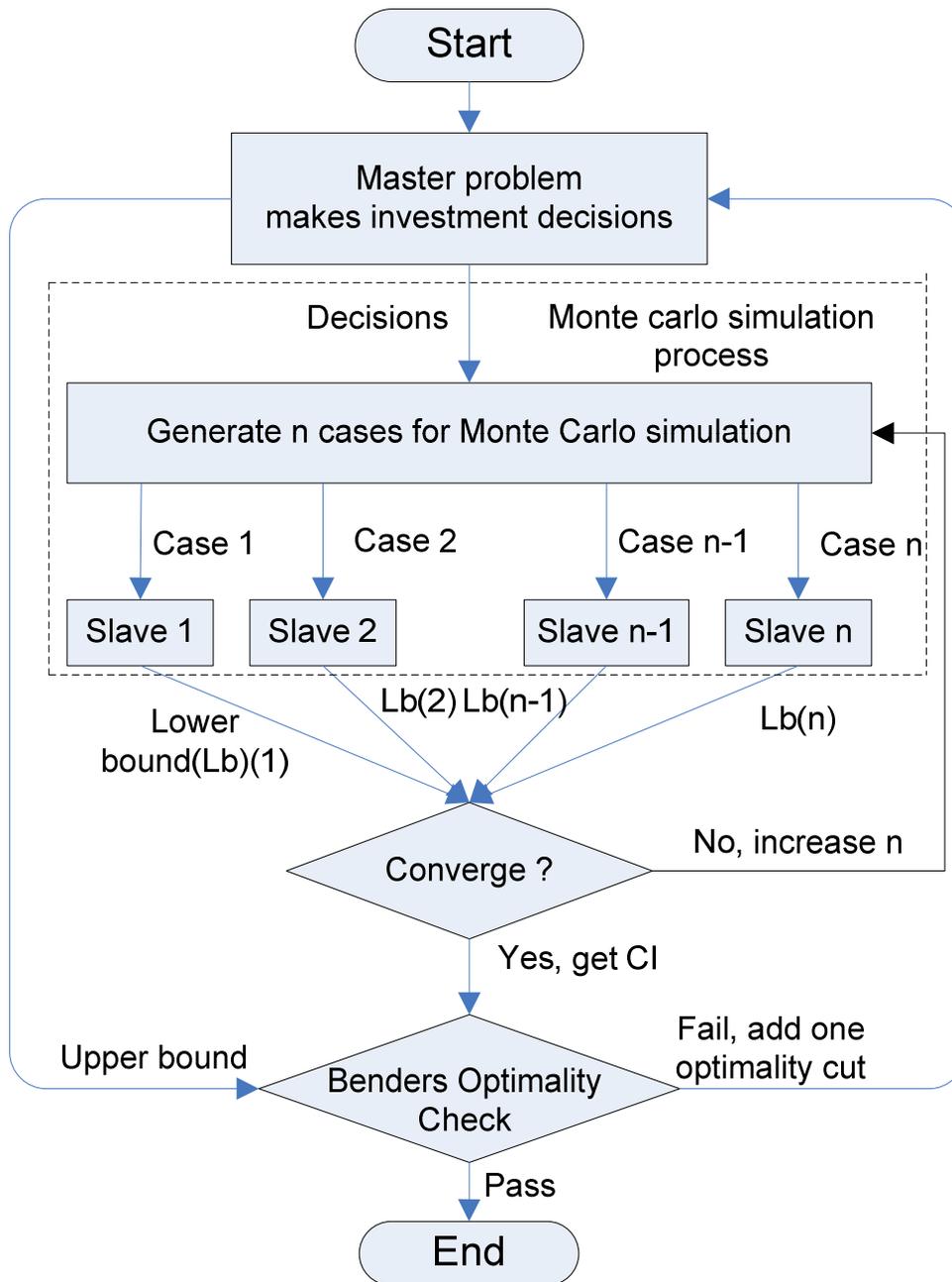


Fig. 5.1. The flow chart of Benders decomposition iteration procedures

5.3 Robustness Testing and Multiple Futures

Robustness testing is used to incorporate major non-random uncertainties in the planning process and identify transmission projects that perform well under most, if not all, Futures.

There are two major components in the robustness testing process: defining the Futures and identifying the attributes that quantify the performance of various investment plans.

A Future is a set of outcomes or realizations of non-random uncertainties [14], for example: “a Carbon tax of \$15 per ton of CO₂ emission will be charged.” As different Futures have different combinations of non-random variables, a transmission investment plan generated on the basis of one Future might not perform as well in another Future. In other words, one transmission investment plan might be very sensitive to different Futures. In order to check the sensitivities of various transmission plans to different Futures, robustness testing technique is employed in the planning process.

Robustness testing will evaluate the performance of each investment plan under all Futures. In order to quantify the long-term performance of the investment plan, various attributes can be identified. Attributes are measures of goodness of a transmission investment from decision makers’ perspective: production cost, benefit/cost ratio, loss of load expectation, environmental impact, etc. The values of attributes are decided by investment plans and Futures. In order to capture various attributes of an investment plan, a production cost model must be employed to simulate the operations of electric market over the whole planning horizon. The attributes of each investment plan under the multiple Futures can then be calculated and compared. The plan that performs consistently well under most Futures will be chosen.

Identifying the best investment plan is a decision making problem as it involves selecting one investment plan among the optimal investment plans under the multiple Futures. As mentioned earlier, the attributes of the investment plan reflect the concerns of decision makers. These attributes might be conflicting in some cases, e.g. lowering production cost vs. reducing carbon emission. Consequently, the decision making process needs to find a plan representing reasonable trade-offs among various attributes. Although it is impossible to thoroughly eliminate the uncertainties in the planning problem, the risk can be managed with proper techniques. According to [62], risk is “a hazard to which a utility is exposed because of uncertainty.” Many decision theory techniques have been applied successfully on managing the risks [62], [63], [68], such as minimax regret approach, maximin approach, expected value approach, etc. However, these techniques are most useful when only one attribute is considered and all Futures have the same weight. When multiple attributes are considered, other methods need to be used to manage the risk. In this section, a scoring method is used to evaluate the performance of candidate investment plans. The scoring method is a function of weights on the attributes and each investment plan’s performance under all Futures. First, the attributes generated by the transmission investments are obtained from the simulation. Then for each plan and each attribute, the expected value of that attribute under all the Futures is calculated. For each attribute, the plan that has the highest expected value of that attribute has a score of 100. For the other plans, their score can be calculated by dividing their expected values of that attribute by the highest value and then

times 100. After the score for each plan on each attributes is obtained, the expected value of the overall score for each plan can then be calculated. The transmission plan that has the highest expected overall score is selected as the best one.

The solution steps for the proposed transmission planning problem are given as follows:

- Step 1) Identify major non-random uncertainties, such as carbon tax, carbon cap-and-trade, high wind penetration level, and new generation technologies. Then multiple futures are generated, each representing a certain set of non-random uncertainties. Futures can have different weight to represent their probabilities of occurrence or how important the decision makers think they are.
- Step 2) Monte Carlo simulation generates a set of scenarios assuming uncertainties of fuel prices, future load growth, availability of generation and transmission units, and capacity factor of wind turbines. Then the market-based transmission planning problem is solved under these random uncertainties and under each Future.
- Step 3) Under each Future, the electric system is updated based on the assumptions made in step one. Then the transmission expansion planning model is executed and one investment plan is generated.
- Step 4) After the preliminary transmission plans under each Future are identified, each preliminary transmission plan must be analyzed under the other Futures to test its robustness. Several attributes of an investment plan are identified, such as social surplus, greenhouse gas emissions, reserve margin, and reliability of electric system.

A long-term production cost model is used to calculate the values of each attributes under each Future for each investment plan. Then the attributes under multiple Futures are obtained and scores are calculated. The plan with the highest overall score is selected.

5.4 Numerical Example

The planning model is applied on the same 5-bus system as shown in Fig. 4.6. Four Futures are considered in the robustness testing part.

Future 1: base case.

Future 2: a 20% wind penetration level is enforced so 3 wind farms will be built in node 1, 3 and 5 with capacity 250 MW, 200 MW and 125 MW, respectively.

Future 3: a 20% wind penetration level is enforced and a 15 \$/tCO₂ carbon tax will be charged since year 1.

Future 4: a 15 \$/tCO₂ carbon tax will be charged since year 1.

Table 5.1. The weights of the four Futures

	Future 1	Future 2	Future 3	Future 4
Weight	0.30	0.30	0.20	0.20

The weights of the four Futures are considered in this study. The weights represent the possibilities of occurrences of these Futures.

Table 5.2. Four investment plans

	1-3	3-4	4-5	1-2	1-5	2-3	Cost (\$)
Plan 1		1 (year 1)		2 (year 1,year 2)			2.51E+07
Plan 2		2 (year 1,year 2)				2 (year 1,year 2)	3.94E+07
Plan 3		2 (year 1)		1 (year 1)		1 (year 1)	4.07E+07
Plan 4		1 (year 1)		2 (year 1)			2.34E+07

After four plans under the four Futures are generated, robustness tests are done to see how well each plan performs under the other Futures. Two attributes are selected: increased social surplus and benefit/cost ratio. Each plan is given scores under four Futures and the average score for each plan will be obtained. In this study, we only consider the 4 Futures have equal possibility of occurrence. Each Future has its weight, as shown in table 5.1.

In table 5.3, by comparing the increased social surplus of several plans under their own futures, carbon tax has a profound impact on the expected economic benefits of the generators. The reason might be that most of the base units are coal-burning units, which are affected by the carbon tax. The increased production cost of coal-burning units causes decreased social surplus.

Table 5.3. The social surplus increases of the four plans

	Social Surplus Increase (\$)				
	Future 1	Future 2	Future 3	Future 4	Expected value
Plan 1	1.670E+08	2.711E+08	2.062E+08	1.185E+08	1.96E+08
Plan 2	1.781E+08	2.863E+08	2.186E+08	1.311E+08	2.09E+08
Plan 3	1.685E+08	2.871E+08	2.237E+08	1.306E+08	2.08E+08
Plan 4	1.651E+08	2.698E+08	2.063E+08	1.172E+08	1.95E+08

Table 5.4. Benefit/cost ratios of the four plans

	Benefit/Cost Ratio				
	Future 1	Future 2	Future 3	Future 4	Expected value
Plan 1	6.65	10.79	8.21	4.72	7.82
Plan 2	4.52	7.26	5.54	3.32	5.30
Plan 3	4.14	7.06	5.50	3.21	5.10
Plan 4	7.06	11.54	8.82	5.01	8.35

Table 5.5. Final scores of the four plans

	Social surplus increase score (weight = 0.6)	Benefit/cost ratio score (weight = 0.4)	Final Score
Plan 1	93.83	93.64	93.76
Plan 2	100.00	63.53	85.41
Plan 3	99.19	61.11	83.96
Plan 4	93.26	100.00	95.96

According to the results given in table 5.5, plan 4 has the highest overall score (95.96), so it is selected. Although plan 2 and 3 outperform plan 4 in terms of the first attribute, plan 4 has a higher benefit/cost ratio than the other plans. In table 5.5, the weights of the two attributes are considered. The weight on the attribute reflects how important the decision maker think it is.

This study only considers two attributes: social surplus increase and benefit/cost ratio. However, the robustness testing technique used in this study can consider more attributes if needed. As long as these attributes are properly defined and their weights are fixed, the risks associated with non-random uncertainties can be managed and one optimal investment plan can be selected.

CHAPTER 6 TRANSMISSION PLANNING CONSIDERING LARGE-SCALE INTEGRATION OF RENEWABLE ENERGY

6.1 Introduction

In the last decade, there has been significant growth in US wind capacity, partly because of advances in wind generation technology, government subsidies, and other policy incentives. By October 2010, 31 states had a Renewable Portfolio Standard (RPS) and an additional 7 states had goals for renewable energy deployment, and so it is apparent that wind capacity will continue to increase in the coming years.

The economic impact of such a highly variable energy source needs to be assessed as wind power penetration level keeps increasing. Compared to other conventional power sources, wind power has many unique characteristics which have significant impacts on the operation and planning of electric system. First, the majority of the wind resource is located remote from the major load centers. For example, in the US most of the wind-rich areas are in Mid-west and Texas which are far away from major urban and industrial centers—where demand for energy is greatest. Long transmission lines with high capacities would be necessary to transport the most economically attractive wind power from where it is generated to where it is consumed. Second, as wind resource is variable in nature, there will be increased volatility in LMPs in the market. Third, as wind energy is less dispatchable than conventional generators, when the wind penetration level is high, it is more difficult for

system operators to balance the market. Currently, system operators commit generating units based on forecasts of load and wind generation, and then dispatch the available units against the actual quantities. While there are mature models and enough historical data to accurately forecast the load level in the next day, hour or minute, there are still high forecasting errors in wind generation. There are energy imbalances in the market as the result of forecasting errors. Fourth, wind energy cannot be used as system reserve, so as wind penetration level increases, more reserve is required. With the increase of wind penetration level, there are less energy generated by conventional generators in the market. Wind farms cannot be used as a source of reserve, so more reserves are required to secure the reliable operation of the electric system and more regulations costs are incurred. Finally, as wind energy is negatively correlated with the demand, large-scale energy storage capabilities are needed. During the peak hours when the demand and electricity price are high, wind generation is generally low; during the off-peak hours when there are less demand and lower price, wind farms have maximal generation. So it makes sense to invest energy storage facilities to store the low-cost wind energy during the night and sell it to the market during the peak hours when the price is high.

As the current transmission is not designed to transport the large amount of wind power, a lot of congestions occur in the system. With the increase of wind penetration, more and more wind power is curtailed out of the market for transmission bottlenecks and minimum generation events. Congestion will cause price differences among the nodes connected by

that transmission line, which indicate that the market is not operating efficiently as electric power from the lower-price end cannot be freely transferred to the high-price end. Consumers will pay more for electricity as LSEs cannot access the low-cost supplies. The result of the congestion is lower market efficiency and less competition. As stated in FERC order 2000, two of the minimal functions that an RTO must perform are managing the congestion and planning transmission system expansion [69]. So from ISO/RTO's point of view, efforts must be made to expand the transmission system in order to alleviate the congestions caused by excess amount of wind power. By adding more transmission to the system properly, less expensive resources that had previously been curtailed are given an opportunity to be used by the system.

The economic impacts of large-scale wind power on the operation and planning of bulk electric transmission are investigated and illustrated in this chapter. The market-based transmission expansion planning method is modified in order to capture the unique features of wind power and storage system. The market-based transmission planning model can justify transmission additions at a regional level which facilitates the efficient utilization of large-scale wind power.

Most planning optimization tools optimize generation expansion plans under an assumed transmission expansion plan, or they optimize transmission expansion plans under an assumed generation expansion plan. In practice, engineers typically find optimal transmission expansion plans for various generation expansion futures, often iterating between generation

planning and transmission planning results, settling on those transmission expansion plans which are needed under most or all of the generation expansion futures [60]. Inadequately accounting for the interdependency between the two planning processes may result in suboptimal investment decisions and lost economic benefits. In this chapter, the interactions between large-scale wind integration and transmission system planning are analyzed, and a new computational procedure of system expansion planning that coordinates generation and transmission investment is proposed.

6.2 Wind Formulation

Wind farms' generation outputs are highly volatile. Many attempts have been made to use various statistical methods to capture the wind power output characteristics, such as using wind generation probability density function (pdf) [70], auto-regressive moving average (ARMA) model [71], or multivariate statistical model [72]. For wind and storage related production cost simulation, a purely "Monte Carlo" sampling using wind generation pdf cannot capture the inter-temporal system dependencies. ARMA is accurate for short-term wind generation forecast. However, it is not suitable for long-term simulation as its accuracy tends to degrade with increasing lead time. The multivariate sequential time-series method has been used with success to model the wind power inter-temporal variations over long period of time [73]. In this study, a nominal 1-MW multivariate wind power hourly production time series is used for each wind farm. The 1-MW wind power time series contains the hourly maximum power output information for a wind farm with 1 MW capacity

in a specific geographic area. As 1-MW wind power time series is independent of the wind farm capacity, it can be used in the planning model to determine the maximum power output for each hour.

6.3 Generation Expansion Planning Model

With the focus on promoting the use of renewable energy, the efficient and cost-effective integration of wind energy to the grid is becoming increasingly important. As the decision makers for the wind integration are generation companies, the generation expansion planning model is formulated from their perspective. The proposed wind generation expansion planning (GEP) model optimizes the large-scale wind power integration by maximizing the expected profits of the wind farms minus the investment costs.

As shown in Fig. 1, the wind generation expansion planning model is decomposed into a master problem, which identifies generation investment decisions, and two slave problems, which simulate the hourly operations of the electric system over the whole planning horizon. The slave problems are comprised of one unit commitment (UC) problem and one economic dispatch (ED) problem. In order to fully capture the impacts of large-scale wind integrations, the co-optimization of the energy market subject to transmission constraints and the ancillary service market subject to resource constraints is implemented. As the result of the co-optimization, the reserve price will reflect the marginal cost of the services as well as any lost opportunity cost incurred by having to back up rather than bidding in the energy market.

The overall planning problem is solved by iterating between the master and the slave problems. In each iteration, the master problem generates a set of investment decisions and passes them to the slave problems. The slave problems simulate the operations of the market using the solution obtained in the master problem. Then the Benders optimality rule is used to check whether the optimal solution is achieved. If not, an optimality cut will be added to the master problem, and generation companies' total profits can be calculated. Then the next iteration gets started. Otherwise the final investment plan is obtained.

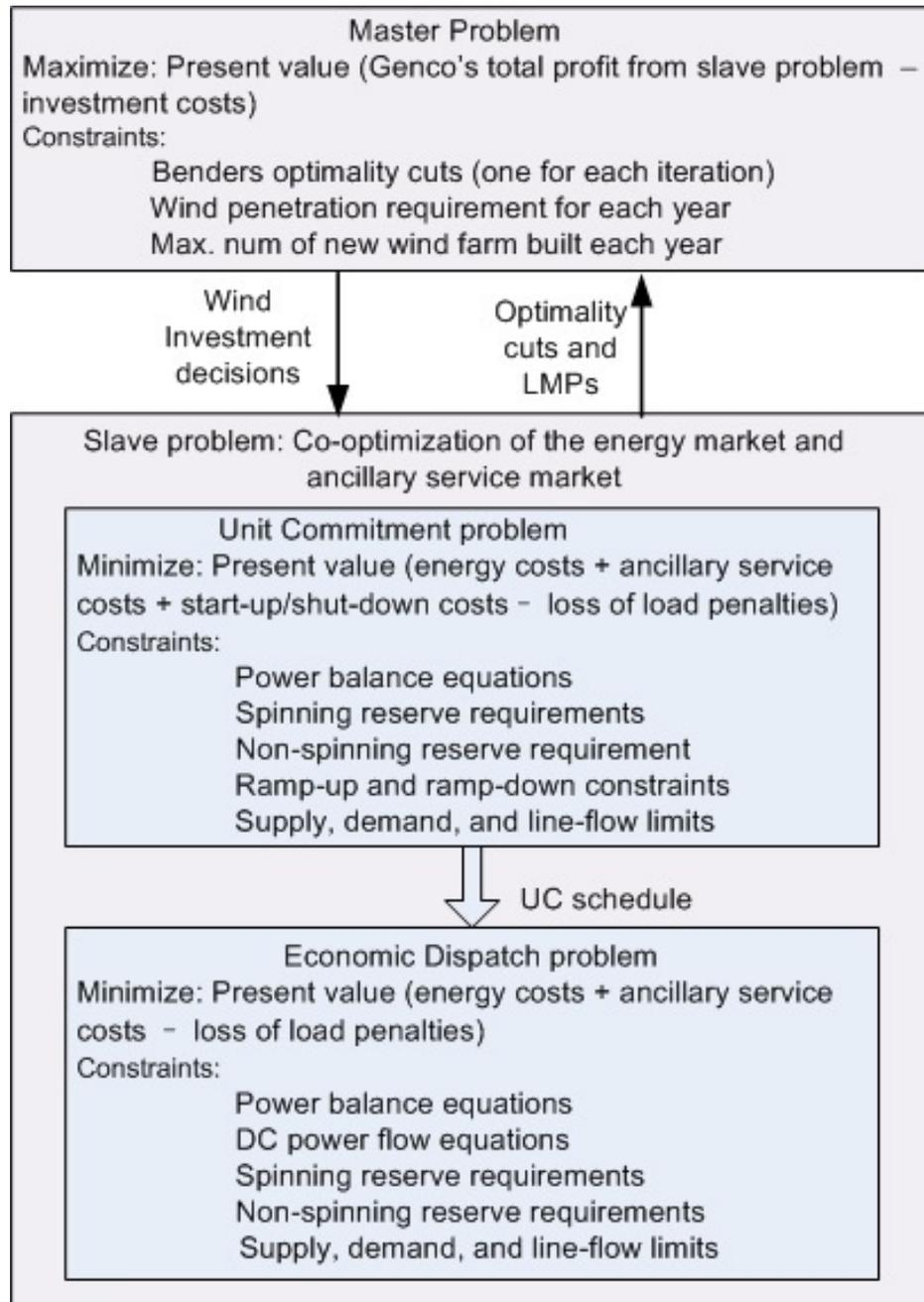


Fig. 6.1. Wind generation expansion planning model

In the production cost simulation model, the hourly operations in a day-ahead energy and ancillary service markets are considered. In the energy market, each generator submits

energy bids to the independent system operator (ISO) according to their marginal production costs. No strategic bidding is considered in this article.

In the ancillary service market, each eligible generator submits hourly bids for the next day for ancillary services, i.e. operating reserve [74]. Operating reserve is used to ensure the reliable and secure operations of the system under normal and emergency conditions. Operating reserve can be divided into two categories: regulating reserve and contingency reserve. The former is provided by generators' automatic generation control (AGC) devices to compensate the minute to minute frequency deviations in the network, while the latter is used to respond to system contingencies, such as losses of generating units or transmission lines. There are two types of contingency reserves, spinning reserve and non-spinning reserve. Only those generators that are running and can provide fast response (fully available within 10 minutes) to system imbalance can bid for the spinning reserve. Non-spinning reserve is off-line generation capacity that can be ramped to capacity and synchronized to the grid within 10 minutes. In order to assure that the highest quality service is procured if economically appropriate, higher quality reserve (spinning reserve) can substitute for low quality reserve (non-spinning reserve).

After the bids in both the energy and ancillary service markets are received, ISO dispatches generation resources based on bid-clearing methodology. In the day-ahead market, the co-optimization of the energy market subject to transmission constraints and the ancillary service market subject to resource constraints is implemented. In this way, both markets are

cleared simultaneously. The clearing of the energy and ancillary service markets is a two-stage procedure. First, a unit commitment (UC) problem is solved to commit the generating resources. Based on the unit commitment schedule, an economic dispatch (ED) problem is then solved to dispatch the generators in the most economical way.

6.3.1. Unit Commitment Problem Formulation

The unit commitment problem is formulated as a mixed-integer optimization problem. The objective function is the minimization of {the total energy and ancillary service biddings + start-up costs + shut-down costs + loss of load penalties}. As the result of the co-optimization of the energy and ancillary services markets, the reserve price will reflect the marginal cost of the services as well as any lost opportunity cost incurred by having to back up rather than bidding in the energy market. Regulating reserve is not considered in this formulation as the time step considered here is one hour, while regulating reserve are generally used in the 1 minute to 10 minute time frame in order to provide fast response to load variations. The results of the UC problem are the operating schedules for all the generators at each time step.

$$\text{Min } \sum_{t \in T} \left(\begin{array}{l} \sum_{(i,j) \in M} \sum_{l \in L_{ij}} C e_{ij}(l,t) e_{ij}(l,t) + \sum_{j \in N} lol(t) r_j(t) + \sum_{(i,j) \in M} \sum_{s \in S_{ij}} C s_{ij}(s,t) f_{ij}(s,t) \\ + \sum_{(i,j) \in M} \sum_{ns \in NS_{ij}} C n_{ij}(ns,t) g_{ij}(ns,t) + \sum_{(ij) \in Mg} S u_{ij} U x_{ij}(t) + \sum_{(ij) \in Mg} S d U y_{ij}(t) \end{array} \right) \quad (6.1)$$

At each node, the sum of flow injections minus the sum of flow extractions is the demand at that node.

$$\sum_{\forall i l \in L_{ij}} \eta_{ij} e_{ij}(l,t) - \sum_{\forall k l \in L_{jk}} e_{jk}(l,t) + r_j(t) = d_j(t), \quad \forall j \in N_t, \forall (ij) \in M, \forall (jk) \in M \quad (6.2)$$

In order to capture the limits on generator ij 's output at each time step, two kinds of constraints are considered: the constraints on each segment of generator ij 's bidding curve and the constraints on generator ij 's total generation level. If generator ij is online at time t ($U_{ij}=0$), then its energy bidding segment l must satisfy the upper and lower flow limits, otherwise it is zero. In order to make sure that the commitment schedule is considered in the equation, the UC decision variable is included in the upper and lower bounds.

$$\underline{e_{ij}(l)U_{ij}}(t) \leq e_{ij}(l,t) \leq \overline{e_{ij}(l)U_{ij}}(t), \quad \forall (ij) \in Mg \quad (6.3)$$

In the UC problem, the transmission system is simulated using a transportation model, which considers the flow limits only.

$$\underline{e_{ij}(l)} \leq e_{ij}(l,t) \leq \overline{e_{ij}(l)}, \quad \forall (ij) \in Mt \quad (6.4)$$

For generator ij , the sum of {energy + spinning reserve + non-spinning reserve} must be less than its thermal limit. If a unit is on-line, it can submit energy, spinning, and non-spinning reserves offers. If it is off-line, it can only bid non-spinning reserve. In both cases, the sum of three biddings needs to be constrained by the generator's maximum capacity.

$$\sum_{l \in L_{ij}} e_{ij}(l,t) + \sum_{s \in S_{ij}} f_{ij}(s,t) + \sum_{ns \in NS_{ij}} g_{ij}(ns,t) \leq \sum_{l \in L_{ij}} \overline{e_{ij}(l)}, \quad \forall (i, j) \in Mg \quad (6.5)$$

The spinning reserve provided by generator ij must follow its capacity constraint. When the unit is off-line, it cannot bid any spinning reserve. Equation (6.5) and (6.6) makes sure that spinning reserve can substitute non-spinning reserve when the unit is synchronized to the grid.

$$\sum_{s \in S_{ij}} f_{ij}(s,t) \leq U_{ij}(t) \sum_{l \in L_{ij}} \overline{e_{ij}(l)} \quad (6.6)$$

In order to ensure the reliable operation of the energy system, sufficient operating reserve needs to be provided at each time step. Spinning and non-spinning reserves are considered in this article, with the possibility of including more reserve types in the future. Operating reserve is defined as:

$$\text{OR} = \max\{\text{OR1}, \text{OR2}\} + 100\% \text{ of non-firm imports}$$

where OR1 is 5% of hydro generation + 7% of generation provided by other conventional generators (excluding intermittent generation resources) + x% of wind power output (x is a number higher than 7); OR2 is the MW loss of generation due to the outage of the largest generating unit at each hour. Spinning reserve needs to be at least 50% of the operating reserve requirement. The reasons for the fact that hydro generation requires less reserve and wind generation requires more reserve than traditional generators are that non-hydro generation has additional risks related to fuel scheduling and wind generation has much higher variations in its output. This definition of operating reserve is in line with California ISO's operation reserve requirement and is similar with that of many other ISO/RTOs [75].

Spinning reserve requirement:

$$\sum_{(i,j) \in Mg} \sum_{s \in S_{ij}} f_{ij}(s,t) \geq \frac{1}{2} OR \quad (6.7)$$

Non-spinning reserve requirement:

$$\sum_{(i,j) \in Mg} \sum_{ns \in NS_{ij}} g_{ij}(ns,t) \geq \frac{1}{2} OR \quad (6.8)$$

Constraint (6.9) shows that at each time step, the maximum generation output is constrained by the wind maximum generation time series forecast.

$$\sum_{l \in L_{ij}} e_{ij}(l,t) \leq C_{ij}(t) w_{ij}(t), \quad \forall (ij) \in Mw \quad (6.9)$$

A generator's start-up and shut-down costs are considered in the objective function. U_x and U_y are binary variables indicating whether unit ij is switched on or shut down at time t or not, respectively.

$$U_{ij}(t) - U_{ij}(t-1) = U_{x_{ij}}(t) - U_{y_{ij}}(t), \quad \forall (ij) \in Mg \quad (6.10)$$

A generating unit has limited ability to vary its generation output from one time step to the next.

Up-ramp constraints:

$$\sum_{l \in L_{ij}} e_{ij}(l,t) - \sum_{l \in L_{ij}} e_{ij}(l,t-1) \leq ru_{ij} \quad \forall (ij) \in Mg \quad (6.11)$$

Down-ramp constraints:

$$\sum_{l \in L_{ij}} e_{ij}(l,t-1) - \sum_{l \in L_{ij}} e_{ij}(l,t) \leq rd_{ij} \quad \forall (ij) \in Mg \quad (6.12)$$

The configurations of CAES are modeled as three parts: the compressor, the gas turbine/generator, and the air reservoir. At the end of time step t , the energy stored at the air reservoir is decided by the storage level at time step $(t-1)$, energy stored at time step t , and storage's power output at time step t .

$$e_{ii}(t) = \eta_{ii} e_{ii}(t-1) + \eta_{ki} e_{ki}(t) - \sum_{l \in L_{ij}} e_{ij}(l,t), \quad \forall i \in N_s \quad (6.13)$$

Storage system can provide not only electric power, but also spinning and non-spinning reserves. In (6.5), the sum of {energy + spinning reserve + non-spinning reserve} is constrained by that generator's maximum output. For storage system, the maximum amount of {energy + spinning reserve + non-spinning reserve} at time step t should also be limited by the storage level at time step $(t-1)$.

$$\sum_{l \in L_{ij}} e_{ij}(l,t) + \sum_{s \in S_{ij}} e_{ij}(s,t) + \sum_{ns \in NS_{ij}} e_{ij}(ns,t) \leq \eta_{ii} e_{ii}(t-1), \quad \forall i \in N_s \quad (6.14)$$

6.3.2. Economic Dispatch Problem Formulation

Based on the commitment schedule generated by the UC problem, the ED problem dispatches the generating units in the minimal cost way and obtains LMPs at each node for energy and market clearing prices (MCP) for ancillary service. Unlike the UC problem, the ED problem considers the transmission network using the DC-OPF formulation.

$$\text{Min} \sum_{t \in T} \left(\begin{array}{l} \sum_{(i,j) \in M} \sum_{l \in L_{ij}} C e_{ij}(l,t) e_{ij}(l,t) + \sum_{j \in N} lol(t) r_j(t) + \sum_{(i,j) \in M} \sum_{s \in S_{ij}} C s_{ij}(s,t) f_{ij}(s,t) \\ + \sum_{(i,j) \in M} \sum_{ns \in NS_{ij}} C n_{ij}(ns,t) g_{ij}(ns,t) \end{array} \right) \quad (6.15)$$

The ED problem is similar with the UC problem in most parts except that u_{ij} is a parameter, not a variable. The start-up and shut-down costs are fixed after the unit commitment schedule is decided so they are not considered in ED problem's objective function. As there is no integer variable in the optimization problem, the ED problem is a linear optimization problem.

$$\sum_{\forall i l \in L_{ij}} \sum \eta_{ij} e_{ij}(l,t) - \sum_{\forall k l \in L_{jk}} \sum e_{jk}(l,t) + r_j(t) = d_j(t), \forall j \in N_t, \forall (ij) \in M, \forall (jk) \in M \quad (6.16)$$

$$\underline{e_{ij}(l)u_{ij}}(t) \leq e_{ij}(l,t) \leq \overline{e_{ij}(l)u_{ij}}(t), \forall (ij) \in Mg \quad (6.17)$$

$$\underline{e_{ij}(l)} \leq e_{ij}(l,t) \leq \overline{e_{ij}(l)}, \quad \forall (ij) \in Mt \quad (6.18)$$

$$\sum_{l \in L_{ij}} e_{ij}(l,t) + \sum_{s \in S_{ij}} f_{ij}(s,t) + \sum_{ns \in NS_{ij}} g_{ij}(ns,t) \leq \sum_{l \in L_{ij}} \overline{e_{ij}(l)}, \quad \forall (i,j) \in Mg \quad (6.19)$$

$$\sum_{(i,j) \in Mg} \sum_{s \in S_{ij}} f_{ij}(s,t) \geq \frac{1}{2} OR \quad (6.20)$$

$$\sum_{(i,j) \in Mg} \sum_{ns \in NS_{ij}} g_{ij}(ns,t) \geq \frac{1}{2} OR \quad (6.21)$$

$$\sum_{s \in S_{ij}} f_{ij}(s,t) \leq u_{ij}(t) \sum_{l \in L_{ij}} \overline{e_{ij}(l)} \quad (6.22)$$

$$\sum_{l \in L_{ij}} e_{ij}(l,t) \leq C_{ij}(t) w_{ij}(t), \quad \forall (ij) \in Mw \quad (6.23)$$

$$e_{ii}(t) = \eta_{ii} e_{ii}(t-1) + \eta_{ki} e_{ki}(t) - \sum_{l \in L_{ij}} e_{ij}(l,t), \quad \forall i \in Ns \quad (6.24)$$

$$\sum_{l \in L_{ij}} e_{ij}(l,t) + \sum_{s \in S_{ij}} e_{ij}(s,t) + \sum_{ns \in NS_{ij}} e_{ij}(ns,t) \leq \eta_{ii} e_{ii}(t-1), \quad \forall i \in Ns \quad (6.25)$$

With some modifications, DC-OPF algorithm is employed in the ED problem. Equation (2.12) and (2.13) represent the Kirchhoff's voltage law.

$$\sum_{l \in L_{ij}} e_{ij}(l,t) - b_{ij}(\theta_i(t) - \theta_j(t)) = 0, \quad \forall (ij) \in Mt \quad (6.26)$$

$$-\pi \leq \theta_i \leq \pi, \quad \forall i \in Nt \quad (6.27)$$

When ED problem is solved, the generation dispatch schedule for each generation unit is decide. As the byproducts of the optimization problem, the LMP in each node and MCP for spinning and non-spinning reserves can be obtained.

6.3.3. GEP Master Problem Formulation

The master problem minimizes the investment cost and the present value of wind generator profits. Constraint (6.30) is the benders optimality constraint which forces the master problem to generate the optimal investment plan for the whole planning problem. Constraint (6.30) refers to the renewable penetration target which requires certain wind penetration levels to be fulfilled each year. Constraints (6.31), (6.32), (6.33) update the total number of wind farms built each year and the constraints on the number of investment each year and the total number of wind farm that can be built.

$$\text{Min} \sum_{t \in T} \sum_{(i,j) \in Mg} (1+r)^{-t} I_{ij} m_{ij}(t) + Z^* \quad (6.28)$$

Subject to:

$$Z^* \leq 0 \quad (6.29)$$

$$Z^* \geq \sum_{t \in T} \sum_{(ij) \in Mw} \sum_{l \in L_{ij}} (1+r)^{-t} C e_{ij}(l,t) e_{ij}^k(l,t) - \sum_{t \in T} \sum_{(ij) \in Mw} \sum_{l \in L_{ij}} (1+r)^{-t} \lambda_j^k(t) e_{ij}^k(l,t) - \sum_{t \in T} \sum_{(ij) \in Mw} w c \lambda_j^k(t) w o_{ij}(t) (n_{ij}^k - n_{ij}) \quad (6.30)$$

$$\sum_{(ij) \in Mw} C_{ij}(t) \sigma w_{ij} - D_{avg} \delta w_{ij}(t) \geq 0 \quad (6.31)$$

$$n_{ij}(t) = n_{ij}(t-1) + m_{ij}(t-a), \quad \forall (ij) \in Mw \quad (6.32)$$

$$0 \leq m_{ij}(t) \leq \overline{m_{ij}}, \quad \forall (ij) \in Mw \quad (6.33)$$

$$0 \leq n_{ij}(t) \leq \overline{n_{ij}}, \quad \forall (ij) \in Mw \quad (6.34)$$

6.4 Transmission Expansion Planning Model

In this section, a market-based transmission planning model in a wholesale electricity market with double-sided auctions is formulated. The market-based transmission is justified based on the trade-off between investment costs and an increase in economic value incurred by network expansions. Effective transmission expansions will promote market efficiency, lower energy delivery cost, enhance system reliability, and mitigate significant market power. In order to quantify the economic benefits brought by transmission investment, the value of transmission investments in the energy market and ancillary service market are considered. According to economic theories, social surplus is a good indicator of how well a market is working. Thus, social surplus is used to quantify the economic benefits that network expansions bring to the energy market. Transmission additions can resolve transmission bottlenecks so local reserve needs can be fulfilled by remote low-cost generators. As local

reserve requirement is now satisfied by a larger fleet of generators, the total ancillary service cost is reduced. Thus, reduction in ancillary service cost is used to quantify the economic benefits that network expansions bring to the ancillary service market. In the objective function, (energy cost + ancillary service cost + investment cost) is minimized to ensure that transmission investments can bring at least as much economic benefits as costs. The master problem makes transmission investment decisions and the slave problem is the same as that of the generation expansion planning problem.

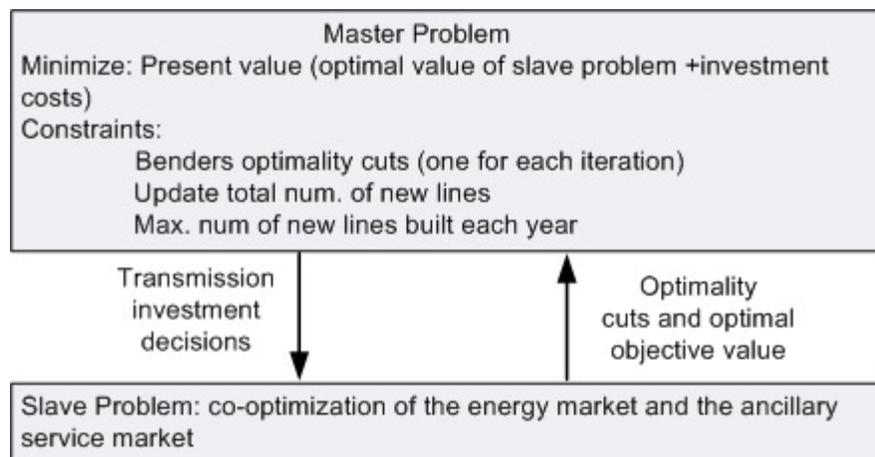


Fig. 6.2. Transmission expansion planning model

In this paper, we assume an ISO will conduct the market-based transmission planning study for the whole system in order to find the profitable investment opportunities for companies or individual investors that are interested. In the objective function, the total present value of system production costs and investment cost is minimized. Constraint (6.30) is the benders optimality cut that is added to the master problem at each iteration.

$$\text{Min } \sum_{t \in T} \sum_{(i,j) \in Mg} (1+r)^{-t} I_{ij} m_{ij}(t) + Z^* \quad (6.28)$$

Subject to:

$$Z^* \geq 0 \quad (6.29)$$

$$Z^* \geq Z^k - \sum_{t \in T} \sum_{(ij) \in Mn'} \delta_{ij}^k(t) (n_{ij}^k(t) - n_{ij}(t)) \quad (6.30)$$

$$n_{ij}(t) = n_{ij}(t-1) + m_{ij}(t-a), \quad \forall (ij) \in Mw \quad (6.31)$$

$$0 \leq m_{ij}(t) \leq \overline{m}_{ij}, \quad \forall (ij) \in Mw \quad (6.32)$$

$$0 \leq n_{ij}(t) \leq \overline{n}_{ij}, \quad \forall (ij) \in Mw \quad (6.33)$$

6.5 Coordinating GEP and TEP

As the planning and decision making for wind integration and transmission investment are separated, the two processes are usually considered as two independent problems. However, both wind and transmission investments will have profound impacts on each other as they will affect the topology of the system and the operation of the market. In order to capture the interactions between large-scale wind integration and transmission planning, a coordinated system expansion planning was formulated. First, the generation planning is conducted. Then the resulted generation investment plan is transferred to the transmission planning model. The TEP model will update the system information based on the generation

investment plan and generate a transmission investment plan which is then passed to the GEP model. This iteration continues until there is enough coordination between the two processes.

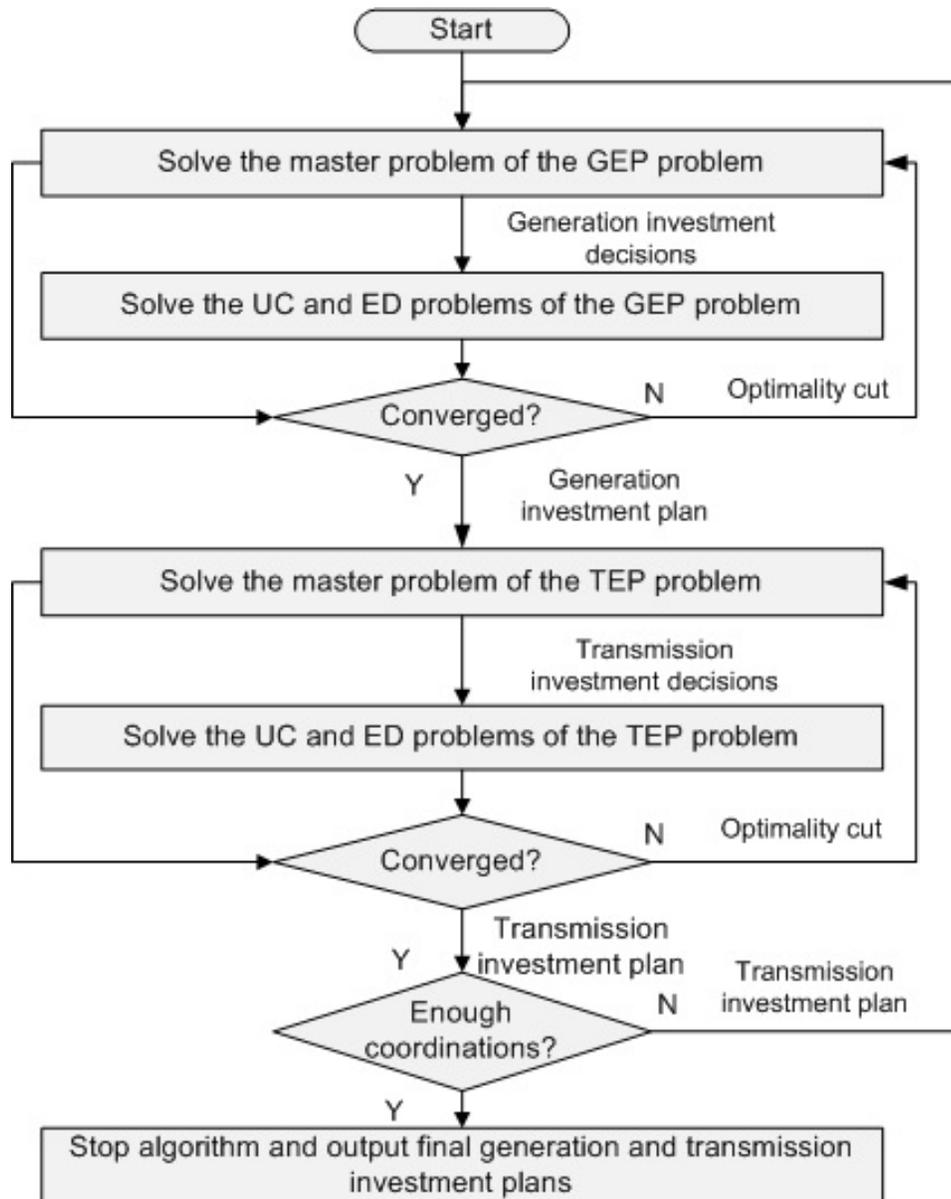


Fig. 6.3. Coordinate the two planning processes

6.6 Numerical Example

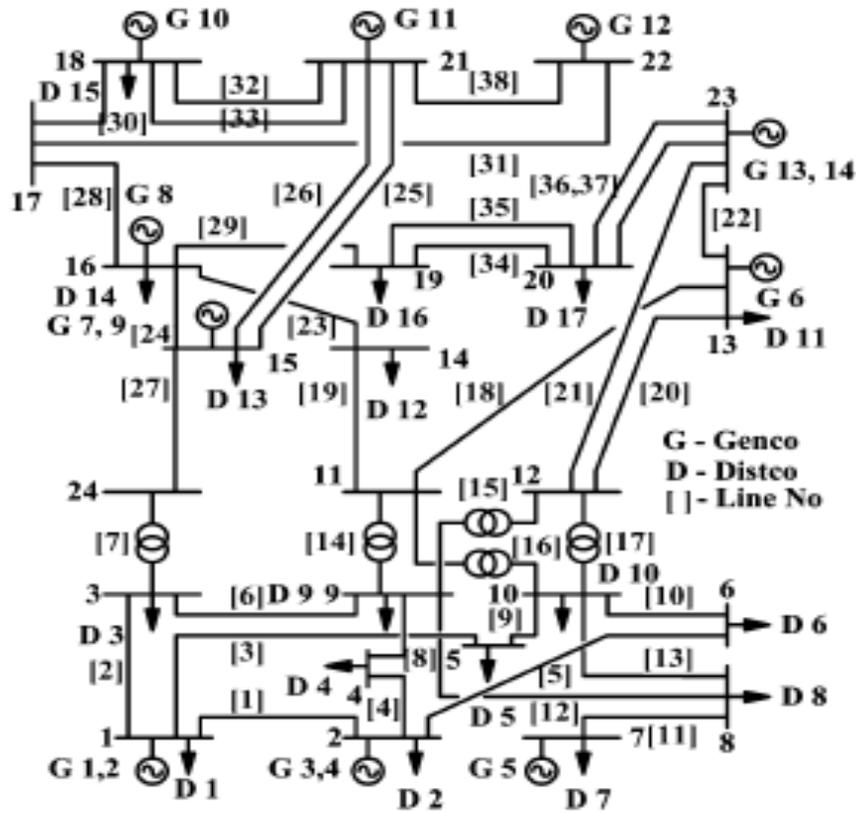


Fig. 6.4. IEEE 24-bus reliability test system

The proposed methodology is applied on a modified IEEE 24-bus reliability test system (RTS) [76]. The planning horizon is 10 years. Some modifications to the original system were made. The load levels increase by 5% per year while the generators' bidding prices increase by 4% per year. The capacities of generators 16, 18, 21, 22 and 23 are increased by 50% at year five.

A 20% wind penetration level is required by the 10th year. There are four candidate wind sites and the capacity factors of the wind farms in these sites are shown in table 6.1.

Table 6.1 Capacity factors for candidate wind sites

Candidate wind sites	Bus 11	Bus 17	Bus 21	Bus 22
Capacity factor	0.3	0.35	0.45	0.5

In order to identify the candidate lines, a method named Copper Sheet method was used. “Copper Sheet” analysis illustrates the increase in energy flows in various transmission paths if the transmission constraints were removed. Firstly, the system average flows over the whole planning horizon were calculated. Then, assuming that the system did not have any transmission line flow limits, the system average flows were calculated. By comparing the results of the two cases, we could identify some candidate lines to invest. The huge changes in averages flows means that the congestions in the system had a significant impact on the lines. So these lines should be considered as candidate lines. In this process, nine candidate lines are selected and shown in bold in table 1.

Table 6.2 Results from the Copper sheet method

Line	With constraints	W/o constraints	Constraint	Line	With constraints	W/o constraints	Constraint
EL01EL02	7.20	29.48	105.00	EL11EL13	-69.71	-0.47	300.00
EL01EL03	3.84	-146.68	105.00	EL11EL14	-11.61	-155.36	300.00
EL01EL05	55.52	115.95	105.00	EL12EL13	-22.82	6.89	300.00
EL02EL04	22.01	-16.42	105.00	EL12EL23	-223.78	-188.67	300.00
EL02EL06	56.83	44.75	105.00	EL13EL23	-158.91	-181.46	300.00
EL03EL09	60.63	255.96	105.00	EL14EL16	-165.45	-345.31	300.00
EL03EL24	-200.00	-570.69	240.00	EL15EL16	31.61	115.97	300.00
EL04EL09	-17.02	-55.46	105.00	EL15EL21	-368.43	-733.79	600.00
EL05EL10	5.52	56.36	105.00	EL15EL24	200.00	570.69	300.00
EL06EL10	-5.72	-20.78	105.00	EL16EL17	-171.20	-374.32	300.00
EL07EL08	38.21	-75.43	105.00	EL16EL19	102.24	204.30	300.00
EL08EL09	-53.96	-152.37	105.00	EL17EL18	20.35	-7.96	300.00
EL08EL10	-22.28	-60.90	105.00	EL17EL22	-79.62	-255.09	300.00
EL09EL11	-32.61	-54.68	240.00	EL18EL21	-20.17	42.16	600.00
EL09EL12	-115.25	-67.65	240.00	EL19EL20	-36.35	64.79	300.00
EL10EL11	-48.71	-101.16	240.00	EL20EL23	-98.44	0.23	600.00
EL10EL12	-131.35	-114.14	240.00	EL21EL22	-120.66	-181.97	300.00

As the Copper Sheet method can only show the changes of flows in existing lines, additional analysis needs to be made to identify candidate lines between buses that were not connected currently. If the existing transmission system is not well designed, the topology of the network might be the major reason for the transmission bottlenecks. In this work, a long term production cost problem is applied to the test system. As the by-product of the production cost problem, the LMP of each load at each hour can be obtained. The existence of congestions in transmission lines will cause the differences in LMPs of the buses connected by the lines.

Table 6.3 Average LMP of each bus

Bus Number	LMP (\$/MWh)	Bus Number	LMP (\$/MWh)
E101	37.33	EL13	24.01
E102	36.99	EL14	23.99
E103	37.48	EL15	23.86
E104	37.05	EL16	23.94
E105	37.01	EL17	23.89
E106	36.92	EL18	23.88
E107	32.62	EL19	23.95
E108	37.01	EL20	23.96
E109	37.13	EL21	23.87
E110	36.71	EL22	23.88
E111	34.75	EL23	23.96
E112	37.62	EL24	23.81

Table 6.2 shows the average LMP of each bus over the planning horizon. As shown in table 6.2, generally the buses in the upper region, where there are significant amount of wind power and plenty of low-cost coal plants, have lower LMPs; while buses in the lower region, where the transmission system has huge congestions, have higher LMPs. It makes senses to add candidate lines to connect the two regions in order to transfer the low cost energy to the high energy price area. Two candidate lines (EL11EL21 and EL12EL22) are identified at the end of this process.

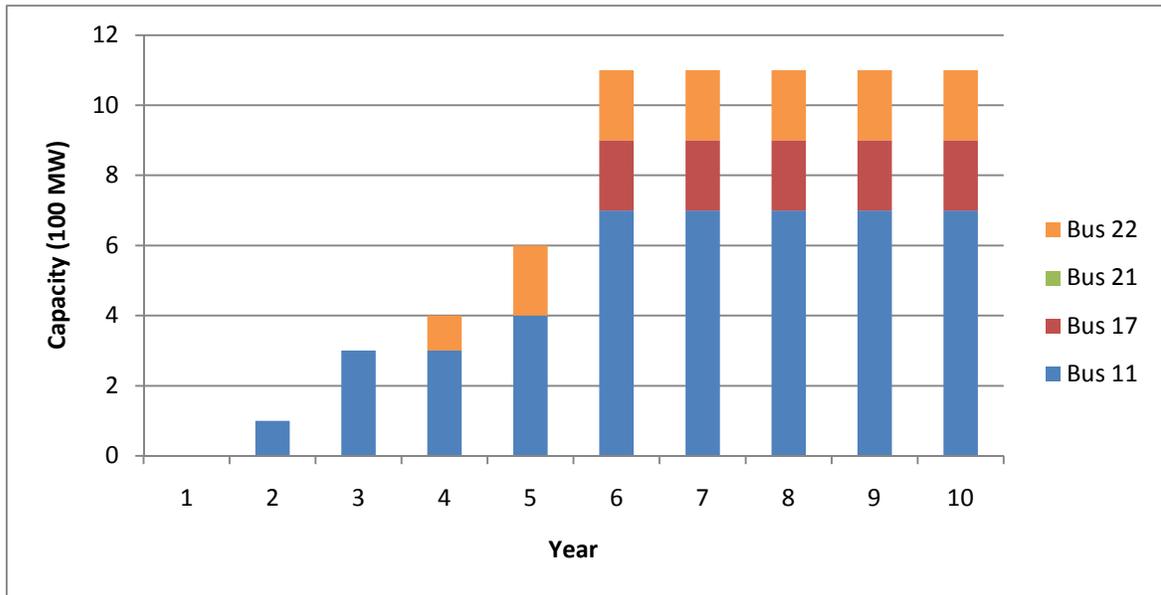


Fig. 6.5. GEP results from the original system

After all of the candidate transmission lines are identified, the GEP and TEP are conducted and coordinated. In this study, 5 iterations of GEP and TEP are considered. Fig. 6.5 shows the generation expansion results when applying the GEP model to the original system. As shown in fig. 6.5, most of the new wind units are built in sites near the load center although they have lower capacity factors compared with that of the sites far away from the load center. This might be due to the high congestions in the transmission lines linking wind rich areas with the load center. When there are congestions, the wind energy from remote wind rich areas cannot be transferred to the demand center. Consequently, although bus 21 and bus 22 have high capacity factors, most wind units are built on bus 11.

Table 6.4 TEP results from the original system

Year	1	2	3	4	5	6	7	8	9	10
EL03EL09							1			
EL08EL09	1									
EL16EL17	1					1				
EL11EL21	1									

Table 6.4 shows the results of the TEP. Transmission lines are built to connect the upper region, where low-cost generators are located, to the lower region, where the demand is high.

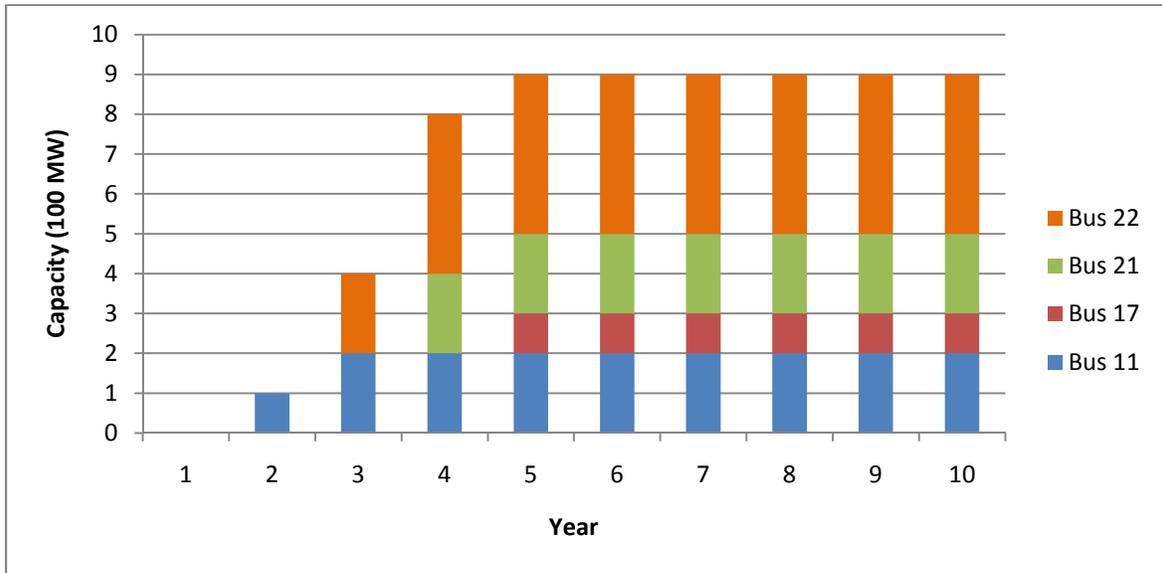


Fig. 6.6. GEP results from the fifth iteration

Fig. 6.6 shows the GEP results from the fifth iteration between generation planning and transmission planning. As previous transmission planning processes have already identified new transmission lines that can relieve the congestions between the two regions, more capacities are built in the upper region. If it were not for the coordination between GEP and TEP, most of the wind units would have been built in sites that have lower capacity factors.

Table 6.5 TEP results from the fifth iteration

Year	1	2	3	4	5	6	7	8	9	10
EL03EL09				1						
EL08EL09	1									
EL16EL17	1				1					
EL09EL10		1								
EL11EL21	1	1								

Comparing table 6.4 and table 6.5, we can notice the differences between conducting TEP one the original system and coordinating TEP with GEP.

Table 6.6 Results from the two cases

Cases	Separate GEP and TEP	GEP and TEP coordination
Present value of Social Surplus(\$)	1.49E+09	2.85E+09
Social Surplus increase (\$)	4.83E+08	1.84E+09
Generation investment cost (\$)	5.50E+08	4.94E+08
Transmission Investment cost (\$)	4.74E+07	8.24E+07

The simulation results obtained from this case study illustrate the impacts of coordinating the GEP and TEP processes on both the generation system and the transmission system. As shown in table 6.6, coordinating GEP and TEP yields a higher system social surplus. The social surplus of the original system is \$1.01E+09, so the social surplus increase incurred by the GEP and TEP coordination is about 3.8 times as much as the social surplus increase caused by conducting GEP and TEP separately. The fundamental advantage of coordinating GEP and TEP is that this planning method can find the optimal generation and transmission investment plans and bring maximum economic benefits to the system. When GEP and TEP are conducted separately, wind rich areas that are remote from load center are

not selected as the result of transmission congestions, so more wind capacity needs to be invested to satisfy the wind penetration target as wind sites near the load center generally has lower capacity factor. When GEP and TEP are coordinated, more transmission lines are invested to transfer the wind energy from remote wind sites to load center. There is a much higher benefit/cost ratio in the GEP/TEP coordination case compared to conducting GEP and TEP separately (3.19 v.s. 0.81). When the interaction between GEP and TEP is considered, more accurate information about the current and future generation system can be obtained. So the transmission planning process can evaluate the system conditions thoroughly and generates a transmission investment plan that can maximize the (system social surplus – transmission investment costs).

More studies are needed to simulate how the current electricity industry coordinates the TEP and GEP and to come up with the better mechanism to stop the interaction between the two processes. Moreover, further studies are required to explore possible market rules or planning methodology than can promote the efficient system capacity expansion planning and generate more economic benefits from the generation and transmission investment.

CHAPTER 7 EVALUATING ENERGY STORAGE SYSTEM AS AN ALTERNATIVE TO TRANSMISSION EXPANSIONS

7.1 Introduction

With the focus on promoting the use of renewable energy, the efficient and cost-effective integration of wind energy to the grid is becoming increasingly important. While transmission system investment can solve the problem associated with transferring the large amount of wind energy in the grid in the long run, significant lead-time and investment hampers the transmission system expansion. The overall system capacity expansion plan should consider the generation and demand-side alternatives to transmission constructions. In the short term, in order to relieve the bottlenecks in the system and promote the efficient operation of the market, other investments can be considered to maximize the use of the electric system. Recently, a number of studies have been carried out to evaluate the possibility of using various kinds of Energy Storage Systems (ESS) to offset the wind generation variation [77], [78], [79], [80]. Energy storage systems can be used to purchase and store energy when the price is low and sell it to the market when energy price is high. Besides peak shifting and load leveling, energy storage can also be used to provide high-value ancillary services, enhance the stability of electric system, and serve as a substitute for transmission line investment. Moreover, as most energy storage systems can provide fast response, they are the ideal options to counterbalance wind output variability.

When wind farm and storage are located near each other, the energy storage can shape the wind output so more energy can be generated during peak hours. At high wind penetration levels and/or imperfect wind forecasts, the value and use of energy storage increases.

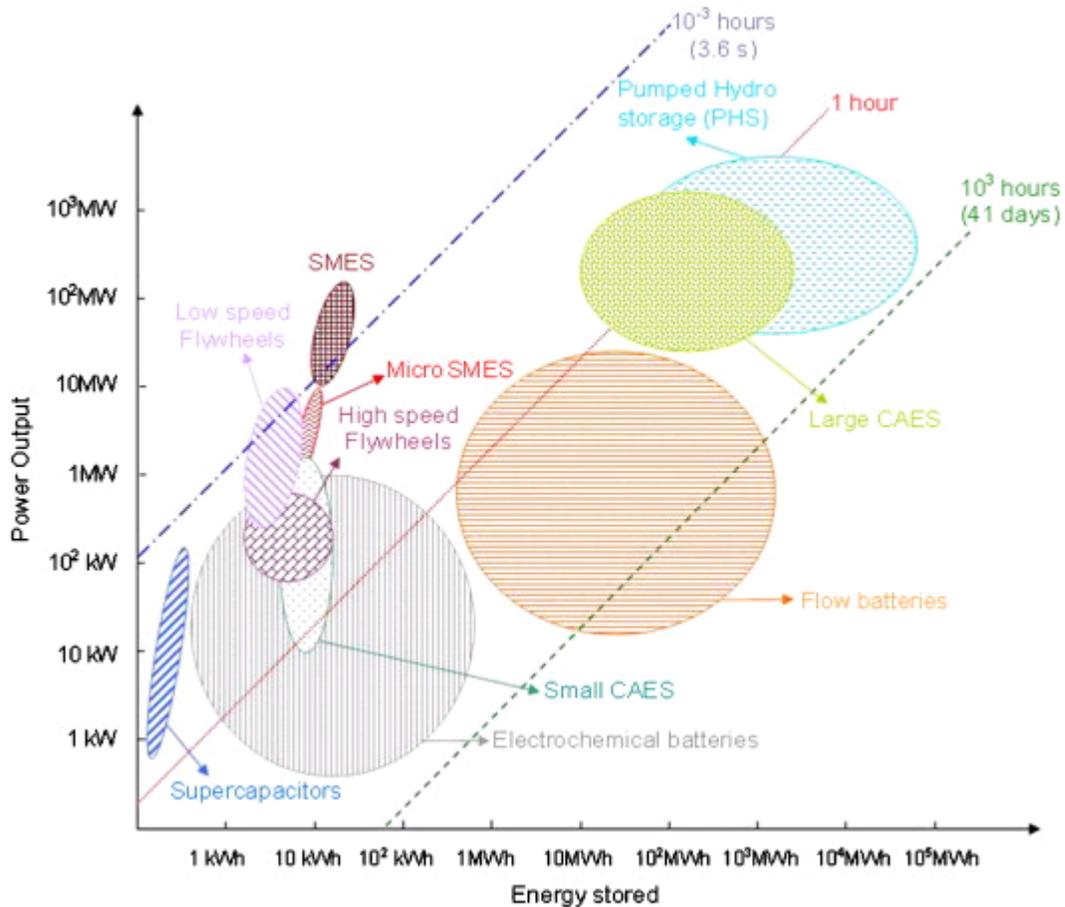


Fig. 7.1. Fields of application of the different storage techniques according to energy stored and power output [81]

Energy storage systems convert electric energy to various kinds of storable intermediary energies, such as mechanical, potential, chemical, biological, electrical, and thermal, and then convert them back to electric energy. The most common energy storage technologies include hydro storage, flywheels, battery, compressed air storage, thermal storage, and hydrogen

storage. A comparison of fields of application of different storage technologies is shown in Fig. 7.1. An extensive comparison of energy storage systems is shown in [82]. One of the major obstacles of the wide adoption of energy storage systems is their economic justification. Converting electric energy to another form and converting it back involves high energy losses and costs. Pumped hydro and compressed air energy storage (CAES) are bulk energy storage options. Pumped hydro storage is the most widespread energy storage system today with about 90 GW of installed capacity which accounts for around 3% of global generation capacity. However, pumped hydro is very site-specific and involves high capital cost. It also has adverse effects on the environment [83]. CAES is a modification of gas turbine (GT) technology, where off-peak (low-cost) electrical power is used to compress air into an underground air storage cavern. When the energy price is high, a natural gas fired burner preheats the compressed air and then uses it to power the turbine. CAES's ability to support large-scale power application with low capital and maintenance costs per unit energy makes it attractive. What is more, compared to pumped hydro, CAES is less site-specific because over 75% of the U.S. has geologic conditions favorable for underground air storage [84].

7.2 Storage Model

The CAES is comprised of a compressor, a gas turbine/generator, and an air reservoir. In Fig. 7.2, these three major components are represented by arcs L1, L2, and L3, respectively.

Each arc has four properties: cost, efficiency, minimum flow, maximum flow. At each time step, storage can buy electricity from the market, sell electricity to the market, or do nothing.

L1 models the operations of the compressor. The compressor capacity ($L1_{max}$) is defined as the maximum amount of power that it can use to compress the air at each time step. The efficiency (η) of the compressor is defined as the total storage energy input divided by the total power input. The O&M cost of the compressor can also be considered.

L2 represents the process of converting the storage energy to electric power. As the co-optimization of both the energy market and the ancillary service market are considered, L2 contains the energy bidding, spinning-reserve bidding and non-spinning reserve bidding. Each kind of bidding is comprised of several arcs, which represent the segments of CAES's bidding curve. The fuel and O&M costs, efficiency, and maximum capacity of the gas turbine/generator can also be considered. At each time step, the maximum amount of the power output is decided by maximum capacity of the gas turbine or the energy storage level in the air reservoir, whichever is less.

L3 represents the storage level in the air reservoir. The energy flow in L3 is decided by L1, L2, and storage level at the last time step. There is a loss factor associated with L3 to represent the leaks in the energy storage system over time.

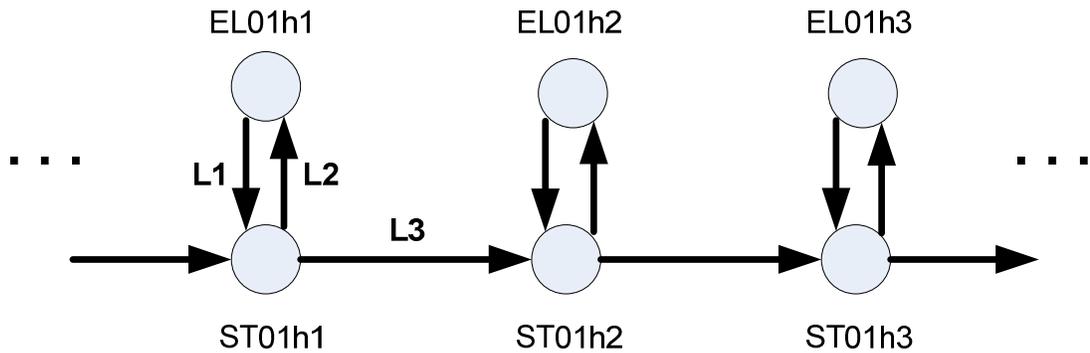


Fig. 7.2. Storage system model

There are two operating scenarios of CAES: co-located with wind farms or located near the load center [77]. Wind rich areas are generally far away from the load center, so the wind energy needs to be transferred via long-distance transmission lines. The transmission lines linking wind farms and load center are often congested as they are not designed to transfer the significant amount of wind power. However, transmission system expansions that facilitate the large-scale wind power integration have many obstacles such as significant lead-time, large investment cost, and low public acceptance [85]. In the short term, storage can be used as an alternative to transmission expansions. When storage is located near the wind sites which are remote from load center, it can take advantage of the time-varying spot prices caused by high-penetration of wind power and ensure the efficient use of wind generation. When storage is located at the load center, it also has many applications such as energy arbitrage and providing regulation services. One of the objectives of this article is to identify the impact of the two operating scenarios on the economic value of storage.

The formulation of the energy storage system is such that the storage model can “plug and play” in the transmission planning tool. Various characteristics of energy storage system are considered in the formulation, yet the application of this model is not technology-specific. Theoretically, any storage technology can be captured in this storage model in detail.

The main characteristics of energy storage system considered in the storage model are listed below:

1. Charging efficiency

This parameter indicates the efficiency of the energy storage system when it is charging.

2. Discharging efficiency

This parameter indicates the efficiency of the energy storage system when it is discharging.

3. Storage capacity (MWh)

This parameter is the maximum amount of energy that can be stored in the storage facility. Different kinds of energy storage system have different ways to store the energy, the amount of energy after a full charge can be captured by this property.

4. Available power (MW)

This property indicates the maximum power of charge or discharge which is decided by the constitution and size of the motor-generator in the energy conversion chain.

5. Self-discharge rate

Due to various technical reasons, such as leakage of air reservoir in the CAES, the energy stored in the storage system cannot maintain the same level. Self-discharge rate indicates the rate that energy that dissipates over time.

6. Ramp-up and ramp-down rates

When a storage system joins the electric market as an energy supplier, the system operator might require the storage system to ramp-up or ramp down to balance the supply and demand. Ramp-up and ramp-down rates describes the speed of the energy storage system to increase or decrease the power output.

7. Cycling capability

The parameter indicates the maximum number of cycles (one charge and one discharge) that the storage can bear because of fatigue or wear by usage.

8. Construction cost

Construction cost is the cost to construct the energy storage system.

9. O&M cost

This refers to the operating and maintenance cost of the storage system.

10. Reliability (forced outage rate)

The forced outage rate of major parts of the energy storage can be considered in the model.

11. Environmental aspect

The greenhouse gases emitted during various parts of the storage processes can be captured.

Many properties mentioned above can be expressed as a curve rather than a value. For example, the discharge efficiency may change at different storage levels, so it makes sense to express this parameter using a curve. More properties which are unique to each storage technology can also be included without too much effort. In this way, various storage technologies can be compared with each other and with transmission additions.

7.3 Case Study

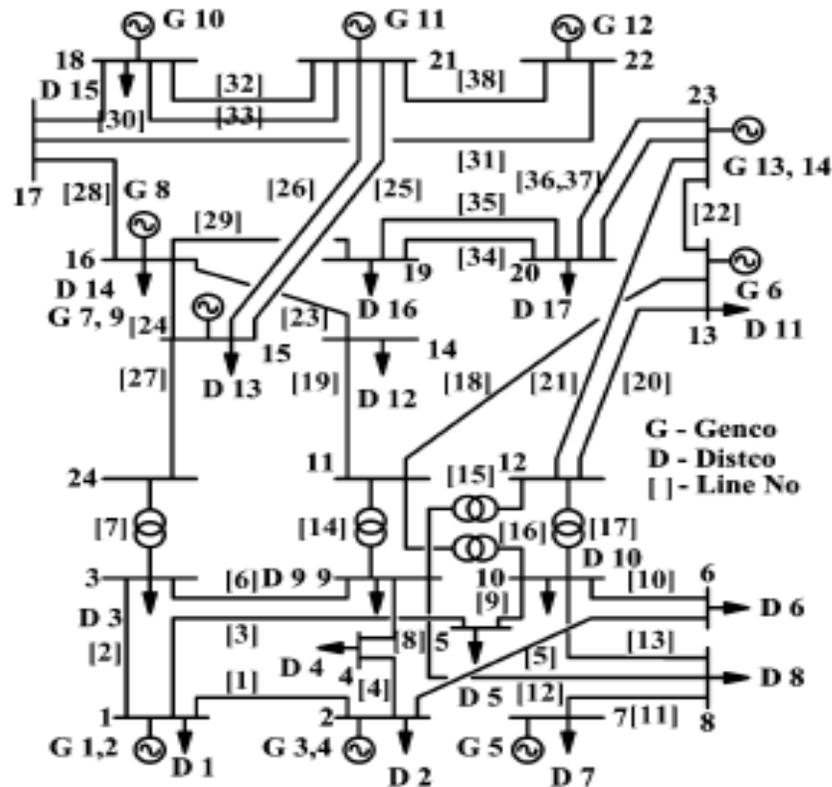


Fig. 7.3. IEEE 24-bus reliability test system

In order to evaluate the CASE's economic performance and impacts on the operations of the electric system and compare it with transmission investments, a mid-term (annual) production cost simulation model is built. Similar with the slave problems shown in chapter 6.3, the co-optimization of the energy and ancillary service market is considered. The hourly operations of the power market are simulated over the study time scope and the detailed information of the system can be obtained, such as LMPs, generation costs, load payments, congestion rents, etc.

The proposed methodology is applied on a modified IEEE 24-bus reliability test system (RTS) [76]. The flow constraints of each transmission line are reduced by 50%. Three wind farms with capacity 300MW, 400MW, and 300MW are located at bus 17, 21, and 22, respectively. The capacity factors for the three wind farms are 30%, 35%, and 30%. In this way, the 20% wind penetration level is reached. Historical synchronously recorded wind power output data at each wind site is normalized to 1-MW capacity.

A CAES with a compressor capacity of 50 MW, a gas turbine capacity of 50 MW and an air reservoir capacity of 200 MWh is considered in the system. The conversion efficiency of the compressor is 0.7. The efficiency of the gas turbine (electric power output / compressed-air energy input) is 2. Per 1 MWh of gas turbine generation output, 4331 MJ natural gas is consumed [78]. The natural gas price is 3.7 \$/MMBTU. An hourly self-discharge rate of 0.99 is considered. The arcs L1, L2, and L3 in Fig. 7.2 can be expressed as (2, 0.7, 0, 50), (31.1, 2, 0, 25), and (0, 0.99, 0, 200), respectively. The operation

of the system is simulated for one year. In order to reduce the computation time, one typical winter week and one typical summer week are considered. The time step of the simulation is one hour.

Four scenarios are considered when evaluating the economic performance of CAES:

- 1) A CAES is located near the wind sites (bus 21), which is far away from load centers.
- 2) A CAES is located near the wind sites (bus 21). A 15 \$/tCO₂ carbon tax is considered.
- 3) A CAES is located near the load center (bus 2).
- 4) A CAES is located near the load center (bus 2). A 15 \$/tCO₂ carbon tax is considered.

Fig. 7.4 and Fig. 7.5 show the performance of CAES when it is located near the wind sites. All of the values shown in the two figures are average values over the year. In the CAES charge curve, positive value means the CAES is charging (buying electric power from the market), while in the CAES discharge curve, negative value means the CAES is discharging (selling electric power to the market). The average LMPs at bus 21 at each hour of the day are also included.

The charge/discharge patterns of CAES are mainly decided by the fluctuations of the LMPs at the bus where CAES is located. As there are many low cost generators in the upper region of the test system, the LMPs are pretty low compared with those of the load center. In the lower region, there are many oil-burning generators and high demand, so the LMPs are generally higher. There are significant congestions in the system as the result of limited transmission capacity between the two regions. In the upper region, during the off-peak hours,

the base-load power is mainly provided by nuclear generators, low-cost coal-burning generators and wind farms. In the peak hours, generators with higher marginal costs are committed.

As shown in Fig. 7.4, CAES tends to buy energy from market during the off-peak hours when the LMPs are low. During the peak hours, CAES sells electricity to the market. As there are plenty of generation capacities in the upper region and the transmission lines between the two regions are congested almost all the time, in the upper region low-cost energy is available all day long and the spread of off- and on-peak prices is relatively small. Consequently, there is not too much room for CAES to perform energy arbitrage.

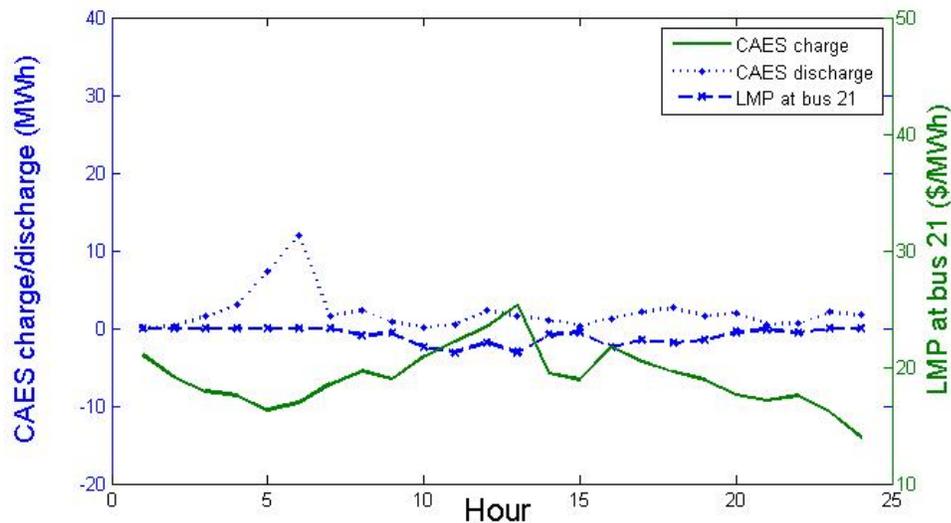


Fig. 7.4. CAES average charge/discharge pattern and LMPs at bus 21 under scenario 1

Fig. 7.5 shows the operations of the CAES when a 15 \$/tCO₂ carbon tax is charged. In the off-peak hours, generators with little or no carbon emissions are running, so the energy prices are similar with the energy prices in scenario 1. In the peak hours, however, there are

many coal-burning generators which are affected by the carbon tax, so the average LMPs are much higher than the case with no carbon tax. As shown in Fig. 7.5, the increase in differences between energy prices in peak hours and off-peak hours creates more opportunities for the CAES to gain profits.

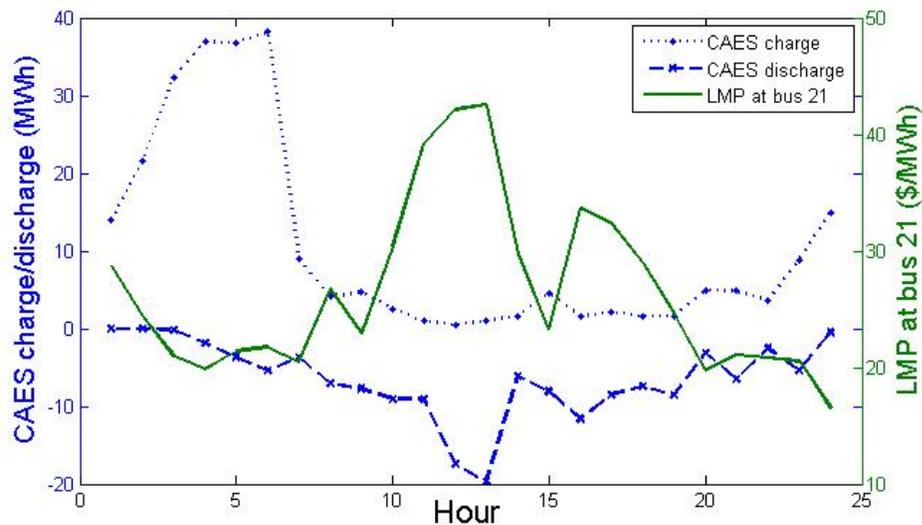


Fig. 7.5. CAES average charge/discharge pattern and LMPs at bus 21 under scenario 2

In the lower region, the LMPs are much higher than those in the upper region as the result of congestions in the system, high demand, and high marginal costs of generators in that region. In the off-peak hours, the transmission lines between the two regions are less congested and wind farms have high output, so low-cost wind energy are transferred to the lower region and stored in the CAES. When the demand gets higher, the transmission system gets congested so high-cost generators in the lower region are used, which results in high LMPs. The high-penetration of wind increases the spread of off- and on-peak prices, so the profitability of the CAES is enhanced. In this scenario, besides performing energy arbitrage,

CAES also helps to relieve the transmission bottlenecks as energy can be transferred from the upper region to the lower region during the off-peak hours when there is less congestion in the system during peak hours. The energy is stored in the CAES and then extracted to serve the load during peak hours.

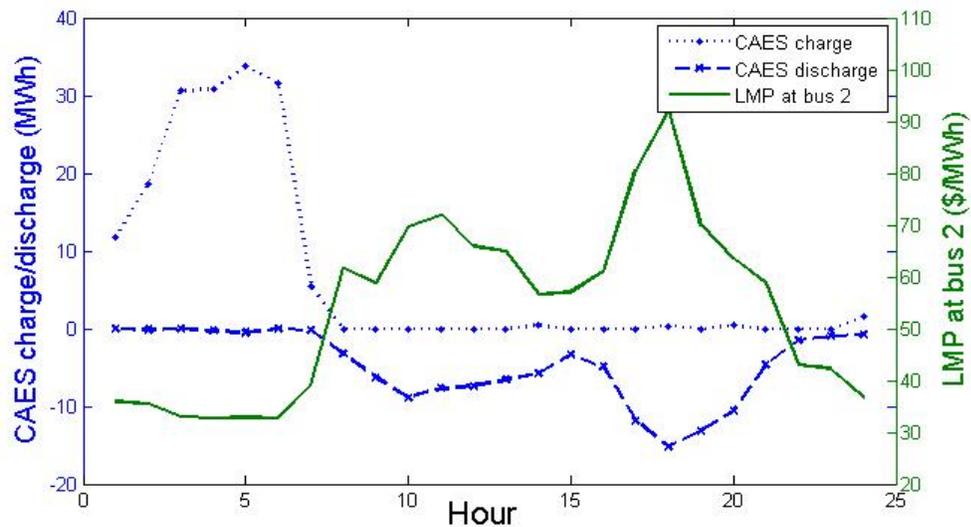


Fig. 7.6. CAES average charge/discharge pattern and LMPs at bus 2 under scenario 3

Carbon tax increased the spread of off- and on-peak prices in the upper region. During the peak hours, most of the peak generators burn coal, natural gas, or oil, which incur high carbon tax and high LMPs. During the off-peak hours, as the low-cost generators don't have too much emission, the energy price differences between the off- and on-peak prices are larger than those of scenario 3.

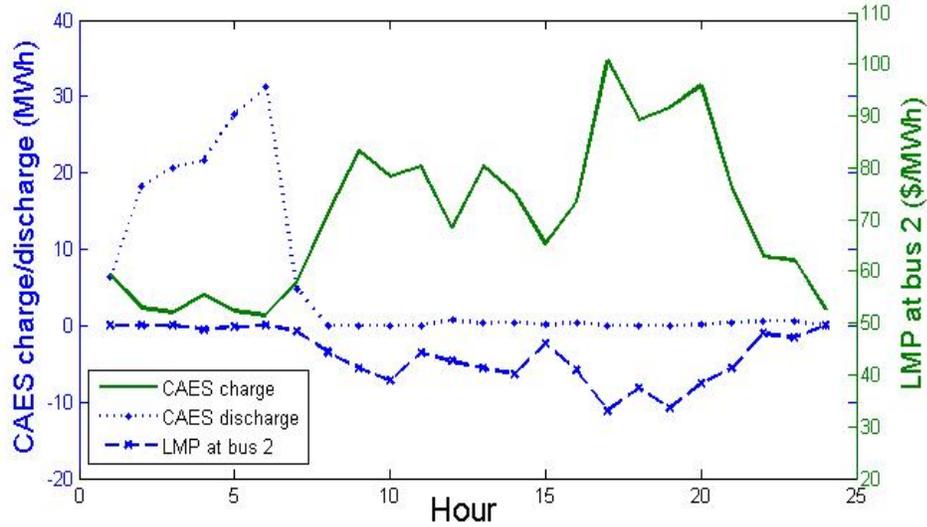
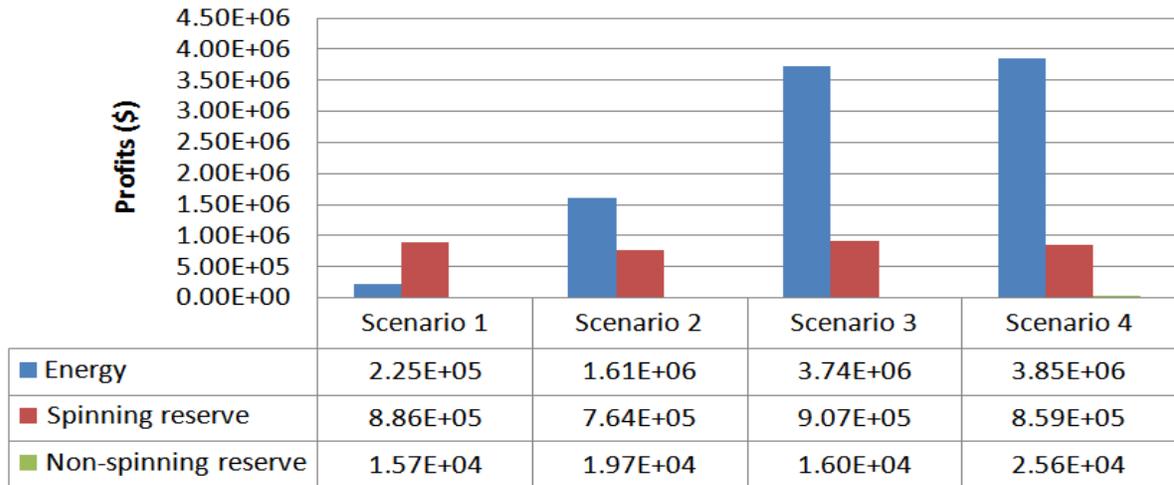


Fig. 7.7. CAES average charge/discharge pattern and LMPs at bus 2 under scenario 4

Besides providing electric energy, CAES can also provide high-value ancillary services such as spinning and non-spinning reserves. Table 7.1 shows the CAES's profits from the energy and ancillary service markets. The CAES has the highest overall profit under scenarios 4, possibly due to volatility in nodal prices and high gap between peak prices and off-peak prices. As shown in the table, the CAES can gain a significant amount of profits from the ancillary service market.

Table 7.1. Annual Profits of the CAES

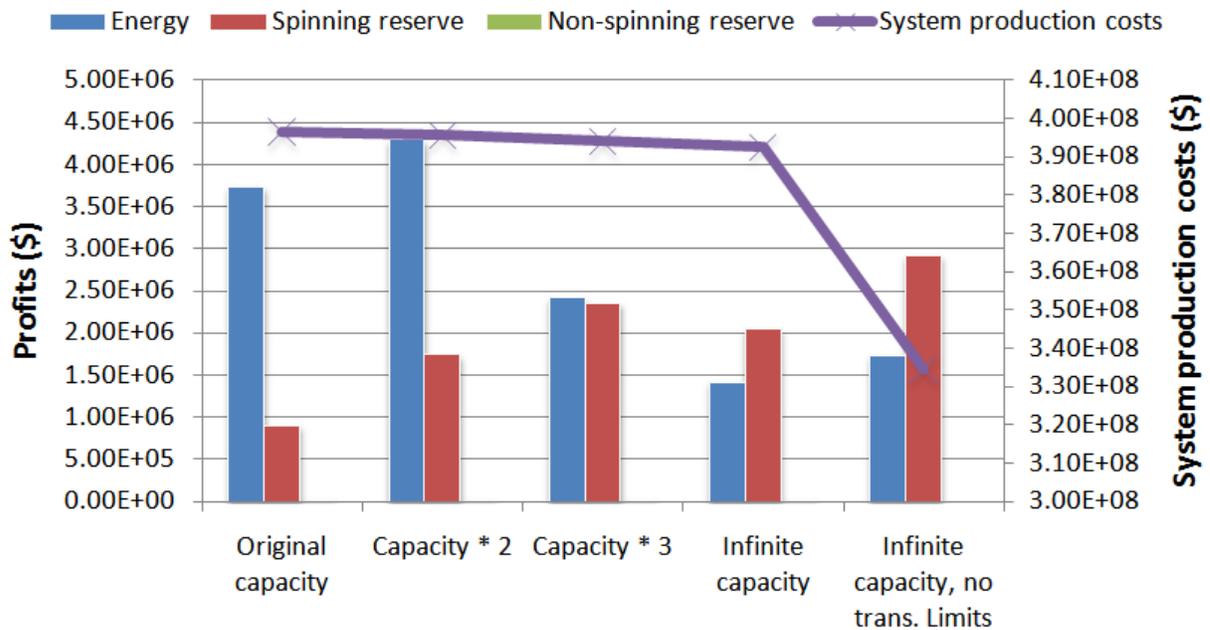


A sensitivity analysis was conducted to evaluate the effects of CAES's capacity on its annual earning and total system production cost under scenario 3. In table 7.2, the CAES's profits first go up then go down as CAES's capacity increases. When the CAES's capacity is twice as large as its original capacity, it can get more profits by providing energy and spinning reserve. However, as CAES is bidding at its marginal cost, when CAES's capacity gets larger and larger, it can substitute the high cost units during the peak hours, resulting in low peak hour prices. As the CAES is paid LMP for its energy, it will have less revenue. When the CAES's capacity is infinite, it will totally substitute the high-cost peak generators and have fewer profits. As strategic bidding is not considered in this study, the actual profits of the CAES should be higher.

The profitability of the CAES is affected by transmission congestions as if system is congested all day long, the CAES cannot obtain enough low-cost energy from the upper

region, which interferes the energy arbitrage function of the CAES. In table 7.2, when there is no transmission limits in the system, the total production costs reduced a lot.

Table 7.2. CAES's Annual Profits and System Total Production Costs V.S. CAES Capacity



The results showed that CAES can provide both energy and reserves, reduce the carbon dioxide emission and promote the efficient use of wind energy. For that particular system, the case study showed that CAES could get the higher profits when it was located near the load center. Carbon tax also had some effects on CAES's profitability, but not too much.

As the regulating reserve is not considered in the study, this analysis only shows the lower bound of CAES's profits. As wind causes a lot of variation in the supply side, many thermal units need to constantly vary their generation outputs to maintain the frequency stability. The excessive cycling of these coal- and natural gas- fired units will cause aging and extra maintenance costs. As wind penetration level gets higher and higher, these units

may bid higher regulating reserve prices in order to offset the extra cycling costs. Fast-responding units such as CAES can benefit from this as they are designed to vary the generation levels frequently at low costs.

The conclusion drawn from this case study about whether storage should be located near the wind sites or load center is applicable to the test system only. The conclusion might be different for another system with different load patterns, generation mix, fuel prices, or transmission topology/constraints. However, the models proposed and analytical methods employed in this study can be applied to various systems.

7.4 Comparing the Economic Performance of CAES and Transmission Line Additions

As illustrated in previous chapters, both CAES and new transmission lines are bring significant economic benefits if planned carefully, however, in order to evaluate the possibility of building CAES to defer or even substitute transmission investments, a systematic approach to compare the two investment plans needs to be designed. The procedures to use the above proposed mid-term hourly production cost simulation model to assess the two planning alternatives are shown below:

- 1) Evaluate system condition and propose candidate CAES investment projects.
- 2) Use the mid-term production cost simulation tool to simulate the operations of the system and identify the best CAES candidate. Depending on the decision maker's

preference, there can be multiple criteria for the candidate CAES projects such as benefit/cost ratio, reduced load payments, reduced congestion costs, etc.

- 3) Evaluate system condition and propose candidate transmission investment projects.
- 4) Use the market-based transmission expansion planning tool to identify the best transmission investment plan.
- 5) Use the mid-term production cost simulation tool to simulate the operations of the system with the new transmission lines.
- 6) Assess the economic performance of the two set of plans by comparing their benefit/cost ratios.

CHAPTER 8 THE MARKET-BASED TRANSMISSION PLANNING TOOL

8.1 Introduction

The Market-based Transmission Expansion Planning (MBTEP) tool is written in MATLAB/TOMLAB and uses CPLEX as the optimization engine. The system information needs to be prepared using a .csv or .txt file following a specific format. After the input files are ready, the preprocessor reads the input files and generates a MPS file for the master problem and a MPS file for slave problem, random seed generators for the Monte Carlo simulation, and the wind speed forecasting model for wind. Then all the generated files are sent to the model generator where the Benders decomposition and Monte Carlo simulation are conducted. Once the final optimal solution is obtained, a solution report will be generated containing information about the system information and investment plan. The MBTEP tool can conduct long-term market-based transmission expansion planning and identify an investment plan that can bring the maximum amount of net economic benefits to the system.

The general properties of the MBTEP tool include:

- Simulating the long-term operation of the electric system in flexible time steps (5-minute, hourly, daily, monthly, annual)
- Simulating different parts of the electric system in different time steps, e.g. hourly simulation time step for traditional generators, 5-min simulation time step for wind and CAES.

- Simulating the operation of electric market with double-sided biddings
- Methodology to calculate the LMPs for all the buses, and MCP for spinning and non-spinning reserves.
- Ability to simulate not only electric system but also related systems such as fuel transportation system.
- Methodology to analyze the long-term economic performance of the system
- Methodology to analyze the long-term reliability performance of the system
- Ability to simulate the greenhouse gas emission, model emission constraints, and include carbon tax in the model.
- Simulating the generation expansion planning problem from generation companies' perspective, i.e. maximize the expected value of (generation profits – investment cost)
- Simulating the transmission expansion planning problem from ISO/RTO's perspective, i.e. maximize the expected value of (social surplus for the whole market – investment cost)
- Methodologies that enable the users to identify/verify specific transmission bottlenecks.
- Ability to easily calibrate the models and subsystems of the tools.

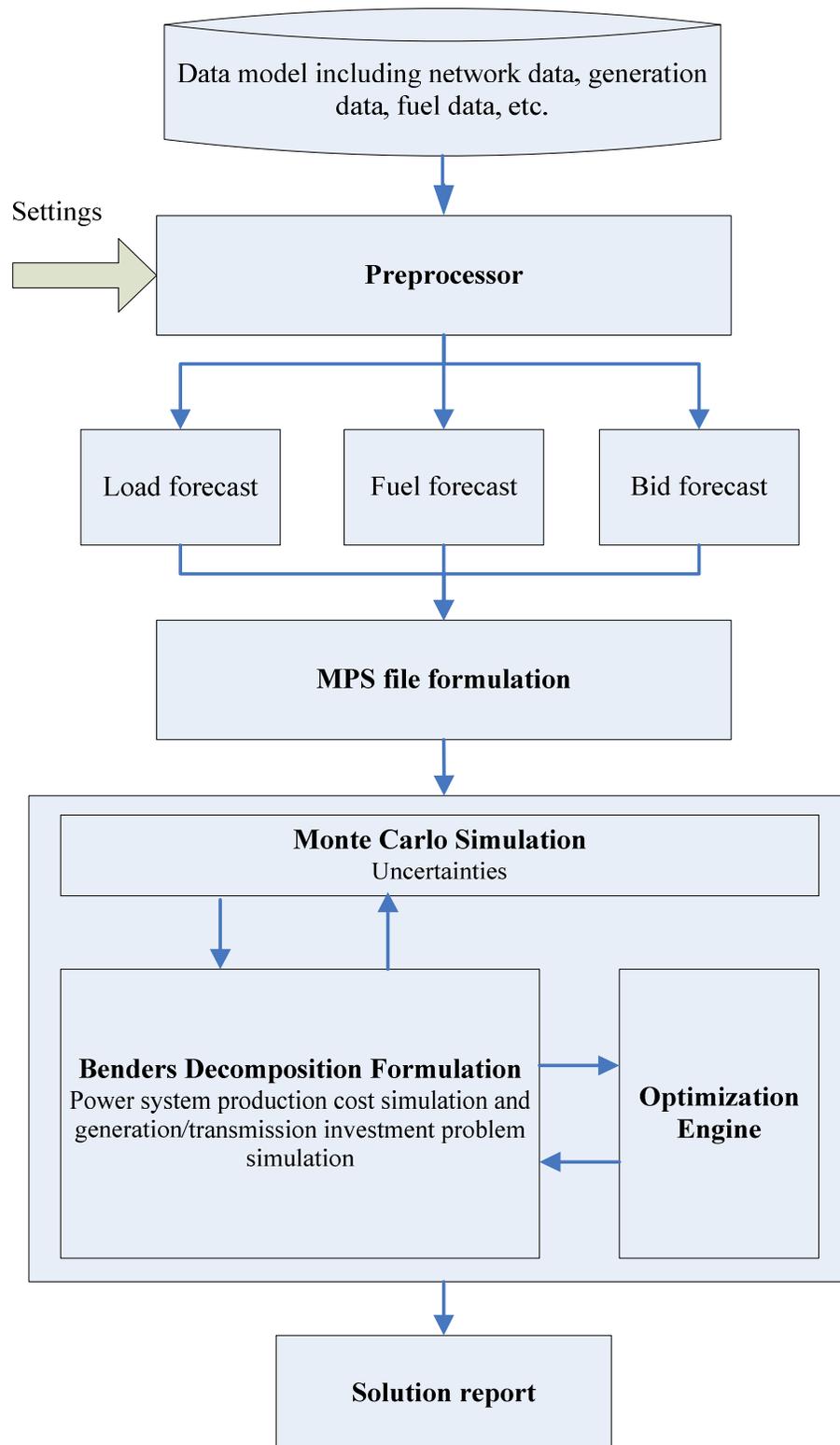


Fig. 8.1. The structure of the MBTEP tool

One concern with using this MBTEP tool on large system is the computation time. Although this dissertation did not test the MBTEP tool on a big system, the structure of the optimization problem makes it possible to solve the large planning problem in a reasonable time. The total computation time is decided by three factors: the number of iterations, computation time of the master problem in each iteration and computation time of the slave problem in each iteration. Section 3.4.3 discussed this issue and analyzed the computation time for the master and slave problems, respectively. One conclusion that can be drawn from that section is that for a large system, the computation time is mainly decided by the number of iterations and the slave problem. In order to reduce the iteration time, the hierarchical decomposition method can be easily introduced in the MBTEP tool [86]. Hierarchical decomposition method will first relieve some constraints from the slave problem (such as the DC power flow constraints) and get the optimal solution set for the relaxed optimization problem. Then this solution can be used as the starting point to get the final optimal solution for the whole planning problem. With regard to the computation time of the slave problem, the slave problem can be further decomposed and parallel computing technique can be employed to make the computation time tractable. In summary, although the system capacity expansion planning problem is very computation intensive, the formulation of the planning model is very suitable to be combined with other techniques to make the computation time on large systems reasonable.

8.2 Input Data

The MTEP tool uses the Generalized Network Flow method to model the whole system. In the GNF formulation, the system is comprised of nodes and arcs. The detailed information on the nodes and arcs of the system is included in the nodesinitial.csv and arcsinitial.csv.

In the nodesinitial.csv file, all of the nodes in the system and their properties are included. The entries in the input file are: node name, the type of flow that go through the node (e.g. coal, natural gas, electricity, oil, etc.), node type (e.g. a generation bus, a transmission bus, etc.).

In the arcsinitial.csv file, all of the arcs in the system and their properties are include. Arcs are considered as the link between two nodes. Many processes such as generation, fuel transportation, transmission can be treated as arcs with flows going through. There are 30 data entries in the arcsinitial.csv file. The data entries are: 1) Arc name (source node name + sink node name), 2) Source node name, 3) Sink node name, 4) Type of flow, 5) Cost, 6) Efficiency, 7) Minimum flow constraint, 8) Maximum flow constraints, 9) Number of arcs, 10) Investment cost (the expansion investment if applicable, otherwise it is 0), 11) Susceptance (for transmission lines only, 0 for other kinds of arcs), 12) Whether it can provide spinning) reserve or not (entries 12 to 28 are valid for arcs representing electric generation processes only, 13) Whether it can provide non-spinning reserve or not, 14) Ramp-up rate , 15) Ramp-down rate, 16) Start-up cost, 17) Shut-down cost, 18)/19)/20) energy bidding segment 1 (minimum capacity, maximum capacity, cost), 21)/22)/23) energy bidding segment 2, 24)/25)/26) energy bidding segment 3, 27) Spinning reserve bid, 28)

Non-spinning reserve bid, 29) Forced-outage rate, 30) Co2 emission coefficient, 32) whether it can provide regulating reserve or not, 32) regulating reserve bid.

The employment of .csv files as input makes it possible to consider more properties of nodes and arcs if needed. For example, if we need one more property for generator such as regulating reserve bid, one more column can be added to the arcsinitial.csv file. The above input files only consider the status of the system at the beginning of the planning horizon, further information are required to capture the dynamic properties of the system such as load level, fuel prices, generation capacities, etc.

8.3 Preprocessor

The preprocessing process read the input files about nodes and arcs and also the input files about load data and wind data. Preprocessor also requires proper setting such as load growth rate, fuel cost growth rate, generation maintenance schedule, planning horizon, time step, etc. The outputs of the preprocessor are nodes.csv and arcs.csv, which contains the system information over the whole planning horizon.

One interesting function of the preprocessor is that it can expand different subsystems of the existing system using different time steps. Various energy subsystems have different dynamics. For example, the wind speed is highly volatile, so in order to capture the impact of wind output on the operation of the market, it makes sense to use a 5-min simulation time step. The coal transportation subsystem, however, has a much lower dynamics as most of the coal-burning power plants have long-term contracts with the fuel provider so a weekly or

monthly time step can be used for this subsystem. If a single simulation time step is used for the whole system as many other system simulation tools do, that time step needs to be small enough to capture the fastest dynamics in the system, which incurs huge computational burden. Using various time steps to account for different dynamics helps to reduce the computation time while capturing the unique operating characteristics of different subsystems.

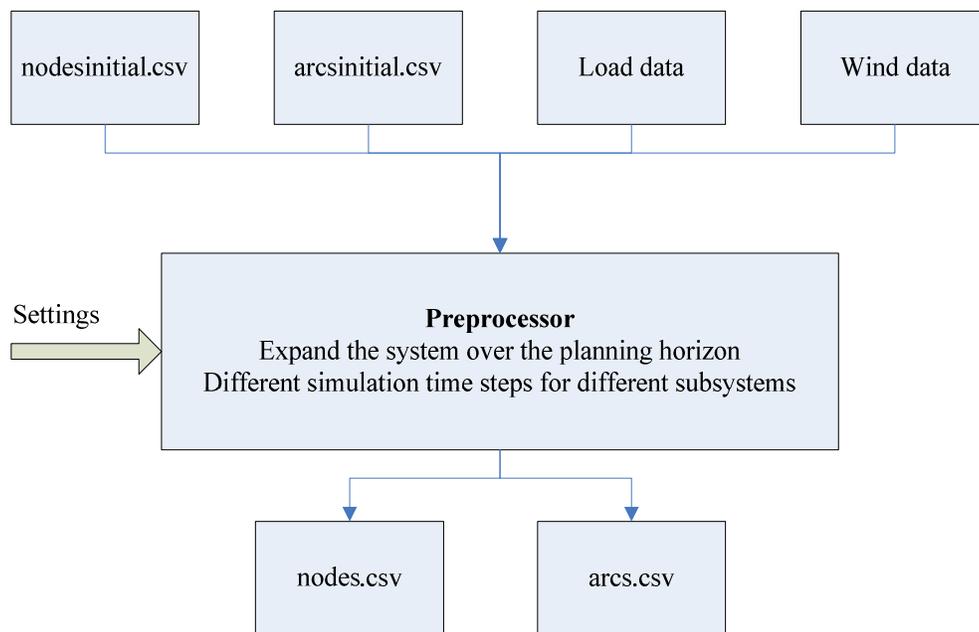


Fig. 8.2. The structure of the preprocessor

8.3 MPS file generation

Mathematical Programming System (MPS) is a file format to store optimization problems. All major optimization engines accept this format, which make the MBTEP flexible to the kind of optimization solver it uses. MPS file has a specific format to formulate the optimization problem, as shown in Fig. 8.3. MPS is a column-oriented format and all of

the components of the optimization problem, such as variables, columns, rows, etc., have unique names. Fig. 8.4 shows the equation-oriented format of the same optimization problem as the one in Fig. 8.3. Most optimization engines have the ability to convert the MPS format to the standard format. One advantage of the MPS format is that, compared to generating huge matrices directly, it is easy to generate the MPS file based on the nodes.csv and arcs.csv. For example, in order to generate the generation/load balance equations for all the buses, first, the list of buses are read from the nodes.csv and n (n is the number of buses) rows are defined; then for each buses, all of the connected arcs are identified in the arcs.csv and the “COLUMNS” section can be created by assigning coefficients (1 for input arc and -1 for output arc if loss is not considered) to the arcs; finally, the “RHS” section can be generated by entering the load for each bus.

```

NAME          TESTPROB
ROWS
N  COST
L  LIM1
G  LIM2
E  MYEQN
COLUMNS
  XONE      COST      1    LIM1      1
  XONE      LIM2       1
  YTWO      COST      4    LIM1      1
  YTWO      MYEQN     -1
  ZTHREE    COST      9    LIM2      1
  ZTHREE    MYEQN      1
RHS
  RHS1      LIM1       5    LIM2      10
  RHS1      MYEQN      7
BOUNDS
UP BND1     XONE       4
LO BND1     YTWO     -1
UP BND1     YTWO       1
ENDATA

```

Fig. 8.3. The MPS file format

```

Optimize
COST:    XONE + 4*YTWO + 9*ZTHREE
Subject To
LIM1:    XONE + YTWO                <= 5
LIM2:    XONE          + ZTHREE    >= 10
MYEQN:   - YTWO + ZTHREE          = 7
Bounds
          XONE <= 4
-1 <= YTWO <= 1
End

```

Fig. 8.4. The same optimization problem written in equation-oriented format

8.4 Optimization model

8.4.1 Benders Decomposition and Monte Carlo Simulation

One of the important features of the MBTEP is that Benders Decomposition is employed to split the whole optimization problem into sub-problems and solve them iteratively. This formulation of the planning problem can:

- 1) Enable the optimization server to solve what previously are unsolvable problems. For instance, the CPLEX solver cannot solve mixed-integer non-linear problem. By dividing the whole problem into a mixed-integer problem and a non-linear problem, the optimal solution can be obtained.
- 2) Reduce the computation time.
- 3) Obtain the dual solution of the slave problem and use it in the master. For instance, in the overall planning problem, it is not possible to consider the LMPs of the buses in the objective function because LMPs is a byproduct of the optimization problem. Benders Decomposition enables the usage of LMPs to calculate the generators' profit in the objective function of the master problem.
- 4) Use several system performance evaluation

sub-systems to capture various aspects of the operation of the system. For example, there can be two sub-problems in the MBTEP tool, the system production cost simulation sub-problem and the system reliability evaluation sub-problem. It is also possible to include other sub-problems to assess other aspects of the operation.

The operation of the electric market is strongly related to physical characteristics of the power system such as loads, fuel prices, hydrological conditions, national energy policy, wind energy output, transmission capability, emission allowances, and unit operating characteristics. Another important feature of the MBTEP tool is the employment of Monte Carlo method to account for the various uncertainties associated with parameters of the planning model. By combining Benders Decomposition method and Monte Carlo simulation technique, the MBTEP can analyze the long-term operations of the electric system and make investment decisions based on numerous simulations of possible states of the system. The flow chart of the Bender Decomposition and Monte Carlo simulation processes is shown in Fig. 8.5.

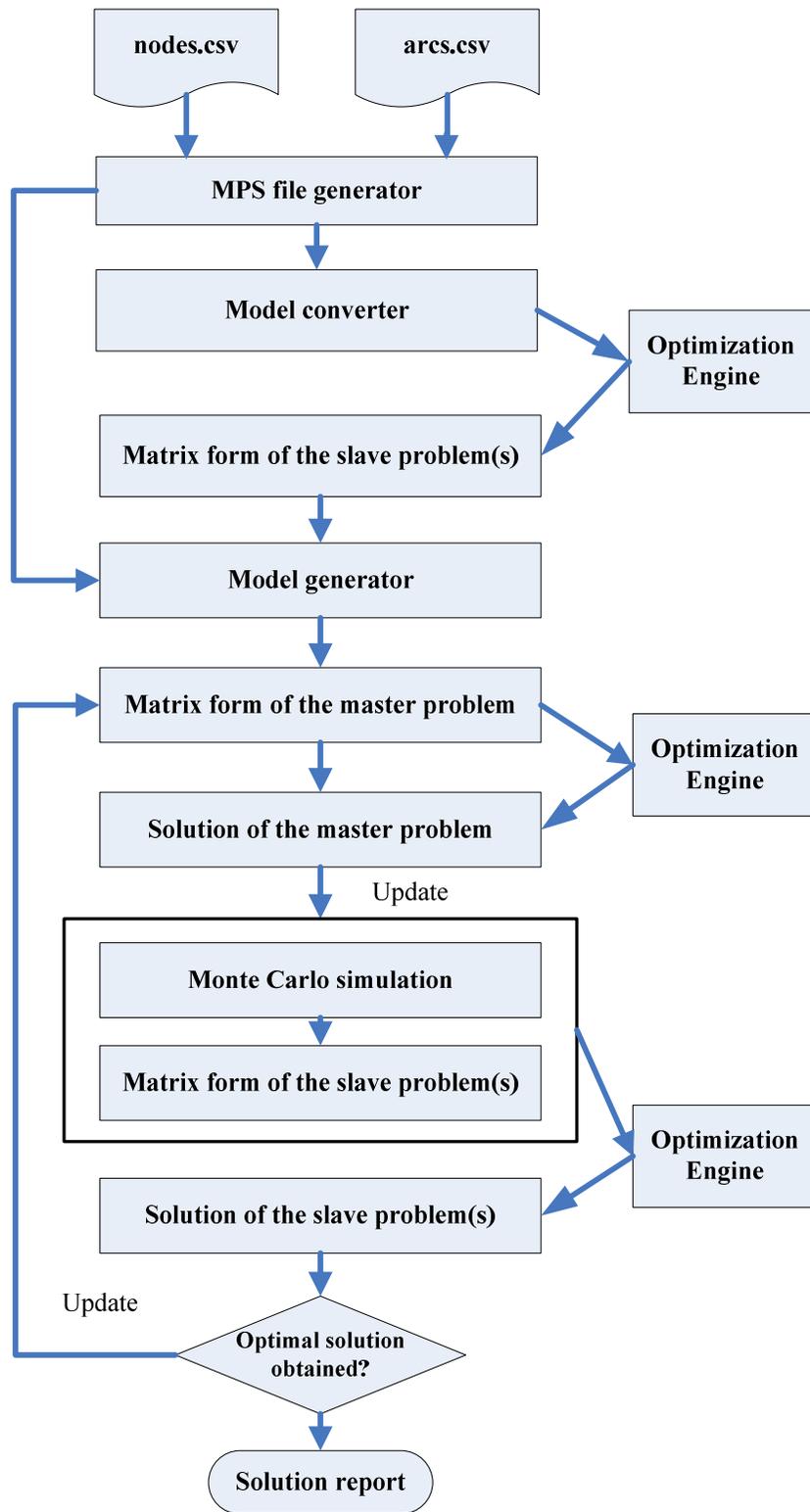


Fig. 8.5. The flow chart of the Benders decomposition and Monte Carlo simulation processes

8.4.2 System Long-term Performance Evaluation

Making the wise transmission and/or generation expansion investment plan involves extensive evaluation of the performance of the electric power system over the whole planning scope. The slave problems of the TEP and GEP models make the long-term system performance evaluation. Currently, there are two kinds of the slave problems in the MBTEP, as shown in Fig. 8.6. The first slave problem assesses the economic performance of the electric market; the second slave problem assesses the reliability of the electric system. The MBTEP can be configured to use either one, or both of the slave problems. The structure of the MBTEP also makes it possible to include other user defined slave problems or constraints.

The economic assessment slave problem simulates the operation of the electric/ancillary market with double-sided biddings. The UC and ED problems are solved hourly in order to simulate the day-ahead market. This slave problem has the capability of producing the following results:

- Locational Marginal Prices for all of the electric buses.
- Nodal prices for all of the nodes in the fuel subsystem (if applicable).
- Market Clearing Prices for the spinning and non-spinning reserves.
- Detailed hourly generation, transmission, and storage information.
- Detailed commitment schedules of the generation fleet.

- Total system emission level and the increased cost as the result of carbon tax or carbon cap.
- Detailed system congestion information in terms of congestion costs, congestion level, and length of the congestion.
- The customer payment and generators' revenues and profits.

The reliability assessment slave problem evaluates the long-term reliability of the system and ensures that the N-1 security requirement is fulfilled.

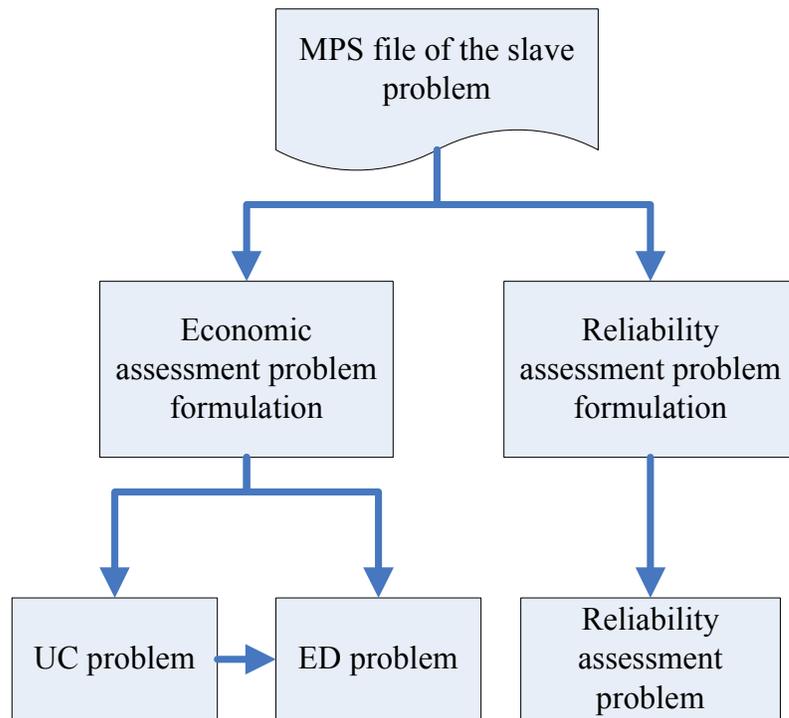


Fig. 8.6. The economic and reliability assessment functions of the MBTEP tool

CHAPTER 9 CONCLUSION

9.1 Contributions

- Proposed a new transmission planning methodology, compared it with the traditional planning models, and validated its advantage over existing models by conducting the case study.
- Implemented the market-based transmission planning method and built a planning tool.
- Proposed a transmission planning methodology that took both the reliability and economic criteria into consideration.
- Employed Benders decomposition method to reduce the computation time and employed Monte Carlo simulation/robustness testing methods to incorporate various uncertainties in the planning model.
- Used generalized network flow model to represent the energy flow in both the electric system and the fuel network.
- Built models for wind farms and storage facilities and incorporated them into the planning model.
- Implemented the co-optimization of both the energy market and ancillary service market in the transmission planning model so that the impacts of increasing wind penetration level on the operating reserve can be evaluated.

- Proposed a new transmission planning methodology that can simulate the interactions between large scale wind integration and transmission expansion planning.
- Designed a systematical way to evaluate the possibility of building energy storage system to defer or substitute the transmission expansion investments.

9.2 Further Research Directions

Further research might be done in a variety of directions based on the proposed research work in the dissertation. Some of the interesting ideas for further research are shown below.

- **Employing parallel computing algorithm in the MBTEP tool.** One of the major issues with the optimization model of transmission expansion planning is the significant computation time. As the transmission expansion planning problem is a mix-integer non-linear optimization problem, the computational complexity of the model would be as bad as NP-hard (non-deterministic polynomial-time hard). In order to reduce the computational time, computer technologies such as parallel computing can be employed. Parallel computing is used in a wide range of fields, from bioinformatics (protein folding and sequence analysis) to economics (mathematical finance). Combining parallel computing algorithm and transmission expansion planning model might significantly reduce the computation time and enable the proposed model to be applied on larger systems.
- **Using statistical model to forecast the long-term wind speed.** Wind turbine generator's output is highly volatile as the result of constantly changing wind speed

and direction. In order to forecast the wind speed, many mathematical models were formulated, such as ARMA model, multi-variable statistical model, neural network model, etc. Wind speed model, combined with detailed wind turbine output model, generate the wind power generation at each time step. While lots of efforts have been made to simulate and forecast the wind output, there are still big errors in the forecast. In order to capture the long term patterns as well as short-term variations of the wind speed, multi-variable statistical model and ARMA model can be used together in the production cost simulation problem. Multi-variable statistical model can be used to forecast the wind output for the next twenty-four hours in the day-ahead market. In the day-ahead market, the UC and ED models decide the commitment and dispatch schedule for the next day based on the wind generation forecast from the multi-variable statistical model. Then in the real-time market, the sequential Monte Carlo simulation method can be employed to account for the uncertainties the wind generation output. In order to capture the wind forecast errors, multiple wind generation forecast can be generated by the ARMA model based on the forecasted values used in the day-ahead market. Then the production cost model simulates the operation of the real-time market for a large number of times. In each simulation, a new wind generation forecast is generated by the ARMA model. The proposed model can properly consider not only the annual, seasonal, weekly, or hourly patterns, but also the sub-hourly fluctuations of the site-specific wind speed variations.

- **Analyzing the interactions between the fuel transportation system and the electric system.** Fuel price is a major component of the generating units' marginal cost. The fluctuation of the fuel price will significantly impact the LMPs, unit commitment schedule, dispatch schedule, and economic benefits. For example, in many electric systems, sometimes the oil-burning units are the marginal units in the peak hours, so the market clearing prices are mainly decided by the oil prices. The fuel prices that generators see are mainly comprised of two components: the raw fuel price and the transportation/storage cost. The fuel transportation will affect the fuel prices that generators pay, and final the LMPs in the market. Investigating the interactions between fuel transportation system and electric power can provide valuable information about the long-term fuel price forecast and uncertainty with the fuel price.
- **Capturing the impacts of emerging technologies on the system expansion planning model.** With the advancement of technologies and applications such as demand-side management, distributed generation, and plug-in hybrid vehicles, the future demand level and shape will be changed. The system expansion planning tool needs to consider the impacts of these new technologies on the economic performance and reliability of the system.
- **Evaluating the impacts of changes in national renewable energy policies on system expansion planning problem.** In the past decades, wind has been the fastest

growing electric power source in U.S. The rising costs of fossil fuels, improvements in renewable energy technologies, growing number of states enforcing renewable portfolio standards (RPS), prospect of future carbon regulations and federal production tax credit (PTC) have been the major driver of the growth of renewable energy. Despite the significance of national/state renewable policies on wind energy, little efforts have been made to analyze their impacts on the long-term electric system expansion outcome. Energy policies such as PTC, carbon tax and/or carbon cap and trade will change the GenCo and TransCo's expectations on their future profits and consequently their investment strategies. It is very important to assess the influence of possible major national/state energy policies on the system capacity expansion planning problem.

- **Evaluate the impacts of large-scale wind power on the operations of the system and the possible way to fix the issues.** Wind energy will have substantial growth in the decade ahead as the result of aggressive wind penetration level and on-shore and off-shore wind potential. Although the variability of wind energy and the significant wind forecast errors in the day-ahead and real-time markets can be partially accommodated by existing operational procedures, the increasing wind penetration level will challenge system operators regarding the procurement of enough ancillary services. Studies need to be carried out to analyze the impact of high wind penetration on the electric market. What is more, possible solutions to that issue such as CAES

should also be evaluated. To thoroughly analyze the operating characteristics of CAES and wind power and how they perform in the energy and ancillary service market, a simulation tool which co-optimize the two markets and simulate the system at a 5-min time step is required.

Appendix: Details of the Test Systems

The network data of the 5-bus test system used in this article is given below.

Table A.1. Generator Data

Arc name	Type	O&M cost (\$/MW)	Efficiency	Min. flow (100 MW)	Max. flow (100 MW)	Incremental heat rate (Mbtu/MWh)
1-1'	Oil	2	1	0	3	9.95
2-2'	Coal	3	1	4	13	8.93
3-3'	Coal	3	1	1	5	10.05
4-4'	Coal	3	1	0.5	5	10.05
5-5'	Natural gas	2	1	0	3	9.55

Table A.2. Transmission Line Data

Arc name	Efficiency	Min. flow (100 MW)	Max. flow (100 MW)	Number	Investment Cost (M\$)	Susceptance (p.u.)
L1	1	-2	2	1	0	5
L2	1	-4	4	1	0	7
L3	1	-4	4	1	0	7
L4	1	-2	2	1	0	5
L5	1	-4	4	1	0	7
1-3	1	-1	1	0	6.4	2.5
3-4	1	-2	2	0	12.64	3.5
4-5	1	-2	2	0	9.44	3.5
1-2	1	-2	1	0	6.56	2.5
1-5	1	-2	2	0	11.2	3.5
2-3	1	0	2	0	8	5

Table A.3. Fuel Characteristics

Supplier	Cost	Heat value
Coal 1	30 \$/ton	11500 Btu/lb
Coal 2	25 \$/ton	10200 Btu/lb
Natural gas	3.7 \$/Mcf	1000 Btu/cf
Oil	21 \$/barrel	143500 Btu/gallon

Table A.4. Interregional Interconnection Data

Arc name	Efficiency	Min. flow (100 MW)	Max. flow (100 MW)	Number	Investment Cost (M\$)	Susceptance (p.u.)
Line 1	1	-1	1	1	0	2.5
Line 2	1	-1	1	1	0	2.5
Line 3	1	-1	1	1	0	2.5
Line 4	1	-1	1	1	0	2.5
Line 5	1	-1	1	1	0	2.5
Line 6	1	-1	1	1	0	2.5
Line 7	1	-1	1	1	0	2.5
Line 1'	1	-2	2	0	15	7
Line 2'	1	-2	2	0	15	7
Line 3'	1	-2	2	0	15	7
Line 4'	1	-2	2	0	15	7
Line 5'	1	-2	2	0	15	7
Line 6'	1	-2	2	0	15	7
Line 7'	1	-4	4	0	20	10

Table A.5. Generators' O&M cost curves and demand bidding curves

Bus	Generators					Demand	
	1	2	3	4	5	2	4
Intercept (\$/MWh)	2	3	3	3	2	32	33
Slope (MW ² h)	0.03	0.02	0.02	0.02	0.03	-0.004	-0.005

BIBLIOGRAPHY

- [1] M. Buygi, G. Balzer, H. Shanechi, and M. Shahidehpour, "Market-based transmission expansion planning," *IEEE Trans. on Power Syst.*, vol. 19, no. 4, November 2004.
- [2] Department of Energy, *National Transmission Grid Study*. May 2002.
- [3] U.S. Department of Energy, *Transmission Bottleneck Project Report*. March 2003.
- [4] G. B. Shrestha and P. A. J. Fonseka, "Congestion-driven transmission expansion in competitive power market," *IEEE Trans. on Power Syst.*, vol. 19, no. 3, August 2004.
- [5] Sevin Sozer, Chan S. Park, and Jorge Valenzuela, "Economic analysis of electric power transmission expansion," *The Engineering Economist*, 53:293--317, 2008.
- [6] S. Wang, J. Zhu, L. Trinh, and J. Pan, "Economic assessment of HVDC project in deregulated energy markets," *DRPT*, April 2008.
- [7] J. Roh, M. Shahidehpour, and L. Wu, "Market-based generation and transmission planning with uncertainties," *IEEE Trans. on Power Syst.*, vol. 24, no. 3, August 2009.
- [8] Consortium of Electric Reliability Technology Solutions, *Economic evaluation of transmission interconnection in a restructured market*, California ISO, June 2004.
- [9] J. F. Benders, "Partitioning procedures for solving mixed-variables programming problems," *Journal Numerische Mathematik*, vol. 4, no. 1, pp. 238–252, Dec. 1962.
- [10] A. M. Geoffrion, "Generalized benders decomposition," *Journal of Optimization Theory and Applications*, vol. 10, no. 4, pp. 237–260, Oct. 1972.
- [11] S. Binato, M. Pereira, S. Granville, "A new Benders Decomposition Approach to Solve Power Transmission Network Design Problems," *IEEE Trans. on Power Syst.*, vol. 16, no. 2, May 2001.

- [12] Y. Li and J. McCalley, "A General Benders Decomposition Structure for Power System Decision Problems," *IEEE International Conference on Electro/Information Technology*, EIT 2008.
- [13] Douglas Hubbard, *How to Measure Anything: Finding the Value of Intangibles in Business*, John Wiley & Sons, 2007
- [14] Midwest ISO, Midwest ISO Transmission Expansion Plan 2009, December 2009
- [15] H. Stoll, "Least-cost electric utility planning," 1989, John Wiley.
- [16] Hobbs BF. "Optimisation methods for electric utility resource planning," *Eur J Operational Research*, 1995
- [17] C.K. Pang; G.B. Sheble, and F. Albuyeh, "Evaluation of Dynamic Programming Based Methods and Multiple area Representation for Thermal Unit Commitments," *IEEE Transactions on Power Apparatus and Systems*, March 1981.
- [18] Y. Gu, J. McCalley, and M. Ni, "Coordinating Large-scale Wind Integration and Transmission Planning," submitted to *IEEE Trans. On Renewable Energy*, 2011
- [19] N. Nabona, "Multicommodity Network Flow Model for Long-Term Hydro-Generation Optimization", *IEEE Trans. on Power System*. Vol. 8, No. 2, May 1993.
- [20] N. J. Balu, R. Adapa, G. Cauley, M. Lauby, and D. J. Maratukulam, "Review of Expert Systems in Bulk Power System Planning and Operation", *Proceedings of the IEEE*, Vol. 80, No. 5, May 1992.
- [21] K. P. Wong. "Artificial Intelligence and Neural Network Applications in Power Systems", *IEE Second International Conference on advances in Power System Control, Operation and Management*. Hong Kong, December 1993.
- [22] Y. Fukuyama, and H. Chiang, "A parallel genetic algorithm for generation expansion planning," *IEEE Transactions on Power System*, Vol. 11, May 1996.

- [23] J. Barquín, E. Centeno and J. Reneses . “Stochastic market equilibrium model for generation planning,” *Probability in the Engineering and Informational Sciences*, 19, pp 533-546, 2005
- [24] F. F. Wu, F. L. Zheng, and F. S. Wen, “Transmission investment and expansion planning in a restructured electric market,” *J. Energy*, 2006
- [25] Y.P. Dusonchet, and A. El-Abiad, “Transmission Planning Under Discrete Dynamic Optimizing,” *IEEE Trans. On Power Apparatus and Systems*, Vol. PAS-92, Jan. 2007.
- [26] J. Contreras and F. F.Wu, “A kernel-oriented algorithm for transmission expansion planning,” *IEEE Trans. Power Syst.*, vol. 15, pp. 1434–1440, Nov. 2000.
- [27] H. Sun and D. C. Yu, “A multiple-objective optimization model of transmission enhancement planning for independent transmission company (ITC),” *Proc. IEEE Power Eng. Soc. Summer Meeting 2000*, vol. 4, pp. 2033–2038.
- [28] E. Handschin, M. Heine, D. König, T. Nikodem, T. Seibt, and R. Palma, “Object-oriented software engineering for transmission planning in open access schemes,” *IEEE Trans. Power Syst.*, vol. 13, pp. 94–100, Feb. 1998.
- [29] F. E. N. Nasser, A. P. A. Silva, and L. A. P. Araujo, “Development of an expert system for long-term planning of power transmission networks,” in *Proc. 2nd Symp. Experts Syst. Applicat. Power Syst.*, Jul. 1989, pp. 237–242.
- [30] Y. Gu and J. McCalley, “Market-based Transmission Planning Considering Large-scale Wind Power,” in *Proc. The International Workshop on Large-Scale Integration of Wind Power into Power Systems as well as on Transmission Networks for Offshore Wind Power Plants, Québec, Canada, October 2010*.

- [31] Y. Gu and J. McCalley, “Market-based Transmission Expansion Planning,” in Proc. IEEE PES Power Systems Conference & Exhibition (PSCE), Phoenix, Arizona, March 2011.
- [32] Y. Gu and J. McCalley, “Market-based Transmission Expansion Planning With Uncertainty,” in Proc. North American Power Symposium, Arlington, Texas, September 2010.
- [33] G. Latorre-Bayona and I. J. Pérez-Arriaga, “Chopin, a heuristic model for long term transmission expansion planning,” *IEEE Trans. Power Syst.*, vol. 9, pp. 1886–1894, Nov. 1994.
- [34] H. K. Youssef and R. Hackam, “New transmission planning model,” *IEEE Trans. Power Syst.*, vol. 4, pp. 9–18, Feb. 1989.
- [35] L. Bahiense, G. C. Oliveira, M. Pereira, and S. Granville, “A mixed integer disjunctive model for transmission network expansion,” *IEEE Trans. Power Syst.*, vol. 16, pp. 560–565, Aug. 2001.
- [36] International Atomic energy agency, “Enhanced electricity system analysis for decision making”, 2000
- [37] GenTrader website: <http://www.powercosts.com/products/gen trader.asp>
- [38] J. Bastian, J. Zhu, V. Banunarayanan, and R. Mukerji, “Forecasting Energy Prices in a Competitive Market,” *IEEE Computer Applications in Power Magazine*, vol. 12, no. 3, pp. 40-45, July 1999.
- [39] V. Koritanov, T. Veselka, “Modeling the regional electricity network in Southeast Europe,” Pwr Engr Society General Meeting, Volume 1, July 2003 .
- [40] Promod Website: <http://www1.ventyx.com/analytics/promod.asp>
- [41] ProSym website: <http://www.ventyx.com/analytics/market-analytics.asp>

- [42] W. Head, H. Nguyen, *et al* “The procedure used to assess the long range generation and transmission resources in the Mid-Continent Area Power Pool,” IEEE Transactions on Power Systems, Volume 5, Nov. 1990
- [43] PLEXOS website: <http://www.energyexemplar.com>
- [44] H. Yamin, J. Finney, W. Rutz and H. Holly, “GENCOs portfolio management using “STRATEGIST” in deregulated power markets,” Large Engineering Systems Conference on Power Engineering, July 2001.
- [45] WASP-IV model documentation: http://www.adica.com/wasp_iv.html
- [46] M. Lu, Z. Dong, T. Saha, “A Framework for Transmission Planning in a Competitive Electricity Market,” Proc. of the Transmission and Distribution Conference and Exhibition: Asia and Pacific, 2005 IEEE/PES 2005, pp 1-6.
- [47] MARS website:
www.gepower.com/prod_serv/products/utility_software/software/en/ge_mars.htm.
- [48] TPLAN website: <http://www.pti-us.com/pti/software/tplan/index.cfm>
- [49] T. Tran, J. Kwon, J. Choi, D. Jeon and K. Han, “Sensitivity Analysis of Probabilistic Reliability Evaluation of KEPCO System Using TRELSS,” International Conf on Probabilistic Methods Applied to Power Systems, 2006.
- [50] Eduardo Ibanez, “A multiobjective optimization approach to the operation and investment of the national energy and transportation systems,” Ph. D dissertation, Iowa State University, 2011.
- [51] A. Quelhas, E. Gil, J. D. McCalley, and S. Ryan, “A multiperiod generalized network flow model of the U.S. integrated energy system part I- model description,” *IEEE Trans. on Power Syst.*, vol. 22, no. 2, 2007.

- [52] H. He, Z. Xu, "Transmission Congestion and its Social Effects," *IEEE PES.*, vol. 1, pp. 350- 354, June 2005.
- [53] R. Romero, A. Monticelli, "A hierarchical decomposition approach for transmission network expansion planning," *IEEE Trans. on Power Syst.*, vol. 9, no. 1, February 1994.
- [54] J. Nicolaisen, V. Petrov, and L. Tesfatsion, "Market Power and Efficiency in a Computational Electricity Market With Discriminatory Double-Auction Pricing," *IEEE Transactions on Evolutional Computation*, vol. 5, no. 5, October 2001.
- [55] S. Ryan, A. Downward, A. Philpott, and G. Zakeri, "Welfare Effects of Expansions in Equilibrium Models of an Electricity Market With Fuel Network." *IEEE Trans Pwr Sys.*, August 2010.
- [56] C. H. Papadimitriou, "On the complexity of integer programming," *Journal of the ACM (JACM)*, 1981
- [57] Cobham, Alan, "The intrinsic computational difficulty of functions," *Proc. Logic, Methodology, and Philosophy of Science II*. North Holland, 1965
- [58] Joint Coordinated System Plan (JCSP). Available online: <http://www.jcspstudy.org/>.
- [59] M. K. Kozlov, S. P. Tarasov and L. G. Khachiyan,. "Polynomial solvability of convex quadratic programming," *Doklady Akademii Nauk SSSR*, vol. 248, 1049-1051. Translated in: *Soviet Mathematics - Doklady* 20: 1108-1111, 1979
- [60] Midwest ISO, *Midwest ISO Transmission expansion plan 2010*, Jan. 2011
- [61] B.G. Gorenstin, N.M. Campodonico, J.P. Costa, and M.V.F. Pereira, "Power system expansion planning under uncertainty," *IEEE Trans. Pwr. Sys.*, Volume 8, Issue 1, Feb. 1991.
- [62] H. M. Merrill and A. J. Wood, "Risk and uncertainty in power system planning," *International Journal of Electrical Power & Energy Systems*, Volume 13, Issue 2, April 1991.

- [63] A.P. Douglas, A.M. Breipohl, F.N. Lee, and R. Adapa, "Risk due to load forecast uncertainty in short term power system planning," *IEEE Trans, Pwr. Sys.*, Volume 12, Issue 4, Nov. 1998.
- [64] I.J. Silva, M.J. Rider, R. Romero, and C.A.F. Murari, "Transmission Network Expansion Planning Considering Uncertainty in Demand," *IEEE Trans, Pwr. Sys.*, Volume 21, Issue 4, Nov. 2006.
- [65] C. P. Robert, G. Casella, *Monte Carlo Statistical Methods* (2nd ed.). New York: Springer, 2004.
- [66] G. Infanger, "Monte Carlo (Importance) Sampling within a Benders Decomposition Algorithm for Stochastic Linear Programs," TECHNICAL REPORT SOL 91-6, *Annals of Operations Research*, 1992
- [67] George Casella and Roger L. Berger. *Statistical Inference*. Duxbury Press, 1990.
- [68] E.O. Crousillat, P. Dorfner, P. Alvarado, H.M. Merrill, "Conflicting objectives and risk in power system planning," *IEEE Trans. Pwr. Sys.*, Volume 8, Issue 3, Aug. 1993.
- [69] H. M. Merrill, "Regional transmission organizations: FERC Order 2000," *IEEE Power Engineering reviews*, vol. 20, July 2000.
- [70] H. Bludszuweit, J. A. Dominguez-Navarro, and A. Llombart, "Statical Analysis of Wind Power Forecasr Error," *IEEE Trans. Power Syst.* Vol. 23, No. 3, August 2008.
- [71] A. Boone, "Simulation of short-term wind speed forecast errors using a multi-variate ARMA(1,1) time-series model," M.Sc. thesis, Royal Inst.Technol., Stockholm, Sweden, 2005.
- [72] P. Pinson, H. Madsen, H. Nielsen, G. Papaefthymiou, and B. Klock, "From probabilistic forecasts to statistical scenarios of short-term wind power production," *Wind Energy*, Vol. 12, Issue 1, pp 51–62, January 2009.
- [73] D. J. Burke and M. J. O'Malley, "Maximizing Firm Wind Connection to Security Constrained Transmission Networks," *IEEE Trans. Power Syst.* Vol. 25, No. 2, May 2010

[74] K. W. Cheung, P. Shamsollahi, D. Sun, J. Milligan, and M. Potishnak, "Energy and Ancillary Service Dispatch for the Interim ISO New England Electricity Market," *IEEE Trans. Power Syst.* Vol. 15, No. 3, Aug. 2000.

[75] California ISO, "Spinning Reserve and Non-Spinning Reserve." available online
<http://www.caiso.com/docs/2003/09/08/2003090815135425649.pdf>

[76] Reliability Test System Task Force of Probability Methods Subcommittee, "IEEE reliability test system," *IEEE Trans. PAS-98*, pp. 2047-2054, 1979.

[77] L. E. Benitez, P. C. Benitez, and G. Cornelis van Kooten, "The economics of Wind Power with Energy Storage," *Energy Economics*, No. 30, pp 1973-1989, 2008.

[78] P. Denholm, R. Sioshansi, "The Value of Compressed Air Energy Storage with Wind in Transmission-constrained Electric Power Systems," *Energy Policy*, No. 37, pp. 3149-3158, 2009.

[79] P. Denholm, E. Ela, B. Kirby, and M. Milligan, "The Role of Energy Storage with Renewable Electricity Generation," Technical Report, NREL/TP-6A2-47187, Jan. 2010.

[80] H. Lund, G. Salgi, "The Role of Compressed Air Energy Storage in Future Sustainable Energy Systems," *Energy Conversion and Management*, No. 50, pp 1172-1179, 2009.

[81] Emerging Energy Storage Technologies in Europe. Rapport Frost and Sullivan, 2003.

[82] H. Ibrahim, A. Ilinca, and J. Perron, "Energy Storage Systems-Characteristics and Comparisons," *Renewable and Sustainable Energy Reviews*, No. 12, pp. 1221-1250, 2008

[83] Y.V. Makarov, et.al. "Wide-Area Energy Storage and Management System to Balance Intermittent Resources in the Booneville Power Administration and California ISO Control Areas," PNNL Report, June 2008. Available Online:

http://www.electricitystorage.org/images/uploads/docs/Wide_Area_EMS_Report_V7.pdf

[84] Succar, S. and R. Williams. “Compressed Air Energy Storage: Theory, Operation, and Applications.” March 2008.

[85] All Island Grid Study, Workstream 4—Analysis of Impacts and Benefits, Irish Government Department of Communications, Energy and Natural Resources/United Kingdom Department of Enterprise, Trade and Investment, Jan. 2008. Available online:

<http://www.dcenr.gov.ie/Energy/North-South+Co-operation+in+the+Energy+Sector/All+Island+Grid+Study.htm>.

[86] R. Romero, A. Monticelli, “A hierarchical decomposition approach for transmission network expansion planning,” *IEEE Trans. Pwr. Syst.* Vol. 9, issue 1, Feb 1994.