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Study of Voluntary Demand Side Load Shift (VDSLS) and Direct Load Control (DLC) for Restructured Power Systems

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School of Electrical and Electronic Engineering

A thesis submitted to the Nanyang Technological University
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Summary

Electric power utilities around the world have been experiencing restructuring since the 1980s. The objectives of power system restructuring are to introduce competition in the electric power industry and to provide more choices to market participants in the way they trade electricity and ancillary services. The direct consequence of the restructuring is the separation of the conventional vertically integrated utilities into independent generation, transmission and distribution companies. Economic segregation and service unbundling have changed the mechanism of conventional system planning and operation. The expected benefits of power system restructuring are cheaper electricity through competition and innovation, and improved generation and planning efficiency and economies. However, the restructuring of power systems has been accompanied by some problems, including capacity shortage, transmission congestion, price volatility, and reduced system reliability. Load management has re-emerged as an important element in fine-tuning the reliability and price in restructured power systems.

Load management, as defined by IEEE's Demand-Side Management Subcommittee, constitutes activities that influence load shape of power systems so as to accomplish peak clipping, valley filling or load shifting which includes everything from direct control of small customer end users to voluntary load shifting by large commercial/industrial customers. By reshaping the system load curve and shaving the system peak load, load management can improve the system reliability and reduce the price volatility of restructured power systems.

Load management faces new challenges due to the problems accompanying restructuring of power systems. The existing load management techniques have to be improved to face these challenges. The issues of load management have been studied in this thesis in order to make load management more successful in the new environment. These include the correlation between electricity prices and demands; the effects of the resulting voluntary demand side load shift on system reliability and electricity price volatility; the impact of

nodal reliabilities of restructured power systems on determining the optimal direct load control (DLC) scheme of air conditioning loads (ACL); and a fair compensation scheme for ACL customers.

In restructured power systems, the conventional “same for all customers” electricity price is replaced by nodal prices which are also known as locational marginal prices (LMP) and vary with time and location. Electricity price is determined by generation companies’ bids, demands and system constraints. Electricity price will increase if there is system resource shortage which may be caused by system component failure or transmission congestion. Customers may modify their demands in this situation to avoid high electricity costs. The modification of demands will influence the electricity price in return. This correlation between demands and electricity price is defined as demand-price elasticity and is studied using the demand-price elasticity matrix in this thesis. The resulting demand change from time periods of higher electricity prices to time periods of lower electricity prices is defined as voluntary demand side load shift. An iterative methodology is utilized to determine the voluntary demand side load shift when there is electricity price change. The effects of voluntary demand side load shift on system reliability improvement and nodal price volatility reduction are investigated using the Optimal Power Flow (OPF) and reliability evaluation techniques.

DLC of ACL is the most common load management program used to shave the load curve and shave the system peak load by cycling the ACL. In practical power systems, ACL are connected to different nodes which have different reliability levels. Same amount of load reduction due to cycling ACL at different nodes may have different impacts on the system reliability. Therefore, it is very important to coordinate the cycling mode of ACL at different nodes in order to improve the system reliability as much as possible. The modification of the system load curve by cycling ACL can reduce the system operating cost correspondingly, which will eventually result in electricity price decline. In this thesis, a fuzzy-logic based DLC scheme of ACL considering nodal reliability characteristics is proposed for restructured power systems. In the proposed DLC technique, transmission system reliability is integrated into the determination

procedure of the DLC scheme using nodal reliability indices. In order to improve system reliability as much as possible, a fuzzy objective function is formulated using the nodal reliability characteristics. The system operating cost is calculated based on all the generators' bids and transmission system constraints. In order to reduce the system operating cost as much as possible, another fuzzy objective function is defined using the system operating cost. Fuzzy dynamic programming (FDP) is used to determine the optimal DLC scheme. The proposed DLC scheme of ACL can strike a balance between system operating cost reduction and system reliability improvement.

The cycling of ACL results in service interruption of air conditioning. The service interruption of ACL may cause discomfort of the customers. Therefore, ACL customers may be reluctant to participate in the DLC program if there is no economic incentive. In order to encourage ACL customers to participate in the DLC program, a compensation scheme should be proposed to give economic incentive to ACL customers. Interrupted energy assessment rate (IEAR) relates the customer losses caused by electric power interruptions to the worth of electric service reliability. The IEAR is a practical tool to assess the reliability worth and is a good index to provide appropriate compensation to ACL customers. Therefore, the IEAR is used in this thesis to determine the compensation to ACL customers for the service interruption of ACL caused by DLC program. The proposed DLC of ACL with considering IEAR is implemented in a Pool-Co power market which consists of energy market and spinning reserve market. The objective of the proposed DLC of ACL is to determine the optimal DLC scheme of ACL with the minimum system operating cost which is comprised of the energy cost, spinning reserve cost and compensation cost to ACL customers. Dynamic programming (DP) is used to solve the problem.

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List of Symbols

ξ	demand-price elasticity
Δd	demand change
d_0	base demand
$\Delta \rho$	price change
ρ_0	base price
ξ_{ii}	self demand-price elasticity
ξ_{ij}	cross demand-price elasticity
Δd_i	demand change at time slot i
$\Delta \rho_i$	price change at time slot i
$\Delta \rho_j$	price change at time slot j
E	demand-price elasticity matrix
$\Delta \mathbf{d}$	demand change vector at each node
$\Delta \mathbf{p}$	price deviation vector at each node
N_g	total number of generators
P_{gi}	real power output of generator i
Q_{gi}	reactive power output of generator i
P_{dj}	real power demand at node j
Q_{dj}	reactive power demand at node j
$C_{pi}(P_{gi})$	cost function of real power of generator i
$C_{qi}(Q_{gi})$	cost function of reactive power of generator i
$P_{gi}^{\min}$	minimum real power output of generator i
$P_{gi}^{\max}$	maximum real power output of generator i
$Q_{gi}^{\min}$	minimum reactive power output of generator i
$Q_{gi}^{\max}$	maximum reactive power output of generator i

$V_j^{\min}$	minimum voltage at node j
$V_j^{\max}$	maximum voltage at node j
$P_{li}^{\min}$	minimum real power flow allowed through line i
$P_{li}^{\max}$	maximum real power flow allowed through line i
$V_j \angle \delta_j$	voltage at node j
$V_k \angle \delta_k$	voltage at node k
$Y_{jk} \angle \theta_{jk}$	admittance between nodes j and k
N_l	number of power lines
N_n	number of nodes
λ_{pj}	Lagrangian multiplier of P_{dj}
λ_{qi}	Lagrangian multiplier of Q_{di}
$\mu_{pi \min}$	Lagrangian multiplier of $P_{gi}^{\min}$
$\mu_{pi \max}$	Lagrangian multiplier of $P_{gi}^{\max}$
$\mu_{qi \min}$	Lagrangian multiplier of $Q_{gi}^{\min}$
$\mu_{qi \max}$	Lagrangian multiplier of $Q_{gi}^{\max}$
$\mu_{li \min}$	Lagrangian multiplier of $P_{li}^{\min}$
$\mu_{li \max}$	Lagrangian multiplier of $P_{li}^{\max}$
$u_{vj \min}$	Lagrangian multiplier of $V_j^{\min}$
$u_{vj \max}$	Lagrangian multiplier of $V_j^{\max}$
p_j	probability of the system being in contingency state j
D_j	departure rate of system leaving contingency state j
F_j	frequency of the system departing contingency state j
d_j	duration in hours of the load curtailment arising due to contingency state j
A_i	availability of component i

λ_i	failure rate of component i
U_i	unavailability of component i
μ_i	repair rate of component i
N_g^j	total number of generators under contingency state j
N_n^j	total nodes under contingency state j
N_{ks}	number of customer sectors
$OC_{ks}(LC_{pks}, LC_{qks})$	interruption cost
LC_{pks}	real power load curtailment of load sector s at node k
LC_{qks}	reactive power load curtailment of load sector s at node k
NC	total number of contingencies
p_{sj}	probability of the system load curtailment under contingency state j
LC_j	load curtailment of the system under contingency state j
k	node number index
p_{njk}	probability of nodal load curtailment at node k under contingency state j
NLC_{jk}	nodal load curtailment at node k under contingency state j
$C(n, j)$	the least cumulative operation cost of the j th state at the n th stage
$FC(n, j)$	fuel cost of the j th state at n th stage
$SC(n-1, m : n, j)$	start-up cost from state $(n-1, m)$ to state (n, j)
$\{m\}$	the set of selected feasible states at the $(n-1)$ th stage
$u_{gi}(n, j)$	commitment state of the i th unit at the j th state of the n th stage
$P_{gi}(n, j)$	real power output of the i th unit at the j th state of the n th stage
$Q_{gi}(n, j)$	reactive power output of the i th unit at the j th state of the n th stage
$P'_{dk}(n, j)$	real power demand of node k at the j th state of the n th stage after DLC

$Q_{dk}'(n, j)$	reactive power demand of node k at the j th state of the n th stage after DLC
$V_k(n, j) \angle \delta_k(n, j)$	voltage of node k at the j th state of the n th stage
$V_l(n, j) \angle \delta_l(n, j)$	voltage of node l at the j th state of the n th stage
$Y_{kl} \angle \theta_{kl}$	admittance between nodes k and l
$RES_i(n, j)$	spinning reserve of the i th unit at the j th state of the n th stage
$REQ(n)$	spinning reserve requirement at the n th stage
$P_{dk}(n)$	real power demand of node k at the n th stage before DLC
$DLC_k(n, j)$	DLC capacity of node k at the j th state of the n th stage
$PB_k(n)$	real power demand payback of node k at the n th stage
K	DLC starting hour
T	time interval of each stage
$S_i(n)$	dispatch state of the i th ACL at the n th stage
$\max T_i$	maximum accumulated disconnection time of the i th ACL
$\min T_i$	minimum accumulated connection time of the i th ACL
$\tilde{D}_r$	Fuzzy set to represent the nodal reliability characteristic of the ACL groups connected to different nodes
$\tilde{u}_{D_r}$	membership function of $\tilde{D}_r$
$\tilde{u}_R(n, j)$	membership value of the reliability characteristic for different DLC schemes at the j th state of the n th stage
$ENLC_i$	expected load curtailment of the node where the i th ACL group is connected
$ENLC_{sum}$	sum of expected nodal load curtailment of all nodes where ACL groups are connected
$\tilde{u}_c(n, j)$	membership value of the cumulated system operating cost at the j th state of the n th stage
W_c	weighting factor for the operating cost

$C_{\max}(n)$	maximum accumulated system operating cost at n th stage
$C_{\min}(n)$	minimum accumulated system operating costs at n th stage
$\tilde{u}_s(n, j)$	membership value of the system spinning reserve at the j th state of the n th stage
SR_a	allowed least system spinning reserve
SR_s	satisfied secure system spinning reserve
$\tilde{u}_L(n, j)$	membership value of the load uncertainty at the j th state of the n th stage
M_+	past positive forecasting error
M_-	past negative forecasting errors
L_a	actual load
L_j	expected load
$\tilde{D}$	fuzzy decision set
P_{SRi}	SR provided by generator i
ρ	uniform SR price
SRR	system SR requirement
SRL_i	biddable SR limit of generator i
β_i	SR bid price of generator i
W_i	integer variable to denote the selection state of a particular bid from generator i
$RAMP_i$	ramp rate of generator i
P_i	real power output of generator i at time t
P_{t-1}	real power output of generator i at time $t-1$
CAP_i	available capacity of generator i
$ENCOST_k$	expected cost of the power interruption to customers at node k
d_{jk}	power interruption duration in hour at node k under contingency state j

$C_k(d_{jk})$	power interruption cost of duration d_{jk} in hour at node k under contingency state j
$IEAR_k$	Interrupted energy assessment rate at node k
$C(n, k)$	accumulated system operating cost with the selected candidate DLC dispatch state k at n th stage
$\{m\}$	feasible DLC dispatch state set at the n th stage with DLC dispatch state i at the $(n-1)$ th stage
$EC(n, j)$	energy cost arising from the energy market with DLC dispatch state j at the n th stage
$SC(n, j)$	SR cost with DLC dispatch state j at the n th stage
$CC(n, j)$	compensation cost for ACL customers with DLC dispatch state j at the n th stage
$C(n-1, i)$	least system operating cost with candidate DLC dispatch state i at the $(n-1)$ th stage

List of Acronyms

VDSLS	Voluntary Demand Side Load Shift
LSE	Load Service Entities
PX	Power Exchange
ISO	Independent System Operator
GenCos	Generation Companies
TransCos	Transmission Companies
DisCos	Distribution Companies
CEGB	Central Electricity Generating Board
NGC	National Grid Company
NETA	New Electricity Trading Arrangements
PJM	Pennsylvania-New Jersey-Maryland
FERA	Federal Energy Regulatory Authority
FTR	Financial Transmission Rights
NEM	National Electricity Market
NZEM	New Zealand Electricity Market
LMP	Locational Marginal Price
DLC	Direct Load Control
ACL	Air Conditioning Loads
OPF	Optimal Power Flow
UPFC	Unity Power Factor Controller
IEAR	Interrupted Energy Assessment Rate
CDF	Customer Damage Functions
RTS	Reliability Test System
SFE	Supply Function Equilibrium
SIC	Standard Industrial Classification
ELCP	Expected Load Curtailment Probability
ELCF	Expected Load Curtailment Frequency
ELC	Expected Load Curtailment

EENS	Expected Energy Not Supplied
PNLC	Probability of Nodal Load Curtailment
FNLC	Frequency of Nodal Load Curtailment
ENLC	Expected Nodal Load Curtailment
ENENS	Expected Nodal Energy Not Supplied
FDP	Fuzzy Dynamic Programming
DP	Dynamic Programming
ALE	Aggregated Load Entity
SR	Spinning Reserve
SRR	Spinning Reserve Requirement
SRL	Spinning Reserve Limit

Chapter 1 Introduction

1.1 Motivation

The electric power industry has been dominated by national or regional utilities for nearly one hundred years around the world. The national or regional utilities have an overall authority over all activities in generation, transmission and distribution of power within their domain of operation [1]. Electric energy and other ancillary services such as spinning reserve, frequency control, and reactive power generation are closely coordinated under one control and dispatch center in a large area. Unit commitment and economic dispatch are centrally controlled and managed by the system operators. Electricity prices are usually determined by the regulatory body, and uniform price policy is implemented for the same type of customers at different locations. Such utilities are often referred to as monopoly utilities because they are the only electricity providers in the region and are obligated to provide electricity to everyone in the region.

From its beginning in Chile and the UK in the 1980s, restructuring of power systems has spread almost throughout the world, especially in the more developed countries [2]. Power system restructuring has occurred in both industrialized countries and in developing countries. The restructuring around the world varies in extent, scope and detail. But in general, the basic objective of restructuring of power systems is to supply electricity to customers by relying less on public enterprise and regulated monopoly, and more on market mechanisms such as private ownership and competition. In restructured power systems, a single power utility is usually separated into different generation companies (GenCos), transmission companies (TransCos) and distribution companies (DisCos), and retail companies [1]. Various market models have been implemented by different countries to cater for their economic considerations, public policy needs, system physical situations, etc. In general, these market models can be categorized into PoolCo model, Bilateral Contracts model and Hybrid model [3].

The objectives of restructuring are to increase efficiency, reduce costs, and improve quality of service by introducing competition. The restructuring of power systems provides more choices to market participants in the way they trade electricity and ancillary services. Electricity price is driven by market forces and is determined by generation companies' bids, system demands and system constraints. Economic segregation and service unbundling have changed the mechanism of conventional system planning and operations. The expected benefits of power system restructuring are cheaper electricity through competition and innovation, and improved generation and planning efficiency and economics.

Although there are many promising benefits of power system restructuring, it has incurred numerous problems, including generation capacity shortages, transmission congestions, wholesale price volatility, and reduced system reliability, etc. [4]. These problems have created new opportunities for technologies and business approaches that allow load serving entities and other aggregators to control and manage the load patterns of wholesale and retail end-users they serve. These technologies and business approaches for manipulating end-user load shapes are known as load management.

Load management has re-emerged as an important element in the fine-tuning of newly restructured power systems [5]. Load management includes everything from direct control of small customer end users to voluntary load shedding by large commercial/industrial customers. Load management has experienced explosive growth in number and participation over the past few years. The resurgence of load management stems from its rediscovered value as a dual hedge against reliability risks such as generation shortfalls and transmission congestion as well as financial risks such as wholesale price spikes [5]. The versatility of load management has attracted the interest of many market participants in both traditional and newly restructured power systems.

Some of the load management issues in restructured power systems are discussed and presented below.

Voluntary demand side load shift

In some restructured power systems, the conventional “same for all customers” electricity price is replaced by the nodal prices also known as locational marginal prices to relate price with usage of generation and transmission equipment. The nodal price is the locational marginal cost of power supply and is determined by generation bids, demands and system constraints. It fluctuates with time and location. The customers face a more volatile electricity price in restructured markets. If electricity price increases due to demand increase or system failure, customers will adjust their profile of electricity consumption to avoid high electricity cost. Customers may mitigate demands from time periods of high electricity price to time periods of low electricity price. The demand adjustment will influence the electricity price in return. The correlation between elastic demands and electricity is called demand-price elasticity and the resulting demand side load shift is known as voluntary demand side load shift.

Demand-price elasticity has been studied in references [6-13]. However, the existing techniques focus on the modeling of demand-price elasticity for different types of customers and the effects of demand-price elasticity on price and demand. The impacts of the resulting voluntary demand side load shift on system and nodal reliabilities of restructured power systems have not been studied in all these techniques. It is well known that the voluntary demand side load shift can improve the system and nodal reliabilities of restructured power systems. Therefore a methodology which can quantitatively investigate the impacts of demand-price elasticity on reliability and price volatility is essential for restructured power systems. It will provide the independent system operator a useful tool to assess the actual reliability of restructured power systems.

Impact of nodal reliabilities on DLC of ACL

Direct load control (DLC) of air conditioning loads (ACLs) is the most common load management program used to reshape the load curve and to shave the system peak load by cycling the ACL. The resultant peak load shaving can improve the system reliability

of restructured power systems. Perceived low reliability of restructured power systems is one of the problems accompanying the restructuring of power systems. The challenge therefore is how to improve the system reliability as much as possible while keeping the system operating cost minimum.

In a practical power system, the GenCos and the load centers are located at different buses which are connected together by the transmission system. The transmission system delivers power from GenCos to load centers. Due the locations of the GenCos and the load centers and the topology of the transmission system, the reliabilities at different buses, also known as nodal reliabilities, are different in most cases. Normally, the system operator is responsible to carry out the contingency study to determine the nodal reliabilities using the specified reliability indices.

In a power system, ACLs are connected to different nodes of the system and the nodal reliabilities are different. Therefore, the same amount of ACL reduction at different nodes will have different impacts on system reliability improvement. The DLC scheme of ACL considering nodal reliability characteristics is needed for the system operator of restructured power systems in order to improve the system reliability as much as possible while keeping the system operating cost minimum.

Compensation scheme for ACL customers

The cycling of ACL due to DLC of ACL will cause service interruption and therefore discomfort to ACL customers. If there is no compensation for the ACL customers, they will be reluctant to participate in the DLC program of ACL. It is therefore necessary to determine an appropriate compensation scheme for the service interruption due to the cycling of ACL by the DLC of ACL.

The reshaping of the system load curve and system peak load shaving will change the energy cost and system spinning reserve cost. The determination of an optimal DLC

scheme of ACL should consider the system energy cost, system spinning reserve cost and compensation for the ACL customers.

Based on the above-mentioned issues of the load management study for restructured power systems, the following research was carried out:

- Develop a methodology to assess the reliability improvement and nodal price volatility reduction for restructured power systems with demand-price elasticity.
- Develop a fuzzy logic-based DLC technique of ACL considering nodal reliability characteristics for restructured power systems with the objective of improving system reliability as much as possible while keeping the system operating cost minimum, the fuzzy logic technique is used to deal with the load uncertainties and the multiple objective optimization problem.
- Develop an appropriate compensation scheme for service interruption due to DLC of ACL and determine the optimal DLC scheme of ACL with minimum system operating cost which includes energy cost, spinning reserve cost and compensation for ACL customers.

1.2 Contributions

A methodology is proposed to investigate the effects of the voluntary demand side load shift based on the correlation between demand and electricity price on reliability and price volatility of restructured power systems. Demand price correlation is studied using the demand-price elasticity matrix. In the demand-price elasticity matrix, the diagonal elements are the self-elasticities which represent the demand change of one time slot corresponding to the price change in the same time slot; the off-diagonal elements are cross-elasticities which represent the demand change of one time slot corresponding to the price change in other time slots. An iterative method is used to determine the demand

side load shift due to the demand price correlation. OPF is utilized to determine the nodal electricity price with and without voluntary demand side load shift which uses Lagrange multipliers as shadow prices. Customer damage functions (CDF) are integrated into the conventional OPF to evaluate the reliability of restructured power systems with and without voluntary demand side load shift. The IEEE reliability test system, RTS [14], is simulated to illustrate the proposed technique.

A fuzzy logic-based DLC technique of ACL considering nodal reliability characteristics is also proposed for restructured power systems. The effect of transmission network reliability on the DLC scheme is considered and represented using nodal reliability indices for the restructured power systems. The nodal reliability indices are used to formulate a single objective function to achieve maximum system reliability improvement. At the same time, the fuzzy objective function is defined using the system operating cost to keep the system operating cost minimum. Fuzzy dynamic programming (FDP) is used to determine the optimal DLC scheme of ACL which strikes a balance between system reliability improvement and system operating cost reduction.

A compensation scheme is proposed for ACL customers using interrupted energy assessment rate (IEAR) for the service interruption of ACL due to the cycling of ACL by DLC. IEAR is a factor that relates the customer losses caused by electric power interruptions to the worth of electric service reliability [12]. It is a practical tool to assess the reliability worth. The compensation scheme will eliminate the ACL customers' reluctance to participate in DLC program of ACL. A DLC technique of ACL is proposed considering the proposed compensation scheme for ACL customers. The reshaping of the system load curve will change the system energy cost and spinning reserve cost. The study of DCL of ACL considering IEAR is therefore implemented in the framework of the PoolCo electricity market which considers energy and spinning reserve markets. Dynamic programming (DP) is utilized to obtain the optimal DLC scheme of ACL with the minimum system operating cost. The system operating cost includes energy cost, spinning reserve cost and compensation for ACL customers. The IEEE RTS is simulated to illustrate the proposed DLC technique of ACL.

1.3 Organization of the Thesis

This chapter describes the motivation of the load management study for restructured power systems. The objectives and contributions of the research work are also presented in this chapter.

In Chapter 2, the history of power system restructuring around the world is introduced to provide background details for the proposed research. Market models and market entities of restructured power systems are described. Nodal price and price volatility, reliability evaluation techniques, load management concepts, and fuzzy set theory application to power systems are reviewed in this chapter.

In Chapter 3, the correlation between demand and price in restructured power systems is investigated using the demand-price elasticity matrix. Voluntary demand side load shift due to this correlation is determined using an iterative method and its effects on reliability improvement and nodal price volatility reduction are quantitatively studied.

Chapter 4 proposes a fuzzy logic-based DLC scheme of ACL considering nodal reliability characteristics which can strike a balance between system reliability improvement and system operating cost reduction.

In Chapter 5, a compensation scheme is proposed based on IEAR for ACL customers to eliminate their reluctance to participate in the DLC program. A DLC scheme of ACL considering such a compensation scheme is proposed to achieve the minimum system operating cost. The system operating cost includes energy cost, spinning reserve cost and compensation for ACL customers.

The conclusions of the thesis and some recommendations for future work are presented in Chapter 6.

Chapter 2 Literature Review

In order to have an overview of the research work, the literature on load management, reliability evaluation and pricing problems, and the related techniques for restructured power systems are briefly reviewed in this chapter. Firstly, monopoly power systems and restructured power systems are discussed in Sections 2.1 and 2.2, respectively. After that, electricity pricing and reliability evaluation techniques of restructured power systems are presented in Sections 2.3 and 2.4, respectively. Finally, Load management techniques and fuzzy set theory application in power systems are discussed in Sections 2.5 and 2.6, respectively.

2.1 Monopoly power system

The electric power industry has over the years been dominated by large utilities which had an overall authority over all activities in generation, transmission and distribution of power within their domain of operation [1]. Such utilities are often referred to as monopoly utilities because they are the only electricity providers in the region and are obliged to provide electricity to everyone in the region.

Figure 2-1 shows the typical structure of a monopoly power system where links of information flow exist only between the generators and the transmission system, and money flow is unidirectional from the customer to the electricity utility [1].

Figure 2-1 Typical structure of monopoly power systems

The operation and control issues for monopoly power systems have been widely examined over the years. The basic objective of operation in such vertically integrated power systems is to minimize the total system cost while satisfying all system constraints. Apart from operational issues, planning issues of monopoly power systems are also centrally managed. All activities such as long-term generation and transmission expansion planning, medium term planning activities such as maintenance, production and fuel scheduling are coordinated centrally.

2.2 Restructured Power Systems

2.2.1 History

In the 1990s, many electric utilities and power network companies all over the world were forced to change their ways of doing business, from monopoly to decentralized operating mechanisms through power system restructuring.

One of the steps in the restructuring process of the power industry was the separation of the transmission activities from the electricity generation activities. The subsequent step was to introduce competition in generation activities, either through the creation of power pools, provision for direct bilateral transactions or bidding in the spot markets [1].

The transmission system has significant economies of scale and consequently has a tendency to become a monopoly. Therefore, it was necessary to continue regulation in transmission so as to prevent it from overcharging for its services. The transmission grid became a neutral, natural monopoly subject to regulation by public authorities. In order to overcome the monopoly characteristic, the trend has been to establish new legal and regulatory frameworks to offer third party open access to the transmission network.

A system operator, known as the Independent System Operator (ISO) or Regional Transmission Operator (RTO), is established for the entire system and it is entrusted with the responsibility of keeping the system in balance, i.e., to ensure that the production and imports continuously match the consumption and exports. This operator is required to be an independent authority without any involvement in the market competition; nor could it own generation facilities for business (except for owning some capacity for emergency use). The system operator ensures the efficient and reliable delivery of power supply by removing transmission barriers between power sellers and buyers.

Figure 2-2 shows the typical structure of a restructured power system with links of energy, information and money (cash) flow between the various market players. Note that this is not a universal configuration and that there exist variations across countries and systems.

Figure 2-2 Typical structure of a restructured power system

Restructuring in the electric power industry has led to the segregation of the traditional vertically integrated electric power systems. The traditional utility is separated into different generation companies, transmission and distribution companies, and retail companies [1]. The restructuring of the electric power industry occurred not only in

industrialized countries but also in developing countries around the world. Different market models have been developed and implemented in different countries or states to cater for the system physical situations, economic considerations, public policy needs, etc. Typical examples of restructured power systems are presented below.

South America

South America was seen as the pioneer in the process of power industry restructuring [16]. Chile was the first country to start the restructuring process in 1982 and other Latin American countries such as Argentina (1992), Peru (1993), Bolivia (1994), Colombia (1994), and Brazil (1996) followed suit [17]. The power system restructuring in South America was very successful: in Chile the power losses in the transmission and distribution networks came down from 21% in 1986 to 8.6%; in Argentina the average electricity price reduced from 39\$/MWh in 1994 to 32\$/MWh in 1996 and the availability of thermal generation units increased from below 47% in 1992 to 75% in 1996 [1, 14, 15].

The centralized PoolCo model was used in the wholesale electricity markets of these countries to dispatch generation units based on their bids and physical constraints. Moreover, the long term bilateral contracts are also guaranteed among market participants by establishing open and nondiscriminatory access of transmission and distribution networks [1, 19]. The nodal pricing scheme was adopted in these power markets.

United Kingdom

U.K. was the first developed country to start the power industry deregulation. It was widely recognized that the U.K. led the power industry restructuring around the world [20] and was seen as a typical example in developed countries.

The privatization of state-owned industries such as Aerospace, Telecommunication, Airways and Steel was initiated in the early 1980s [1-3, 19]. Actually the last major state-owned industry to be deregulated was the electric power industry and the process of privatization began in 1988 ([19, 21]) with the implementation of the Electricity Act. The Central Electricity Generating Board (CEGB), which owned nearly 60,000 MW of capacity and all high voltage transmission lines in Britain, was broken into four independent companies [1, 19]: National Power, Power Gen, Nuclear Electric and National Grid Company (NGC), where the Nuclear Electric and NGC are state-owned companies. The NGC is responsible for the management and maintenance of the transmission grid and setting up of transmission prices. The NGC also operates the centralized power pool and assumes the role of the independent system operator (ISO) with the responsibility of promoting competition and managing the activities of the market [22]. The electricity distribution companies emerged from the former privatized regional area boards [19].

From 1990 to 2001, the system marginal price (SMP), which was the cost of the generation from the most expensive generation set accepted and was the single clearing price in the electricity spot market, was used. The day-ahead model is used in U.K., in which the next day system load is estimated by the NGC and represented by 48 half-hour portions. The GenCos must submit price-quantity bids represented by blocks and a set of operation parameters (minimum load, ramp rate, etc.) to the power pool. Based on the submitted bids the system cost is minimized and the last accepted bid is accepted as the system price for every half hour [23] if no system constraints are violated.

The potential concerns from the government about high price volatilities and market power caused by duopolists has greatly increased. In 1994 the two major electric-power companies - National Power and Power Gen were forced by the regulator to sell 15% of their capacities and agree to a two-year price-cap in the pool [23].

In 2001, the Electricity Pool set up in 1990 was replaced by the New Electricity Trading Arrangements (NETA). The NETA was extended to cover Scotland under the British

Electricity Trading & Transmission Arrangements from 2005, and continues to evolve as new rules are discussed and accepted [2].

United States of America

The USA has the largest number of electricity markets around the world. Till now, the power markets in the USA include California, the Pennsylvania-New Jersey-Maryland (PJM), New England, New York and Texas. Unlike most other countries, individual states in the US, with the exception of the ERCOT part of Texas, are under the jurisdiction of Federal Energy Regulatory Authority (FERC) and hence do not have an unfettered right to develop their own markets. Rather, FERC has allowed various alternative market designs, including the spectacularly unsuccessful original California market, directed by the Energy Policy Acts of 1992. The first Regulatory Act on the deregulation process in USA was initiated in 1978 [24]: the non-utility generators were allowed to enter the wholesale power market. Following the first Regulatory Act, the 1992 Energy Policy [25] Act ordered the electric power industry to become restructured and asked the FERC to facilitate the restructuring. In 1996, the FERC issued the Order 888 [26] and Order 889 [27]. The goal of Orders 888 and 889 was to increase competition by allowing the market participants to access the "non-discriminatory transmission services" through public utilities. The primary aim of Orders 888 and 889 was to eliminate the undue discrimination and to bring more competition to the power industry [1, 19, 21].

The California power market was the first power market in USA, which was opened in 1998. From 1998 to now, zonal pricing mechanism has been implemented in the California Power Exchange [28], which acted as the wholesale spot market. The replacement of zonal pricing methods by nodal pricing methods has been delayed. Bilateral contracts were discouraged in the original California market, which is a major reason for the problems that occurred there. The California market crisis prompted the rushed signing of various long-term bilateral contracts.

The PJM interconnection has the largest electric power market in the world and is one of the largest power grids in North America, which coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbus [3, 29, 30]. Currently there are more than 200 market participants in the PJM power market. From 1997 to 1998 the uniform pricing scheme had been used in the PJM power market like the U.K. [28]. Since 1998, nodal pricing methods have been implemented to evaluate electricity prices at every bus and to manage congestion. Financial transmission rights (FTR) developed by Reference [31] are used to hedge the risk of high transmission cost caused by congestion in PJM. Bilateral contracts among the market participants are also allowed in the PJM interconnection.

Australia and New Zealand

The National Electricity Market (NEM) of Australia [1, 18, 33] was established in 1998 and the market structure is a centralized power pool. In NEM, the electricity can be traded through spot market, bilateral contract and vesting contract. In addition to these, there exists a secondary market to hedge risk [1]. The zonal pricing methods have been used in the spot market of NEM: electricity price at every region for each half hour is evaluated by the system operator.

The New Zealand Electricity Market (NZEM) was created in 1996. The Electricity Market Company has conducted its trading, which is based on a day-ahead settlement from bids submitted at half-hour blocks [1, 33]. Nodal pricing methods have been used in the spot market of NZEM. Moreover, the NZEM is a typical hybrid market structure: market participants can sell or buy electricity either from a centralized power pool or directly through bilateral contracts.

2.2.2 Market Structures

Markets have existed since 600 B.C. and are treated as a mechanism for matching the supply and demand for a commodity through the discovery of an equilibrium price [34]. A power market is defined as a place where electricity and ancillary services can be traded. There are different power markets based on trading rules between sellers and buyers. These market models can be classified into PoolCo, Bilateral Contract and Hybrid models [3].

PoolCo model

A PoolCo is defined as a marketplace where market participants submit bids to trade electricity and other ancillary services. The submitted bids to the PoolCo include energy bids or/and ancillary service bids and may include some physical parameters of generation units which depend on the corresponding market rules. A set of the bids are selected by the ISO according to the previously agreed rules [35]. Unlike the bilateral contract model, GenCos must compete for the right to sell electricity and other ancillary services to the power pool, not to specific customers. DisCos and large customers must also submit their bids to compete for buying power from the power pool, not from specific GenCos [1, 3].

The bids submitted by GenCos to the PoolCo should include different information on their operations [1]. In some markets, the GenCos are required to supply the energy bid supply, the associated price, the start-up price offers, ramp rates, minimum up and down times, etc. The PJM power market is a typical example of these markets. In PJM and the New York (NY) power market, the ISO uses the unit commitment model to obtain the generation dispatch and commitment schedules [36]. However, in the NZEM market, the ISO assumes that the GenCos have carried out their own unit commitment schedules while submitting their energy bids to the PoolCo [33]. In the U.K. pool, ISO carried out a centralized unit commitment schedule based on the energy prices, ramp rates, offered capacity, generation level, and other constraints [1]. In 2001, self-commitment replaced

the centralized unit commitment in the Electricity Pool in England and Wales which was a significant element of the New Electricity Trading Agreements for the wholesale power.

Currently there are three pricing methods for the PoolCo model in the existing power markets [28]: a single price for the whole power system, which is called the uniform price; several prices for the system but only one price for a given region, which is called the zonal price; different prices at different nodes, which are called nodal prices. More details about these pricing methods are presented in the next section.

Bilateral Contract model

In a bilateral contract market, the participants trade electricity or/and ancillary services directly through negotiated bilateral contracts. The establishment of open and non-discriminatory access to the transmission services makes direct delivery and reception of electricity between seller and buyer possible in most restructured power systems. But the effect of bilateral contracts must be represented in the pool from the perspective of transmission and the prices for transmission must be charged to bilateral contracts. Therefore, bilateral contracts are not independent of the centralized pool. Typical characteristics of the bilateral contract model are described below [1, 3, 35]:

- Supply (price, quantity and locations) is determined by contract between any two market participants, which is independent of the ISO.
- The role of ISO is limited to system security management, congestion management and reliability/security aspects.
- Access to the transmission and distribution services is acquired by paying the usage charges.
- Generation resources scheduled and dispatched in the bilateral contracts are independent from the generation resources in the centralized power pool.

The bilateral contract model is extremely flexible for the market participants to state explicitly the terms and conditions they expect. However, its disadvantages come from the high price of negotiating and writing contracts and the cost of assessing

creditworthiness of counterparties [35, 36]. The role of ISO in the bilateral contract model is to check the status of the system reliability and security, the load levels and transmission capacity availability, etc. If needed, it will arrange additional transmission capacity and ancillary services, or curtail some transactions based on the system security requirements and market rules [1]. The long term bilateral contracts are very popular in electricity markets in Scandinavian countries. About 70% of electricity trading is directly negotiated among market participants in the Norwegian market [37]. In NYMEX future markets, there is correlation between the indexed bilateral contracts and the spot markets.

Hybrid model

The hybrid model combines various features of the previous two models [3, 35]: customers can either buy electric energy from a spot market or through contracts with suppliers. Suppliers can also sell electricity directly to buyers or to a spot market. A customer can also sign a long-term contract with a supplier to reduce the risk of price in a spot market.

Hybrid market structure has been popularly implemented in the power industry worldwide like South America, PJM, California and Australia, etc., due to its flexibility for accommodating the different market participants' reliability, price and the related risk requirements. The PJM interconnections and the California ISO (CISO) [29] are two typical examples of practical hybrid markets. The PJM provides flexible choices for trading electricity and ancillary services (reliability and security, etc.) through the centralized power pool or by bilateral contracts. The market participants in California ISO may choose to self-provide energy and/or the ancillary services that are required to support their energy schedules. They may also opt for the ISO to procure energy and/or the required ancillary services on their behalf.

The main entities of restructured power systems can be categorized into ISO and independent market participants [3, 35] who resulted from the economic segregation of a vertically integrated power system and open access to the transmission network

previously controlled and owned by the utility. The ISO is responsible for the reliable system operation and for setting market regulations. Three main market participants are discussed in this sub-section: GenCos, TransCos and DisCos.

ISO: An independent system operator (ISO) is the most important market entity in the operation of restructured power systems. The ISO controls the operation of transmission network and manages the ancillary services to maintain the system reliability and security. The ISO is a non-profit entity, which should be independent of other market participants such as GenCos, TransCos and DisCos [35]. The ISO should also supervise and coordinate Transcos to provide open and non-discriminatory services to all market participants.

GenCos: The independent GenCos are created from the economic segregation of a vertically integrated generation system. GenCos may own one or more generating plants of different technologies [35, 38]. Currently most power markets provide flexible choices to the GenCos for electricity trading: GenCos can not only sell electricity to a centralized power pool or a PX but can also sell electricity to customers directly through bilateral contracts. Other ancillary services which can be provided by GenCos include reactive power support, capacity reserve, spinning reserve, etc.

TransCos: The transmission network is the key for the reliable operation of restructured power systems [35]. Therefore the ISO has the responsibility to instruct the corresponding transmission companies to operate their equipment [20, 39]. TransCos are defined as transmission companies owning one or more transmission lines and other transmission equivalents such as FACTS and transformers. TransCos deliver electric power from GenCos to DisCos by using the high voltage transmission system [35]. In most restructured power systems, the TransCos are still controlled by public utilities and the number of these TransCos is limited. However, the open access services of the transmission network are provided to all market participants without discrimination, which are regulated and supervised by the authority of government.

DisCos: DisCos are defined as distribution companies which deliver electric energy from bulk load points to different customers through the distribution network. The DisCos are also responsible for the reliable operation of their distribution system [35]. DisCos can be large users which are sometimes connected directly to the transmission system [20], or aggregators of many small customers.

The proposed load management is implemented in restructured power systems. The PoolCo market model is used to carry out the proposed study. The system operator takes the responsibility to determine the optimal load management schemes to improve system reliability and to reduce system operating cost at the same time.

2.3 Nodal Price in Restructured Power Systems

2.3.1 Nodal Price Characteristics

In conventional power systems electricity prices are centrally controlled by the system operators based on price regulations from the government body, and prices are fixed for the same sector customers at different locations. In the restructured power system, electricity prices are no longer fixed but vary with time and/or locations, which can be determined according to the power market structure, generation biddings, locations of demands, and customers' choices on price and reliability.

The basic theory of real time pricing of electricity was developed in Reference [40]. Basically, there are three spot pricing systems prevalent in the present power markets [28] around the world. The first pricing system is that there is only a single price for the entire system, which is called the uniform marginal price. The power markets implementing such pricing systems include [28]: the electricity market in U.K. [1] (1990 - present), the previous PJM market (1997-1998), the previous New England market (1999 - 2003), the Sweden market (1996 – present) and the Finland market (1998 - present). The second pricing system stipulates several prices in the market but only one price in a given zone, which can be named as the zonal marginal price [28]: The California market (1998 –

present), the Norway market (1991 - present) and the Denmark market (2000 - present) are typical examples implementing zonal marginal pricing system. The third pricing system is the nodal pricing system. Different from the single-price structure in conventional system and the uniform marginal price structure, the nodal price varies both in time and in node on the transmission system [28, 41]. A real time pricing method was proposed to implement the real time electricity pricing of both the energy and selected ancillary services which can be extended to incorporate constraints on power quality and environmental impact [42]. Typical examples of power markets implementing the nodal pricing systems are the PJM market [29] (1998 - present), New Zealand market [1, 28] (1996 - present), New York Market [43], the Chile market (1991 – present) and the Argentina power market (1992 - present).

The optimization model based on the nodal pricing system respects the physical laws of electricity and network configuration as established by the *Kirchoff's laws* and other constraints of generation dispatch. In the model for uniform pricing system, the demand is the aggregate load of the entire system and the power flow is reduced to a simple equality constraint. The model based on the zonal pricing system ignores the intra-zonal constraints but respects physical constraints among inter-zones.

From a theoretical view, the economic efficiency and fairness in nodal pricing system are much better than those in uniform pricing system and zonal pricing system because the losses and constraints of transmission network are explicitly considered in the model. In a recent research, Reference [28] showed that the total social surplus can be the same among the three pricing systems if dispatch is according to the results of an optimal power flow calculation that maximizes total social surplus while respecting transmission constraints and losses, but pricing for settlement is according to a uniform or zonal pricing approach, with constrained-on and off payments, however the surplus is distributed to market participants in different ways. Constrained-on and off generators receive perverse incentives with respect to generation expansion under uniform or zonal pricing. Therefore, the generation expansion incentives under the nodal pricing system can be better than the one under the uniform pricing system or the zonal pricing system.

More and more power markets are now using or planning to adopt the nodal price system. However, some critics allege that the market participants are confused with the great number of prices [28] – e.g., the customers at some nodes are not satisfied with the relatively high prices because of transmission losses and congestion. Therefore, in some power markets, nodal pricing system is only implemented on the supply side while uniform pricing system (Singapore market) or zonal pricing system (New York market) is used on the demand side. Moreover, the Financial Transmission Rights (FTR) developed by Reference [27] is used to maintain short-run efficiency through the calculation of transmission prices and to hedge the risk of high transmission cost caused by congestion in the nodal pricing system.

A lot of research work has been carried out to study nodal prices, but the tie of the nodal prices to the long term price signals is not fully developed due to implementation acceptance. In the recent research, the techniques for nodal pricing have been summarized in References [28, 42] and the proposed pricing model includes selected ancillary services, power quality and environmental impact. Reference [41] presents a method to decompose nodal prices into different components corresponding to the generation, transmission congestion and other constraints. The information about these components can be used to design a penalty scheme to control price risk caused by system outages and to improve the economic efficiency of congestion management. Reference [44] proposed a technique to compute the sensitivities of nodal prices with respect to power demands. The technique can help the ISO to evaluate the degree of competitiveness of restructured power systems and for the market participants to build their bidding strategies. In Reference [45], the transmission-constrained residual demand derivative was characterized by using DC power flow model. The condition under which the residual demand derivative is bounded or unbounded was characterized when there are perfectly elastic supplies/demands at some buses in the systems. A nodal price control mechanism for the allocation of transmission network cost has been proposed in Reference [46]. The proposed mechanism has been designed to recover the required transmission revenue from the resulting congestion rent by creating the nodal price

differences. In Reference [47] the nodal pricing system has been discussed for distribution networks which is used to improve the economical efficiency of locating distributed generation resources. References [49-51] proposed a comprehensive optimization model for the dispatch of power networks under mixed pool/bilateral trading. It has been shown in these papers that the increased bilateral contracts without sufficient coordination with the operation of centralized power pool may lead to high nodal prices and transmission congestion. Reference [51] introduced an extended PoolCo model to evaluate the nodal prices of electricity and reserve capacities. Reference [10] discussed the effect of the elasticity of demand for electricity, and how different types of customers react to the price volatilities. In Reference [52], the OPF techniques and Monte Carlo simulation have been used to forecast the electricity prices with the consideration of associated volatilities and risks. The technique for evaluating the cost of reactive power in a restructured power system has been proposed in Reference [53]. Reference [54] suggested that the proposed technique can be used to price reactive power. In Reference [55] a formulation has been proposed to price both active power and reactive power in the new environment. A method used to forecast nodal prices by using artificial intelligence has been proposed in Reference [56].

In restructured power systems, the nodal prices are often determined using the OPF techniques.

2.3.2 OPF Techniques for Price Determination

The OPF techniques have been studied in electric power engineering since the 1970s. In the conventional economic dispatch problem, the system demand is aggregated from the load in the entire system. When more complicated AC or DC network constraints are used to replace the simplified system demand-supply balance equation, the economic dispatch is OPF. The OPF is defined as a linear or nonlinear optimization problem that determines optimal values for control variables while satisfying system physical and operational constraints [57].

With the restructuring of the electric power industry, the OPF techniques have been used to obtain the economic information regarding system operation. OPF plays a crucial role in power markets around the world. The Lagrange multipliers evaluated by the solutions of OPF can be explained as the derivatives of the objective function with respect to the respective constraints [19]. Therefore the Lagrangian multipliers correlated with the power flow equations are interpreted as the marginal costs of electric power injected from the system to the corresponding nodes (nodal prices).

Reference [54] shows that optimal power flow could be a very promising model for calculating nodal prices. An optimal power flow model used to calculate the spot price and analyze its effects was first utilized in Reference [58]. Reference [59] proposed an OPF model to calculate nodal prices of both active power and reactive power by using interior point methods. The nodal prices have also been decomposed into the components from the corresponding Lagrangian multipliers to represent the selected ancillary services in restructured power systems. The impact of unified power flow controller (UPFC) to nodal prices has been discussed in Reference [60] by using the OPF technique.

In the area of OPF solution techniques, References [61] and [62] have reviewed and discussed the relative merits of different mathematical programming algorithms used in the OPF. In Reference [63], the publications are classified according to the optimization techniques. In recent research, an ordinal optimization theory-based algorithm has been proposed in Reference [64] to solve the OPF with discrete control variables. A relatively good enough solution set can be obtained by using this algorithm. Reference [65] proposed a primal–dual interior point method to improve the optimal power flow convergence by using the filter technique to choose the search step length and search direction. An OPF technique based on the non-linear interior point method has been introduced in Reference [66] to handle new functional type inequality constraints, e.g., network congestion, generation bundling and price response demands. Reference [67] proposed a dynamic OPF model based on the non-linear interior point method. In the proposed model time-correlated and time-separated constraints are considered. An interior point algorithm has been used in Reference [68] to solve the large scale

hydrothermal optimal power flow problems. The Benders decomposition technique has been proposed in Reference [69] for solving a dynamic OPF considering transmission network constraints. A genetic algorithm has been introduced in Reference [70] for solving the OPF with both discrete and consecutive control variables. An OPF technique considering the transient stability constraints has been proposed in Reference [71]. The OPF with transient stability constraints has been equivalently converted into a classic nonlinear optimization problem in the Euclidean space. The converted problem can be solved by any non-linear programming techniques. The stability-constrained OPF has also been discussed in Reference [72], in which the dynamic equations of stability constraints have been approximated by equivalent algebraic equations. The direct nonlinear primal-dual interior-point method has been proposed in Reference [73] for solving the transient stability OPF. Jacobian and Hessian matrices of the transient stability constraints have been derived for using the interior-point method. Reference [74] proposed an OPF model with the multi-contingency transient stability constraints. The problem has been solved by a primal-dual Newton interior point method. In Reference [75], the models of VAR compensator, generator and exponential load have been incorporated into the stability-constrained OPF and their effects have also been studied. Reference [76] discussed the OPF with complementary constraints. The proposed method can be applied in such problems: maximum stability problem, multistage maximum stability margin problem and voltage security-constrained optimal power flow. The existence of an optimal power flow solution in the search space has been discussed in Reference [77].

In the field of OPF application, an extended OPF model for a restructured power system operation considering relatively comprehensive constraints, e.g., power quality and environment impact has been summarized in Reference [42]. In recent research, an expected-security-cost OPF model has been proposed in Reference [78]. The objective of the proposed model is to minimize the total expected system cost, which includes both expected operation cost and expected security cost. Reference [79] presented a detailed OPF formulation for integrated market systems for procuring, pricing, and settling energy and ancillary service in simultaneous auctions. The optimal dispatch model under the

hybrid market structure has been comprehensively discussed in [49-50]. In these papers, the problem of how pool/bilateral trading influences the market performance, the performance of firm and non-firm bilateral contracts under various curtailment strategies and the revenue derived from the pool and bilateral trading have been examined. A comparative analysis of various schemes using different OPF models to relieve network congestion has been presented in Reference [80] to assess their efficiency and effectiveness. Reference [81] proposed a security constrained OPF model. The economic operation of FACTS-devices in restructured power systems has been considered in the model. An OPF model has been introduced in Reference [82] to evaluate the optimal balance between preventive and corrective security actions, which is based on the Benders decomposition technique.

In the proposed load management study in restructured power systems, the OPF technique is utilized to determine the nodal prices. The Lagrangian multipliers are used to determine the locational marginal cost-nodal prices. Therefore, the effects of the proposed load management schemes on system operating cost are investigated.

2.4 Reliability Evaluation and Reliability Worth Evaluation Techniques

The techniques used to evaluate the reliability of a conventional power system are well developed [83-94], and provide the basic tools to logically analyze the reliability of restructured power systems. Reliability studies are focused on the impact of system random variation to the system safety. This random behavior is often described as a random process (stochastic process). The random behavior of systems varies with time and space discretely or continuously and therefore stochastic processes can be classified into four categories according to whether their state-spaces and time are continuous, and discrete [92]. A stochastic process can be modeled as the Markov process if the process has the characteristics of being memoryless and stationary. Generally speaking the Markov process models are the basis for reliability assessment of power systems. In basic

reliability evaluation studies, the state space model is usually represented by discrete and identifiable states [92] and time is modeled as continuous.

The reliability evaluation methods for power systems can be classified into two categories: analytical methods and Monte-Carlo simulation methods [84, 92, 93].

The reliability indices evaluated by analytical techniques are usually obtained from direct mathematical solutions [92]. The computational resources required by the analytical techniques are less than those required by simulation methods. However, analytical techniques usually can only provide expected values of reliability indices such as loss of load probability and expected energy not supplied. Therefore if the operating conditions are not complex, the computing resources are limited, and/or the system is very reliable, the analytical methods are very efficient [93].

The simulation techniques estimate the reliability indices by simulating the system stochastic process behaviors, which are based on the random numbers generated [92]. The solving problem is modeled as a series of real experiments and the associated reliability indices are estimated by counting the number of times an event occurs [93, 94]. Both the expected values of the reliability indices and the probability distribution parameters such as probability density functions can be obtained from the simulation techniques. However, the simulation methods are very sensitive to the model dimension and often require enormous computational resources. Therefore simulation methods are usually used to solve the reliability problems requiring relatively exact results and having complex operating conditions.

The nodal reliability assessment techniques for conventional composite generation and transmission systems have been well developed and are summarized in Reference [83]. In these reliability evaluation techniques, the centralized load shedding and generation re-scheduling strategy have been implemented. Most techniques for reliability evaluation perform DC and AC power flow analysis and determine remedial actions for each contingency state. Proportional or priority load shedding are commonly used methods.

Optimization techniques have been used for load shedding and generation re-scheduling in reliability evaluation of conventional power systems [95-97]. The objectives of load shedding and generation re-scheduling are to minimize the total load curtailment subject to system voltage and power flow constraints. However, these techniques can not guarantee the minimum interruption costs although the curtailment is the minimum. Customer reliabilities at load points for the distribution system have been discussed in some recent research because statistics show that the failures in the distribution systems account for approximately 80% of the average customer interruptions [97]. The nodal reliability evaluation for distribution system has been developed in Reference [97] by using reliability network equivalents.

Reliability worth evaluation provides the opportunity to explicitly consider reliability in an economic assessment of alternative plans, designs and operating philosophies. It is an important extension of predictive reliability assessment as it permits reliability to be explicitly considered in system economic analysis [83]. Establishing the reliability worth is a difficult task because direct evaluation is not feasible. A practical approach is to evaluate the impacts and the monetary losses incurred by customers due to electric power supply failures. Customer interruption costs provide a valuable surrogate for the actual worth of electric power supply reliability [15].

Various methods have been utilized to evaluate customer interruption costs [98-100]. These methods can be grouped into three categories: indirect analytical evaluation, case studies of blackouts and customer surveys. Customer survey is the favored method to determine customer interruption costs. One convenient way to display customer interruption costs is in the form of customer damage functions (CDF) [83]. The CDF can be determined for a given customer type and aggregated to produce sector customer damage functions for the various classes of customers in the system.

Two approaches and a CDF were used in Reference [101] to evaluate the interrupted energy assessment rate (IEAR) which can be used in with expected energy not supplied to evaluate the reliability worth. Reference [102] extends the concepts for the evaluation

of IEAR at the generating capacity level to calculate the IEAR for the composite generation and transmission system.

Reference [103] presented the customer interruption costs for generation, transmission and distribution outages of different occurring under varying circumstances. Customer expectation for service reliability and their satisfaction for service currently provided were also presented. In Reference [104], a coherent method for evaluating customer outage costs was presented and the required generic data for such an evaluation were also presented.

Reference [105] presented a technique for evaluating customer unreliability costs in distribution systems by using a sequential Monte Carlo simulation technique. The customer load point unreliability costs caused by the contingencies in different segments of the power system including generation, transmission and distribution have been evaluated in Reference [106].

In Reference [107], an approach of reliability evaluation using reliability block diagram was proposed and the determined reliability indices were compared with the ones obtained using other reliability methods to check the accuracy of this approach. Reference [108] studied the impact of the load forecast uncertainty and bus load correlation on composite system reliability indices and the associated index probability distribution. In Reference [109], a model for evaluating small hydro power plants was proposed which can be applied to the generation system reliability analysis and generation system planning. The model considered both the river inflow variation and the unit operation. It can provide more accuracy compared to the convention model of the small hydro power plants.

In the proposed load management study in restructured power systems, the OPF and CDF are integrated to analyze the effects of the proposed load management schemes on the system reliability and nodal reliabilities. In Chapter 5, IEAR are utilized to develop an incentive scheme for ACL customers to participate in the DLC program.

2.5 Load Management

Load management has been defined by IEEE's Demand-Side Management Subcommittee as a set of activities that influence power systems' load shape so as to accomplish peak clipping, valley filling or load shifting [110].

In general, load management can be categorized into the following sections: indirect load control, which allows customers to control their loads independently according to the price signals sent by the utilities; DLC, which allows the system operator to shed remote customer loads unilaterally; and local energy storage, which allows both systems and customers to store energy during the off-peak/low-cost session and consume during the on-peak/high-cost session [111].

Load management is undertaken by power systems to alter the load shape to achieve a better match between the customers' cyclic demands and systems' current and planned generating and T&D (transmission and distribution) resources. Specifically, load management actions may aim to control load growth, alter the shape of the load curve or increase the supply through non-system or non-traditional sources. Actions may be initiated to reduce capital expenditures, improve capacity utilization, provide for economic dispatch, reduce the cost of service, improve load factors, improve system efficiency, or improve system reliability [110].

The restructuring of power systems has been accompanied by numerous problems, including generation capacity shortages, transmission congestion, wholesale price volatility, and reduced system reliability [5]. These problems have brought new opportunities in load management where load serving entities and other aggregators are requested to control and manage the load patterns for their wholesale or retail end-users. Load management has recently re-emerged as an important element in the fine-tuning of restructured power systems.

2.5.1 Voluntary Demand Side Load Shift

In restructured power systems, the conventional “same for all customers” electricity price has been replaced by the nodal price. The electricity price varies with time and location and customers are exposed to more volatile electricity prices. The customers may adjust their electricity consumption profile if there is commensurate cost reduction due to this electricity consumption adjustment. In return, the electricity consumption adjustment will result in electricity price change. The correlation between demand and price is called demand-price elasticity and this demand adjustment due to demand price elasticity is defined as voluntary demand side load shift.

Demand-price elasticity and voluntary demand side load shift have been studied widely to assess the effects of the demand-price correlation on both the system load curve and the electricity price volatility in restructured power systems.

Reference [6] extended the general models of dynamic tariffs to include the issues of optimal response of industrial consumers and the effect of large scale penetration of these tariffs on the utility load curve. The theoretical models of customer and utility are integrated to establish an overall system approach to the behavior and interaction of the participants in a dynamic tariff environment. Reference [7] explored some assumptions on demand elasticity across time and degree of consumer economic rationality to develop analytical models for an electricity supply system with real time pricing. It developed different possible types of customer response models and studied their effects on the overall supplier-consumer price-demand interaction.

Reference [8] proposed a theoretical framework for the solution of the price formulation and optimal dispatch problems taking into account inter-temporal dependence of demand under spot and dynamic tariffs. It studied the mechanisms of cross-time price elasticity of demand, inter-temporal definitions of customer utility, and the interaction of these two effects with the supply side factors of least cost system operation and dispatch. The

definition and conceptual models for spot-rational customer, long term rational customer and real world customer were proposed to study the behaviors of different kinds of customers under spot and dynamic tariff environments. An iterative solution methodology was developed to implement the study. Reference [9] computed optimal security prices near security constraints, taking customer demand response into account as a method to help in preserving system security. A two-level approach is proposed which maximizes the benefits of all the participants in the restructured power system - the Gencos, the customers and the system operator.

Reference [10] studied the effect of the market structure on the elasticity of the demand for electricity. It modeled the customer demands' behavior using an elasticity matrix and investigated how demand elasticity can be taken into account when scheduling generation and setting the price of electricity in a PoolCo power market. Reference [113] developed the theory of categorizing customer demand types to optimize the customer demands' response in the short range marginal tariff environment, and proposed appropriate optimization methods for different kinds of customer demands. A dynamic OPF is developed in Reference [114] to serve as a meaningful tool for both utilities and market participants to incorporate demand-price inter-temporal elasticity.

The existing studies focus on the modeling of demand price interaction and its effect on price. The effect of demand price interaction on reliability has not been studied. In the proposed reliability and price volatility study of restructured power systems, a methodology is proposed to study the effects of voluntary demand side load shift on reliability improvement and system operating cost reduction simultaneously. The demand-price elasticity matrix is used to represent the interaction between demand and electricity price. An iterative method is implemented to obtain the voluntary demand side load shift.

2.5.2 Direct Load Control (DLC) of Air Conditioning Loads (ACL)

DLC is the most common load management program which shapes the load curve by cycling customers' large current-drawing appliances. DLC is a dispatchable load

management option that has the potential of being considered as power systems' resource. As an alternative system resource, DLC is available, whenever needed, to the system operator and has a capacity which depends on the rated load under control, time of day, season of year, and customer lifestyle. Therefore, DLC capacity is a function of the natural diversity of the load being controlled. DLC capacity is organized in blocks with all devices within a block being assigned a code. Thus each block of devices can be selectively controlled over a specified period of time. Once the supply is restored, the load will be an increase in the diversified demand of the load. This phenomenon is known as "payback". Therefore, to avoid new inadvertent peaks, any use of DLC should be coordinated with other resources. Since DLC disrupts the normal duty cycle of the load under control, once it is initiated, constraints on its on/off time periods arising from customer considerations have to be observed. Thus, any block of DLC can be dispatched for no longer than a specified upper time limit. Once this limit is reached, there should be a minimum off-time constraint on DLC to allow the load sufficient time to recover. During this off-time period(s) the blocks are not available for dispatching.

At any time that a loss of load is about to occur, the available DLC capacity, the amount of DLC needed for dispatch, and the required number of blocks (if available and if they are not in the payback mode due to previous dispatches) are determined and dispatched for a predetermined control time period. If the loss of load event is over before the maximum control time limit is reached, DLC dispatch for the controlled blocks ends and payback starts. If the on-line generating capacity is not sufficient for the current payback effects, a new loss of load event occurs. For the new load loss, those blocks that have not been dispatched so far (and are not in a payback mode) will be dispatched in an attempt to avoid uncontrolled load loss by load deferment.

Based on the cost/market price function, a profit-based DLC strategy was developed to examine generic direct load control scheduling [111]. Instead of determining the amount of energy to be deferred or to be paid back, the objective of the proposed DLC technique was to maximize the profit of the utilities by controlling the number of groups per customer/load type. The proposed DLC technique has the advantage of better physical

feel on how the control devices should operate and provided a relatively inexpensive and powerful approach to the scheduling problem.

DLC can be used to reduce system spinning reserve requirement which can contribute a significant additional system operating cost saving [115]. A quasi-static system simulation algorithm was employed to compute the potential variable system operating cost saving for a sample system consisting of thermal generation and DLC. This algorithm considered probabilistic load models, outage probabilities and reliability economics.

Several critical factors of implementing large-scale DLC systems were studied in Reference [116]. How to maintain flexibility and to carefully monitor critical variables was investigated during the implementation of large-scale DLC systems. The critical factors relating to integrating DLC systems at Florida Power and Light Company to the bulk system operation were illustrated.

The impact of dynamic dispatch of DLC on generation system reliability performance was studied in Reference [117] using the Monte Carlo simulation methodology. Instead of using load duration curves as the load model, it modeled the DLC by exogenously changing the system load to reflect the expected results of load management and to study the dynamic relationship between time, load and system use. The Monte Carlo method was used to model the details of the relationships between time, load and generating capacity and to provide more accurate assessment of the effects of the dynamic nature of DLC on system reliability performance.

Three transferable analysis tools, the Duty Cycle Model, the Demand-Side Design and the Analysis Workstation, were described in Reference [118] for the analysis and evaluation of end-use monitoring, direct load control programs. The dispatch of DLC was first combined with system unit commitment to achieve the minimization of system production cost using dynamic programming [119]. In this formulation, both the generation schedule and the amount of load control at each interval were computed at one

time by using the dynamic programming algorithm. The amount of load control was treated as a variable in the optimization process. The resultant fuel cost saving was greater than that of the case where the amount of load control was fixed at each interval.

Reference [120] studied the production cost implications of the dynamic DLC model. The GENESIS Monte Carlo generation model and the dynamic DLC model were coupled with a fast piece-wise linear incremental cost economic dispatch scheme to implement this study. It was shown that operating cost reductions produced by exogenous models of DLC were different from those produced by dynamic models of DLC. In order to overcome the problem of large amount of computer time and storage memory in the conventional dynamic programming method of DLC, the multi-pass dynamic programming method was utilized to dispatch air conditioning direct load control to obtain both peak load reduction and production cost saving [121]. The proposed DLC technique using multi-pass dynamic programming can converge to an optimal DLC scheme very quickly.

Reference [122] presents a very effective method for direct load control with the objective of minimizing system operational costs by coordinating a DLC group with the available supply-side options. It discusses the coordination between DLC dispatch and unit commitment and illustrates the significant potential benefit accrued from using direct load control capacity as a part of system spinning reserve. The proposed DLC technique was extended to include consideration of capital cost saving. A fuzzy load model for the direct load control of appliances was first developed and a methodology for optimizing both customer satisfaction and utility unit commitment savings was presented based on this fuzzy DLC load model [123].

DLC controlled by local bus frequency was proposed for damping of electro-mechanical oscillations [124]. The viability of the idea was studied for one load in a three-machine system with a meshed network. Active power mode controllability and phase angle mode observability were determined from the eigenvectors of a differential algebraic description of the uncontrolled system.

A load model based on the stochastic difference equation was used in Reference [125] to study the effects of the load parameters and the direct load control actions. The Monte Carlo simulation technique was used to implement the case study for an example system. The effects of load parameter dispersion and different load actions were analyzed and the distribution of house temperatures was studied for control actions. The results for the load parameter dispersion and the direct load control actions on aggregated load for the example system were presented.

Reference [126] proposed a fuzzy set based DLC methodology to minimize system operating cost and to address customer satisfaction for the DLC. The scheduling of the DLC and the unit commitment was integrated to reduce the system peak load as well as the total operating cost.

A new approach of DLC was proposed to minimize power losses and the associated dollar costs in the distribution system [127]. This approach was based on DLC of residential electric water heaters and on increasing the storage capacity of the water heaters under DLC. An optimization algorithm based on the Lagrangian Multiplier method was developed to minimize the power system distribution losses. The objective function was obtained by the summation of the system peak real power loss cost, annual energy loss cost, and the cost associated with purchasing and installing the additional water heaters used for DLC.

Physically based electrical models of heating, ventilation and air conditioning residential loads were proposed in Reference [128]. These models were based on energy balances between the internal air, the dwelling constructive elements, the conditioner appliances and the external environment through a discrete state-space equation system. These dynamic models were used to evaluate load management programs, above all DLC actions. The models were implemented and tested to assess their accuracy and suitability in specific kinds of applications.

An efficient approach was proposed to cluster the DLC curves through a structure of self-organizing maps [129]. Nonlinear principal component analysis and periodic analysis were used for selecting significant features of DLC curves. The dual multilayer neural networks model was employed in the proposed nonlinear principal component analysis method. In the periodic analysis method, the periodic characteristics of the DLC curves are investigated. Davies-Bouldin indexes and a k-means algorithm decided the best number of clusters to be classified. The DLC curves are categorized into two categories: DLC complying and DLC non-complying loads. Results obtained from the comparison of six different approaches show that the clusters obtained from the proposed approach exhibit lowest degrees of misclassification for the practical data on Taiwan Power Company (TPC) DLC programs.

An approach was proposed to determine a boundary of small-signal stability performance of a power system in terms of active power loads selected at a few buses [130]. The analysis in forming the above boundary was based on Structured Singular Value (SSV or μ) framework. The detailed development of the analysis framework was presented and results on the Nordic32 test system were illustrated. Such a scheme for direct control of loads from a central control center could be employed at times when the system is vulnerable.

A reasonable DLC program with a least enthalpy estimator-based fuzzy thermal comfort controller of air-conditioning systems was proposed in order to alleviate the DLC constraints such as outdoor temperature, thermal comfort level of consumers, and air-conditioning load payback phenomenon [131]. It can store the heat transfer capacity of the chilled water by a time delay after load-shedding command is issued. With the help of the proposed least enthalpy estimator-based fuzzy control and this pre-stored chilled-water heat transfer capacity, a smaller increase of the chilled-water temperature during off-shift period was obtained which can avoid the transient payback load effect. At the same time, the thermal comfort was maintained within an acceptable level.

Auto-regression moving-averaging modeling techniques were employed in Reference [132] to extract the features of the DLC curves in order to reduce the number of variables for classification and to enhance the classification effectiveness. In order to ensure the adequacy of the auto-regression moving-averaging models used for the DLC curves, the Akaike information criterion is assessed. Based on the extracted features, the genetic k-means algorithm was adopted for classification owing to its ability to partition given global data optimally into a specified number of clusters.

An iterative deepening GA (IDGA) is proposed to optimize the scheduling of direct load control (DLC) strategies [133]. The control strategy (or scheduling) arranged by the IDGA not only sheds the load so that the load required to be shed at each sampling interval is individually satisfied, but it also minimizes the shedding load so that the utility company's revenue loss due to DLC is minimized. The scheduling obtained by the proposed IDGA tends to level off the accumulated shedding time of each load group, avoiding customers' complaints about fairness of shedding time.

The framework of preventive modulation of selected loads through direct control for small-disturbance angle stability enhancement was presented in Reference [134]. The analysis framework is based on the structured singular value theory in which the controllable load range at selected buses that satisfies the desired stability robustness performance criterion is determined. Two conceptually different approaches for the analysis of load modulation were presented. Case study results on an equivalent of the Western Electric Coordinating Council system were presented in Reference [135].

The application of Controller Area Networks to Direct Load Control programs was presented in Reference [136]. The proposed system allows the customers to monitor and control automatically their heating and cooling individual loads, maintaining minimum comfort levels and offering a flexible, low-cost and friendly tool in order to increase the demand-side participation in restructured power systems.

An interactive evolutionary algorithm for the identification and selection of DLC actions in electrical distribution networks was proposed in Reference [137]. The evolutionary algorithm accommodates a progressive articulation of the decision maker's preferences by changing aspiration or reservation levels used in the fitness assessment of the individuals in the population (load control strategies).

A residential customer-centered load control strategy in real-time electricity pricing environment was presented in Reference [138]. The advantage of the proposed control strategy is that it can effectively strike a balance between user comfort and consumer price preferences. Particularly, this strategy is customer-centered, effective and simple enough for real-life use of residential consumers.

Relaxed dynamic programming (RDP) algorithm was used to generate an optimal or near optimal daily control scheduling for ACL with relaxing bounds [139]. The proposed optimum loads control scheduling (LCS) scheme was used to determine the optimal scheme of demand control, cycling control and timer control in order to obtain maximum cost saving during the dispatch period. Field tests of controlling the ACL located in the campus were implemented to demonstrate the effectiveness of the proposed load control strategy.

To the best knowledge of the author, the existing studies of DLC have not considered the transmission system reliability and economic incentives for ACL customers.

In practical power systems, ACL are connected to different nodes where reliability is different due to the topology of the transmission system. The same amount of resulting peak load shaving due to cycling of ACL by DLC at different nodes may have different effects on system reliability. In restructured power systems, the restructuring of power systems has resulted in many problems. Reduced system reliability is one of them. Therefore, system reliability improvement is a major concern of the system operator. This issue should be taken into account to determine the DLC scheme of ACL.

In restructured power systems, customers have the right to decide to participate in DLC program or not. In order to make the DLC program of ACL to be successful, the customers' preference should be taken into account. A fair economic incentive scheme is necessary to eliminate the customers' reluctance to participate in the DLC program because the cycling of ACL results in service interruption of ACL and therefore causes discomfort. This issue should also be considered in the load management of restructured power systems.

These two issues are the motivation for implementing the studies in Chapters 4 and 5.

2.6 Fuzzy Set Theory Applications

The concept of fuzzy set theory was introduced by Zadeh in 1965 [140] and it was first introduced in 1979 for solving power system problems. Fuzzy set theory can be considered as a generalization of the classical set theory. In classical set theory, an element of the universe either belongs to or does not belong to the set. Thus, the degree of association of an element is crisp. In fuzzy set theory, the association of an element can be continuously varying. Mathematically, a fuzzy set is a mapping (known as membership function) from the universe of discourse to the closed interval $[0,1]$. The membership function is usually designed by taking into consideration the requirement and constraints of the problem. Fuzzy logic implements human experiences and preferences via membership functions and fuzzy rules. Due to the use of fuzzy variables, the system can be made understandable to a non-expert operator. In this way, fuzzy logic can be used as a general methodology to incorporate knowledge, heuristics, or theory into controllers and decision makers.

The mathematical formulations of power system problems are derived under certain restrictive assumptions and even with these assumptions, the solution of large-scale power system problems is not simple. On the other hand, there are many uncertainties in power system problems, because power systems are large, complex, geographically

widely distributed, and influenced by unexpected events. These facts make it difficult to effectively deal with many power system problems through strict mathematical formulations alone. Therefore, fuzzy set theory-based approach has emerged as a complementary tool to mathematical approaches for solving power system problems [125-139]. The advantages of fuzzy set theory over conventional methods are as follows [135, 137]:

1. It is based on natural language and is conceptually easy to understand.
2. It resolves conflicting objectives by designing weights appropriate to the selected objectives.
3. It is tolerant of imprecise data and provides capability for handling ambiguity expressed in diagnostic processes, which involves systems and causes.
4. It develops process control as a fuzzy relation between information about the conditions of the process to be controlled.

Fuzzy set theory has been effectively used in power systems to represent uncertainties by using fuzzy set for ambiguous variables and assigning membership functions based on preference and/or experience. Fuzzy set theory has been applied in different areas of power system studies, such as reactive power/voltage control, control design of power system stabilizer, load forecasting, generator maintenance, thermal/hydro/hydrothermal generation scheduling, unit commitment, economic dispatch, fault diagnosis, power system protection/relaying, power system restoration, optimal power flow, power system stability analysis, voltage security analysis, power system planning, power system reliability evaluation, load flow, automatic generation control/load frequency control, power system control, etc.

Fuzzy set theory has been effectively applied in reactive power/voltage control problems due to its complexity and nonlinear nature of reactive power-voltage relationship. Power system stabilizers (PSS) are necessary to provide appropriate damping of undesirable oscillations caused by disturbances. One advantage of fuzzy logic controller (FLC) over other forms of knowledge-based controllers is the interpolative nature of fuzzy control rules. A large number of FLC-based PSS have been proposed in the literature. Because of

interpolative quality, FLCs require fewer rules than other knowledge based controllers [150].

Loads in power system depend on weather conditions, economic situation, holidays, geographical locations, daylight hours, etc. Some of these factors are uncertain but known to be within certain ranges. Fuzzy logic approach can provide better reasoning with membership values to give more accurate load forecasts under these uncertain conditions. The main objectives of maintenance scheduling are to reduce generation cost, to improve system reliability, and to increase the lifetime of units. Uncertainties like reserve, production cost, manpower hours, geographical constraints, etc., can be represented by defining membership functions to use fuzzy set theory in generator maintenance scheduling problem.

Reliability evaluation is an important issue in the scope of planning studies. Fuzzy concepts can be used to model the uncertainty-related future load behavior parameter to evaluate generation/transmission system reliability. The main information obtained from the load flow study comprises magnitude and phase angles of load bus voltages, reactive powers, and voltage angles at generator buses, real and reactive power flow on transmission lines together with power at the reference bus, other information being specified. In case of ambiguous data, fuzzy logic can be an appropriate approach.

In Chapter 4, fuzzy set theory is used to represent the uncertainties of load, system reserve, reliability improvement and system operating cost. Fuzzy dynamic programming is used to determine the optimal DLC scheme which strikes a balance between system reliability improvement and system operating cost reduction.

2.7 Summary

The models and techniques related to load management studies in restructured power systems are briefly reviewed in this chapter. Conventional monopoly power systems and

restructured power systems are discussed first. The history of power system restructuring and the electricity market structures are presented in detail. The nodal price characteristics of restructured power systems and OPF techniques used to determine the nodal prices are reviewed. Reliability evaluation and reliability worth evaluation techniques are also discussed. Load management techniques have been reviewed and discussed with emphasis on the voluntary demand side load shift and DLC. Fuzzy set theory application in power systems is also reviewed in this chapter.

Chapter 3 Reliability and Price Volatility Study of Restructured Power Systems with Demand Side Load Shift

3.1 Introduction

Power industries in many countries around the world have been under restructuring since the 1980s. The objective of power system restructuring is to replace the monolithic regulated public utilities with competitive power markets. The restructuring of power systems has changed the way electricity and ancillary services are traded.

In order to induce efficient use of both the transmission and generation resources by providing correct economic signals, nodal price (also known as locational marginal price (LMP)) was introduced for restructured power systems [40]. There have been a number of references on the pricing problem in restructured power systems. Supply function equilibrium (SFE) model has been widely used to analyze the bidding behavior in restructured power systems [143-148]. It is demonstrated in [155] that the parameterization of the supply function equilibrium model has a significant effect on the calculated results. A linear asymmetric supply function equilibrium model with transmission constraints is proposed to develop firms' optimal bidding strategies considering forward contracts [156]. A coevolutionary approach is presented to analyze supply function equilibrium models of an oligopolistic electricity market [157]. A security constrained optimal power flow technique is proposed for pricing reactive power on the NGC system [158]. An interior-point linear programming based auction method is developed to find the exact optimal solution and to recover the optimal basis [159]. Experimental market power and efficiency outcomes are presented in [160] for a computational wholesale electricity market operating the short run under systematically varied concentration and capacity conditions.

In restructured power systems, electricity price is no longer determined by the regulator; it is instead determined by generation bids, demands and system constraints. In such a situation, electricity price varies with time and location because demands and system

states change with time. Consumers are therefore getting exposed to more volatile electricity prices and may modify the profile of their demands to avoid high electricity cost if there is a commensurate electricity cost reduction. In other words, customers would be willing to shift their electricity consumption from time slots of higher prices to those of lower prices if there is a commensurate economic benefit. This means that the demand at a given time slot may well depend not only on the electricity price at the same time slot but also on the electricity prices prevailing at other time slots. At the same time, the resulting demand changes caused by price changes will influence the electricity prices. There is a correlation between demands and electricity prices in restructured power systems. This correlation is defined as demand-price elasticity and the eventual demand changes are called as voluntary demand side load shift. The voluntary demand side load shift will have significant impacts on reliability and price volatility of restructured power systems. The impact of voluntary demand side load shift due to demand-price elasticity should therefore be considered in both reliability and price volatility evaluation techniques for restructured power systems.

Demand-price elasticity has been investigated to analyze its effect on spot electricity prices in restructured power systems [6-10]. The general models of dynamic tariffs are extended to include the issues of optimal response of industrial consumers and the effect of large scale penetration of these tariffs on the utility load curve [6]. Some assumptions on demand elasticity across time and degree of consumer economic rationality are explored to create analytical models for an electricity supply system with real time pricing [7]. The models which represent the mechanisms of cross-time price elasticity of demand, inter-temporal definitions of customer utility, and the interaction of these two effects have been developed [8]. Security pricing is generalized to include any security constraint for a competitive model assuming that demand is elastic and varies as a function of price [9]. The effect of market structure on the elasticity of the demand for electricity was analyzed and consumer behavior was modeled using a matrix of self- and cross-elasticities [10]. The study in Reference [11] considered the potential demand elasticity according to the consumption characteristics in different areas of Mexico. It was shown that the demand elasticity can avoid the market power in Mexico due to the

tight supply demand functions interacting with the transmission system [11]. Reference [12] proposed a method for market equilibrium that did not require the specification of a representative demand function. This method can determine market equilibrium for all valid demand conditions and hence can provide market solutions which are independent of the characteristic form of demands. In Reference [13], the demand elasticity impacts on the strategic bidding behavior of the electricity producers were studied. It was shown that the demand elasticity can improve the performance of the market in terms of the Lerner index and the reduced congestion.

The existing literature investigated the modeling of demand-price elasticity and its effects on electricity prices and demands. The impacts of resultant voluntary demand side load shift on composite system and nodal reliabilities have not been addressed, to the best knowledge of the author.

The techniques for the reliability evaluation of conventional power systems are well-developed [80-82]. In conventional power systems, reliability is centrally managed and uniform price is usually applied to the same type of customers. Price is therefore not an issue in the reliability evaluation of conventional power systems. The customers have no motivation to adjust their demands. The reliability assessment techniques for restructured power systems have to be developed in order to consider customer participation in reliability management. Reliability issues in restructured power systems have been discussed in [149, 150]. Some techniques have been developed in [151-153] to solve problems brought about by the power system restructuring. The impact of random failures on nodal prices and reliabilities in restructured power systems was investigated in [165]. However, the voluntary demand side load shift across time horizons cannot be considered in this technique.

A methodology is proposed in this chapter to assess the reliability improvement and nodal price volatility reduction of restructured power systems considering voluntary demand side load shift. Demand-price elasticity matrix [10], which includes self-elasticities and cross-elasticities, is used to represent the correlation between demands

and nodal prices in restructured power systems. The optimal power flow (OPF) technique is utilized to determine the nodal prices using the Lagrangian multipliers as shadow prices. OPF and customer damage functions (CDF) are combined to evaluate the reliability of restructured power systems with and without voluntary demand side load shift. The IEEE RTS is simulated to illustrate the developed techniques.

3.2 Modeling of Demand-Price Elasticity

In general, the demand for a commodity decreases as the price of the commodity increases. The relationship between price and demand for a commodity can be illustrated using the demand-price curve shown in Figure 3-1.

Figure 3-1 Demand price curve

The demand response of a commodity to price is usually characterized by the demand-price elasticity. The elasticity is normally defined as a derivative, with an approximation as specified by Equation (3.1).

$$\xi = \frac{\Delta d / d_0}{\Delta \rho / \rho_0} \quad (3.1)$$

where Δd and $\Delta \rho$ are changes of demand and price, respectively; d_0 and ρ_0 are the base demand and the base price at the given equilibrium point, respectively.

In Equation (3.1), the elasticity is a linearized coefficient which is to show the relative change of the demand of a commodity that would result from the price change of this commodity. In order to simplify the study, the price change and the demand change are normalized by the price and demand at the given equilibrium point (ρ_0, d_0) . In this Chapter, all the elasticity coefficients are normalized.

The demand-price elasticity coefficient indicates the demand change for a commodity corresponding to the price change. In restructured power systems, electricity price is determined by bids from generation companies, transmission system capability and demands every hour or every half an hour. The electricity prices at high demands are higher than the ones at low demands if there is no system contingency. The electricity price at peak load is much higher than the one at valley load. Customers are facing varying electricity prices during a day. The customers will adjust their demands from time periods of high prices to time periods of low prices to reduce the cost of electricity consumption. The resulting demand load change is called voluntary demand side load shift. When customers reschedule the electricity consumption in one time period, they will take all the electricity prices into account. In other words, the demand change of one time period is influenced by both the electricity price in the same period and the electricity prices in other time periods.

Therefore, two types of demand-price elasticity coefficients are defined to represent the demand price correlation in restructured power systems. The effect of the price change on the demand change in the same time slot is defined as the self-elasticity coefficient. The cross-time effects between demands and electricity prices can be represented using cross-time coefficients. These two types of coefficients are shown in Equations (3.2) and (3.3), respectively.

$$\xi_{ii} = \frac{\Delta d_i / d_0}{\Delta \rho_i / \rho_0} \quad (3.2)$$

$$\xi_{ij} = \frac{\Delta d_i / d_0}{\Delta \rho_j / \rho_0} \quad (3.3)$$

where Δd_i and $\Delta \rho_i$ represent demand and price changes at time slot i , respectively; $\Delta \rho_j$ represents the price change at time slot j .

The self-elasticity coefficient ξ_{ii} shows the effect of price change on demand change at the same time slot i . The cross-elasticity coefficient ξ_{ij} relates demand change at time slot i to price change at time slot j .

It is assumed that the electricity price is determined every one hour. Therefore, the elasticity coefficients can be arranged in a 24 by 24 matrix E , as shown in Equation (3.4).

$$\mathbf{E} = \begin{bmatrix} \xi_{1,1} & \xi_{1,2} & \cdots & \xi_{1,23} & \xi_{1,24} \\ \xi_{2,1} & \xi_{2,2} & \cdots & \xi_{2,23} & \xi_{2,24} \\ \vdots & \vdots & \ddots & \vdots & \vdots \\ \xi_{23,1} & \xi_{23,2} & \cdots & \xi_{23,23} & \xi_{23,24} \\ \xi_{24,1} & \xi_{24,2} & \cdots & \xi_{24,23} & \xi_{24,24} \end{bmatrix} \quad (3.4)$$

In demand-price elasticity matrix, the diagonal elements of the matrix represent the self-elasticities and the off-diagonal elements correspond to the cross-elasticities. The nonzero

elements above the diagonal in the column mean that consumers react to a high price by bringing forward their consumption. The nonzero elements below the diagonal mean that the customers postpone their consumption to avoid the high price time periods. If consumers reschedule their production over all the time periods, the nonzero elements will be spread widely over the column.

A rescheduling of production implies that a consumer reduces his electricity consumption at some time slots of higher prices and increases it at those of lower prices. The interaction between demands and prices will continue until the price discrepancy between the eventual price and the customer expected price is smaller than the predetermined threshold. An iterative methodology is utilized to determine the voluntary demand side load shift due to the demand-price correlation. The iterative methodology is illustrated in Figure 3-2.

Figure 3-2 Iterative methodology to determine voluntary demand side load shift

The demand change at time slot i in each iteration caused by a deviation of the eventual prices from the customer expected prices is given by Equation (3.5).

$$\Delta d_i = \sum_{j=1}^{24} \xi_{ij} * (\Delta \rho_j / \rho_0) * d_0 \quad (3.5)$$

where Δd_i is the load change at time slot i , ξ_{ij} is the elasticity coefficient which is self-elasticity when $i = j$ and cross-elasticity when $i \neq j$, and Δp_j is the deviation of the eventual price from the customer expected price during time slot j .

Therefore, the load changes of 24 time periods in any iteration can be calculated using Equation (3.6).

$$\Delta \mathbf{d} = \mathbf{E} * (\Delta \mathbf{p} / \rho_0) * d_0 \quad (3.6)$$

where $\Delta \mathbf{d}$ is the demand change vector of 24 hours, $\mathbf{E}$ is the elasticity matrix, and $\Delta \mathbf{p}$ is the price deviation vector.

3.3 Nodal Price Determination

In restructured power systems, electricity price is determined by bids from generation companies, transmission constraints and demands. In this section, OPF is used to determine the electricity price. The locational marginal cost is used as electricity price which is also called as nodal price.

The determination of nodal prices can be depicted by the following OPF problem.

Objective function

$$\text{Min} \sum_{i=1}^{N_g} [C_{pi}(P_{gi}) + C_{qi}(Q_{gi})] \quad (3.7)$$

subject to the following constraints

Load flow constraints

$$\sum_{i \in j} P_{gi} - P_{dj} - \sum_{k \in j} V_j V_k Y_{jk} \cos(\theta_{jk} + \delta_j - \delta_k) = 0 \quad (3.8)$$

$$\sum_{i \in j} Q_{gi} - Q_{dj} - \sum_{k \in j} V_j V_k Y_{jk} \sin(\theta_{jk} + \delta_j - \delta_k) = 0 \quad (3.9)$$

Generation constraints

$$P_{gi}^{\min} \leq P_{gi} \leq P_{gi}^{\max} \quad (3.10)$$

$$Q_{gi}^{\min} \leq Q_{gi} \leq Q_{gi}^{\max} \quad (3.11)$$

Voltage constraints

$$V_j^{\min} \leq V_j \leq V_j^{\max} \quad (3.12)$$

Line flow constraints

$$P_{li}^{\min} \leq P_{li} \leq P_{li}^{\max} \quad (3.13)$$

where N_g is the total number of generators; P_{gi} is the real power output of generator i ; Q_{gi} is the reactive power output of generator i ; P_{dj} is the real power demand at node j ; Q_{dj} is the reactive power demand at node j ; $C_{pi}(P_{gi})$ is the cost function of real power of generator i ; $C_{qi}(Q_{gi})$ is the cost function of reactive power of generator i ; $P_{gi}^{\min}$ is the minimum real power output of generator i ; $P_{gi}^{\max}$ is the maximum real power output of generator i ; $Q_{gi}^{\min}$ is the minimum reactive power output of generator i ; $Q_{gi}^{\max}$ is the maximum reactive power output of generator i ; $V_j^{\min}$ is the minimum voltage at node j ; $V_j^{\max}$ is the maximum voltage at node j ; $P_{li}^{\min}$ is the minimum real power flow allowed through line i ; $P_{li}^{\max}$ is the maximum real power flow allowed through line i ; $V_j \angle \delta_j$ and $V_k \angle \delta_k$ are the voltages at node j and node k respectively; and $Y_{jk} \angle \theta_{jk}$ is the admittance between node j and node k .

The Lagrangian function of Equations (3.7) to (3.13) can be stated by Equation (3.14).

$$\begin{aligned}
 L = & \sum_{i=1}^{N_g} (C_{P_i}(P_{g_i}) + C_{Q_i}(Q_{g_i})) + \sum_{j=1}^{N_n} \lambda_{pj} (\sum_{i \in j} P_{g_i} - P_{dj} - \sum_{k \in j} V_j V_k Y_{kj} \cos(\theta_{jk} + \delta_j - \delta_k)) + \\
 & \sum_{j=1}^{N_n} \lambda_{qj} (\sum_{i \in j} Q_{g_i} - Q_{dj} - \sum_{k \in j} V_j V_k Y_{kj} \sin(\theta_{jk} + \delta_j - \delta_k)) + \sum_{i=1}^{N_g} u_{pi \min} (P_{g_i \min} - P_{g_i}) + \\
 & \sum_{i=1}^{N_g} u_{pi \max} (P_{g_i} - P_{g_i \max}) + \sum_{i=1}^{N_g} u_{qi \min} (Q_{g_i \min} - Q_{g_i}) + \sum_{i=1}^{N_g} u_{qi \max} (Q_{g_i} - Q_{g_i \max}) + \\
 & \sum_{i=1}^{N_l} u_{lim \min} (P_{lim \min} - P_{li}) + \sum_{i=1}^{N_l} u_{lim \max} (P_{li} - P_{lim \max}) + \\
 & \sum_{j=1}^{N_n} u_{vj \min} (V_{j \min} - V_j) + \sum_{j=1}^{N_n} u_{vj \max} (V_j - V_{j \max}) \quad (3.14)
 \end{aligned}$$

where N_l is the number of power lines, N_n is the number of nodes, and λ_{pj} , λ_{qj} , $\mu_{pi \min}$, $\mu_{pi \max}$, $\mu_{qi \min}$, $\mu_{qi \max}$, $\mu_{lim \min}$, $\mu_{lim \max}$, $u_{vj \min}$ and $u_{vj \max}$ are the Lagrangian multipliers of the corresponding constraints.

The nodal price of real power at node j is the calculated “shadow price”, which is the hypothetical incremental cost to the system that would result from the optimized re-dispatch of available units for one hypothetical additional kWh demand at node i . In a similar way, the nodal price of reactive power at node j can be determined assuming that one additional kVArh is demanded at node j , and the hypothetical incremental cost to the system that would result from the optimized re-dispatch of available units establishes the hypothetical production cost of the hypothetical kVArh [3]. The nodal prices at node j can be calculated by Equations (3.15) and (3.16).

$$\rho_{pj} = \frac{\partial L}{\partial P_{dj}} \quad (3.15)$$

$$\rho_{qj} = \frac{\partial L}{\partial Q_{dj}} \quad (3.16)$$

3.4 Nodal Price Volatility

Price volatility is a measure of the price fluctuation over a time period. A quantitative analysis of day-ahead spot price volatility in 1999 and 2000 for four electricity markets was carried out based on an original definition of price volatility [166]. An empirical study of the price volatility in actual power markets was conducted and frequency-domain methods were utilized to identify periodic components of price volatility [167].

A nodal price volatility index is defined to analyze the impact of the voluntary demand side load shift on price volatility. The price volatility index σ is defined as the standard deviation of the 24 hour prices, which can be calculated using equation (3.17).

$$\sigma = \sqrt{\frac{\sum_{i=0}^{23} (\rho_{i+1} - \rho_i)^2}{23}} \quad (3.17)$$

where ρ_i and ρ_{i+1} are prices in time period i and time period $i+1$, respectively.

3.5 OPF Based Reliability Evaluation

Most reliability evaluation techniques use ac power flow to check network violations and use proportional load curtailment to alleviate the system voltage and overload problems caused by generation inadequacies and transmission congestions. This type of contingency alleviation technique does not consider the customers' choices. In this chapter, OPF is combined with CDF to alleviate the network violation(s). The interruption costs of different customers are used to represent the choices of different customers.

Considering an n -bus power system with m independent components, for contingency state j with exactly s failed components, the probability of the system being in state j , p_j ,

the departure rate of system leaving state j , D_j , and the frequency of the system departing state j , F_j , are given by Equations (3.18), (3.19) and (3.20), respectively.

$$p_j = \prod_{i=1}^s U_i \times \prod_{i=s+1}^m A_i \quad (3.18)$$

$$D_j = \sum_{i=1}^s \mu_i + \sum_{i=s+1}^m \lambda_i \quad (3.19)$$

$$F_j = p_j \times D_j \quad (3.20)$$

where A_i is the availability of component i ; λ_i is the failure rate of component i ; U_i is the unavailability of component i ; and μ_i is the repair rate of component i .

Load curtailment is required under severe system contingencies to keep the system operating and is an important parameter to determine the reliability indices. In restructured power systems, the operator would determine the load curtailment scheme according to the interruption costs of different types of customers in order to obtain the optimal one with minimum generation costs and interruption costs.

The interruption cost is a function of customer and interruption characteristics [15]. The sector CDF is used to reflect the diversities of customer sectors. A Standard Industrial Classification (SIC) [15] has been used to divide customers into large user, industrial, commercial, agriculture, residential, government & institutions and office & buildings categories. Postal surveys have been done, among others, by the University of Saskatchewan and Canadian Electric Power Utilities to estimate customer interruption costs. The survey data have been analyzed to give sector CDF as a function of the electricity interruption duration. A series of sector CDF are shown in Table 3-1 in \$/kW of the annual peak demand [83]. The data shown in Table 3-1 are illustrated graphically in Figure 3-3.

Table 3-1 Sector Interruption Cost Estimates (\$/MWh)

User sector	Interruption duration				
	1min	20 min	1 hr	4 hr	8 hr
Large users	1.005	1.508	2.225	3.968	8.240
Industry	1.625	3.868	9.085	25.163	55.808
Commercial	0.381	2.969	8.552	31.317	83.008
Agricultural	0.060	0.343	0.649	2.064	4.120
Residential	0.001	0.093	0.482	4.914	15.690
Govt. & Inst.	0.044	0.369	1.492	6.558	26.040
Office & Bldg.	4.778	9.878	21.065	68.830	119.160

Figure 3-3 Sector interruption cost estimates

The formulation to determine the optimal load curtailment scenario under system contingency j using OPF and customer interruption costs can be depicted by the following optimization problem:

Objective function:

$$\text{Min} \sum_{i=1}^{N_g^j} [C_{pi}(P_{gi}) + C_{qi}(Q_{gi})] + \sum_{k=1}^{N_n^j} \sum_{s=1}^{N_{ks}} OC_{ks}(LC_{pks}, LC_{qks}) \quad (3.21)$$

Subject to the following constraints:

Load flow constraints:

$$\sum_{i \in k} P_{gi} - P_{dk} + \sum_{s \in k} LC_{pks} - \sum_{l \in k} V_k V_l Y_{kl} \cos(\theta_{kl} + \delta_k - \delta_l) = 0 \quad (3.22)$$

$$\sum_{i \in k} Q_{gi} - Q_{dk} + \sum_{s \in k} LC_{qks} - \sum_{l \in k} V_k V_l Y_{kl} \sin(\theta_{kl} + \delta_k - \delta_l) = 0 \quad (3.23)$$

Generation constraints:

$$P_{gi}^{\min} \leq P_{gi} \leq P_{gi}^{\max} \quad (3.24)$$

$$Q_{gi}^{\min} \leq Q_{gi} \leq Q_{gi}^{\max} \quad (3.25)$$

Voltage constraint:

$$V_j^{\min} \leq V_j \leq V_j^{\max} \quad (3.26)$$

Line flow constraint:

$$P_{li}^{\min} \leq P_{li} \leq P_{li}^{\max} \quad (3.27)$$

Load curtailment constraint:

$$0 \leq LC_{pks} \leq P_{dk} \quad (3.28)$$

where N_g^j is the total number of generators under contingency state j ; N_n^j is the total nodes under contingency state j ; N_{ks} is the number of customer sectors; $OC_{ks}(LC_{pks}, LC_{qks})$ is the interruption cost; LC_{pks} is the real power load curtailment of load sector s at node k ; and LC_{qks} is the reactive power load curtailment of load sector s at node k .

The system expected load curtailment probability ($ELCP$) and expected load curtailment frequency ($ELCF$) can be calculated using Equations (3.29) and (3.30), respectively.

$$ELCP = \sum_{j=1}^{NC} p_j \times p_{sj} \quad (3.29)$$

$$ELCF = \sum_{j=1}^{NC} F_j \times p_{sj} \quad (3.30)$$

where NC is the total number of contingencies, p_{sj} is the status of load curtailment of the system under contingency state j . p_{sj} is 1 when there is load curtailment of the system under contingency j , otherwise it is 0.

The system expected load curtailment (ELC) and expected energy not supplied ($EENS$) can be obtained using Equations (3.31) and (3.32), respectively.

$$ELC = \sum_{j=1}^{NC} LC_j \times F_j \times P_{sj} \quad (3.31)$$

$$EENS = \sum_{j=1}^{NC} LC_j \times p_j \times p_{sj} \times 8760 \quad (3.32)$$

where LC_j is the load curtailment of the system under contingency state j and is the sum of LC_{pks} .

Nodal reliability indices such as probability of nodal load curtailment ($PNLC_k$), frequency of nodal load curtailment ($FNLC_k$), expected nodal load curtailment ($ENLC_k$), and expected nodal energy not supplied ($ENENS_k$) can be calculated using Equations (3.33) to (3.36), respectively.

$$PNLC_k = \sum_{j=1}^{NC} p_j \times p_{nj} \quad (3.33)$$

$$FNLC_k = \sum_{j=1}^{NC} F_j \times p_{nj} \quad (3.34)$$

$$ENLC_k = \sum_{j=1}^{NC} NLC_{jk} \times F_j \quad (3.35)$$

$$ENENS_k = \sum_{j=1}^{NC} NLC_{jk} \times p_j \times 8760 \quad (3.36)$$

where k is the node number; p_{nj} is the probability of nodal load curtailment at node k under contingency state j ; and NLC_{jk} is the nodal load curtailment at node k under contingency state j .

The determination of NLC_{jk} includes the following steps:

- Step 1. The conventional OPF is used to check whether the system can operate without load curtailment under contingency j ; if yes, go to step 4, otherwise, go to step 2.
- Step 2. The OPF based reliability evaluation technique is utilized to determine the LC_{pjks} which is the active load curtailment of different customer sectors at node k under contingency j .
- Step 3. NLC_{jk} is calculated as the sum of LC_{pjks} .
- Step 4. Stop.

The OPF based reliability evaluation technique is the optimization problem described by Equations (3.21)-(3.28). The objective of OPF based reliability evaluation technique is to determine the optimal load curtailment scheme with the minimum generation costs and customer interruption costs.

3.6 Case Studies

In order to illustrate the effects of the voluntary demand side load shift on nodal price volatility, system reliability and nodal reliabilities of restructured power systems, the IEEE RTS was simulated using the proposed techniques.

The single line diagram of the RTS is shown in Figure 3-4. The RTS generating system consists of 32 units, ranging from 12 MW to 400 MW. The transmission system consists of 24 load/generation buses connected by 38 lines or autotransformers at two voltage levels, 138 and 230 kV.

Figure 3-4 Single line diagram of the RTS

In the case studies, two types of customers were considered: flexible customers and

$$FNLC_k = \sum_{j=1}^{NC} F_j \times p_{nj} \quad (3.34)$$

$$ENLC_k = \sum_{j=1}^{NC} NLC_{jk} \times F_j \quad (3.35)$$

$$ENENS_k = \sum_{j=1}^{NC} NLC_{jk} \times p_j \times 8760 \quad (3.36)$$

where k is the node number; p_{nj} is the probability of nodal load curtailment at node k under contingency state j ; and NLC_{jk} is the nodal load curtailment at node k under contingency state j .

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- Step 1. The conventional OPF is used to check whether the system can operate without load curtailment under contingency j ; if yes, go to step 4, otherwise, go to step 2.
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Figure 3-4 Single line diagram of the RTS

In the case studies, two types of customers were considered: flexible customers and

inflexible customers.

For the flexible customers, they have the ability to reschedule their demands over all the time periods and are willing to do so in order to reduce the electricity cost as much as possible.

They will shift their demands from the higher price time periods (08:00 am to 03:00 pm) to normally lower price time periods (12:00am to 07:00am and 04:00pm to 12:00am). During the low price time periods, the demand is quite low compared to the demands in the high price time periods. The self-elasticity parameter is set as -0.2. The negativity of self-elasticity parameter means that customers will shift demands from the current time period to lower price time periods. The ratio of the relative price change to the relative demand change is 0.2. The cross-elasticity parameters are set as 0.01 for time periods from 12:00am to 03:00am and from 04:00pm to 12:00am, and as 0.025 for the time period from 04:00am to 07:00am.

The ratio of the relative demand change to the relative price change for time periods from 12:00am to 03:00am is 0.01 and the ratio of the relative price change to the relative demand change for time periods of 04:00am to 07:00am and time periods of 04:00pm to 12:00am is 0.01. The cross-elasticity parameters are set in this way to make sure that the energy consumption for customers does not change before and after the rescheduling. The cross-elasticity values for the time periods from 04:00am to 07:00am are a bit lower than the ones for the time periods from 12:00 am to 03:00am and from the time periods from 04:00 pm to 12:00am, because it is not convenient to do so.

For the inflexible customers, they will shift their loads to the three hours immediately preceding and following each period because of physical constraints. The self-elasticity parameter is set as -0.2 too. The cross-elasticity parameters are set as 0.033 in order to make sure that the energy consumption does not change.

In order to study the effects of voluntary demand side load shift on price volatility and reliability of restructured power systems, nodal prices, nodal price volatility, system reliability indices and nodal reliability indices for six cases were obtained and are presented in this section. Case study 1 is the base case study in which there is no voluntary demand side load shift. In Case study 2, all the customers are treated as flexible customers. In Case study 3, all the customers are treated as inflexible customers. In Case studies 4, 5 and 6, sensitivity studies are carried out to study the effect of different combinations of flexible and inflexible customers on nodal price and reliability of restructured power systems.

3.6.1 Case study for flexible customers

Nodal Prices and Nodal Price Volatility for Cases 1 and 2

Nodal prices of nodes 1, 8, 16 and 24 of the RTS for Cases 1 and 2 are shown in Figures 3-5 to 3-8, respectively.

Figure 3-5 Nodal prices at node 1 of the RTS for Cases 1 and 2

Figure 3-6 Nodal prices at node 8 of the RTS for Cases 1 and 2

Figure 3-7 Nodal prices at node 16 of the RTS for Cases 1 and 2

Figure 3-8 Nodal prices at node 24 of the RTS for Cases 1 and 2

It can be seen from the figures that the nodal prices of nodes 1, 8, 16 and 24 changed due to the voluntary demand side load shift. The higher prices in Case 1 are reduced to the lower prices in Case 2. The lower prices in Case 1 are increased in Case 2. Nodal prices of other nodes change in a similar manner. The highest and lowest nodal prices of Case 1 are 15.618 \$/MWh and 9.9914 \$/MWh, respectively; the highest and lowest nodal prices of Case 2 are 15.509 \$/MWh and 10.015 \$/MWh respectively. The highest nodal price with voluntary demand side load shift is reduced by 0.109 \$/MWh and the lowest nodal price with voluntary demand side load shift is increased by 0.0236 \$/MWh.

Nodal price volatility indices of all the 24 nodes for Cases 1 and 2 are illustrated in Table 3-2. It is shown in Table 3-2 that price volatility of the 24 nodes are reduced by voluntary demand side load shift. The percentage change of price volatility of node 18 is the biggest (6.51%). The smallest percentage change of price volatility occurs at node 7 (3.98%). The nodal price volatility is reduced significantly by the voluntary demand side load shift. The nodal prices become more stable when voluntary demand side load shift is implemented in system operation.

Table 3-2 Nodal Price Volatility Indices for Cases 1 and 2

Cases Node	Case 1	Case 2	Change (%)
1	0.48631	0.4631	4.77
2	0.48767	0.46446	4.75
3	0.5112	0.47991	6.12
4	0.58113	0.55115	5.15
5	0.55589	0.52736	5.13
6	0.63065	0.5963	5.44
7	0.34684	0.333	3.98
8	0.53907	0.51278	4.87
9	0.50312	0.47395	5.79
10	0.51266	0.48313	5.76
11	0.49775	0.4687	5.83
12	0.49231	0.46368	5.81
13	0.47045	0.44309	5.81
14	0.49166	0.46204	6.02
15	0.46425	0.43509	6.28
16	0.46432	0.43537	6.23
17	0.4509	0.42204	6.40
18	0.44601	0.41695	6.51
19	0.46437	0.43569	6.17
20	0.45503	0.4271	6.13
21	0.44291	0.41414	6.49
22	0.43347	0.40623	6.28
23	0.44659	0.41924	6.12
24	0.49213	0.4618	6.16

From the analysis of the specific nodal price data and nodal price volatility indices, it can be concluded that voluntary demand side load shift from flexible customers could be utilized as an important tool to reduce the nodal price volatility.

System Reliability Indices for Cases 1 and 2

The effects of the voluntary demand side load shift from flexible customers on system reliability were studied using the RTS. The system reliability indices for the RTS for Cases 1 and 2 are shown in Table 3-3.

Table 3-3 System Reliability Indices of the RTS for Cases 1 and 2

<div>Indices \ Cases</div>	Case 1	Case 2
ELCP	0.173	0.15388
ELCF(occurrences/day)	76.558	64.887
ELC(MW)	7729.5	4629.9
EENS(MWh)	424.81	252.4

The ELCP is reduced from 0.173 of Case 1 to 0.15388 of Case 2. The ELCF is reduced from 76.558 occurrences/day of Case 1 to 64.887 occurrences/day of Case 2. The ELC is reduced from 7729.5 MW Case 1 to 4629.9 MW of Case 2 and the EENS is reduced from 424.81 MWh of Case 1 to 252.4 MWh of Case 2.

The analysis of the reliability indices for the RTS for Cases 1 and 2 show that system reliability is significantly improved by the voluntary demand side load shift when the reserve is maintained at the same level for the two cases.

Nodal Reliability Indices for Cases 1 and 2

The effects of the voluntary demand side load shift from flexible customers on nodal reliabilities were also investigated using the RTS.

Nodal reliability indices of the RTS for Cases 1 and 2 are shown in Figures 3-9 to 3-12 and in Tables 3-4 to 3-7.

Table 3-4 PNLC of the RTS for Cases 1 and 2

Cases Nodes	Case 1	Case 2	Percentage Reduction (%)
3	0.031162	0.02734	12.2649
4	0.14298	0.035435	75.2168
5	0.028752	0.0025745	91.0458
6	0.15848	0.14662	7.4836
7	0.0013722	0.0013722	0
8	0.047322	0.036083	23.7501
9	0.009925	0.0099248	0.0020
10	0.01539	0.009925	35.5101
14	0.012381	0.0042856	65.3857
18	0.0042856	0.0042854	0.0047

Table 3-5 FNLC of the RTS for Cases 1 and 2

Cases Nodes	Case 1 (occ/yr)	Case 2 (occ/yr)	Percentage Reduction (%)
3	15.289	12.439	18.6409
4	58.57	17.645	69.8737
5	13.16	1.3577	89.6831
6	67.704	60.344	10.8708
7	0.93051	0.93051	0
8	23.553	17.17	27.1006
9	4.7256	4.7253	0.0063
10	6.8578	4.7256	31.0916
14	5.0526	1.5455	69.4118
18	1.5455	1.5453	0.0129

Table 3-6 ENLC of the RTS for Cases 1 and 2

Cases Nodes	Case 1 (MW)	Case 2 (MW)	Percentage Reduction (%)
3	918.38	683.86	25.5363
4	891.69	340.94	61.7647
5	74.93	3.5845	95.2162
6	4680.7	2892.1	38.2122
7	45.254	44.934	0.7071
8	563.88	344.62	38.8842
9	86.299	18.298	78.7970
10	170.32	77.08	54.7440
14	177.95	128.99	27.5133
18	120.09	96.202	19.8917

Table 3-7 ENENS of the RTS for Cases 1 and 2

Cases Nodes	Case 1 (MWh)	Case 2 (MWh)	Percentage Reduction (%)
3	48.993	37.566	23.3237
4	48.408	17.605	63.6320
5	3.6909	0.15331	95.8463
6	263.29	159.7	39.3444
7	1.2528	1.2415	0.9020
8	26.295	16.377	37.7182
9	4.3505	0.92277	78.7893
10	8.8104	3.8842	55.9135
14	11.729	8.5838	26.8156
18	7.9931	6.4031	19.8922

It can be seen from Figures 3-9 to 3-12 of the nodal reliability indices for Cases 1 and 2 that all the four nodal reliability indices (PNLC, FNLC, ENLC and ENENS) are significantly reduced by voluntary demand side load shift from flexible customers.

The PNLC for Cases 1 and 2 are shown in Table 3-4. The PNLC of all nodes except node 7 are reduced by the voluntary demand side load shift from flexible customers. The percentage change of PNLC for node 5 is the biggest and is 91.0458%. The percentage changes of PNLC for nodes 4 and 14 are also significant at 75.2168% and 65.3857%, respectively. The FNLC of Cases 1 and 2 are illustrated in Table 3-5. The FNLC of all nodes except node 7 are reduced by demand side load shift from flexible customers. The percentage change of FNLC for node 5 is the biggest at 89.6831%. The percentage changes of FNLC for nodes 4 and 14 are also significant at 69.8737% and 69.4118%, respectively.

The ENLC of Cases 1 and 2 are illustrated in Table 3-6. The ENLC of all nodes are reduced by the voluntary demand side load shift from flexible customers. The percentage change of ENLC for node 5 is the biggest and is 95.2162%. The percentage changes for nodes 9 and 4 are next at 78.7970% and 61.7647%, respectively. The ENENS of Cases 1 and 2 are illustrated in Table 3-7. The ENENS of all nodes are reduced by the voluntary demand side load shift from flexible customers. The percentage change of ENENS for

node 5 is the biggest and is 95.8463%. The percentage changes for nodes 9 and 4 are next at 78.7893% and 63.6320%, respectively.

Therefore, it can be concluded that voluntary demand side load shift from flexible customers can be a very useful tool to improve the nodal reliabilities of restructured power systems.

3.6.2 Case study for inflexible customers

Nodal Prices and Nodal Price Volatility for Cases 1 and 3

Nodal prices of nodes 1, 8, 16 and 24 of the RTS for Cases 1 and 3 are shown in Figures 3-13 to 3-16, respectively.

Figure 3-13 Nodal prices at node 1 of the RTS for Cases 1 and 3

Figure 3-14 Nodal prices at node 8 of the RTS for Cases 1 and 3

Figure 3-15 Nodal prices at node 16 of the RTS for Cases 1 and 3

Figure 3-16 Nodal prices at node 24 of the RTS for Cases 1 and 3

It can be seen from the figures that the nodal prices of nodes 1, 8, 16 and 24 do not change much due to the voluntary demand side load shift from inflexible customers. Nodal prices of other nodes change in a similar manner. The highest and lowest nodal prices of Case 1 are 15.618 \$/MWh and 9.991 \$/MWh, respectively; the highest and lowest nodal prices of Case 3 are 15.617 \$/MWh and 9.997 \$/MWh respectively. The highest nodal price with voluntary demand side load shift is reduced by 0.001 \$/MWh and the lowest nodal price with voluntary demand side load shift is increased by 0.006 \$/MWh.

Nodal price volatility indices of all the 24 nodes for Cases 1 and 3 are illustrated in Table 3-8. It is shown in Table 3-8 that price volatility of the 24 nodes are reduced by voluntary demand side load shift. The percentage change of price volatility of node 7 is the greatest (0.48%). The smallest percentage change of price volatility occurs at node 7 (0.29%). The nodal price volatility is not reduced much by the voluntary demand side load shift from inflexible customers.

Table 3-8 Nodal Price Volatility Indices for Cases 1 and 3

Cases Node	Case 1	Case 3	Change (%)
1	0.48631	0.48466	0.34
2	0.48767	0.48602	0.33
3	0.5112	0.50894	0.44
4	0.58113	0.57899	0.36
5	0.55589	0.55384	0.36
6	0.63065	0.62819	0.38
7	0.34684	0.34583	0.29
8	0.53907	0.53715	0.35
9	0.50312	0.50101	0.41
10	0.51266	0.51052	0.41
11	0.49775	0.49565	0.42
12	0.49231	0.49024	0.42
13	0.47045	0.46847	0.42
14	0.49166	0.48951	0.43
15	0.46425	0.46214	0.45
16	0.46432	0.46222	0.45
17	0.4509	0.4488	0.46
18	0.44601	0.44389	0.48
19	0.46437	0.46228	0.44
20	0.45503	0.453	0.44
21	0.44291	0.44082	0.47
22	0.43347	0.43149	0.45
23	0.44659	0.4446	0.44
24	0.49213	0.48993	0.44

From the analysis of the specific nodal price data and nodal price volatility indices, it can be concluded that voluntary demand side load shift from inflexible customers does not reduce the nodal price volatility significantly.

System Reliability Indices for Cases 1 and 3

The effects of the voluntary demand side load shift from inflexible customers on system reliability were studied using the RTS. The system reliability indices for the RTS for Cases 1 and 3 are shown in Table 3-9.

Table 3-9 System Reliability Indices of the RTS for Cases 1 and 3

Indices \ Cases	Case 1	Case 3
ELCP	0.173	0.173
ELCF(occurrences/day)	76.558	76.558
ELC(MW)	7729.5	7529.5
EENS(MWh)	424.81	413.77

The ELCP and the ELCF are the same for Cases 1 and 3. The ELC is reduced from 7729.5 MW for Case 1 to 7529.5 MW of Case 3 and the EENS is reduced from 424.81 MWh for Case 1 to 413.77 MWh for Case 3.

The analysis of the system reliability indices for the RTS for Cases 1 and 3 shows that system reliability is not improved much by the voluntary demand side load shift from inflexible customers when the reserve is maintained at the same level for the two cases.

Nodal Reliability Indices for Cases 1 and 3

The effects of the voluntary demand side load shift from inflexible customers on nodal reliabilities were also investigated using the RTS.

Nodal reliability indices of the RTS for Cases 1 and 3 are shown in Figures 3-17 to 3-20 and in Tables 3-10 to 3-13.

Figure 3-17 PNLC of the RTS for Cases 1 and 3

Figure 3-18 FNLC of the RTS for Cases 1 and 3

Figure 3-19 ENLC of the RTS for Cases 1 and 3

Figure 3-20 ENENS of the RTS for Cases 1 and 3

Table 3-10 PNLC of the RTS for Cases 1 and 3

Cases Nodes	Case 1	Case 3	Percentage Reduction (%)
3	0.031162	0.031162	0
4	0.14298	0.14296	0.01
5	0.028752	0.027442	4.55
6	0.15848	0.15848	0
7	0.0013722	0.0013722	0
8	0.047322	0.047322	0
9	0.009925	0.0099248	0
10	0.01539	0.01539	0
14	0.012381	0.0097512	21.2
18	0.0042856	0.0042856	0

Table 3-11 FNLC of the RTS for Cases 1 and 3

Cases Nodes	Case 1 (occ/yr)	Case 3 (occ/yr)	Percentage Reduction (%)
3	15.289	15.289	0
4	58.57	58.563	0
5	13.16	12.479	5.17
6	67.704	67.704	0
7	0.93051	0.93051	0
8	23.553	23.553	0
9	4.7256	4.7253	0
10	6.8578	6.8578	0
14	5.0526	3.678	27.2
18	1.5455	1.5455	0

Table 3-12 ENLC of the RTS for Cases 1 and 3

Cases Nodes	Case 1 (MW)	Case 3 (MW)	Percentage Reduction (%)
3	918.38	906.77	1.28
4	891.69	843.11	5.76
5	74.93	68.789	8.92
6	4680.7	4577.7	2.25
7	45.254	45.254	0
8	563.88	545.87	3.29
9	86.299	83.062	3.89
10	170.32	164.88	3.29
14	177.95	174.6	1.91
18	120.09	119.48	0.51

Table 3-13 ENENS of the RTS for Cases 1 and 3

Cases Nodes	Case 1 (MWh)	Case 3 (MWh)	Percentage Reduction (%)
3	48.993	48.479	1.04
4	48.408	45.473	6.06
5	3.6909	3.3798	8.42
6	263.29	257.51	2.19
7	1.2528	1.2528	0
8	26.295	25.493	3.05
9	4.3505	4.1874	3.74
10	8.8104	8.5167	3.33
14	11.729	11.522	1.76
18	7.9931	7.9526	0.5

It can be seen from Figures 3-17 to 3-20 of the nodal reliability indices for Cases 1 and 3 that all the four nodal reliability indices (PNLC, FNLC, ENLC and ENENS) are not reduced much by voluntary demand side load shift from inflexible customers.

The PNLC for Cases 1 and 3 are shown in Table 3-10. The PNLC of all nodes except node 14 are almost the same as those without demand side load shift. The FNLC of Cases 1 and 3 are illustrated in Table 3-11. The FNLC of all nodes except node 14 are not changed by the demand side load shift from inflexible customers.

The ENLC of Cases 1 and 3 are illustrated in Table 3-12. The ENLC of all nodes are reduced a little bit by the voluntary demand side load shift from inflexible customers. The percentage change of ENLC for node 5 is the biggest and is 8.92%. The ENENS of Cases 1 and 3 are illustrated in Table 3-13. The ENENS of all nodes are reduced a little bit by the voluntary demand side load shift from flexible customers. The percentage change of ENENS for node 5 is the biggest and is 8.42%.

Therefore, it can be concluded that the voluntary demand side load shift from inflexible customers would not be a useful tool to improve the nodal reliabilities of restructured power systems.

3.6.3 Sensitivity study with both flexible and inflexible customers

In order to study the impact of the diversified demand side load shift on nodal prices, nodal price volatility, system reliability and nodal reliabilities of restructured power systems, four case studies were implemented. Case 1 is the base case without demand side load shift. Cases 4, 5 and 6 use different diversified demand side load shift. In this paper, the customer diversity is defined as the ratio of the demand of one type of customer over the total load at one node. The specific customer diversity data are illustrated in Table 3-14.

Table 3-14 Customer Diversity

Cases Nodes	Case 4		Case 5		Case 6	
	type 1	type 2	type 1	type 2	type 1	type 2
3	0.7	0.3	0.5	0.5	0.3	0.7
4	0.7	0.3	0.5	0.5	0.3	0.7
5	0.7	0.3	0.5	0.5	0.3	0.7
6	0.7	0.3	0.5	0.5	0.3	0.7
7	0.7	0.3	0.5	0.5	0.3	0.7
8	0.7	0.3	0.5	0.5	0.3	0.7
9	0.7	0.3	0.5	0.5	0.3	0.7
10	0.7	0.3	0.5	0.5	0.3	0.7
14	0.7	0.3	0.5	0.5	0.3	0.7
18	0.7	0.3	0.5	0.5	0.3	0.7

Nodal Prices and Nodal Price Volatility for Case 1, Case 4, Case 5 and Case 6

Spot prices of nodes 1, 8, 16 and 24 of the RTS for Cases 1, 4, 5 and 6 are shown in Figures 3-21 to 3-24, respectively.

Figure 3-21 Nodal prices at node 1 of the RTS for Cases 1, 4, 5 and 6

Figure 3-22 Nodal prices at node 8 of the RTS for Cases 1, 4, 5 and 6

Figure 3-23 Nodal prices at node 16 of the RTS for Cases 1, 4, 5 and 6

Figure 3-24 Nodal prices at node 24 of the RTS for Cases 1, 4, 5 and 6

It can be seen from the figures that the nodal prices of nodes 1, 8, 16 and 24 are changed a bit by the diversified voluntary demand side load shift. Nodal prices of other nodes change in a similar manner.

Nodal price volatility indices of all the 24 nodes for Cases 1 and 4 are illustrated in Table 3-15.

Table 3-15 Nodal Price Volatility Indices for Cases 1 and 4

<div>Cases</div> <div>Nodes</div>	Case 1	Case 4	Change (%)
1	0.48631	0.45247	3.339
2	0.48767	0.45384	3.325
3	0.5112	0.46586	4.284
4	0.58113	0.53762	3.605
5	0.55589	0.51446	3.591
6	0.63065	0.58096	3.808
7	0.34684	0.32697	2.786
8	0.53907	0.50143	3.409
9	0.50312	0.46087	4.053
10	0.51266	0.46989	4.032
11	0.49775	0.45566	4.081
12	0.49231	0.45083	4.067
13	0.47045	0.43078	4.067
14	0.49166	0.44876	4.214
15	0.46425	0.42202	4.396
16	0.46432	0.4224	4.361
17	0.4509	0.40913	4.48
18	0.44601	0.40398	4.557
19	0.46437	0.42283	4.319
20	0.45503	0.41458	4.291
21	0.44291	0.4013	4.543
22	0.43347	0.39401	4.396
23	0.44659	0.407	4.284
24	0.49213	0.44819	4.312

Nodal price volatility indices of all the 24 nodes for Cases 1 and 5 are illustrated in Table 3-16.

Table 3-16 Nodal Price Volatility Indices for Cases 1 and 5

<div>Cases</div> <div>Nodes</div>	Case 1	Case 5	Change (%)
1	0.48631	0.46309	2.385
2	0.48767	0.46446	2.375
3	0.5112	0.4799	3.06
4	0.58113	0.55114	2.575
5	0.55589	0.52735	2.565
6	0.63065	0.59629	2.72
7	0.34684	0.333	1.99
8	0.53907	0.51278	2.435
9	0.50312	0.47394	2.895
10	0.51266	0.48312	2.88
11	0.49775	0.46869	2.915
12	0.49231	0.46367	2.905
13	0.47045	0.44308	2.905
14	0.49166	0.46203	3.01
15	0.46425	0.43508	3.14
16	0.46432	0.43536	3.115
17	0.4509	0.42203	3.2
18	0.44601	0.41694	3.255
19	0.46437	0.43568	3.085
20	0.45503	0.42709	3.065
21	0.44291	0.41413	3.245
22	0.43347	0.40622	3.14
23	0.44659	0.41924	3.06
24	0.49213	0.46179	3.08

Nodal price volatility indices of all the 24 nodes for Cases 1 and 6 are illustrated in Table 3-17.

Table 3-17 Nodal Price Volatility Indices for Cases 1 and 6

<div>Cases</div> <div>Nodes</div>	Case 1	Case 6	Change (%)
1	0.48631	0.4631	1.431
2	0.48767	0.46447	1.425
3	0.5112	0.47991	1.836
4	0.58113	0.55116	1.545
5	0.55589	0.52736	1.539
6	0.63065	0.5963	1.632
7	0.34684	0.33301	1.194
8	0.53907	0.51278	1.461
9	0.50312	0.47395	1.737
10	0.51266	0.48313	1.728
11	0.49775	0.46871	1.749
12	0.49231	0.46368	1.743
13	0.47045	0.4431	1.743
14	0.49166	0.46204	1.806
15	0.46425	0.43509	1.884
16	0.46432	0.43537	1.869
17	0.4509	0.42204	1.92
18	0.44601	0.41696	1.953
19	0.46437	0.43569	1.851
20	0.45503	0.4271	1.839
21	0.44291	0.41415	1.947
22	0.43347	0.40623	1.884
23	0.44659	0.41925	1.836
24	0.49213	0.4618	1.848

Nodal price volatility for Cases 1, 4, 5 and 6 are illustrated in Figure 3-25.

Figure 3-25 Nodal price volatility for Cases 1, 4, 5 and 6

It is shown in Tables 3-15 to 3-17 that price volatility of the 24 nodes are reduced by diversified voluntary demand side load shift. It is shown that the nodal price volatility is reduced more with more flexible customers in the system. The nodal prices become more stable when there are more flexible customers.

System Reliability Indices for Cases 1, 4, 5 and 6

The impacts of diversified demand side load shift on the system reliability were studied using the RTS. The system reliability indices for the RTS for Cases 1, 4, 5 and 6 are shown in Table 3-18.

The ELCP is reduced from 0.173 of Case 1 to 0.146 of Case 4, 0.149 of Case 5 and 0.153 of Case 6. The ELCF is reduced from 76.558 occurrences/day of Case 1 to 60.587 occurrences/day of Case 4, 62.187 occurrences/day of Case 6 and 64.887 occurrences/day of Case 6. The ELC is reduced from 7729.5 MW of Case 1 to 3907 MW of Case 4, 4579 of Case 5 and 4664 MW of Case 6. The EENS is reduced from 424.81 MWh of Case 1 to 210.91 MWh of Case 4, 249.66 MWh of Case 5 and 254.53 MWh of Case 6.

Table 3-18 System Reliability Indices of the RTS for Cases 1, 4, 5 and 6

<div>Indices</div> <div>Cases</div>	ELCP	ELCF (occurrences/day)	ELC (MW)	EENS (MWh)
Case 1	0.173	76.558	7729.5	424.81
Case 4	0.146	60.587	3907	210.91
Case 5	0.149	62.187	4579	249.66
Case 6	0.153	64.887	4664	254.53

The analysis of the system reliability indices of the RTS for the four cases shows that system reliability is improved significantly by the diversified demand side load shift when the reserve is maintained at the same level for the four cases.

It is also illustrated in Table 3-18 that the system reliability improvement is biggest for Case 4 in which the percentage of the flexible customers is biggest. It can be concluded that a power system with more flexible customers will be more reliable than that with more inflexible customers.

Nodal Reliability Indices for Cases 1, 4, 5 and 6

The effects of diversified demand load shift on nodal reliabilities were also investigated for the RTS. Nodal reliability indices of the RTS for Cases 1, 4, 5 and 6 are shown respectively in Figures 3-26 to 3-29 and Tables 3-19 to 3-22.

Figure 3-26 PNLC of the RTS for Cases 1, 4, 5 and 6

Figure 3-27 FNLC of the RTS for Cases 1, 4, 5 and 6

Figure 3-28 ENLC of the RTS for Cases 1, 4, 5 and 6

Figure 3-29 ENENS of the RTS for Cases 1, 4, 5 and 6

It can be seen from Figures 3-26 to 3-29 that nodal reliability indices (PNLC, FNLC, ENLC and ENENS) are reduced quite significantly by including the diversified demand side load shift.

Table 3-19 PNLC of the RTS for Cases 1, 4, 5 and 6

<div>Cases Nodes</div>	Case 1	Case 4	Case 5	Case 6
3	0.031162	0.02734	0.02734	0.02734
4	0.14298	0.031589	0.035435	0.03543
5	0.028752	0.0099331	0.012499	0.01249
6	0.15848	0.14344	0.14662	0.14662
7	0.0013722	0.001372	0.0013722	0.00137
8	0.047322	0.019164	0.028915	0.03346
9	0.009925	0.000009	0.009925	0.00992
10	0.01539	0.009925	0.009925	0.00992
14	0.012381	0.0042857	0.0042857	0.00428
18	0.0042856	0.0042854	0.0042854	0.00428

Table 3-20 FNLC of the RTS for Cases 1, 4, 5 and 6

<div>Cases Nodes</div>	Case 1 (occ/yr)	Case 4 (occ/yr)	Case 5 (occ/yr)	Case 6 (occ/yr)
3	15.289	12.439	12.439	12.439
4	58.57	14.796	17.645	17.645
5	13.16	4.7368	6.0827	6.0827
6	67.704	58.726	60.345	60.345
7	0.93051	0.93071	0.93051	0.93051
8	23.553	9.4305	13.108	15.808
9	4.7256	0.0005759	4.7256	4.7253
10	6.8578	4.7256	4.7256	4.7256
14	5.0526	1.5456	1.5457	1.5457
18	1.5455	1.5452	1.5452	1.5452

Table 3-21 ENLC of the RTS for Cases 1, 4, 5 and 6

Cases Nodes	Case 1 (MW)	Case 4 (MW)	Case 5 (MW)	Case 6 (MW)
3	918.38	596.78	667.07	675.43
4	891.69	317.45	353.18	357.78
5	74.93	1.3964	7.5321	8.4939
6	4680.7	2416.6	2893.6	2952.6
7	45.254	42.626	43.107	43.172
8	563.88	279.2	306.19	311.32
9	86.299	0.046562	13.033	15.464
10	170.32	48.591	74.25	76.724
14	177.95	120.25	129.01	129.95
18	120.09	84.01	92.021	92.994

Table 3-22 ENENS of the RTS for Cases 1, 4, 5 and 6

Cases Nodes	Case 1 (MWh)	Case 4 (MWh)	Case 5 (MWh)	Case 6 (MWh)
3	48.993	33.054	36.722	37.156
4	48.408	16.629	18.264	18.466
5	3.6909	0.059395	0.35254	0.39816
6	263.29	130.95	159.66	163.2
7	1.2528	1.1598	1.1769	1.1792
8	26.295	13.015	14.382	14.638
9	4.3505	0.0027395	0.65735	0.77992
10	8.8104	2.4484	3.7416	3.867
14	11.729	8.002	8.5854	8.6479
18	7.9931	5.5916	6.1248	6.1896

The PNLC of Cases 1, 4, 5 and 6 are shown in Table 3-19. The PNLC of all nodes are reduced by including the diversified demand side load shift. Table 3-20 shows that the FNLC of all nodes are reduced by the diversified demand side load shift. The ENLC for Cases 1, 4, 5 and 6 are illustrated in Table 3-21. The ENLC of all nodes are reduced by

including the diversified demand side load shift. The ENENS of Cases 1, 4, 5 and 6 are illustrated in Table 3-22. The ENENS of all nodes are reduced by including the diversified demand side load shift. Therefore, it can be concluded that the diversified demand side load shift can be a very useful tool to improve the nodal reliabilities of restructured power systems.

The PNLC of node 4, 5, 8 and 9 for Case 4 are smaller than those for Cases 5 and 6. The FNLC of node 4, 5, 8 and 9 for Case 4 are smaller than those of Cases 5 and 6. In Table 3-21, it is shown that ENLC of all nodes for Case 4 are smaller than those for Cases 5 and 6. It is also shown in Table 3-22 that ENENS of all nodes for Case 4 are smaller than those for Cases 5 and 6. Therefore, it can be concluded that nodal reliabilities of restructured power systems are increased with the increase of flexible demands.

3.7 Conclusion

An evaluation technique is proposed in this chapter to investigate the impact of voluntary demand side load shift on nodal price volatility, system reliability and nodal reliabilities of restructured power systems. In this technique, demand and price correlation is represented using the demand-price elasticity matrix which consists of self- and cross-elasticities. Voluntary demand side load shift is determined using an iterative methodology. Nodal prices are determined using OPF which uses the Lagrangian multipliers as shadow prices. System and nodal reliabilities of restructured power systems are evaluated using the OPF based reliability evaluation technique. The IEEE RTS is simulated to illustrate the developed concepts.

The case study results show that voluntary demand side load shift can reduce the nodal price volatility and improve both system reliability and nodal reliabilities of restructured power systems although the impact of inflexible customers is a bit small. Voluntary demand side load shift can therefore be utilized as a possible efficient tool to reduce price volatility and to improve the reliability of restructured power systems.

Chapter 4 DLC of ACL considering Nodal Reliability Characteristics

4.1 Introduction

The restructuring of power systems has been accompanied by numerous problems, including capacity shortage, transmission congestion, wholesale price volatility, and reduced system reliability. These problems have created new opportunities for technologies and business approaches that allow load serving entities and other aggregators to control and manage the load patterns of wholesale and retail end-users they serve. These technologies and business approaches for manipulating end-user load shapes are known as load management. Load management has re-emerged as an important element of the fine-tuning of restructured power systems [5].

Direct load control (DLC) is the most common load management program to shape the load curve by cycling customers' large current drawing appliances. Various DLC schemes have been developed to achieve peak load shaving and operating cost saving [111], [103-127]. However, the existing DLC techniques have not, to our best knowledge, considered transmission system reliability in determining the DLC scheme. The air conditioning loads (ACL) are treated as a number of no difference groups with the same capacity. In practical power systems, ACL are connected to different nodes which may have different reliabilities. The load reduction at peak hours by cycling ACL groups at different nodes may have different effects on peak load shaving, system operating cost reduction and system reliability improvement. Therefore, this issue should be considered in determining the optimal DLC scheme of ACL which could strike a balance between the system operating cost reduction and the system reliability improvement.

In this chapter, a fuzzy logic-based DLC scheme of ACL considering nodal reliability characteristics is proposed. The effect of transmission network reliability on the DLC scheme is considered and represented using nodal reliability indices for restructured power systems. Fuzzy dynamic programming (FDP) is utilized to determine the optimal

DLC scheme of ACL to achieve a good tradeoff among peak load shaving, operating cost reduction and system reliability improvement. The IEEE RTS is simulated to illustrate the developed techniques.

4.2 DLC Problem Formulation

The basic DLC problem is to schedule the cycling on/off times and durations of customers' large current drawing appliances, aiming to reduce the peak load as much as possible. The objective is to minimize the system operating cost arising from the DLC and the associated unit commitment.

In this chapter, the transmission system is integrated into the DLC problem. The basic formulation of the DLC problem considering transmission constraints is depicted in the following dynamic recursive form.

At the n th stage, the least cumulated operating cost of the j th state is depicted in Equation (4.1).

$$C(n, j) = \min_{\{m\}} (FC(n, j) + SC(n-1, m : n, j) + C(n-1, m)) \quad (4.1)$$

where $FC(n, j)$ is the fuel cost, $SC(n-1, m : n, j)$ is the start-up cost from state $(n-1, m)$ to state (n, j) , $\{m\}$ is the set of feasible states at the $(n-1)$ th stage.

Subject to the following constraints:

Load flow constraints:

$$\sum_{i \in k} u_{gi}(n, j) P_{gi}(n, j) - P_{dk}'(n, j) - \sum_{l \in k} V_k(n, j) V_l(n, j) Y_{kl} \cos(\theta_{kl} + \delta_k(n, j) - \delta_l(n, j)) = 0 \quad (4.2)$$

$$\sum_{i \in k} u_{gi}(n, j) Q_{gi}(n, j) - Q_{dk}'(n, j) - \sum_{l \in k} V_k(n, j) V_l(n, j) Y_{kl} \sin(\theta_{kl} + \delta_k(n, j) - \delta_l(n, j)) = 0 \quad (4.3)$$

Generation constraints:

$$P_{gi}^{\min} \leq P_{gi}(n, j) \leq P_{gi}^{\max} \quad (4.4)$$

$$Q_{gi}^{\min} \leq Q_{gi}(n, j) \leq Q_{gi}^{\max} \quad (4.5)$$

Voltage constraint:

$$V_k^{\min} \leq V_k(n, j) \leq V_k^{\max} \quad (4.6)$$

Line flow constraint:

$$P_m^{\min} \leq P_m(n, j) \leq P_m^{\max} \quad (4.7)$$

System spinning reserve constraint:

$$\sum_{i=1}^{N_g} u_{gi}(n, j) RES_i(n, j) \geq REQ(n) \quad (4.8)$$

where $u_{gi}(n, j)$ is the commitment state of the i th unit at the j th state of the n th stage, $P_{gi}(n, j)$ is the real power output of the i th unit at the j th state of the n th stage, $Q_{gi}(n, j)$ is the reactive power output of the i th unit at the j th state of the n th stage, N_g is the total number of units, $P'_{dk}(n, j)$ is the real power demand of node k at the j th state of the n th stage after DLC, $Q'_{dk}(n, j)$ is the reactive power demand of node k at the j th state of the n th stage after DLC, $P_{gi}^{\min}$ is the minimum real power output of the i th unit; $P_{gi}^{\max}$ is the maximum real power output of the i th unit; $Q_{gi}^{\min}$ is the minimum reactive power output of the i th unit; $Q_{gi}^{\max}$ is the maximum reactive power output of the i th unit, $V_k^{\min}$ is the minimum voltage at node k ; $V_k^{\max}$ is the maximum voltage at node k ; $P_m^{\min}$ is the minimum real power flow allowed through line m ; $P_m^{\max}$ is the maximum real power flow allowed through line m ; $V_k(n, j) \angle \delta_k(n, j)$ and $V_l(n, j) \angle \delta_l(n, j)$ are the voltages of nodes k and l at

the j th state of the n th stage, respectively; $Y_{kl} \angle \theta_{kl}$ is the admittance between nodes k and l , $RES_i(n, j)$ is the spinning reserve of the i th unit at the j th state of the n th stage, $REQ(n)$ is the spinning reserve requirement at the n th stage. In the case studies, a typical value of 20% of the peak load was used as the spinning reserve requirement.

In Equation (4.2), $P_{dk}'(n, j)$ can be obtained using:

$$P_{dk}'(n, j) = \begin{cases} P_{dk}(n) & \text{if there is no DLC at node } k \\ P_{dk}(n, j) - DLC_k(n, j) + PB_k(n) & \text{if there is DLC at node } k \end{cases} \quad (4.9)$$

where $P_{dk}(n)$ is the real power demand of node k at the n th stage before DLC, $DLC_k(n, j)$ is the DLC capacity of node k at the j th state of the n th stage, and $PB_k(n)$ is the real power demand payback of node k at the n th stage.

The following is the DLC capacity constraint:

$$DLC_k(n, j) \begin{cases} \geq 0 & K \leq n \leq K + DT \\ = 0 & n > K + DT \end{cases} \quad (4.10)$$

where K is the DLC starting hour, and DT is the time step of the DLC of ALC.

The employed load pay-back pattern of node k at the n th stage, $PB_k(n)$, based on the DLC at previous stages, can be determined by Equation (4.11) [120]:

$$PB_k(n) = 0.6 \times DLC_k(n-1) + 0.3 \times DLC_k(n-2) + 0.1 \times DLC_k(n-3) \quad (4.11)$$

It is assumed that the power factor of node k does not change before and after DLC.

$Q_{dk}'(n, j)$ can be calculated by using $P_{dk}'(n, j)$ and the power factor at node k .

The accumulated disconnection time interval of the i th ACL at the n th stage is depicted in Equation (4.12).

$$AT_i(n) = \begin{cases} AT_i(n-1) + T & \text{if } S_i(n-1) = 0 \\ & \text{and } S_i(n) = 0 \\ T & \text{if } S_i(n-1) = 1 \\ & \text{and } S_i(n) = 0 \\ -T & \text{if } S_i(n-1) = 0 \\ & \text{and } S_i(n) = 1 \\ AT_i(n-1) - T & \text{if } S_i(n-1) = 1 \\ & \text{and } S_i(n) = 1 \end{cases} \quad (4.12)$$

where T is the time interval of each stage, and $S_i(n)$ is the dispatch state of the i th ACL at the n th stage. $S_i(n)$ is 1 if ACL is connected to the system, otherwise $S_i(n)$ is 0. The constraint of $S_i(n)$ is depicted in Equation (4.13).

$$S_i(n) = \begin{cases} 1 & \text{if } AT_i(n-1) > \max T_i \\ 1 & \text{and if } -\min T_i < AT_i(n-1) < 0 \\ 0 & \text{otherwise} \end{cases} \quad (4.13)$$

where $\max T_i$ is the maximum accumulated disconnection time of the i th ACL, and $\min T_i$ is the minimum accumulated connection time of the i th ACL.

4.3 Fuzzy Formulation of DLC

There are many uncertainties such as load variation and random failures of system components in power system operation. The DLC scheme may not be the most optimal if the load uncertainty is not considered. Likewise, system spinning reserve and nodal reliabilities in DLC problem should also be taken into account. In order to incorporate load uncertainty and various constraints into the DLC problem, FDP is generally utilized to handle various constraints and the multi-objective optimization problem.

The basic DLC formulation in Section 4.2 is extended to include the load uncertainty, system spinning reserve requirement and nodal reliability characteristics using the fuzzy technique to improve the system reliability and to reduce the system operating cost. In the fuzzy formulation, two fuzzy objective functions are defined to obtain both system reliability improvement and system operating cost reduction. The system spinning reserve requirement and load uncertainty issues are treated as two fuzzy constraints. FDP is utilized to determine the optimal DLC scheme of ACL.

4.3.1 Fuzzy Objective Functions

In order to obtain both system reliability improvement and system operating cost reduction, two fuzzy objective functions are formulated in this section.

4.3.1.1 System Reliability Improvement

It is well known that DLC of ACL can improve the system reliability of power systems. By cycling ACL, the system load curve is reshaped and the system peak load is shaved. The load shift at peak hours due to the DLC of ACL is the main reason for system reliability improvement. In the existing DLC techniques, all the ACL groups are treated as some ACL groups with the same capacity in the determination of the DLC scheme. However, the load shift at peak hours at different nodes has different effects on system reliability improvement. The same load shift at peak hours at a node with a big reliability value will improve the system reliability more compared to the one at a node with a small reliability value. The effects of load shift at peak hours of different nodes on system reliability improvement should be considered in the DLC technique in order to improve the system reliability as much as possible.

In the proposed DLC technique, the transmission network reliability of restructured power systems is incorporated into the determination procedure of the optimal DLC

scheme. The nodal reliability characteristic is utilized to represent the transmission network reliability using the expected nodal load curtailment (ENLC).

In this chapter, the nodal reliability indices are calculated using the OPF based reliability evaluation technique. The nodal load curtailment is determined by the system operator based on the minimum generation and interruption costs. The formulation to determine the optimal load curtailment scenario, if load curtailment is needed, under the j th contingency can be depicted by the optimization problem of Equations (4.14)-(4.17).

Objective Function:

$$\text{Min} \sum_{i=1}^{N_g^j} C_{pi}(P_{gi}) + \sum_{k=1}^{N_n^j} \sum_{s=1}^{N_{ks}} OC_{ks}(LC_{pks}) \quad (4.14)$$

Subject to the following constraints:

Load flow constraints:

$$\sum_{i \in k} P_{gi} - P_{dk} + \sum_{s \in k} LC_{pks} - \sum_{l \in k} V_k V_l Y_{kl} \cos(\theta_{kl} + \delta_k - \delta_l) = 0 \quad (4.15)$$

$$\sum_{i \in k} Q_{gi} - Q_{dk} + \sum_{s \in k} LC_{qks} - \sum_{l \in k} V_k V_l Y_{kl} \sin(\theta_{kl} + \delta_k - \delta_l) = 0 \quad (4.16)$$

Load curtailment constraint:

$$0 \leq LC_{pks} \leq P_{dks} \quad (4.17)$$

where N_g^j is the total number of generators under the j th contingency, N_n^j is the total nodes under the j th contingency, N_{ks} is the number of customer sectors, $OC_{ks}(LC_{pks}, LC_{qks})$ is the interruption cost, LC_{pks} is the real power load curtailment of load sector s at node k , and LC_{qks} is the reactive power load curtailment of load sector s at node k .

The generation, nodal voltage and power line flow constraints are expressed in Equations (3.22) to (3.28) of Chapter 3.

The expected nodal load curtailment of node k ($ENLC_k$) can be calculated using Equation (4.18).

$$ENLC_k = \sum_{j=1}^{NC} NLC_{jk} \times F_j \quad (4.18)$$

where NLC_{jk} is the nodal load curtailment of node k under the j th contingency, NC is the total number of considered contingencies, and F_j is the frequency of the j th contingency which can be calculated using the reliability indices calculation technique.

4.3.1.2 Membership Function of DLC Scheme

Fuzzy set $\tilde{D}_r$ is defined using the $ENLC$ to represent the nodal reliability characteristic of the ACL groups connected to different nodes. The membership function of $\tilde{D}_r$ is formulated as:

$$\tilde{u}_{D_r} = \frac{ENLC_i}{ENLC_{sum}} \quad (4.19)$$

where $ENLC_i$ is the expected load curtailment of the node where the i th ACL group is connected, and $ENLC_{sum}$ is the sum of expected nodal load curtailment of all nodes where ACL groups are connected.

The membership function shows that the ACL group at the node with higher ENLC has a bigger membership value. In other words, the ACL group at a node with high ENLC

should have a priority to be selected than the one at a node with small ENLC if the operating cost saving is the same. This is because load shift at a node with a higher ENLC will improve the system reliability more than the one at a node with a smaller ENLC.

In order to integrate the transmission network reliability into the DLC problem formulation and to study the effects of load shifts at different nodes on system reliability improvement, we define a fuzzy objective function, $\tilde{R}$, which is related to the reliability characteristic of the DLC scheme.

The membership function of the reliability characteristic for different DLC schemes is expressed as:

$$\tilde{u}_R(n, j) = \frac{\sum_{i=1}^{N_A} u_i(n, j) ENLC_i}{ENLC_{sum}} \quad (4.20)$$

where N_A is the total number of ACL groups, and $u_i(n, j)$ is the DLC state of the i th ACL at the j th state of the n th stage.

Figure 4-1 displays the membership function of the reliability characteristic of different DLC schemes. It shows that the DLC scheme with a large sum of ENLC has a large value. Thus, the DLC scheme which can improve system reliability more has a bigger membership value.

Figure 4-1 Membership function of the reliability characteristic of DLC dispatch

4.3.1.3 System Operating Cost

In the proposed DLC technique, the system operating cost reduction due to load shift is considered in the determination of the optimal DLC scheme.

The membership function of the system operating cost in Equation (4.1) is formulated as [126]:

$$\tilde{u}_c(n, j) = 1 - W_c \frac{C(n, j) - C_{\min}(n)}{C_{\max}(n) - C_{\min}(n)} \quad (4.21)$$

where W_c is the weighting factor for the operating cost, and $C_{\max}(n)$ and $C_{\min}(n)$ are the maximum and minimum cumulated operating costs at n th stage, respectively. In the case studies, W_c was set as 1.0.

Figure 4-2 shows the membership function of the system operating cost. It shows that a smaller system operating cost has a larger membership value, which translates into bigger system operating cost reduction.

Figure 4-2 Membership function of the system operating cost

4.3.2 Fuzzy Constraints

The system spinning reserve and load uncertainty issues are represented using fuzzy constraints.

4.3.2.1 System Spinning Reserve

The membership function of the system spinning reserve constraint can be defined as [126]:

$$\tilde{u}_s(n, j) = \begin{cases} 0 & SR_s < SR_a \\ 1 - \frac{SR_s - SR(n, j)}{SR_s - SR_a} & SR_a \leq SR(n, j) < SR_s \\ 1 & SR \geq SR_s \end{cases} \quad (4.22)$$

where SR_a and SR_s are the allowed least and the satisfied secure system spinning reserves respectively. Figure 4-3 describes the membership function of the system spinning reserve constraint.

Figure 4-3 Membership function of the system spinning reserve

4.3.2.2 Load Uncertainty

The load error, ΔL , is assumed for each possible state. The membership function of the load uncertainty is [126]:

$$\tilde{u}_L(n, j) = \begin{cases} \frac{1}{1 + a\left(\frac{\Delta L}{M_+}\right)^2} & \Delta L \geq 0 \\ \frac{1}{1 + a\left(\frac{\Delta L}{M_-}\right)^2} & \Delta L < 0 \end{cases} \quad (4.23)$$

$$\Delta L = \frac{L_f - L_a}{L_a} \times 100\% \quad (4.24)$$

where M_+ and M_- are the past positive/negative forecasting errors, and L_a and L_f are the actual and expected loads respectively. The parameter a is used to adjust the shape of the membership functions. Three membership functions giving 'large', 'medium' and 'small' load uncertainties when a is 1.0 are depicted in Figure 4-4. During a specific interval of the DLC, once the load uncertainty is given linguistically, the related membership function is chosen.

Figure 4-4 Membership functions for diverse load uncertainties

4.3.3 FDP Solution Methodology

In order to take the variation of the on/off control duration of the ACL and the load uncertainty into account, FDP was utilized to solve the DLC problem.

In the fuzzy set notations, the fuzzy decision set, $\tilde{D}$, is the “intersection” of the objective functions and the constraints [168]. In this approach, the fuzzy decision set is expressed in Equation (4.25).

$$\tilde{D} = \tilde{R} \cap \tilde{C} \cap \tilde{S} \cap \tilde{L} \quad (4.25)$$

where $\tilde{D}$ is the decision set.

Let $\tilde{u}_D$ be the membership function of the decision set $\tilde{D}$, and $\tilde{u}_D(n, j)$ be the membership value to be maximized at the j th state of the n th stage according to the fuzzy set theory. The recursive strategy for each state is expressed in Equation (4.26).

$$\tilde{u}_D(n, j) = \max_{\{k\}} \{ \min \{ \tilde{u}_R(n, j), \tilde{u}_C(n, j), \tilde{u}_S(n, j), \tilde{u}_L(n, j), \tilde{u}_D(n-1, j) \} \} \quad (4.26)$$

where $\{k\}$ is the states stored in the $(n-1)$ th stage.

The DLC period is first divided into a number of time intervals, each of which is defined as a stage in the FDP.

In each stage, several state-sets are given. All the states in a state-set are facing the same load level. The states in different state-sets are facing different load levels which range from $\Delta L_{\max}$ (positive) to $\Delta L_{\min}$ (negative) around the predicted load level. Every state faces one combined DLC dispatch and unit commitment state. In such a combined DLC and unit commitment state, the cumulative operating cost is minimal with the particular DLC dispatch state. Figure 4-5 displays the search structure of the FDP [126].

As noted in Figure 4-5, each state in the state-set in the current stage represents the on/off combinations of all the ACL groups, originating from the state with the maximum membership value in the state-set of the previous stage. The unit commitment optimization method [169] is combined with each state in Figure 4-5 to obtain the corresponding UC schedule.

In order to avoid the explosion of the computation dimension needed, only the state with maximum membership value defined in equation (4.26) is saved in each stage, and then branches out the feasible states in the next stage.

Let $\tilde{u}_D(n, j)$ be the membership value to be maximized at the j th state of n th stage. The recursive strategy for each state is expressed as:

$$\tilde{u}_D(n, j) = \max_{\{k\}} \{ \min \{ \tilde{u}_R(n, j), \tilde{u}_C(n, j), \tilde{u}_S(n, j), \tilde{u}_L(n, j), \tilde{u}_D(n-1, j) \} \} \quad (4.26)$$

where $\{k\}$ is the states stored in the $(n-1)$ th stage.

According to the optimization concept of dynamic programming (DP), the optimal schedule of combined DLC dispatch and unit commitment at the last stage can be achieved by back-tracking the trajectory of all the states with the maximum $\tilde{u}_D(n, j)$ at each stage.

Figure 4-5 FDP search structure

4.4 Reliability Indices

After the determination of the DLC scheme of ACL, the reliability improvement is evaluated using a reliability evaluation technique [84]. The reliability indices utilized to investigate the impact of the proposed DLC scheme of ACL on the system reliability are discussed in this section.

Considering an N-bus power system with m independent components, for the *j*th contingency with exactly s failed components, the probability of the system being under the *j*th contingency, the departure rate of system leaving the *j*th contingency, and the frequency of the system departing the *j*th contingency are given by Eqations (4.27)-(4.29), respectively.

$$p_j = \prod_{i=1}^s U_i \times \prod_{i=s+1}^m A_i \quad (4.27)$$

$$D_j = \sum_{i=1}^s \mu_i + \sum_{i=s+1}^m \lambda_i \quad (4.28)$$

$$F_j = p_j \times D_j \quad (4.29)$$

where λ_i is the failure rate of component i , and μ_i is the repair rate of component i .

The expected load curtailment probability (ELCP), expected load curtailment frequency (ELCF), expected load curtailment (ELC), and expected energy not supplied (EENS) can be calculated using Equations (4.30)-(4.33), respectively.

$$ELCP = \sum_{j=1}^{NC} p_j \times p_{sj} \quad (4.30)$$

$$ELCF = \sum_{j=1}^{NC} p_j \times D_j \times p_{sj} \quad (4.31)$$

$$ELC = \sum_{j=1}^{NC} LC_j \times F_j \times p_{sj} \quad (4.32)$$

$$EENS = \sum_{j=1}^{NC} LC_j \times p_j \times p_{sj} \times 8760 \quad (4.33)$$

where NC is the total number of considered contingencies, p_{sj} is the probability of load curtailment of the system under the j th contingency (p_{sj} is 1 when load curtailment is needed under the j th contingency, otherwise it is 0), and LC_j is the system load curtailment under the j th contingency which is the sum of nodal load curtailments under the j th contingency. The nodal load curtailments can be obtained using the optimal load curtailment scheme described in Section 4.3.1.

4.5 Solution Algorithm

The proposed DLC technique determines the optimal DLC scheme considering nodal reliability characteristics and transmission network with minimum system operating cost and maximum system reliability improvement. The solution algorithm is as follows:

1. Evaluate system nodal reliability indices.
2. Obtain fuzzy set $\tilde{D}_r$ using Equation (4.19).
3. Determine the system operating cost and unit commitment state from 1:00 to 16:00 before the DLC start hour using the unit commitment program.
4. Find the candidate DLC dispatch states in each stage from 17:00 to 20:00 using the FDP searching structure demonstrated in Figure 4-5. Each stage is divided into 10 state-sets and each state-set consists of 1024 states with the same load level. The membership values of load uncertainty for the ten state-sets, $\tilde{u}_L(n, j)$, are from 1.0 to 0.7 in decrement of 0.03. Each state stands for the ACL dispatch and unit commitment. The membership value of reliability characteristic of each state, $\tilde{u}_R(n, j)$, is obtained using Equation (4.20). The operating cost of each state is calculated using OPF model with DLC dispatch and unit commitment. The membership value of the operation cost of each state, $\tilde{u}_c(n, j)$, is calculated using Equation (4.21). The membership value of spinning reserve of each state, $\tilde{u}_s(n, j)$, is calculated using Equation (4.22). The membership value of decision of each state, $\tilde{u}_D(n, j)$, is calculated using Equation (4.26). In each state-set, the state with maximal membership value of decision is one candidate state.
5. Determine the optimal DLC scheme by back-tracking the trajectory of all the states with the maximum $\tilde{u}_D(n, j)$ in each state.
6. Implement reliability evaluation for the system with the optimal DLC scheme.

The flowchart of the solution algorithm is demonstrated in Figure 4-6.

Figure 4-6 Flowchart of the solution algorithm

4.6 Case Studies

In order to illustrate the effectiveness of the developed DLC scheme of ACL on peak load shaving, system operating cost reduction and system reliability improvement, the IEEE RTS was simulated using the proposed models and techniques.

Ten ACL are connected to different nodes of the IEEE RTS as shown in Figure 3-4. Table 4-1 shows the nodal reliability characteristics and ACL capacities of each node. In

the case studies, the ACL capacities of different nodes are set to be the same in order to eliminate the impact of the ACL capacity on system reliability improvement.

Table 4-1 Nodal Reliability Characteristic and ACL Configuration

NODE NO.	ENLC (MW)	ACL CAPACITY (MW)
3	918.38	20
4	891.69	20
5	74.93	20
6	4680.7	20
7	45.254	20
8	563.88	20
9	86.299	20
10	170.32	20
14	177.95	20
18	120.09	20

The DLC is performed during the peak load period from 17:00 to 20:00. The historic average load errors within the peak load periods are listed in Table 4-2.

Table 4-2 Historical Average Load Errors

Hour	Forecast load, (MW)	Positive error, %(M+)	Negative error, %(M-)	Linguistic description
17	2850	3	4	L
18	2821.5	2	2	M
19	2793	1	2	S
20	2736	2	2	M

Each stage of the FDP structure is 1 hour and is further subdivided into ten state-sets. Each state-set consists of 1024 states with the same load level. A state in each stage stands for the combination of the on/off states of the ACL and the generation units.

Three cases have been studied to show the effects of the DLC scheme on peak load shaving, system operating cost reduction and system reliability improvement. Case 1 is the base analysis without DLC. The DLC scheme considering the nodal reliability

characteristic is applied in Case 2. The DLC scheme in Case 3 does not consider the nodal reliability characteristic.

The simulation was implemented using a Pentium IV 3.0G computer with the MATLAB simulation programs [170]. The total CPU time was 29 hours 34 minutes 48 seconds. In practice, the DLC schemes can be pre-determined offline based on load reliability characteristics and different load scenarios. In real time operation, the system operator will send the control signal for load shift to the aggregated load entity (ALE). The ALE will send the control signals to the control systems of the individual air conditioning customers.

4.6.1 System Peak Load Shaving

System peak load will be shaved by the DLC scheme of ACL. In order to illustrate the peak load shaving effect of the DLC scheme of ACL, load curves of the three cases were obtained. The daily load curves of the three cases are shown in Figure 4-7 and the load curves during the DLC control period of the three cases are shown in Figure 4-8.

Figure 4-7 Daily load curves of the RTS for Cases 1, 2 and 3

Figure 4-8 Load curves of DLC control period of the RTS for Cases 1, 2 and 3

It can be seen from Figures 4-7 and 4-8 that the peak load is shaved by the DLC scheme of ACL.

The specific peak load data of the three cases are listed in Table 4-3.

Table 4-3 Peak Loads for Cases 1, 2 and 3

Cases	Case 1	Case 2	Case 3
Load			
Peak Load (MW)	2850	2780.5	2781.5

The DLC scheme of ACL considering nodal reliability characteristics obtains peak load shaving of 69.5MW. The peak load shaving of the DLC scheme of ACL which does not consider nodal reliability characteristics is 68.5 MW. The peak load shaving effect of the proposed DLC scheme is therefore better than the one which does not consider nodal reliability characteristics.

4.6.2 System Reliability Improvement

Four system reliability indices, ELCP, ELCF, ELC and EENS, were calculated to analyze the system reliability improvement due to the proposed DLC scheme. The system reliability indices for the three cases are shown in Table 4-4.

Table 4-4 System Reliability Indices for Cases 1, 2 and 3

<div>Cases</div> <div>Indices</div>	Case 1	Case 2	Case 3
ELCP	0.173	0.15853	0.15974
ELCF	76.558	67.755	68.479
ELC(MW)	7729.5	4553.4	4901.3
EENS(MWh)	424.81	248.66	267.94

The ELCP is reduced from 0.173 of Case 1 to 0.15853 of Case 2 and 0.15974 of Case 3. The ELCF is reduced from 76.558 occurrence/day of Case 1 to 67.755 occurrence/day of Case 2 and to 68.479 occurrence/day of Case 3. The ELC is reduced from 7729.5 MW of Case 1 to 4553.4 MW of Case 2 and 4901.3 MW of Case 3. The EENS is reduced from 424.81 MWh of Case 1 to 248.66 MWh of Case 2 and 267.94 MWh of Case 3.

The system reliability indices of Case 2 are much smaller than those of Case 1. It can be concluded that the proposed DLC scheme improves the system reliability significantly.

The system reliability indices of Case 2 are smaller than those of Case 3. The system reliability improvement of the proposed DLC scheme is bigger than that of the DLC scheme not considering nodal reliability characteristics. Hence integrating the nodal reliability characteristics into the DLC scheme determination technique has merit in system reliability improvement.

4.6.3 System Operating Cost Reduction

In order to demonstrate the system operating cost reduction of the DLC schemes, system operating costs of the three cases during the DLC period were calculated and are listed in Table 4-5.

Table 4-5 Operation Costs for Cases 1, 2 and 3

<div>Cases</div> <div>Cost</div>	Case 1	Case 2	Case 3
Operating cost (\$)	431276	430134	429622

The system operating cost is reduced from \$431276 of Case 1 to \$430134 of Case 2. The system operating cost reduction is \$1124 and the percentage change of operating cost is 0.26%. It can be concluded that the proposed DLC scheme can reduce the system operating cost.

The operating cost of Case 3 is \$429622 which is \$1654 less than that of Case 1. The percentage change is 0.38%. The operating cost reduction of the DLC scheme of Case 2 is smaller than that of the DLC scheme of Case 3.

The DLC scheme determination technique of Case 3 does not consider system reliability improvement and obtains the DLC scheme with minimum operating cost. This explains why the system operating cost reduction of Case 2 is a bit less than that of Case 3.

4.7 Conclusion

A fuzzy-logic based DLC scheme of ACL is proposed in this chapter for restructured power systems. The transmission network reliability is integrated into the determination of the DLC scheme of ACL to study the effects of load shifts at different nodes on system reliability improvement and to improve the system reliability as much as possible. Nodal

reliability characteristics of nodes where ACL are connected are utilized to represent the transmission network reliability.

The FDP is used to determine the DLC scheme of ACL to improve system reliability as much as possible and to keep the system operating cost as low as possible. In the formulation of the proposed DLC scheme of ACL, the FDP handles the uncertainties related to the DLC problem of ACL in restructured power systems and multi-objective optimization. The determined optimal DLC scheme of ACL strikes a balance between system operating cost reduction and system reliability improvement.

The simulation results with and without the proposed DLC technique show that the developed DLC scheme of ACL is an efficient tool to shave the system peak load, to improve the system reliability and to reduce the system operating cost of restructured power systems.

The simulation results of the DLC technique with and without considering nodal reliability characteristics also show that the reliability improvement and load shaving of the DLC scheme considering nodal reliability characteristics are bigger than those of the DLC scheme of ACL without considering the nodal reliability characteristics. Although the system operating cost reduction of the proposed DLC scheme is a bit less than that of the DLC scheme of ACL without considering nodal reliability characteristics, the proposed DLC scheme achieves a balance between the system operating cost reduction and the system reliability improvement.

Chapter 5 DLC of ACL considering Compensation for ACL Customers

5.1 Introduction

DLC is the most common load management program to shape the load curve by cycling customers' large current drawing appliances. The DLC of ACL will schedule service interruption of air conditioning equipment and may make the ACL customers uncomfortable. The ACL customers may be reluctant to participate in the DLC program of ACL if there is no economic incentive.

The restructuring of power systems has changed the way of operation and planning of power systems. Customers have the right not to participate in the DLC program of ACL. The preference of each customer has to be considered in market trading and system operation. A compensation scheme for service interruption caused by DLC program of ACL is necessary to make the DLC program of ACL successful. Various DLC schemes have been developed to reach peak load shaving and operating cost saving [111], [115-139]. Although there is compensation to the customers for participating in the DLC program, such as providing the thermostat, etc., this compensation is much smaller than the one to the utilities. Existing DLC programs have not considered a direct money compensation scheme to the ACL customers.

It is difficult to estimate the direct payment to a customer with ACL for compensating its willingness to act as a participant in DLC. IEAR is a factor that relates the customers' losses caused by electric power interruptions to the worth of electric service reliability. It is a practical tool to assess the reliability worth [102]. Evaluation of reliability worth and value of lost load have been studied widely [101-106].

In this chapter, a compensation scheme for service interruption of ACL caused by DLC is proposed based on IEAR to eliminate the reluctance of the ACL customers participating in the DLC program. If an ACL is disconnected at a time stage DLC, the compensation

for this ACL customer is the IEAR of the node. Dynamic programming (DP) is used to determine the optimal DLC scheme of ACL considering compensation for ACL customers with the minimum system operating cost. The IEEE RTS is simulated to illustrate the developed techniques.

5.2 Energy Market and Spinning Reserve Market

The DLC of ACL reshapes the system load curve and shaves the system peak load. It will change the energy price and spinning reserve price. The study of DLC of ACL discussed in this chapter was therefore carried out in a PoolCo electricity market including energy market and spinning reserve market.

Most nodal price techniques use the Lagrangian multipliers as shadow prices and this methodology is used in this paper to obtain the nodal prices. The determination of the nodal prices of each time period is implemented separately. The determination of nodal prices in each time period can be depicted by the optimization problem of Equations (5.1)-(5.7).

Objective Function:

$$\text{Min} \sum_{i=1}^{N_g} [C_{pi}(P_{gi}) + C_{qi}(Q_{gi})] \quad (5.1)$$

Subject to the following constraints:

Load flow constraints:

$$\sum_{i \in j} P_{gi} - d_{pj} - \sum_{k \in j} V_j V_k Y_{jk} \cos(\theta_{jk} + \delta_j - \delta_k) = 0 \quad (5.2)$$

$$\sum_{i \in j} Q_{gi} - d_{qj} - \sum_{k \in j} V_j V_k Y_{jk} \sin(\theta_{jk} + \delta_j - \delta_k) = 0 \quad (5.3)$$

Generation constraints:

$$P_{gi}^{\min} \leq P_{gi} \leq P_{gi}^{\max} \quad (5.4)$$

$$Q_{gi}^{\min} \leq Q_{gi} \leq Q_{gi}^{\max} \quad (5.5)$$

Voltage constraint:

$$V_j^{\min} \leq V_j \leq V_j^{\max} \quad (5.6)$$

Power line flow constraint:

$$P_{li}^{\min} \leq P_{li} \leq P_{li}^{\max} \quad (5.7)$$

where P_{gi} and Q_{gi} are the real and reactive power output of generator i , respectively; d_{pj} and d_{qj} are the real and reactive power demand at node j , respectively; $P_{gi}^{\min}$ and $P_{gi}^{\max}$ are the minimum and maximum output of real power of generator i , respectively; $Q_{gi}^{\min}$ and $Q_{gi}^{\max}$ are the minimum and maximum output of reactive power of generator i , respectively; $V_j^{\min}$ and $V_j^{\max}$ are the minimum and maximum voltage at node j , respectively; $P_{li}^{\min}$ and $P_{li}^{\max}$ are the minimum and maximum real power flow allowed through line i , respectively; $V_j \angle \delta_j$ and $V_k \angle \delta_k$ are the voltages at nodes j and k , respectively; and $Y_{jk} \angle \theta_{jk}$ is the admittance between nodes j and k .

The Lagrangian function of Equations (5.1) to (5.7) can be stated by Equation (5.8).

$$L = \sum_{i=1}^{N_g} C_{pi}(P_{gi}) + \sum_{j=1}^{N_n} \lambda_{pj} (\sum_{i \in j} P_{gi} - P_{dj} - \sum_{k \in j} V_j V_k Y_{kj} \cos(\theta_{jk} + \delta_j - \delta_k)) +$$

$$\sum_{j=1}^{N_n} \lambda_{qj} (\sum_{i \in j} Q_{gi} - Q_{dj} - \sum_{k \in j} V_j V_k Y_{kj} \sin(\theta_{jk} + \delta_j - \delta_k)) + \sum_{i=1}^{N_g} u_{pi \min} (P_{gi \min} - P_{gi}) +$$

$$\begin{aligned}
 & \sum_{i=1}^{N_g} u_{pi \max} (P_{gi} - P_{gi \max}) + \sum_{i=1}^{N_g} u_{qi \min} (Q_{gi \min} - Q_{gi}) + \sum_{i=1}^{N_g} u_{qi \max} (Q_{gi} - Q_{gi \max}) + \\
 & \sum_{i=1}^{N_l} u_{lim \min} (P_{li \min} - P_{li}) + \sum_{i=1}^{N_l} u_{lim \max} (P_{li} - P_{li \max}) + \\
 & \sum_{j=1}^{N_n} u_{vj \min} (V_{j \min} - V_j) + \sum_{j=1}^{N_n} u_{vj \max} (V_j - V_{j \max}) \quad (5.8)
 \end{aligned}$$

where N_l is the number of power lines, N_n is the number of nodes, λ_{pj} , λ_{qj} , $\mu_{pi \min}$, $\mu_{pi \max}$, $\mu_{qi \min}$, $\mu_{qi \max}$, $\mu_{lim \min}$, $\mu_{lim \max}$, $u_{vj \min}$ and $u_{vj \max}$ are the Lagrangian multipliers of the corresponding constraints.

The nodal prices of real and reactive powers at node j are the marginal cost at the optimal solutions of Eqn. (5.8). Hence the nodal prices at node j are given by Equation (5.9) and (5.10).

$$\rho_{pj} = \frac{\partial L}{\partial P_{dj}} \quad (5.9)$$

$$\rho_{qj} = \frac{\partial L}{\partial Q_{dj}} \quad (5.10)$$

In this chapter, only the real power price is calculated and considered for calculating energy cost.

Spinning reserve (SR) is one of the most important resources used by system operators to respond to unforeseen events such as generation outages and sudden load changes and is the amount of generation made available to restore the system frequency immediately after an outage [171, 172]. The ISO or such other responsible organization evaluates the gross SR capability requirements for the system, about one year in advance. The ISO is responsible on a day to day and hour to hour basis to ensure that SR is available when required. SR requirements are specified much closer to day-ahead in US ISOs. The ISO

can obtain this service from synchronized generating units that are able to respond within about 10 minutes of the request while satisfying their ramp rates.

In this chapter, a competitive SR market is utilized to determine the SR price which is a uniform market price of SR derived from a competitive auction model. Each generating unit participating in the SR market provides the ISO with a quantity of SR that can be made available in MW and a bid price in \$/MWh. The bid price indicates a generator's expectation of price per unit real power deviation from its scheduled operating point. Once the ISO receives all the bids, the uniform market price for SR can be determined using the competitive SR market model. In this SR market model, the objective is to minimize the total payment. ρ is the SR price in \$/MWh for all contracted SR generators.

The determination of SR price can be depicted as the following optimization problem:

Objective Function:

$$\min(\sum_{i=1}^{N_g} P_{SRi} \times \rho) \quad (5.11)$$

Subject to the following constraints:

System SR requirement constraint:

$$\sum_{i=1}^{N_g} P_{SRi} \geq SRR \quad (5.12)$$

Generator SR limit constraint:

$$0 \leq P_{SRi} \leq SRL_i \quad (5.13)$$

Price constraint:

$$\rho \geq \beta_i \times W_i \quad (5.14)$$

where P_{SRi} is the SR provided by generator i , ρ is the uniform SR price, N_g is the total number of generators, SRR is the system SR requirement, SRL_i is the biddable SR limit of generator i , β_i is the SR bid price of generator i , and W_i is an integer variable to denote the selection state of a particular bid from generator i .

The load flow, generation, voltage and power line flow constraints are same as those in the energy market and are omitted to avoid redundancy.

The biddable SR limit for generator i can be obtained using Equation (5.15).

$$SRL_i = \min\{\min\{RAMP_i, (RAMP_i - (P_t - P_{t-1}))\}, CAP_i\} \quad (5.15)$$

where $RAMP_i$ is the ramp rate of generator i , P_t and P_{t-1} are real power output of generator i at time t and $t-1$, CAP_i is the available capacity of generator i and is the difference between maximum real power output and actual real power output.

Figure 5-1 shows the dynamic determination of SR limit of a generator at any time period.

Figure 5-1 Dynamic determination of SR limit of a generator

5.3 Determination of IEAR

In this section, the formulation for determining the system reliability indices and IEAR is presented. The system reliability indices are used to analyze the effect of DLC scheme of ACL on the system reliability of the restructured power systems. The IEAR is used to determine the compensation for service interruption caused by DLC program of ACL.

The IEAR is a factor that relates the customer losses caused by electric power interruptions to the worth of electric service reliability [164]. It is a practical tool to assess the reliability worth. The reliability indices and the customers' interruption costs under all considered system contingencies are used to calculate the IEAR.

To calculate the IEAR at a node with ACL, nodal reliability indices are determined using the OPF based reliability evaluation technique. The formulation for determining nodal reliability indices is same as the one in Chapter 4.

The expected cost of the power interruption to customers at node k , $ENCOST_k$, for all the contingencies that lead to load curtailment is given by Equation (5.16).

$$ENCOST_k = \sum_{j=1}^k NLC_{jk} \times F_j \times p_{nj} \times C_k(d_{jk}) \quad (5.16)$$

where $C_k(d_{jk})$ is the outage cost of duration d_{jk} in hour at node k under contingency j which can be obtained from the CDF at node k .

The CDF has been developed to evaluate the customer losses due to the electric service interruptions which is a cost estimate associated with power supply interruption duration and customer sector. In this chapter, all the customers are ACL and the CDF is illustrated in Table 5-1 and Figure 5-2.

Figure 5-2 Customer damage function for ACL

Table 5-1 Customer Damage Function for ACL

Interruption Duration	Interruption Cost (\$/MW)
1 minute	0.67
20 minutes	1.56
1 hour	3.85
4 hours	12.14
8 hours	29.41

The IEAR at node k is evaluated using Equation (5.17).

$$IEAR_k = \frac{ENCOST_k}{ENENS_k} = \frac{\sum_{j=1}^{NC} NLC_{jk} \times F_j \times p_{njk} \times C_k(d_{jk})}{\sum_{j=1}^{NC} NLC_{jk} \times p_j \times p_{njk} \times 8760} \tag{5.17}$$

5.4 DLC Problem Formulation

The DLC of ACL is required to schedule the cycling on/off times and durations of ACL, aiming to reduce the peak load as much as possible. In this chapter, the objective is to

minimize system operating cost arising from energy cost, spinning reserve cost and compensation cost for ACL customers. The market structure for determining the optimal DLC scheme of ACL is illustrated in Figure 5-3.

Figure 5-3 Market structure for determining the optimal DLC scheme of ACL

It is shown in Figure 5-3 that the market operator receives energy bids and spinning reserve bids from all GenCos and therefore determines the energy price and SR price. It also determines the compensation for ACL customers. The market operator will determine the optimal DCL scheme of ACL with the minimum total system cost including energy cost, spinning reserve cost and compensation cost for ACL.

The formulation of the DLC problem considering IEAR is depicted in the following dynamic recursive form.

At the n th stage of DLC of ACL, the least cumulated system operating cost with the candidate DLC dispatch state i at the $(n-1)$ th stage is given in Equation (5.18).

$$C(n,k) = \min_{\{m\}} (EC(n,j) + SRC(n,j) + CC(n,j) + C(n-1,i)) \tag{5.18}$$

where $C(n, k)$ is the least cumulated system operating cost with the selected candidate DLC dispatch state k at n th stage, $\{m\}$ is the feasible DLC dispatch state set at the n th stage with DLC dispatch state i at the $(n-1)$ th stage, DLC dispatch state j is in $\{m\}$, $EC(n, j)$ is the energy cost arising from the energy market with DLC dispatch state j at the n th stage, $SC(n, j)$ is the SR cost with DLC dispatch state j at the n th stage, $CC(n, j)$ is the compensation cost for ACL customers with DLC dispatch state j at the n th stage, and $C(n-1, i)$ is the least system operating cost with candidate DLC dispatch state i at the $(n-1)$ th stage.

Subject to the following constraints:

Load flow constraints:

$$\sum_{i \in k} P_{gi}(n, j) - P'_{dk}(n, j) - \sum_{l \in k} V_k(n, j) V_l(n, j) Y_{kl} \cos(\theta_{kl} + \delta_k(n, j) - \delta_l(n, j)) = 0 \quad (5.19)$$

$$\sum_{i \in k} Q_{gi}(n, j) - Q'_{dk}(n, j) - \sum_{l \in k} V_k(n, j) V_l(n, j) Y_{kl} \sin(\theta_{kl} + \delta_k(n, j) - \delta_l(n, j)) = 0 \quad (5.20)$$

where $P_{gi}(n, j)$ is the real power output of the i th generator at the j th state of the n th stage, $Q_{gi}(n, j)$ is the reactive power output of the i th generator at the j th state of the n th stage, $P'_{dk}(n, j)$ is the real power demand of node k at the j th state of the n th stage after DLC, and $Q'_{dk}(n, j)$ is the reactive power demand of node k at the j th state of the n th stage after DLC.

The generation, voltage, power line flow and system spinning reserve constraints are given in Equations (3.22) to (3.28).

In Equation (5.19), $P'_{dk}(n, j)$ can be obtained by using Equation (5.21).

$$P'_{dk}(n, j) = \begin{cases} P_{dk}(n) & \text{if there is no DLC at node } k \\ P_{dk}(n, j) - DLC_k(n, j) + PB_k(n) & \text{if there is DLC at node } k \end{cases} \quad (5.21)$$

where $P_{dk}(n)$ is the real power demand of node k at the n th stage before DLC, $DLC_k(n, j)$ is the DLC capacity of node k at the j th state of the n th stage, and $PB_k(n)$ is the real power demand payback of node k at the n th stage.

The following is the DLC capacity constraint:

$$DLC_k(n, j) \begin{cases} \geq 0 & K \leq n \leq K + DT \\ = 0 & n > K + DT \end{cases} \quad (5.22)$$

where K is the DLC starting hour.

The employed load pay-back pattern of node k at the n th stage, $PB_k(n)$, based on the DLC at previous stages, is described by Equation (5.23) [173]:

$$PB_k(n) = 0.6 \times DLC_k(n-1) + 0.3 \times DLC_k(n-2) + 0.1 \times DLC_k(n-3) \quad (5.23)$$

It is assumed that the power factor of node k does not change before and after DLC.

$Q'_{dk}(n, j)$ can be calculated using $P'_{dk}(n, j)$ and the power factor of node k .

The accumulated disconnection time interval of the i th ACL at the n th stage is depicted in Equation (5.24).

$$AT_i(n) = \begin{cases} AT_i(n-1) + T & \text{if } S_i(n-1) = 0 \\ & \text{and } S_i(n) = 0 \\ T & \text{if } S_i(n-1) = 1 \\ & \text{and } S_i(n) = 0 \\ -T & \text{if } S_i(n-1) = 0 \\ & \text{and } S_i(n) = 1 \\ AT_i(n-1) - T & \text{if } S_i(n-1) = 1 \\ & \text{and } S_i(n) = 1 \end{cases} \quad (5.24)$$

where T is the time interval of each stage, and $S_i(n)$ is the dispatch state of the i th ACL at the n th stage. $S_i(n)$ is 1 if ACL is connected to the system, otherwise $S_i(n)$ is 0. The constraint of $S_i(n)$ is given by Equation (5.25).

$$S_i(n) = \begin{cases} 1 & \text{if } AT_i(n-1) > \max T_i \\ 1 & \text{and if } -\min T_i < AT_i(n-1) < 0 \\ 0 & \text{otherwise} \end{cases} \quad (5.25)$$

where $\max T_i$ is the maximum accumulated disconnected time of the i th ACL, and $\min T_i$ is the minimum accumulated connected time of the i th ACL.

In order to deal with the variation of the on/off control duration of the ACL, DP is utilized to solve the DLC problem.

The DLC period is divided into a number of time intervals, each of which is defined as a stage in the DP. In each stage, a state set is given which includes all the possible DLC dispatch states combined with the corresponding energy market clearing state and spinning reserve clearing state. In such a state, the cumulative system operating cost is the minimum which includes energy cost, spinning reserve cost and compensation for ACL customers. The search structure of the DP is illustrated in Figure 5-4.

Figure 5-4 Search structure for DP

The forward DP approach is used in this chapter to determine the optimal DLC scheme. As illustrated in Figure 5-4, one candidate DLC dispatch state at current stage reaches all the feasible DLC dispatch states subject to the physical constraints of the ACL. In those feasible DLC dispatch states, the DLC dispatch state with minimum system operating cost is chosen as the candidate DLC dispatch state at the next stage. In order to avoid the explosion of the computation dimension, only m candidate DLC dispatch states are chosen at each stage. The choosing of the candidate DLC dispatch states is based on the system operating cost. The m chosen DLC dispatch states at each stage are with the smallest m system operating costs.

The solution algorithm is as follows:

- Step 1. Determine the system loads with all possible DLC schemes.
- Step 2. Calculate the system energy cost using Equation (5.1) and system spinning reserve cost using equation (5.11) from time 1 to time $K-1$, where K is the first time interval of DLC period.
- Step 3. Determine m candidate DLC dispatch states at each stage of DLC period using DP which are with the m smallest system operating costs among all

the feasible DLC dispatch states, the DLC period is from time K to time $K+DT$.

- Step 4. Calculate the cumulated system operating costs after DLC period with the m th candidate DLC schemes.
- Step 5. Determine the optimal DLC scheme with the minimum cumulated system operating cost.
- Step 6. Carry out reliability evaluation for the system with the optimal DLC scheme to study the reliability improvement of the system.

The flowchart of the solution algorithm is demonstrated in Figure 5-5.

Figure 5-5 Flowchart of the solution algorithm

5.5 Case studies

In order to illustrate the effectiveness of the developed DLC scheme of compensated ACL on peak load shaving, system operating cost reduction and system reliability improvement, the IEEE RTS was utilized to carry out the simulation.

The DLC is performed during the peak load period from 17:00 to 20:00. Ten ACL were connected to different nodes of the system. Table 5-2 shows the nodal IEAR and ACL capacities of each node.

Table 5-2 Nodal IEAR and ACL Capacity

Group No.	Node No.	IEAR (\$/kWh)	ACL Capacity (MW)
1	3	17.804	20
2	4	16.966	20
3	5	17.007	20
4	6	20.589	20
5	7	13.332	20
6	8	10.857	20
7	9	13.775	20
8	10	12.542	20
9	14	16.642	20
10	18	16.828	20

Each stage of DP structure is 1 hour and includes 1024 states with different DCL dispatch state. In order to avoid the explosion of the computation dimension, only 100 candidate DLC dispatch states were chosen at each stage.

Two cases have been studied to show the effects of the proposed DLC scheme on peak load shaving, system operating cost reduction and system reliability improvement. Case 1 is the base analysis without DLC. The DLC scheme considering IEAR is applied in Case 2.

The simulation was implemented using a Pentium IV 3.0G computer with the MATLAB simulation programs [170]. The total CPU time was 2 hours 22 minutes 51 seconds. In

practice, the DLC scheme can be pre-determined offline based on nodal IEAR and predicted load. In real time operation, the system operator will send the control signal for load shift to the aggregated load entity (ALE). The ALE will send the control signals to the control systems of the individual air conditioning customers.

5.5.1 System Peak Load Shaving

The system peak load will be shaved by the proposed DLC scheme. In order to illustrate the peak load shaving effect of the DLC scheme, load curves of the two cases were obtained. The daily load curves of the two cases are shown in Figure 5-6 and the load curves during the DLC period of the two cases are shown in Figure 5-7. The peak loads of the two cases are listed in Table 5-3.

Figure 5-6 Daily load curves of the RTS for Cases 1 and 2

Figure 5-7 Load curves of DLC period of the RTS for Cases 1 and 2

Table 5-3 Peak Loads for Cases 1 and 2

Cases	Case 1	Case 2	Change (%)
Load			
Peak Load (MW)	2850	2781.5	2.4

It can be seen from Figures 5-6 and 5-7 that the peak load is shaved by the proposed DLC scheme of ACL. The peak load shaving of the DLC scheme is 68.5 MW. The percentage reduction of the peak load is 2.4%.

5.5.2 System Reliability Improvement

Four system reliability indices, ELCP, ELCF, ELC and EENS, were calculated to analyze the system reliability improvement due to the proposed DLC scheme. The system reliability indices for the two cases are shown in Table 5-4.

Table 5-4 System Reliability Indices for Cases 1 and 2

<div>Cases</div> <div>Indices</div>	Case 1	Case 2	% Reduction
ELCP	0.173	0.15974	7.66
ELCF	76.558	68.479	10.55
ELC(MW)	7729.5	4901.3	36.59
EENS(MWh)	424.81	267.94	36.93

The ELCP is reduced from 0.173 of Case 1 to 0.15974 of Case 2 and the percentage change of ELCP is 7.66%. The ELCF is reduced from 76.558 occurrences/day of Case 1 to 68.479 occurrences/day of Case 2 and the percentage change is 10.55%. The ELC is reduced from 7729.5 MW of Case 1 to 4901.3MW of Case 2 and the percentage change is 36.59%. The EENS is reduced from 424.81 MWh of Case 1 to 267.94 MWh of Case 2 and percentage change is 36.93%. The EENS has the biggest percentage change.

It can be concluded from the reliability indices of Cases 1 and 2 that the proposed DLC scheme improves the system reliability significantly.

5.5.3 System Operating Cost Analysis

The system operating costs of the two cases during the DLC period were calculated to demonstrate the system operating cost reduction of the DLC schemes. The system operating cost includes energy cost, spinning reserve cost and compensation cost for ACL customers.

Energy costs of the two cases are listed in Table 5-5.

Table 5-5 Energy Costs for Cases 1 and 2

<div>Cases</div> <div>Cost</div>	Case 1	Case 2	% Reduction
Energy cost (\$)	431276	427622	0.85

With the proposed DLC scheme of ACL, the energy cost is reduced from \$431276 of Case 1 to \$429622 of Case 2. The reduction of total energy cost is \$3654 and the percentage change of energy cost is 0.85%. The proposed DLC scheme of ACL can therefore reduce the total energy cost of the market.

Spinning reserve costs of the two cases are listed in Table 5-6.

Table 5-6 Spinning Reserve Costs for Cases 1 and 2

Cases Cost	Case 1	Case 2	% Reduction
Spinning Reserve cost (\$)	55659	51532	7.4

The spinning reserve costs of Case 1 and Case 2 are \$55659 and \$51532, respectively. The reduction of spinning reserve cost is \$4127 and the percentage of spinning reserve cost is 7.4%. The proposed DLC scheme of ACL can reduce the system spinning reserve cost of the market.

Compensation costs for ACL customers are listed in Table 5-7.

Table 5-7 Compensation for ACL Customers

GROUP NO.	NODE NO.	COMPENSATION (\$)
1	3	712.16
2	4	678.64
3	5	680.28
4	6	823.56
5	7	533.28
6	8	434.28
7	9	551.
8	10	501.68
9	14	665.68
10	18	673.12

The customers are compensated based on IEAR for the service interruption caused by cycling of the equipment. The compensation for the ACL customer at node 4 is the largest because the IEAR of node 4 is the largest. The compensation for the ACL customers at node 6 is the smallest. The total compensation for the ACL customers is \$6253.7.

The total system operating costs of Cases 1 and 2 are listed in Table 5-8.

Table 5-8 System Operating Costs for Cases 1 and 2

<div>Cases Cost</div>	Case 1	Case 2	% Reduction
Operating cost (\$)	486935	485407.7	0.67

The system operating cost is reduced from \$486935 of Case 1 to \$485407.7 of Case 2. The reduction of the system operating cost is \$1527.3 and the percentage reduction in the system operating cost is 0.31%.

Therefore, it can be concluded that the system operating cost is reduced by implementing the proposed DLC scheme of ACL.

5.6 Conclusion

A DLC scheme of ACL considering compensation for ACL customers is proposed in this chapter for restructured power systems. The IEAR are utilized to determine the compensation for the ACL customers for the service interruption caused by the implementation of the DLC scheme of ACL. DP is used to determine the optimal DLC scheme of ACL with the minimum system operating cost. The system operating cost includes the energy cost, the spinning reserve cost and the compensation cost for the ACL customers.

The IEEE RTS is simulated to illustrate the proposed DLC technique of ACL. The simulation results with and without the proposed DLC technique show that the developed DLC scheme of ACL is an efficient tool to shave peak load, to improve the system reliability and to reduce the system operating cost in restructured power systems. Moreover, the proposed DLC scheme of ACL takes into account a fair compensation scheme for ACL customers based on the reliability worth of different ACL customers. A compensation scheme for ACL customers is very essential for the success of the DLC scheme of ACL because it is able to eliminate the ACL customers' reluctance to participate in the DLC program of ACL.

Chapter 6 Conclusions and Recommendations

6.1 Conclusions

In the thesis, the Voluntary Demand Side Load Shift and Direct Load Control of Air-Conditioning Loads for restructured power systems have been studied and presented.

An evaluation methodology was proposed in Chapter 3 to determine the VDSLS and to analyze the impact of the resultant VDSLS on the price volatility and the reliability of restructured power systems. The methodology is comprised of the iterative VDSLS determination process using the demand-price elasticity matrix, OPF based nodal price determination method and the OPF based reliability evaluation technique. Six case studies were carried out using the MATPOWER simulation tool with purely flexible customers, purely inflexible customers and three combinations of flexible and inflexible customers. The simulation results show that the VDSLS is an efficient tool to improve the reliability and to reduce the price volatility of restructured power systems. The proposed methodology can be a useful tool for the system operator to quantitatively assess the system reliability and the price volatility of restructured power systems.

In Chapter 4, a fuzzy logic-based DLC scheme of ACL considering nodal reliability characteristics is proposed to achieve the optimal balance between system reliability and operating cost. In order to incorporate the transmission system into the DLC of ACL, the nodal reliability indices where ACL are connected are used to formulate a fuzzy objective function and to represent the system reliability improvement. The system operating cost is used to formulate another objective function in order to keep the system operating cost as low as possible. The FDP is used to deal with both the uncertainties related to the DLC of ACL for restructured power systems and for multi-objective optimization. The simulation results show that the proposed DLC scheme of ACL can strike a good balance between system reliability improvement and system operating cost reduction.

In Chapter 5, a DLC scheme of ACL considering direct compensation to ACL customers is proposed. In order to determine the compensation to ACL customers, the reliability worth evaluation index, IEAR, is used. In the compensation scheme, the compensation for ACL customers is determined based on the IEAR of the node where this ACL is connected. The DLC scheme of ACL considering direct compensation to ACL customers is determined using DP with the minimum system operating cost. The simulation results show that the proposed DLC scheme of ACL can improve the system reliability and reduce the system operating cost.

6.2 Recommendations

Integration of the renewable energy to the grid has been a hot topic. The penetration level of the renewable energy has been increased dramatically during the last few years. Due to the uncertainty of the renewable energy like wind power, solar energy, tidal energy, etc., load management techniques can offer good alternatives to reduce the impact of the uncertainty in the operation of power systems.

The microgrid is a good concept to utilize the renewable energy. For the islanding operation mode of the microgrid, load management techniques can be good control elements for the EMS of the microgrid to control the frequency and voltage inside the microgrid.

The suggestions for future work of load management are presented below:

- In order to improve the system capability to cater for the uncertainty caused by the high level penetration of the renewable energy, the determination of load management has to consider the characteristics of the integrated renewable energy resource.

- For the islanding operation of the microgrid, load management techniques can be utilized to improve the frequency and voltage control capability of the microgrid.

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Appendix A Generator Cost Data

The generator cost data used in the studies is listed in Table A.1. The generator cost data were extracted from Reference [85]. The generator cost data were used to get the bid price for generators.

Table A.1 Generator Cost Data

Gen. Size (MW)	Output (MW)	Cost (\$)	Output (MW)	Cost (\$)	Output (MW)	Cost (\$)	Output (MW)	Cost (\$)	Output (MW)	Cost (\$)
12.00	0.00	15.60	2.40	42.24	6.00	74.30	9.60	130.94	12.00	144.00
20.00	0.00	15.25	14.00	201.02	16.00	219.00	18.00	235.25	20.00	290.00
50.00	0.00	13.73	10.00	129.23	30.00	369.56	40.00	470.50	50.00	652.5
76.00	0.00	15.60	15.20	184.32	38.00	401.75	60.80	765.82	76.00	912.00
100.00	0.00	13.00	25.00	228.00	55.00	505.60	80.00	778.10	100.00	1000.0
155.00	0.00	11.20	54.30	476.00	93.00	837.80	124.00	1163.0	155.00	9700.0
197.00	0.00	10.75	60.00	603.46	118.20	1169.4	157.60	1371.5	197.00	1891.2
350.00	0.00	10.20	140.00	1219.8	227.50	2072.3	280.00	2669.5	350.00	3235.0
400.00	0.00	12.55	100.00	922.55	200.00	1826.4	320.00	2992.6	400.00	4000.0

Appendix B Generator Spinning Reserve Bids

The generator spinning reserve bid prices are listed in Table Appendix B.1. The generator spinning reserve bid prices were used to get the market spinning reserve price.

Table B.1 Generator Spinning Reserve Bid Prices

Gen. Size (MW)	SRC (MW)	Bid Price (\$)	SRC (MW)	Bid Price (\$)	SRC (MW)	Bid Price (\$)	SRC (MW)	Bid Price (\$)
12.00	2.40	4.17	6.00	4	9.60	3.7	12.00	3.6
20.00	14.00	4.83	16.00	4.42	18.00	4.25	20.00	4.08
50.00	10.00	4.35	30.00	4.3	40.00	4.11	50.00	4
76.00	15.20	4.13	38.00	4	60.80	3.7	76.00	3.41
100.00	25.00	3.33	55.00	3.2	80.00	3	100.00	2.87
155.00	54.30	3.23	93.00	3.1	124.00	2.97	155.00	2.85
197.00	60.00	3.27	118.20	3.2	157.60	2.88	197.00	2.86
350.00	140.00	3.27	227.50	3.17	280.00	3.02	350.00	2.88
400.00	100.00	3.33	200.00	3.11	320.00	3.03	400.00	3.03

VITA

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