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Optimal Generation Scheduling with Demand Side Participation

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School of Electrical and Electronic Engineering

A thesis submitted to the Nanyang Technological University
in fulfilment of the requirement for the degree of
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Abstract

With the deregulation of the power industry worldwide, it becomes more flexible for participants in a competitive electricity market to actively take part in the open market. The movement to this restructuring has changed the way of doing business, or the way that how electricity is traded. The function of the vertically integrated electric utility is dividing into separate companies, such as GENCOs, TRANSCOs, and retailers. Unlike the minimization of the operating cost of the former system, maximizing the social welfare of the pool, the profits of GENCOs, retailers or even customers become the main objective nowadays.

The new trading environment has given rise to more opportunities and more problems. In many countries, power suppliers have already been permitted to bid for their own electricity price and the research work so far is focused on the supply side. Very little has been done on the demand side because demand-side participation is only permitted in a few countries. Even if customers are allowed to participate, the active participation in the market is very limited due to the lack of proper tools to help customers to access the sophisticated market.

This thesis discusses the importance of incorporating demand-side participation for consumers in a restructured electric power industry, as well as for the establishment of a full electricity market where the demand side is allowed to bid for load reduction in the energy market and to compete with generators in the reserve market. A pool-based market model is proposed by incorporating demand-side participation. The solution optimizes the consumer's benefit by making consumers gain a financial reward via a direct payment/compensation from the pool for the electricity that they did not consume at a pre-agreed time. With the new methodology

presented in this thesis, the optimal generation schedules which can maximize the social welfare of the pool are compared with those from the traditional unit commitment (UC) problem. The impact of demand-side participation on the market is analyzed. This thesis addresses issues related to the market structure and the operation of power pools, such as operating constraints of generating units, and determination of market clearing price (MCP). How the unit minimum output and minimum up time influence the market clearing process is also analyzed. A piece-wise linear supply/demand function of suppliers/consumers is assumed in this thesis, and the system is dispatched to maximize social welfare. The pool-based problem is solved using a Lagrange Relaxation based procedure.

The effect of demand-side participation on spinning reserve and expected energy not supplied (*EENS*) is also studied. A probabilistic approach is proposed for the spinning reserve scheduling based on two *EENS* evaluation models. One is through the convolution of the MW capacity outage probability distribution function to calculate *EENS* for each interval as described in Chapter 4. The other computes *EENS* for each involved unit using the proposed formulations in Chapter 5. The cost of *EENS* is included in the objective function together with the schedule cost to obtain the minimization of the total cost. No matter how the *EENS* is evaluated, the probabilistic spinning reserve schedule is achieved by balancing the schedule cost of providing reserve and the cost of energy not served. How the demand-side participation influences the energy market, the reserve market, and the balancing point of the probabilistic approach is examined.

Furthermore, the impacts of customers participating in the reserve market as interruptible loads are scrutinized. The customers, who can be interrupted as agreed when outages happen, bid directly into the market as a kind of reserve providers. Like the generators, these customers share the same market clearing engine which decides whether they are selected or not. It is also assumed that these customers have varying outage rates and may cause energy deficiency under any contingencies. A settlement scheme for the reserve payment which considers all the factors mentioned above is proposed. Interruptible loads, depending on their performance, share the same responsibility with generators to pay or be paid for the continuity of reserve service. Those with high reliability to operate will gain compensation, whilst those with poor

reliability will be penalized by paying others. This scheme aims to motivate all the participants in the market to improve their performance and to achieve a more reliable and secure system.

The method presented in this thesis can be utilized in many areas. For example, consumers can use it to maximize their own profits through the participation in the market; ISO (Independent System Operator) can use it to maximize social welfare and to mitigate the abuse of market power so as to get a more ideal power market evolved through the deregulation process. At the same time, GENCOs are given the opportunity to compete as well. To stay in business, they must maximize the value of their service they provide and minimize the production cost to gain maximal profits. In a non-competitive market, they can also exercise market power by withholding MW generation and/or generation capacity to make more profits.

Table of Contents

Acknowledgementsi

Abstract..... ii

List of Symbols and Abbreviationsix

List of Figuresxii

List of Tables.....xiv

Chapter 1 Introduction 1

 1.1 Motivation 1

 1.1.1 Deregulation of Electricity industry 1

 1.1.2 Competition Introduced in Deregulated Power Industry.....2

 1.1.3 Issues of Demand-Side Participation in Electricity Markets4

 1.1.4 Issues of Spinning Reserve in Electricity Markets5

 1.2 Major Contributions.....7

 1.3 Thesis Overview 12

Chapter 2 Overview of Deregulated Electricity Markets14

 2.1 Regulated and Deregulated Power Industries..... 14

 2.1.1 Vertically Integrated Electric Utilities 14

 2.1.2 Restructured Power Industries 15

 2.1.3 Comparison of Regulated and Restructured Power Industries 16

 2.2 Restructured Market Models 17

 2.3 Types of Power Markets 18

 2.4 Deregulation around the World 19

 2.5 Demand-Side Participation in Deregulated Electricity Market.....21

 2.5.1 Demand-Side Bidding21

2.5.2 Types of Demand-Side Bidding.....	23
2.5.3 Categories of DSB.....	25
2.5.4 International Practices in Demand-Side Participation	26
2.5.5 Studies of Demand-Side Participation	31
2.5.6 Interruptible Loads	35
2.6 Spinning Reserve in the Restructured Environment.....	37
2.6.1 Reserve Market Clearing Approaches.....	37
2.6.2 Spinning Reserve Management Techniques.....	39
2.6.3 Spinning Reserve Studies	40
2.7 Market Settlement.....	42
2.7.1 Energy Market Settlement	42
2.7.2 Problem Formulation of New Market Settlement.....	44
2.7.3 Reserve Market Settlement.....	44
2.8 Summary	46
Chapter 3 Incorporating Demand Reduction Bids	47
3.1 Model for Generation Scheduling with DSB	47
3.1.1 Generator Model	47
3.1.2 Demand Reduction Model.....	50
3.2 Problem Formulation	51
3.2.1 Objective Function	52
3.2.2 Demand Reduction Bids.....	54
3.2.3 Constraints	56
3.2.4 Lagrangian Relaxation Method.....	58
3.2.5 Load Recovery Scheduling.....	59
3.3 UC Simulation Results Incorporating DSB	60
3.3.1 Base Case—Results without DSB	61
3.3.2 Results with Single DSB Agent	62
3.3.3 Results with Multiple DSB Agents	64
3.4 Cost/Benefit Analysis of DSB.....	67
3.4.1 Single Demand-Side Agents	67
3.4.2 Multiple Demand-Side Agents	71
3.5 Extended Analysis for Effect of DSB on MCP	74
3.5.1 Effect of Minimum Output (P^{min}) and Minimum Up Time (T^{on}).....	74

3.5.2 Simulation Results.....	77
3.6 Summary	79
Chapter 4 Probabilistic Reserve with Demand-Side Participation	82
4.1 Introduction	82
4.2 Probabilistic Reserve Assessment	83
4.2.1 Probabilistic Spinning Reserve Scheduling.....	83
4.2.2 Capacity Outage Probability Table	84
4.2.3 Expected Energy Not Supplied.....	85
4.2.4 Optimal Risk Index	85
4.3 Simulation Results for Effect of DSB on Spinning Reserve.....	87
4.4 Extended Analysis for Probabilistic Reserve with Demand-Side Participation.....	95
4.4.1 Problem Formulation.....	96
4.4.2 Probabilistic Spinning Reserve Scheduling.....	99
4.5 Simulation Results for Extended Analysis.....	103
4.5.1 Effect of Demand-Side Participation	104
4.5.2 Effect of Unit's <i>ORR</i>	108
4.6 Summary	111
Chapter 5 A Settlement Scheme for Probabilistic Reserve with Interruptible Loads.....	113
5.1 Introduction	113
5.2 Problem Formulation	114
5.2.1 Objective Function	114
5.2.2 Formulation of <i>EENS</i> for Generators	117
5.2.3 Formulation of <i>EENS</i> for Interruptible Loads	120
5.3 Simulation Results	125
5.3.1 Effect of Generator's Reliability.....	125
5.3.2 Effect of Settlement Scheme.....	130
5.4 Summary	135
Chapter 6 Conclusions and Future Works.....	137
6.1 Conclusions	137

6.2 Suggestions for Future Works 139

Appendix 141

References 144

Curriculum Vitae 155

List of Symbols and Abbreviations

$C_i(P_{i,t})$	Unit offered cost as a function of generation output [\$/h]
$P_{i,t}$	Output power of Unit i at time t [MW]
$P_i^{\max}$	Maximum power generation by Unit i [MW]
$P_i^{\min}$	Minimum power generation by Unit i [MW]
$EL1_i / EL2_i$	Generation elbow point 1 and 2 of Unit i [MW]
$NL1_i / NL2_i / NL3_i$	No-load price 1/2/3 of the piece-wise segment of the linear bidding price function for Unit i [\$/h]
$INC1_i / INC2_i / INC3_i$	Incremental price 1/2/3 of the piece-wise segment of the linear bidding price function for Unit i [\$/MWh]
$S_{i,t}$	Start-up price for Unit i in hour t [\$/h]
α_i	Fixed part (includes crew expense, maintenance expenses) [\$/h]
β_i	Cold start-up price [\$/h]
η_i	Thermal time constants in the start-up price function of unit i [h]
$X_i^{off}(t)$	Time duration for which unit i has been off at hour t [h]
$Q_{j,t}$	Demand reduction amount of consumer j at period t [MW]
$Q_j^{\max}$	Maximum reduction amount of customer j [MW]
$Q_j^{\min}$	Minimum reduction amount of customer j [MW]
$EL1_j / EL2_j$	Demand elbow point 1 and 2 of customer j [MW]
$B1_j / B2_j / B3_j$	Bidding prices of customer j for the three segments [\$/MWh]
B_j	Bidding price of customer j for energy [\$/MWh]
$D_{j,t}$	Demand of consumer j at period t [MW]

$U_{j,t}$	Status of customer j at time t , 0 = customer not selected, 1 = customer selected
$U_{i,t}$	Status of Unit i at time t , 0 = unit not scheduled, 1 = unit scheduled
T	Number of time periods
N	Number of units
J	Number of demand-side agents
$D_j^{\max}$	Maximum demand of customer j by load forecast [MW]
D_t	Inelastic demand portion at time t (without demand reduction bid)
$r_{i,t}$	Unit reserve contribution of Unit i at period t
R_t	Spinning reserve requirement
τ	Reserve response time (which is set to 10 minutes in this thesis)
UR_i	Ramp up rate of Unit i [MW/hour]
DR_i	Ramp down rate of Unit i [MW/hour]
$T_i^{on/off}$	Minimum up/down time of Unit i
$X_i^{on/off}$	Time duration for which Unit i has been on/off at hour t
$X_{i,t}$	State of Unit i at time t , denoting number of hours that Unit i has been on (positive values) or off (negative values)
m	All the possible states for different unit capacity at period t .
E_k	Energy that might be on outage for state k .
p_k	Probability for state k in which this amount of energy will not be supplied. Its value is obtained from the capacity outage probability table (COPT).
$PR_{i,t}^g$	Bidding price offered by Unit i for spinning reserve at time t [\$/MWh].
$R_{i,t}^g$	Spinning reserve contributed by Unit i at time t [MW].
$U_{i,t}^{gr}$	A discrete variable which is 1 if Unit i is committed for reserve at time t and 0 otherwise.
$PR_{j,t}^d$	Bidding price offered by customer j for spinning reserve at time t [\$/MWh].

$R_{j,t}^d$	Spinning reserve contributed by customer j at time t [MW].
$U_{j,t}^{dr}$	A discrete variable which is 1 if customer j is committed for reserve at time t and 0 otherwise.
L	Number of interruptible loads.
$PR_{l,t}^{il}$	Bidding price offered by customer l for spinning reserve at time t [\$/MWh].
$R_{l,t}^{il}$	Spinning reserve contributed by customer l at time t [MW].
$U_{l,t}^{il}$	A discrete variable which is 1 if customer l is committed for reserve at time t and 0 otherwise.
$EENS_{i,t}$	The $EENS$ caused by Unit i at period t .
$EENS_{l,t}$	The $EENS$ caused by customer l at period t .
GENCOs	Generation companies
TRANSCOs	Transmission companies
DISCOs	Distribution companies
ISO	Independent System Operator
IPP	Independent Power Producer
MO	Market Operator
PX	Power Exchange
PJM	Pennsylvania-New Jersey-Maryland Interconnected System
DSB	Demand-Side Bidding
OPF	Optimal Power Flow
MCP	Market Clearing Price
UC	Unit Commitment
$EENS$	Expected Energy Not Supplied
ORR	Outage Replacement Rate
FOR	Forced Outage Rate
AGC	Automatic Generation Control
SRR	Spinning Reserve Requirement
$COPT$	Capacity Outage Probability Table
$LOLP$	Loss of Load Probability
$VOLL$	Value of Lost Load

List of Figures

Figure 2.1	Comparing DSB and DSM	23
Figure 2.2	Price-demand curves.....	24
Figure 2.3	Demand reduction bid.....	24
Figure 2.4	Time-frame for bids associated with different DSB categories	26
Figure 2.5	Market settlement in double auction power pools	43
Figure 2.6	Market settlement in single auction power pools.....	43
Figure 3.1	Generator offered cost function.....	49
Figure 3.2	Generator incremental price curve	49
Figure 3.3	The demand reduction model.....	51
Figure 3.4	Market clearing process in combined generator's offer and demand reduction bids	54
Figure 3.5	Total changes in demand	59
Figure 3.6	Hourly offered costs with and without DSB (single agent).....	68
Figure 3.7	MCP profile with and without DSB (single agent)	69
Figure 3.8	Hourly loads with and without DSB (single agent)	69
Figure 3.9	Supply side profits with and without DSB (single agent)	71
Figure 3.10	Hourly costs with and without DSB (multiple agents).....	72
Figure 3.11	Load changes with and without DSB (multiple agents)	73
Figure 3.12	MCP profile with and without DSB (multiple agents)	73
Figure 3.13	Supply side profits with and without DSB (multiple agents)	74
Figure 3.14	Market cleared with high DSB price	75
Figure 3.15	Market cleared with high generator price	76
Figure 3.16	The effect of DSB on the MCP	80
Figure 4.1	Probabilistic reserve assessment	84
Figure 4.2	Schedule cost comparison vs. risk index with and without DSB	89

Figure 4.3	<i>EENS</i> comparison vs. risk index with and without DSB.....	90
Figure 4.4	<i>EENS</i> cost vs. risk index for different values of <i>VOLL</i> without DSB..	90
Figure 4.5	<i>EENS</i> cost vs. risk index for different values of <i>VOLL</i> with DSB.....	90
Figure 4.6	Total cost vs. risk index for different values of <i>VOLL</i> without DSB ...	92
Figure 4.7	Total cost vs. risk index for different values of <i>VOLL</i> with DSB.....	92
Figure 4.8	Total cost comparison vs. risk index with and without DSB when <i>VOLL</i> = \$4/kWh.....	92
Figure 4.9	Total cost comparison vs. risk index with and without DSB when <i>VOLL</i> = \$6/kWh.....	93
Figure 4.10	Optimal risk index vs. <i>VOLL</i> with and without DSB	93
Figure 4.11	Total reliability cost.....	99
Figure 4.12	Calculation of Golden-Section search method at first iteration.....	100
Figure 4.13	Iteration points of Golden-Section search technique.....	101
Figure 4.14	Convergence of total cost curve	102
Figure 4.15	Optimal scheduling with probabilistic reserve assessment.....	103
Figure 4.16	Reserve comparison for with and without DSB.....	105
Figure 4.17	<i>EENS</i> comparison vs. risk index with and without DSB.....	105
Figure 4.18	Reserve cost comparison vs. risk index with and without DSB	106
Figure 4.19	Total cost comparison vs. risk index with and without DSB when <i>VOLL</i> = \$3/kWh.....	107
Figure 4.20	Total cost comparison vs. risk index with and without DSB when <i>VOLL</i> = \$5/kWh.....	107
Figure 4.21	Optimal risk index vs. <i>VOLL</i> – with and without DSB	108
Figure 4.22	<i>EENS</i> comparison of three cases	110
Figure 4.23	Optimal risk index of the three cases.....	111
Figure 5.1	Payment comparison for the reserve market.....	134

List of Tables

Table 2.1	Comparison of the basic functions in power industries.....	16
Table 2.2	Different features between regulated and restructured power industries	17
Table 2.3	Main characteristics of various electricity markets	20
Table 2.4	DSB according to characteristics and categories	25
Table 2.5	Experiences with demand-side participation in different countries	30
Table 3.1	UC schedule for 26-unit system without DSB	62
Table 3.2	UC schedule for 26-unit system with single DSB agent	63
Table 3.3	UC schedule for 26-unit system with multiple DSB agents	64
Table 3.4	Load changes, offered cost, profit, MCP comparison with single agent.....	65
Table 3.5	Load changes, offered cost, profit, MCP comparison with multiple agents	66
Table 3.6	Unit output comparison with single agent	70
Table 3.7	Unit output comparison with multiple agents	72
Table 3.8	Demand-side bidding data	77
Table 3.9	P^{min} and T^{on} of different cases	77
Table 3.10	UC schedule of different cases.....	78
Table 3.11	DSA selection of different cases	78
Table 3.12	Marginal unit of different cases	79
Table 3.13	SMP of different cases.....	79
Table 4.1	Schedule cost and <i>EENS</i> comparison between the with and without DSB	87
Table 4.2	Cost/benefit analysis for an optimal risk index without DSB.....	88
Table 4.3	Cost/benefit analysis for an optimal risk index with DSB	88

Table 4.4	Demand-side bidding data	94
Table 4.5	Selection of demand-side agent under different risk indices	94
Table 4.6	Demand for 24-hour period	104
Table 4.7	Demand-side MW bid quantities.....	104
Table 4.8	Demand-side bid prices	104
Table 4.9	Spinning reserve and unit status comparison of Cases I and II	109
Table 5.1	Effect of <i>EENS</i> terms towards costs in (5.1).....	126
Table 5.2	Unit status and energy dispatch at Hour 11	127
Table 5.3	Unit status comparison for the base case and Case II	128
Table 5.4	Unit status and energy dispatch comparison for the base case and Case III.....	129
Table 5.5	Reserve settlement and payment among units in Case IV at Hour 1 (Interruptible loads not participated)	131
Table 5.6	Reserve settlement and payment among units and interruptible load in Case V at Hour 1 (Perfectly reliable interruptible loads)	131
Table 5.7	Reserve settlement and payment among units and interruptible load in the base case at Hour 1 (Interruptible loads with non-zero failure rates)	133

Chapter 1

Introduction

1.1 Motivation

1.1.1 Deregulation of Electricity Industry

Electric utilities all over the world are undergoing great changes. The former vertically integrated electric utility, which performed all the functions involved in power generation, transmission, distribution, and retail sales is disaggregating into separate companies, each devoted to a function of the former integrated utility. The new structure is the so-called deregulated power industry.

For many decades, vertically integrated electric utilities were doing their businesses as a monopoly and could not provide services as efficiently as competitive firms. Hence, the electric power industry is deregulating and establishing a restructured environment in which customers could choose to buy from different suppliers and change suppliers as they wish in order to pay market-based rates.

The goal of deregulation is to enhance competition and bring consumers new choices and economic benefits. Ultimately, small customers such as households will be able to select their energy providers in much the same way that they now choose any kinds of commodities. One of the common purposes of deregulation is to set up a fairly competitive environment for power producers. The ideal target is to set up a perfectly competitive power market, in which all the power producers bid the production costs of their generating units. In a decentralized electricity market, the

power producers make their own generation planning, and their financial decisions are guided by the objective of maximizing their own benefits [1].

In response to the electric industry restructuring, new phenomena, new circumstances, new risks, and new tools have emerged. Some of these new topics have risen for the lack of experience with newborn issues. The new electric power structure requires new tools and approaches for decision-making and improving the efficiency of the power network. In this market, energy trading tools would help buyers and sellers sign up freely for a range of energy resources and various types of electricity products. Customers benefited as they are allowed to sign contract for buying power from cheaper sources.

The vertically integrated system is steadily restructuring to a more market-based system in which competition will replace the role of regulation in setting the price of electricity. The electric power restructuring hopes to fulfill the main objective of significantly reducing the cost of power charged to customers. The cost of electricity generation will be reduced through market forces and more competition. This task will be accomplished by creating an open access environment that will allow consumers to choose a provider for electric energy. In this environment, it is possible that in future customers will have the option of choosing the level of service reliability which will provide greater incentives for short and long term efficiencies as a result of economic regulation. Restructuring in the electricity industry will create new business opportunities where new firms selling new products and services will appear, consumers will have alternatives in buying electricity services and new technologies.

1.1.2 Competition Introduced in Deregulated Power Industry

Opening up the electricity sector to competition is an important tool to improve the efficiency of power generation and thereby to benefit consumers. The vertically integrated utilities could recover their costs regardless of whether they operated efficiently or not. However, with the introduction of competition, this approach has changed dramatically. Competitive markets provide the driving force for generators to innovate and operate in the most efficient and economic manner in order to remain in the business and recover their costs. The suppliers are encouraged to bid

the most competitive prices to compete for dispatch in the wholesale market. When a bidder bids too high, the generator would presumably not be dispatched and the bidder might not earn any revenues.

There are two levels of competition. In the wholesale electricity market, power generation is disaggregated into a number of power producers and these producers which include generating companies and Independent Power Producers (IPPs) submit offers to compete for generation. Thus competition is introduced among power producers and these power producers must survive on the revenues obtained from the sale of electric power. In addition, in some electricity market, competition is also introduced among power buyers (retail companies). The retail companies compete to sell the energy to the consumer, which is called the retail market.

The competitive electricity market offers customers a range of benefits. Especially for large consumers which are energy intensive. Cheap electricity lowers their production costs. It attracts them to invest in more industries and increases business opportunities. In addition, customers have more choices in a competitive market and are provided with better services from retailers. Rather than a set tariff in traditional power industries, pricing now is cost reflective which encourages GENCOs to minimize the cost of supplying electricity to customers.

On the contrary, from the GENCO side, competition always guarantees that the cheapest suppliers will be the ones producing. Hence, to stay in business, generation companies must maximize the value of the service they provide and minimize their production cost. However, lower prices discourage expansion of generation. Every supplier wants to raise the market price, just as every buyer wants to lower it. Perfect competition frustrates both intentions. A lower price producer will not be able to cover their fixed costs. This will make future investors think twice. For example, in recent years, 40% of the New England generating capacity owners have financial distress [2] partly because that these generating units are not efficient and competitive enough in operation and partly because of the electricity market imperfection. But if the electricity price remains low, the investors may have no interest in developing new power plants. Generation technologies may not continue to evolve toward a combination of large inflexible units and renewable generation as

these technologies are usually more expensive. Although these technologies benefit the sustainability of energy and improve resource adequacy, the high costs may cause the electricity more expensive which may result in these new technologies noncompetitive in the market.

1.1.3 Issues of Demand-Side Participation in Electricity Markets

As discussed above, the competitive electricity market offers customers and industry participants a lot of benefits, such as cheaper prices, more choices, better and efficient services in both wholesale and retail electricity markets. In most instances, however, consumers have very little influence on the design of these electricity markets. This is because except for large consumers, most consumers do not have the financial incentive and the expertise required to contribute effectively towards such a complex and time-consuming task.

Most electricity markets do not treat consumers as a genuine demand side capable of making rational decisions but simply as a load that needs to be served under all conditions, and active participation in these markets by the demand side remains minimal. Hence, the demand side should be encouraged and allowed to actively participate in the electricity market. Enhancing the ability of the demand side to respond to price signals could benefit not only the consumers who choose to participate in electricity markets, but would also help these markets operate more efficiently and satisfactorily.

Since the participation of demand side has so many advantages, many schemes and products are designed for demand-side participation. Broadly, trading in any electricity market can be simplified into two basic types of process: the bulk purchase of electricity which bids for total demand and system balancing which bids for a change in demand to ensure that demand exactly matches generation at any given time. Similarly, demand-side participation can fall into one of these two types. The demand-side participation in the later type means consumers resale, or selling the non-consumption of electricity that they have already secured the right to consume. According to the definition of International Energy Agency (IEA) [3], there are five main categories of demand-side participation schemes for different purposes. They are

(i) maintaining quality of supply in which customer participate in ancillary services to provide reserve, (ii) solving network constraints such as transmission and distribution constraints, (iii) electricity balancing in which customer participate in balancing market, (iv) access to market prices in which customer participate in spot market and may set the market clearing price. All these four types of DSB require consumers to change their electricity demand, which normally involves load reduction. The last category is (v) price setting, a type of DSB that involves bulk purchase of electricity in which customers take part in the spot markets or bilateral contracts. Most of these categories are currently being utilized in many countries with liberalized electricity markets. The research conducted in this thesis is about the demand-side participation and falls into the fourth category, that is “access to market prices”.

However, despite the fact that there are many different demand-side participation schemes available, many of them fall short of their objectives. Few schemes can be considered to be operating successfully. One of the difficulties associated with demand-side participation is ensuring that consumers deliver their load reductions as promised. This is particularly important when load reductions are offered to the system operator for the purpose of maintaining the quality and security of supply. Hence, more work is needed on the development of cost effective communication technologies that can actively monitor demand changes consumed by individuals or small groups of consumers. It necessitates the enhancement of existing schemes and the development of new schemes to make good use of benefits brought by demand-side participation and to improve the performance of demand-side participation to maximize the benefits it will bring to the system. A summary of the literature in this area will be provided in Chapter 2.

1.1.4 Issues of Spinning Reserve in Electricity Markets

In the deregulated environment, power producers are facing more uncertainties of fuel price, load demand, electricity price, and generation failure, which will make it more difficult to carry out generation schedule and dispatch for preparing the offer bids. Maintaining system reliability may not be as easy as in the conventional integrated power systems. The reliability issue under such a new environment needs to be investigated.

Spinning reserve in a system is a measure of its ability to increase the generation in order to take care of contingencies such as generation outage or shortfall. The system reliability can be improved by increasing the system reserve. Spinning reserve management is a kind of short-time evaluation of operating reserve in a system. The operating capacity relates to the short-term evaluation of the actual capacity required to meet a given load level. It is an important aspect of power system planning and operation that determines the required amount of system generating capacity to ensure an adequate supply. Therefore, spinning reserve scheduling is an essential factor in the evaluation of reliability in a deregulated power system. New reliability analysis techniques need to be developed to handle the new uncertainties introduced by the free market concept. However, due to the complexities involved in real-time system operation, few techniques have been developed to investigate the determination of short-term reserve.

In most systems, spinning reserve requirements are generally determined by deterministic methods, which may result in a higher cost than necessary when committing excessive spinning reserve. Probabilistic methods are intended to complement this deficiency. The probabilistic approach is normally used due to forecast uncertainties and the random nature of an outage event. The Pennsylvania-New Jersey-Maryland Interconnected System (PJM) probabilistic method was the main approach used for short-term planning in power systems. Besides the PJM method, many methods based on the risk of unit contingencies in a generating system have been developed. A probabilistic technique has been developed in [4] for unit commitment and assessment of generating system operating health, margin and risk. The concept of some indices used to evaluate long-term probability problems is applied to determine the spinning reserve amount for short-term dispatch in [5]. Siddiqi [6] investigated spinning reserve issues in deregulated power systems, pointing out the importance of an optimal pricing policy for spinning reserve. New probabilistic methods for spinning reserve studies in deregulated power systems still need to be developed.

In the deregulated competitive market, spinning reserve is traded in an independent market. Spinning reserve providers have more options to consider bilateral contracts and/or bidding to the spot market. Spinning reserve can be

determined simultaneously with energy or separately cleared after the energy amount is determined. Customers may have more chances to take part in the market to choose their suppliers freely or rearrange their load profile for the purpose of maximizing their profits. Under the deterministic reserve criterion, customers will be exposed to electricity supply of varying system reliability levels. No compensation is given to customers when the load is shed due to system accidents. On the contrary, customers may benefit more through the open market, such as the reliability insurance scheme proposed in [7]. Customers will pay the insurance premium to the pool and pool will pay customers an agreed amount for the loss of revenues and inconveniences due to outages. Or they can participate directly in the reserve market as spinning reserve providers through interruptible load contracts. This results in more market uncertainties and risks than in the traditional regulated environment. Therefore, the task of system operators who maintain the physical system reliability will be more complex after considering market optimized benefit and uncertainties. Recently, some new spinning reserve market models have been developed [8]. Developing new techniques based on market models for spinning reserve determination is very important under the current deregulated environment. Continuous research is strongly encouraged to ride on the evolution of the markets and new schemes will be developed for the benefit of the whole society.

1.2 Major Contributions

Dramatic changes are happening in the power industries all over the world. Many studies are needed to keep electricity market designers/researchers updated with the newest trends and situations in the electricity market around the world. Based on the motivation described in the last section, some research works on the aspects of demand-side participation which include interruptible loads in the electricity market, the spinning reserve scheduling, and the settlement of the reserve market are investigated. Some new models and methods for the electricity market are proposed, and some simulation results are obtained to illustrate the observation from these studies. Several major contributions are given as follows:

➤ **Development of a market model incorporating demand-side reduction bids**

A market model incorporating demand-side reduction bids into a pool-based market solution is proposed in this thesis. A software package is developed to simulate this market clearing process. Unlike the conventional power market in which the objective function is aimed to minimize the GENCOs' total cost including operational cost, start-up cost and no-load cost, customers are allowed to bid for load reduction in this thesis. Thus consumers are given more opportunities to take part in the power market. They can respond to the market price promptly and correctly redistributing their consumption profile for their own benefit. The topics related to demand side participation in electricity markets and the work done in this area so far are introduced briefly.

Based on the main objective to maximize social welfare, a market clearing study is examined by incorporating demand-side reduction bids in the energy market. The relationship between the bulk purchase and load reduction bids is presented. Conventional scheduling programs usually ignore the impact of load recovery. Since producing this recovered energy has a cost, load reduction bids without consideration of load recovery may artificially enhance the value of demand-side bids from the scheduler's perspective. The effect of load recovery is analyzed in this thesis. The results also indicate that while load recovery addresses customer needs, it reduces the value of demand-side bidding (DSB).

In order to assist in studying the features of restructured power systems, the techniques for generation scheduling are introduced and the differences between a vertically integrated power system and the new deregulated power system have been investigated and presented in this thesis. A Lagrangian Relaxation optimization method is developed to simultaneously clear generation and demand reduction bids, while maximizing the overall benefits for market participants.

With customers participating in the deregulated power market, the influence of DSB on the total cost, profit of supply and MCP is carefully analyzed. Different cases are compared to illustrate the desired results. And in Chapter 3 the results with

different load recovery profiles are also compared. With the proposed method, the total consumption has not been changed while at the same time the total cost, MCP and the profit of GENCOs are reduced. Simulation results show that demand reduction bids may mitigate price volatility by smoothing MCP. Thus it contributes greatly to the real market and aids in mitigating the abuse of market power.

Furthermore, case studies performed demonstrate that flexible DSB is likely to be competitive when compared with inflexible generators from the point of view of the total cost minimization. Although, in general, DSB aids in reducing MCP, there are times the value of DSB is affected when offer bids of inflexible units are replaced by higher demand-side bids. Some demand-side bids will be selected even if their actual value, i.e. their contribution to the global social welfare, is smaller than the value of competing generation bids. The method developed in this thesis can take this effect accurately into consideration.

Reference [9] discussed the two models for load management, which are cost-based and price-based. They are formulated in a very different way from the problem formulation in the thesis. For example, in the cost-based load management model, the objective function, equation (7.9) on Page 285 of the book, includes the reduced cost of deferring the energy, the increased cost for paying back the energy and the possible revenue loss. Customers are grouped into several types according to their controllability. Linear Programming is used to solve this problem. The problem formulation in the thesis is a typical cost minimization problem which considers demand-side participation. It incorporates the possible cost of customers for the amount of load reduction into the objective function. Lagrangian Relaxation is used and the unit commitment pattern could be obtained by this solution algorithm. Some other related work is reviewed and compared later in Section 2.5.5.

➤ **Probabilistic reserve schedule with demand-side participation**

The proposed market model is extended to include spinning reserve scheduling problem. And demand-side reserve offers are allowed to submit into the reserve market. Different spinning reserve is required to satisfy different reliability level of the system. A substantial amount of spinning reserve will enhance the reliability of a

system, but will result in a high scheduling cost, while a less reliable system may lead to an increase in the expected cost of energy not served. Hence a balance point is needed to achieve an optimal scheduling of spinning reserve. The risk index is used as a criterion to find the optimal point for the pool operation.

The optimal spinning reserve scheduling which integrates probabilistic reserve assessment in the unit commitment function is usually treated as a constraint to the main objective function. The Lagrangian Relaxation optimization method is used to solve the social welfare maximization problem. Unlike the widely used objective function, in this study the possible cost of not providing enough energy is taken into account together with the schedule cost in the objective function. This means that the cost of *EENS* is added to the schedule cost that includes both the energy and reserve cost. For this problem, the Golden-Section search method is incorporated in the Lagrangian Relaxation algorithm to obtain the optimal risk index. The global optimal solution is obtained when the total cost is minimum.

Demand-side reserve offers are incorporated into the scheduling process of spinning reserve based on probabilistic reserve assessment. The effect of demand-side participation is analyzed to show how it influences the optimal balance point to achieve the optimal solution for spinning reserve scheduling. In addition, the influence of demand-side participation on the schedule cost and the cost of *EENS* is analyzed using various scenarios of the with and without DSB. Simulation results reveal that demand-side participation can reduce the system risk of being unable to meet the demand. Hence, the reliability of the system is improved.

Furthermore, the effect of the unit's outage replacement rates (*ORR*) on the market clearing and settlement is analyzed. It is found that with the participation of the demand side, the total cost is reduced significantly together with the reduction of the *EENS* and reserve cost. Accordingly, the system reliability level is markedly improved with demand-side participation since the optimal risk index for the system operation is decreased. It is also found that the *EENS* increases with the increase of the unit's *ORR*.

➤ **A settlement scheme for a probabilistic reserve market with interruptible loads**

Continuously exploring in the study of reserve markets, a probabilistic reserve scheme is proposed by considering the reliability of each generator. The individual unit's reliability is taken into account in the proposed method. The effect of each unit's *ORR* on the system schedule is analyzed. A unit with high *ORR* will be dispatched less MWs and fewer hours by the system.

Interruptible load, a kind of potential reserve providers to compete with generators, has been widely considered and implemented in many power markets all over the world. It may reduce the total pool cost and reserve price, especially at hours when a contingency happens. Interruptible loads help maintain the system security and control the market power in a deregulated power market. In the proposed market structure, interruptible load is incorporated as a provider of reserve in the scheduling process. It is allowed to bid into the market to contribute towards the reserve market.

Furthermore, a settlement scheme with the participation of interruptible loads is proposed in this thesis to allocate the payment among generators and customers in the reserve market. It is set up for the reserve market to reward participants with low failure rates and penalize those with high failure rates. Interruptible loads are included into the settlement scheme along with all the generators for the reserve market to share the reserve responsibility. Different scenarios are set up to demonstrate the reserve responsibility share of each participant in the market. Those with a high reliability level will be paid for their good performance and those which operate poorly will be penalized for the loss they cause. Although interruptible loads do not contribute energy, they may cause energy deficiency if they fail to respond when the system operator calls the reserve in. Hence, this scheme provides incentives for all the market participants to improve their performance and to be responsible for their failures. The incorporation of interruptible loads not only improves the security and reliability of the system, but also relieves the burden of generators to provide reserve. Interruptible loads also compete with units to bring down the reserve price.

1.3 Thesis Overview

In this thesis, a more comprehensive mechanism of demand-side participation in the electricity market, the probabilistic spinning reserve scheduling method, the reserve settlement, and their model in the studies will be presented. The materials in Chapter 3, Chapter 4 and Chapter 5 describe these studies and the associated results.

This chapter describes the motivation of the study conducted in this thesis. The basic concepts on deregulation in the electric power industry are briefly introduced. The background of the studies, the current research work of demand-side participation and spinning reserve studies including the settlement for the reserve market are generalized.

Chapter 2 gives a more detailed introduction about the prevailing deregulated electricity market and the topics discussed in this thesis. A review of the relevant literature on these topics is summarized.

In Chapter 3, studies associated with demand-side participation are investigated. The market model with the incorporation of demand-side reduction bids is proposed. The general effects of DSB on the market are presented and the value of DSB is reassessed.

Starting from Chapter 4, the reserve market is included in the market structure. The probabilistic approach of spinning reserve scheduling is discussed. Based on the probabilistic reserve criterion, an optimal risk index can be achieved by balancing the schedule cost and the expected cost of energy not served. The solution is obtained via a Lagrangian Relaxation based unit commitment equipped with the Golden-Section search technique.

In Chapter 5, a different calculation technique for the value of *EENS* is shown. Interruptible loads which provide spinning reserve also bid into the reserve market. The spinning reserve is dispatched probabilistically by taking the individual unit's outage rate into consideration under a uniform system risk or reliability level. A

settlement scheme is proposed for the payment of the reserve allocation. Both generators and interruptible loads share the reserve responsibility and are responsible for their failures.

Finally, conclusions of the research work and the recommendations for further studies are presented in Chapter 6.

Chapter 2

Overview of Deregulated Electricity Markets

The electricity industry throughout the world, which has long been dominated by vertically integrated utilities, is undergoing enormous changes. The electricity industry is evolving into a distributed and competitive industry in which market forces drive the price of electricity and reduce the cost through increased competition. In this chapter, a comparison of the electric utility before and after the deregulation is provided. After that, a review of the deregulation around the world follows. Demand-side participation in the electricity markets is presented. The basic concepts of DSB and demand-side management are also introduced. In addition, spinning reserve issues in the restructured power industries are briefly reviewed. An introduction of different settlement schemes for different reserve markets is conducted as well. Based on these concepts and topics, the related studies in the proposed research area and the related research publications are outlined in this chapter.

2.1 Regulated and Deregulated Power Industries

2.1.1 Vertically Integrated Electric Utilities

Electric utility is the traditional term for an investor-owned company or government-operated department that produces and sells electric power [10]. For over one hundred years and until the 1990s, the power industries in nearly all the countries operated as regulated entities. Every electric utility had a local monopoly. In any area, there was only one utility that produced, transmitted, distributed and sold electric power and services. It usually denotes a vertically integrated electric utility that

performs all four of the functions involved in producing and selling electric power. These functions are known as Generation, Transmission, Distribution and Retail Sales.

Such a utility served as the only electricity provider in the region and was obliged to provide electricity to all the consumers in the region. The prices were set in accordance with government regulatory rules and the utility was assured a fair return on its investment.

The structure of the vertically integrated electric utility is fairly simple as there are mainly two parties of the electricity delivery, which are seller and buyer. Electric utility is the only one company which sells electricity to customers; hence customers have to accept whatever price setting by this monopoly [11].

2.1.2 Restructured Power Industries

Since the 1980s, drastic changes and restructuring in the electricity industry have occurred, with the traditional vertically integrated electric utility structure being deregulated and replaced by a competitive market scheme. One of the principle characteristics of a competitive structure is the identification and separation of the various tasks which are normally carried out within the traditional organization so that these tasks can be open to competition whenever practical and profitable. This process of commercial rearrangements for trading energy is called restructuring [1].

The forces that lead to the restructuring are not uniform across different countries and states, and vary according to different needs. In a summary, there are four common reasons behind: (1) To achieve market efficiency through competition. (2) To open up the retail market for competition and customer choice. (3) To allow government owned assets to be privatized. (4) To encourage private investment in power system infrastructure [12]. Thus, it is expected that competition might be a better way to reduce the price, to encourage investment for the operation of the electricity industry, to improve the investment decisions, to better use the existing plant and to enhance the choices for customers.

With the restructuring of power industries, some new entities are created in the deregulated electricity market and its structure becomes much more complicated compared with that before restructuring. It is no longer a simple transaction between sellers and buyers. The activity involved in producing electricity, is broken into processes managed by individual companies like GENCO, TRANSCO and DISCO. Everyone of them must participate in the electricity market and the trading of electricity must through the market by bilateral contracts or the pool, which may be named as Market Operator (MO) or Power exchange (PX) in different markets and countries. They are responsible for the operation of the electricity market trading. In addition, Independent System Operator (ISO) in some markets is an entity entrusted with the responsibility of ensuring the reliability and security of the entire system. It is an independent, non-profit organization which does not participate in the electricity market trades.

2.1.3 Comparison of Regulated and Restructured Power Industries

For a better understanding of restructuring, some differences between the pre- and post- deregulation of power industries are briefly compared in this section.

As shown in Table 2.1, all the functions in regulated power industries are entirely performed by the same electric utility, while they are now separated and managed by different individual entities.

Table 2.1 Comparison of the basic functions in power industries

Function	Regulated Power Industries	Restructured Power Industries
Generation	Electric utility owned	Individual GENCOs
Transmission	Electric utility owned	Individual TRANSCOs
Distribution	Electric utility owned	Individual DISCOs
Retail Sales	Electric utility owned	Retailers
Market Operation	--	MO, PX or ISO

Table 2.2 indicates the comparison of different features between the regulated and deregulated power industries in terms of pricing, objective and system planning activities.

Table 2.2 Different features between regulated and restructured power industries

Feature	Regulated Power Industries	Restructured Power Industries
Pricing	Unified price setting Generation, transmission and all other costs were wholly charged to the customer	Price of electrical energy
		Price of energy delivery
		Price of other services such as frequency regulation and voltage control (Ancillary services), which are priced separately and charged independently
Objective	Minimizing the total system cost	Maximizing the social welfare
Planning	Centralized system planning	Individual planning activities

2.2 **Restructured Market Models**

In order to achieve electricity market goals, several models, namely PoolCo, Bilateral Contracts and Hybrid Models [13] for the market structure have been considered.

PoolCo Model. PoolCo is like a stock exchange, which provides a platform for all market participants to buy and sell electricity. It is generally operated by MO or PX, in which both GENCOs and Retailers bid the prices for the amount of energy that they are willing to trade. Normally the electricity is paid by a spot price depending on how long the spot market is cleared.

Bilateral Contracts Model. Bilateral Contracts differs from the PoolCo in that GENCOs and Retailers can negotiate and sign contracts directly without going through the pool. It is very flexible as GENCOs and Retailers have the opportunity to

specify their desired contract terms based on their own benefits to achieve an agreement. The price is fixed for a certain period until a new contract is produced.

Hybrid Model. As the name implied, the hybrid model is the combination of the above two models discussed. The customer can buy electricity either through the pool spot market or by signing bilateral contracts. Hence, the customer has the true freedom to participate in the market in whatever way and buy any amount of electricity at whatever price. Generally, a hybrid model is prevailingly utilized in most markets all over the world.

2.3 Types of Power Markets

The markets may be classified into different categories using different classification criteria. Based on the type of electricity services, they include the energy market, ancillary services market, and transmission market. Furthermore, according to the time frame that the markets are cleared, they can have the forward market (day-ahead or hour-ahead) and real-time (spot) market [14].

Energy, Ancillary Services and Transmission Markets. The energy market is trading the energy demand of the customers. Ancillary services are normally for the purpose of maintaining system reliability. They include spinning reserve, non-spinning reserve and regulation. The energy and ancillary service markets can be cleared sequentially or simultaneously. In the sequential model, the ancillary service is cleared after the energy market clearing. In the simultaneous model it is cleared at the same time with the energy market. The transmission market trades the transmission right, which becomes critical when the lines are highly congested. The transmission network is still government owned in some countries.

Forward and Real-time Markets. The forward market may include bilateral contracts, day-ahead and hour-ahead markets for energy, and, in some regions, ancillary service markets. In most electricity markets, a day-ahead market is for scheduling resources at each hour of the following day. An hour-ahead market is a market which incorporates deviations from the day-ahead schedule. The real-time

market, also called the spot market, accepts the offers from GENCOs and Retailers, to determine the market price. To ensure the reliability of the power system, the production and consumption of electric power must be balanced in real-time. However, real-time load, generation, and the transmission capacity values can differ from those of the forward market schedules. Therefore, the real-time market is established to meet the balancing requirement. It is usually operated by MO or PX.

2.4 Deregulation around the World

This section provides a discussion on some major market models all over the world. Although the number of case studies is limited, it provides an interesting perspective for challenges faced by electricity restructuring across the globe. The study is conducted by comparing these different markets in terms of some aspects of market operation. All of these are summarized in Table 2.3.

The hybrid model is widely used in almost every electricity market. Each of them has both the spot market in which energy transactions are performed in real time, and bilateral contracts through which buyers and sellers sign agreements for the quantity of electricity they want to buy/sell. In some aspects, the deregulation of the electric power industries worldwide is undergoing similar processes. But there are still many differences for each country adopting a specific model according to specific situations in the country.

In a competitive environment, the market chooses to use different UC models that suit its requirements depending upon the need of the system and computational facilities. Different organizations are responsible for executing UC in different electricity markets [15-39] as shown in Table 2.3.

Table 2.3 Main characteristics of various electricity markets

	PJM	New York	New England	Nord Pool	Australia	Alberta	UK	New Zealand	Singapore
Market operation	ISO	ISO	ISO	PX	National Electricity Market (NEMMCO)	Alerta Electric System Operator (AESO)	New Electricity Trading Arrangements (NETA)	Trans Power	Energy Market Company
Bidding structure	Energy price and quantities, start-up costs, minimum generation level, maximum generation level	Energy price and quantities, start-up costs, minimum generation level, maximum generation level	Energy prices and quantities, ramp rate limits, reserve bids	Energy prices and quantities for both buying and selling. There is also a short term market for trade close to real time market	Energy prices and quantities, ramp rate, capacity profile, energy availability, fixed loading	Energy prices and quantities, ramp rate limits, reserve bids	Energy price, start-up price, offered capacity, ramp rate, minimum up/down time	Energy prices and quantities, ramp rate limits, reserve bids	Energy prices and quantities, ramp rate limits, reserve bids
Pricing	Locational marginal price	Locational based marginal price	Highest bid setting MCP hourly	Bids intersection from buyers and sellers	Highest bid setting MCP half-hourly	Highest bid setting SMP hourly	Highest bid setting SMP half-hourly	Nodal price	Uniform price based on nodal prices
Demand-side participation	Economic and emergency load response program	Day-ahead and real-time demand response program	Day-ahead and real-time demand response program	Fully participation in day-ahead and real time markets	Load reduction bids	Load reduction bids	Full demand-side participation	Full demand-side participation	Interruptible load bids in reserve market
Unit commitment	UC run by PJM-ISO	Self commitment by individual Gencos	UC run by NEISO	Self commitment by individual Gencos	Self commitment by individual Gencos	UC run by AESO	Self commitment by individual Gencos	Self commitment by individual Gencos	Self commitment by individual Gencos

2.5 Demand-Side Participation in Deregulated Electricity Market

In this section, some aspects of electricity markets from the perspective of the demand side are discussed. Some basic concepts of DSB and the differences between DSB and demand-side management are presented as well. At the same time, demand-side participation in deregulated power markets of different countries is briefly introduced.

The following sections argue that increasing the short-run price elasticity of the demand for electrical energy would improve the operation of power markets. However, they also show that enhancing this elasticity is not an easy task. Finally, how consumers of electricity can take part in the provision of power system security is described.

2.5.1 Demand-Side Bidding

Reducing the price paid by customers for electrical energy is invariably the first reason given for introducing competitive electricity markets. However, consumers have very little influence on the design of these electricity markets [40]. Competition fosters the development and the implementation of diverse technologies and products. In an electricity market some generating companies could offer low cost for inflexible generation while others may opt for more expensive but highly flexible generation. Actually, consumers have the ability to reduce their demand during periods of peak prices if they could be given the opportunity to bid into the market. Hence a mechanism called DSB can be adopted in the market to include the participation of consumers.

DSB is a mechanism that enables consumers to actively participate in electricity markets if they offer to undertake changes to their normal pattern of consumption. Rescheduling of loads or agreed load reductions can help maintain the balance between electricity supply and demand; maintain the quality and security of supply and could also enable electricity prices to be reduced in the short term [3].

Consumers can participate in DSB individually or as a group, by either bidding directly into the market or through a retailer. Any consumer can participate in DSB so long as they have the flexibility to reduce their normal electricity demand profile and install the necessary control and monitoring devices to execute bids and demonstrate bid delivery. Consumers may gain a financial reward, via a reduced tariff, a participation payment or a direct payment for the electricity they did not consume at an agreed time. Consumers may also benefit through improved energy efficiency.

DSB is all about involving the demand side (the actual consumers of electricity) in the processes of setting prices and maintaining the quality of supply. The demand side participation is encouraged and rewarded for its flexible usage of electricity.

DSB can reduce overall market costs by avoiding the need to call upon expensive reserve generators. In the short term, DSB can thus be regarded as a means of optimizing overall system energy efficiency and also enhance the efficiency of electricity supply [41].

Although closely related, DSB is very different from Demand-Side Management (DSM). The main difference between these arises from the impact the two have on the demand profile of consumers. DSB involves short-term discrete changes to demand profiles whereas DSM involves sustainable and permanent changes to demand profile. Figure 2.1 below summarizes the differences and similarities between DSB and DSM.

Figure 2.1 Comparing DSB and DSM

2.5.2 Types of Demand-Side Bidding

There are two basic kinds of DSB schemes - those involving a bid for the bulk purchase and those involving a bid for a change in demand. Both of these two types of schemes are important as they offer consumers an opportunity to manage their consumption of electricity and thus, have an impact on the global environment.

❖ Bid for total demand

A bid for total demand can take one of the two basic forms. Firstly, consumers or retailers representing consumers can sign a bilateral contract for a volume of electricity at a fixed price with generators. Alternatively, consumers can bid their total demand into an electricity market or pool in a similar way to that undertaken by generators. In these schemes, consumers bid how much electricity they will consume for a given price, and generators offer how much electricity they will generate for a given price. This results in two price-demand curves, as shown in Figure 2.2. One is a

generation curve showing the increase in generation costs with increased demand, and the other is a customer curve showing a reduction in demand in response to increased cost. The point at which the two curves intersect determines the market clearing price [42].

Figure 2.2 Price-demand curves

❖ Bid for a change in demand

The other scheme for DSB is that customers bid a change in their demand for electricity. For example, consumers could bid to reduce their demand, as shown in Figure 2.3. At a certain time, the demand bids may change by a reduced amount of consumption from customers, which are denoted as the stair curve and the gray area with strip lines indicates the total demand reduction. The bid for a change in demand can be an offer to reduce demand. The demand block can be an offer from an individual customer, e.g. a large industrial consumer, or from a group of smaller customers, e.g. domestic consumers.

Figure 2.3 Demand reduction bid

2.5.3 Categories of DSB

DSB refers to mean consumers’ resale, or selling the non-consumption of electricity that they have already secured the right to consume. DSB can exist between the consumer and almost any of the other market participants [43]. There are five main categories and seven broad types of markets/services that DSB can participate, as shown in Table 2.4 below.

Table 2.4 DSB according to characteristics and categories

Characteristics	DSB Category	Markets/Services of DSB Participation
DSB requiring consumers to change their electricity demand	DSB to maintain quality of supply	i) Ancillary services (of various types)
	DSB to solve network constraints	ii) Distribution constraints iii) Transmission constraints
	DSB for electricity balancing	iv) Balancing market
	DSB for access to market prices	v) Spot markets
DSB involving the bulk purchase of electricity	DSB for price setting	v) Spot markets vi) Bilateral contracts vii) Supply contracts

The main difference between these markets/services is the length of time before the point of delivering electricity. DSB can take part in any one of these markets/services as long as it can comply with the time given for its manipulation to load changes in an agreed manner. The scheduling time-frame associated with each particular DSB category is depicted in Figure 2.4. Each DSB category has been allocated to one of three main time frames, with the different periods defined as ‘months ahead of trading’, ‘day ahead of trading’ and ‘within day trading’. The within day trading time-frame can be either several hours ahead of delivery or immediately at the time of delivery [44].

Figure 2.4 Time-frame for bids associated with different DSB categories

2.5.4 International Practices in Demand-Side Participation

Customers can actively participate in both the energy and reserve markets. In electricity trading, customers can dramatically reduce the market clearing price and collect payment from the pool by providing flexible demand at real time. Interruptible load in the reserve market can also help to reduce the price of reserve and gain benefit via reserve bid offers. The participation of customer bidding enhances the efficiency of the market operation and makes the market more competitive. Meanwhile, the system security and integrity are improved.

All of the competitive electricity markets currently operating in the US (the PJM, New York, New England and California electricity markets) and many other countries, such as Alberta, Ontario, Finland, Spain, Sweden, UK, Norway, Australia and Singapore, all allow customers participate into their day-ahead market and their real-time markets. For example, a demand reduction bid is used in Finland and UK for the purpose of automatic frequency control in ancillary services. A demand reduction bid is also used to balance supply and demand in Finland, Spain and Sweden. A demand reduction scheme is used in UK as standby reserve [42]. The major difficulty with implementing significant amounts of demand-side participation in these markets is primarily due to the fact that very few customers participate in the real-time electricity bidding.

In the PJM market, load reduction is implemented in their economic load response program. A participant has the ability to reduce a measurable and verifiable portion of its load. But it is not on a supply contract where that customer pays the real time LMP (Locational Marginal Pricing) price. The economic option of the load response program is intended to encourage broad participation in economic load reductions by any hourly-metered curtailable loads. The objective function of PJM market aims to minimize the total schedule cost. If the total cost by scheduling demand reduction bids is lower than that by serving those loads, including consideration of paying the demand reduction bid for the length of their commitment time, demand reduction bids will be scheduled. Otherwise, they will not be scheduled unless they reduce the total costs. PJM also designs an emergency load response program to provide a method by which customers may be compensated for voluntarily load reduction during an emergency event. This scheme encourages interruptible load to participate in the reserve market [45, 46].

In the New York day-ahead demand response program, the New York ISO provides similar mechanisms to PJM for load reduction during both normal and emergency conditions (the day ahead demand response and emergency demand response program). It accepts demand reduction bids from customers or a agent on behalf of a demand side resource for a specific MW curtailment. The demand reduction bid could include two parts, one is the day-ahead LBMP (Location Based Marginal Pricing) above which the load would not consume, and the other is a curtailment initiation cost. Participants in the program are required to reduce their electricity consumption during a given period of time and they are paid a fixed payment or the clearing price of electricity for the reduced consumption. The time span for a single bid cannot be more than eight hours. There is a provision for customers to offer interruptible load service and thereby provide additional operating reserve. In order to bid in the day-ahead or operating reserve market, customers contract their interruptible load with NYISO directly with the permission of direct control, monitoring and billing. The curtailable load will be modeled as a generator (with negative generator) in the ISO's unit commitment software [47-50].

The Alberta Electric System Operator (AESO, the former power pool of Alberta) is responsible for operating an independent, fair, open and efficient real-time

market for the exchange of electricity, and for ensuring the safe, reliable and economic operation of the Alberta's interconnected power system. Power producers and importers submit electricity supply offers. Exporters submit bids to purchase electricity. And consumers can submit demand bids to purchase electricity at or below a specific price. They may bid not to purchase electricity if the price of electricity reaches a specific point. This bid reflects a submission by consumers to decrease load by a pre-agreed megawatts when this electricity is dispatched and the system marginal price is set. However, the demand bid scheme is on paper only. So far there are no participants. In the Alberta market, interruptible customers are allowed to supply the operating reserve. It contributes to the safe and reliable operation of the Alberta's electric power system [51-54].

The Ontario electricity market has a similar demand bids scheme as that of Alberta. The Ontario's Independent Electricity System Operator (IESO) also has several dispatchable loads which are large consumers of electricity capable of responding to five minute dispatch instructions. A dispatchable load is required to place a price/quantity bid in the real time energy market to state the price at which they will reduce their energy consumption. A dispatchable load can also place bids in both the 10 minute non-spinning and the 30 minute operating reserve markets. If their bids are economic, then they will receive operating reserve payments for the ability to reduce their load if system conditions necessitate that operating reserve be activated [55]. In addition, IESO also has a Transitional Demand Response Program (TDRP). It is a voluntary program wherein loads decide if they want to reduce demand when the three hour ahead price is at or above \$120. Program participants do not "bid" into the system – they indicate voluntarily to IESO whether or not they will participate, but their offer is not binding. At the end of the month, they submit data of hours that they did participate and the amount of load that was shed [56]. IESO currently has another program called the Emergency Load Reduction Program (ELRP) which will be in place by June 2006. The main difference between ELRP and TDRP is that the trigger for ELRP is reliability. ELRP participants will be contacted by system control room operators when they foresee the possibility of an emergency event. Participants will receive a stand-by payment for participating in the program and will receive a \$/MW payment for 2-4 hours of consecutive demand reduction [57].

Norway's market-based reforms have generally been considered successful. But market power still can be detected in Norway from several aspects, such as zonal pricing, whereby prices in different geographic areas are varied to reflect constraints in the transmission system and demand-side bidding. In the Norway market, demand-side bidding has been proposed as an effective means to mitigate market power in electricity markets. While customers always have the option to buy power if prices are high, Norway was one of the first few countries to permit consumers to bid demand curves into the wholesale market [58].

The NEMMCO, which is the ISO in Australia, allows for DSB in the market. However the rules and codes are not very attractive to the customers. So far, only a few large customers and pump-storage hydro power plants are participating. Customers can register as scheduled loads and can submit their dispatch bids to the NEMMCO. Both generators and customers are centrally dispatched. The dispatch bid can be specified so as to increase or decrease the load if the price is below or above the pre-specified level. The Australian National Electricity Code Administration is taking initiatives to change the rules to introduce more attractive arrangements for DSB [59].

In the Singapore's wholesale electricity market, there are three reserve classes, namely primary, secondary and contingency reserves with response times of 8 seconds, 30 seconds and 10 minutes respectively. Currently, interruptible load is allowed to bid into the real time market to provide spinning reserve in the Singapore electricity market. Direct Market Participants (DMP) or Retailers who can have their electricity supply interrupted for a duration of at least 30 minutes can offer interruptible load. This load can be voluntarily interrupted for a limited duration to enable the power system to return to its normal operating state. It can be offered in all or some of the primary, secondary and contingency reserve markets if it meets the criteria for the respective reserve class. Hence, interruptible loads compete with generators to provide reserve under the same time response requirement. It helps the customer to defray some of its energy cost since interruptible load is activated for only three times within the past three years but it collects money from the market most of the time [60].

The England and Wales of UK also has similar reserve markets (although slightly different time scales are associated with the corresponding reserve/response services) and interruptible loads are actively encouraged to compete with generators in the provision of all types of reserve services. An example is the direct market participant of the chemical industry. In the UK, interruptible loads take active part in the provision of (non-dynamic) primary and secondary frequency response services and standing reserve [61] of about 500 MW in total. Aluminum Smelters are one of the key contributors which are significant electricity users but also have considerable load management flexibility. They often can interrupt (reduce) consumption and postpone the production process and this flexibility is being offered (sold) to the system operator as a source of reserve.

Table 2.5 summarizes the types of demand-side participation in different countries all over the world. It shows that most market participants view demand-side participation favorably, primarily due to the fact that it improves the choice of products in the electricity market and improves market liquidity. More work on the development of cost effective communication technology which can activate and monitor demand changes for individuals or small groups of consumers is needed.

Table 2.5 Experiences with demand-side participation in different countries

Regulating power market	Norway
Frequency response	UK
Interruptible supply contracts for domestic customers	Finland, Norway, UK
Fuel substitution	Norway, Sweden
Standing reserve	UK
Load management in refrigerated warehouses	New Zealand
Use of standby generators for peak price avoidance	UK
Real time domestic load management	USA

2.5.5 Studies of Demand-Side Participation

Sheble [62] presented an overall review of the power industry deregulation process. Some possible deregulation details are discussed, as well as the technical issues, such as standards and algorithms. A summary is given to identify unresolved issues in the deregulated environment in an auction market structure. As discussed in the earlier sections, generally there are two approaches for customers participating in the market. These two approaches are: (1) The demand side can offer bids in the double auction bulk purchase, and (2) Customers make load reduction at peak period as pre-agreed for the purpose of maximizing their own benefits, improving system reliability and security, and mitigating high electricity prices.

Reference [63] discusses the issue of how to model the price responsive customers in the system and subsequently how the software program can represent it. It concludes that the demand response program is cost effective. A more price responsive system can make the grid more robust.

Much research work has been conducted based on the double auction market model or the bulk purchase approach. Reference [64] discusses the importance of information from a market and the information needed by market participants. It also presented an ideal market model and a comparison of this market to existing markets of USA. A framework of power market with both energy service companies (customers/buyers) and GENCOs (sellers) in a double auction market is presented. A brokerage system is formulated in [65] based on maximizing the social welfare. The objective function includes bulk purchase bids from customers in both energy and reserve markets. Transmission losses and reserve margin requirements are incorporated in the proposed model and a pricing mechanism for spinning reserve margins is developed for a competitive electric market. An auction market simulator [66] is used to conduct experimental studies of the aspects in power system operation under a price-based environment. Reference [67] provides a comparison of several operation research tools, such as sensitivity analysis, parametric analysis, stochastic linear programming and fuzzy linear programming for risk management. The application of interior-point linear programming to the auction methods is illustrated in [68]. It proves to be very efficient in finding the exact optimal solution and useful

for matching buyers and sellers in the market. The usage of Lagrangian Relaxation in auction implementation problems is illustrated in [69]. The study is focused on the effect of identical or similar generating units on finding optimal solutions for auctions. Reference [70] also investigates the effect of identical or similar units to the LaGrangian Relaxation algorithm in finding the optimal solution under certain situations. It proposed a method to change unit data to obtain an advantage by using LaGrangian Relaxation as an auction method. Various formulations of different auction structures are proposed in [71] according to special requirements from different regions in the world. Comprehensive mathematical formulations for auctions are presented when various characteristics for different auction structures are desired. A total of thirteen cases which include both single and double auction markets is developed.

At the same time, many studies analyzed the bidding strategies in a competitive market environment. Reference [72] describes a competitive double auction marketplace where both the buyer and seller could access the auctions implemented to buy and sell power. Genetic Algorithm is used to study bidding strategies in the trading process. A framework is presented to test and modify these bidding strategies. Bidding strategies which combine genetic programming and finite state automata are developed for the double auction market [73]. The objective is to maximize profits of trading agents in the markets. A profit-based unit commitment GA algorithm is developed in [74]. A price/profit-based UC formulation is provided by considering the softer demand constraint and allocating fixed and transitional costs to the scheduled hours. It concludes that UC GA is a useful tool for GENCOs to obtain the expected prices and demands and to offer their bids strategically for their own benefits. A model for optimization of investments in power generation is presented in [75]. Incorporating demand uncertainties and price responses on the demand side, a stochastic dynamic programming algorithm is implemented to solve the problem. Optimal investment strategies are obtained and compared for both centralized and decentralized decision making.

In addition, game theory and Nash equilibria are applied in the power market for the purpose of studying the implementation process of making the electricity to be the same as other commodities. A gaming model with the Cournot strategy is

presented in [76]. After consideration of flexible demand which shifted the consumption from the peak time to the non-peak time, it is found that GENCOs' market power can be mitigated. A methodology to find Nash equilibria in pool-based electricity markets is presented in [77]. Based on the double auction market, multiperiod bidding, price elasticity and bidding strategies are considered. An approach is also presented in [78] to find Nash equilibria in electricity markets. The demand price elasticity and its importance in the studies are illustrated.

Customers' participation is very important in a market environment. A tutorial paper [40] discusses some aspects of electricity markets from the perspective of the demand side. It gives an overview for some features of the demand for electricity, which include economic characteristics and price elasticities. It also suggests that some tools are needed by consumers to actively participate in the electricity market. In [79], the potential impacts of the demand-side bidding (DSB) on market prices are analyzed and it concludes that DSB and other forms of flexible generation can cause sharp and unwarranted price increases if the schedule is established on the basis of a minimization of the total cost. In [80], a two-level optimization procedure for building bidding strategies is presented in which market participants try to maximize their profits under the constraint that their dispatch and price are determined by OPF (Optimal Power Flow). The optimal bidding strategies of generators and large consumers are addressed simultaneously in [81], utilizing linear bidding functions. The behaviors of rival competitors are represented as continuous probability distributions. A Monte Carlo-based method is developed to find the optimal bidding strategies and the associated market power is evaluated. It is shown that market power can be mitigated through the introduction of DSB. A composite model for optimal generation and demand reduction scheduling is presented in [82]. It proposes a model for a comprehensive evaluation of possible scenarios for incorporating DSB into the electricity market. The influence of DSB on total costs, system marginal price, capacity element payments and benefit allocation between producers and consumers are examined. A tool based on OPF assessing the effects of consumer participation in power market is developed in [83]. Two scenarios, price-responsive loads and consumers subject to constant tariffs, are compared to illustrate the effectiveness of consumers' participation programs. It is concluded that consumers' reduction of their energy consumption relieves critical system operating conditions, especially during

critical operating conditions. Incentive programs are designed to encourage this kind of behavior of customers.

Demand elasticity can be defined according to several criteria, such as price elasticities, time of service elasticities, and delay of service elasticities. To test the response of customers to the electricity market price, some studies have been conducted worldwide. A profit-based load management using linear programming is presented in [84]. It is compared with the conventional cost-based direct load control approach. The results show that the proposed method achieves better solution when the rate structure charging customers is different. A sensitivity analysis on price is conducted to investigate the possible range to obtain an optimal solution. Reference [85] discusses the consideration of the demand elasticity during the price setting for electricity in a centralized market. A model is set up to incorporate consumers' behavior using a matrix of self- and cross-elasticities. A demand-price elasticity model is incorporated in the context of the Interior Point based OPF algorithm [86]. Customer load can vary in response to various prices and load shifting is considered as an efficient method in the electricity market. A consumer sensitive time-of-use pricing model based on global optimization is presented in [87]. Consumer-differentiated and time-dependent marginal prices are determined by the proposed model. The consumers' consumption pattern would be changed according to this time-of-use prices. Thus a new plan is obtained by using a new demand curve. Optimal electricity demands and prices are achieved through consideration of demand responsiveness. Residential consumers' responses to the dynamic pricing of electricity are modeled in [88]. Consumers' daily electricity consumption pattern is described and the effects of outdoor temperature are considered. Simulation results indicate that consumers plan their hourly consumption according to the daily price pattern. Some reduction of consumers' consumption during peak periods occurs. The consumers' response to a time-of-use tariff structure is examined in [89]. It shows that the price elasticity is a function of electricity cost share. It proves that the electricity consumption by time-of-use is highly responsive to price changes. Customers intend to decrease electricity use during peak period and increase usage during off-peak time. Reference [90] also analyzes the time-of-use pricing for load management programs.

2.5.6 Interruptible Loads

Interruptible load is not a new term. Interruptible load contracts have been widely used in reserve markets in many countries. These usually involve commercial and industrial consumers. The customer entering such a contract, benefits from reduction in its energy costs and from other incentives provided by the scheme. While all the market participants benefit from the load reduction scheme in system peak time and subsequently the improved quality of service and security and reliability of electricity delivery.

Generally, interruptible loads can lessen the reserve burden of generators significantly and can provide another source of reserve during emergency when their service is needed most. Hence interruptible loads increase the diversity of supply of reserve services and can aid in maintaining online reserve, voltage profile, providing real and reactive power relief. Meanwhile, successful demand bidders have been able to effectively compete with generators. As a result, the level of competition in the provision of reserve services has increased and the prices and the overall cost of reserve have reduced.

Much research work has been done to investigate optimal schemes for interruptible load. An optimal power flow based interruptible load management is evaluated in [91]. The consideration of economic incentives offered to customers is modeled in the optimization problem. The price-response and price-elasticity of demand are investigated. The effect of different behaviors from consumers on the interruptible load management is assessed. A market for interruptible load, or callable forward contracts for electric power is proposed in [92]. In this contract, the consumer grants the power supplier the right to interrupt a given amount of load in return for a price discount. Although most interruptible load contracts are specified well in advance, present-day energy transactions allow for much more frequent update such as hourly spot-price, calculated based on system operating conditions and forecasts of how much interruptible energy will be purchased by customers. A real time interruptible load scheme is proposed in [93]. The framework of this scheme is based on optimal power flow which determines the incentive rates of an interruptible tariff mechanism on an hour-to-hour basis. Interaction between the utility and customers

contracting interruptible load is incorporated in the analytical framework by formulating customer response functions to this mechanism. It is shown that this mechanism is able to reduce costs and aid in system operation during peak load periods.

The success of interruptible load programs often depend on the incentive rate offered by the schemes. The market therefore needs to design appropriate incentive rates which not only are attractive enough to induce the best customer response, but also are sustainable to other parties in the market for their profit considerations. Reference [94] has worked out a comprehensive pricing formulation for interruptible loads and assignment of power pool reserves. It is shown that optimal pricing mechanisms do exist, and these invoke customer participation in a socially optimum manner to aid in system operation and provide the necessary system security. Consequently, it is shown in [95] that system security can be maintained in an operating environment where all participants, including those on the supply-side and those on the demand-side, seek to optimize their own benefits through pricing mechanisms. A generalized model for inclusion of security constraints in competitive markets is developed in [96] where the prices are determined considering demand price elasticities. Two methods are presented in [97] to assess the customers' outage costs of their willingness to pay in order to avoid an outage and their willingness to accept compensation for having an outage.

In the current market environment, interruptible load is no longer a long-term program. It can participate in the real time market to compete with generators for providing spinning reserve. Reference [98] discusses the possibility of load to compete against generators for providing spinning reserve. Reference [99] shows that the participation of interruptible loads in the market as a competitor to generators can reduce the energy prices and improve the voltage security. A technique is presented in [100] to include interruptible loads in the probabilistic assessment of the operating reserve. The paper concludes that the proposed technique can be used to evaluate the effect of load interruption on the system risk.

2.6 Spinning Reserve in Restructured Environment

Generally speaking, the determination of the required amount of system generating capacity to ensure an adequate supply is an important aspect of power system planning and operation. The total problem can be divided into two conceptually different areas designated as static and operating capacity requirements [101]. The static capacity area relates to the long-term evaluation of this overall system requirement. The operating capacity area relates to the short-term evaluation of the actual capacity required to meet a given load level.

The reliable operation of a power system requires generation reserves to be available in order to cover generation and transmission contingencies. Reserve, defined as extra energy for supplying the load in the case of unplanned events such as the outage of a major generation facility, needs to be scheduled to maintain system security and reliability. The reserve capacity that is spinning, synchronized and ready to take up load is generally known as spinning reserve. The unit which provides the reserve is on-line and operates at less than maximum output, and is ready to serve load immediately.

2.6.1 Reserve Market Clearing Approaches

The possibility of random failure of any of the main components of a power system as well as the unpredictable behavior of the demand necessitates the introduction of reserve as a way of reducing the risk of blackouts. In many established electricity markets, energy and reserve are often traded and scheduled in separate markets, which is the so called sequential approach, such as in the initial market design for the California and New England markets [102]. In this kind of markets, the auction for all the reserve products is conducted sequentially from the highest to the lowest quality. Each market is operated separately and cleared sequentially.

Unfortunately, a sequential auction with independent uniform market clearing prices in each round may result in price reversal, i.e., the market clearing price for a high quality resource (e.g. regulation) may be lower than that for a lower quality

resource (e.g. spinning reserves). Indeed such price reversals have been observed in the California and New England ancillary service markets.

Price reversals pose serious incentive compatibility problems since even price taking generators anticipating such reversal may be induced to understate their capability and wait for a later round of the sequential auction that is expected to fetch a higher market clearing price. With market power, the situation is exacerbated as losing bids in early rounds may raise their bids in subsequent round when they perceive potential scarcity of bids. That type of low liquidity and high prices for low quality reserves has been observed in California and has motivated the reforms to the new market model later.

Although this sequential approach is easy to implement, some unexpected phenomena emerged after the implementation as discussed above. Hence, various simultaneous approaches are proposed and adopted by many electricity markets in the world. Key elements of the market reform have been to move from a sequential to a simultaneous procurement auction for the various services and to allow the ISO to exploit the substitutability among the different reserve types. Sequential and joint dispatch for ancillary services are compared and analyzed in [103]. It is concluded that energy and reserve can be co-optimized to achieve the best tradeoff between them by the joint dispatch approach, which is proved by the experiences with the joint dispatch in the New Zealand electricity market.

In the simultaneous approach, each product, including generation and reserve, is scheduled jointly. The objective of this market could be to maximize the social welfare by minimizing the total cost. This approach is socially efficient and incentive compatible. Co-optimization among the all market services could be achieved. It makes an important contribution to economic efficiency by ensuring that the market is able to choose the most efficient combination of energy outputs and ancillary service from each participant, as well as ensuring that energy and ancillary service contributions are optimized among participants. The basic energy and reserve dispatch optimization (co-optimization) in a pool model market is investigated by Gan *et. al.* [104]. The co-optimization is extended further to include the lost opportunity cost. A

general approach for modeling lost opportunity cost is presented in the context of co-optimization.

2.6.2 Spinning Reserve Management Techniques

The system reliability can be improved by scheduling sufficient system reserve capacity. This security of supply comes at a price: carrying reserve capacity significantly increases the cost of operating the system. As the electric power industry moves toward the full competition, various services previously provided by electric utilities are being changed. How to schedule spinning reserve and at what amount become fundamental questions that need to be scrutinized.

A wide range of techniques has been used to determine operating reserve requirements. These methods can be divided into two categories, deterministic and probabilistic approaches. The former does not incorporate any explicit recognition of the actual risk. The deterministic criterion could be, (i) “n-1 security” where the largest online generator’s capacity is used as the spinning reserve requirement (*SRR*), (ii) the *SRR* is set at 10 percent of the hourly load, or (iii) some combination of the two previous criteria [105]. The most widely implemented deterministic criterion is “n-1 security”. Under the “n-1 security” criterion, regardless of historical records the generators hold, the system is able to continue operating after the loss of a single unit. However, when two or more generators fail at the same time, the system cannot promise not to cut off loads. Similarly, the “n-2 security” scheme can guarantee continuous supply up to the second order outage (contingency of simultaneous outages of 2 units). The “n-x security” schemes are simple to implement but may expose the system to unnecessary risk at peak load and/or when generators of high outage rates are scheduled or may overprotect the system at the other extreme.

Scheduling spinning reserve based on a deterministic approach is easy to implement, however, it does not match the stochastic nature of the system behavior and does not provide a means to assess the system risk. In the restructuring competitive electricity market, risk assessment is increasingly used to reflect the electricity price and the risk that the customer is exposed to. Subsequently, probabilistic techniques were developed to incorporate the concept of risk that is

defined as the product of probability and consequence [106]. The *EENS* is the energy deficiency amount obtained from a risk evaluation using the probabilistic approach. A capacity outage probability table (*COPT*) is set up to calculate the *EENS*. The probabilistic spinning reserve criteria take different order outages into consideration by calculating the loss of load probability (*LOLP*) or *EENS*. The historical outage records of the generators are also considered so that a relative accurate system reliability level can be obtained.

The probabilistic approach to evaluate reserve involves two distinctly different aspects. The first is unit commitment, in which the system operator decides how many and which units to commit to satisfy the operating criteria. The second aspect is associated with the dispatch decisions regarding the units that have been committed. A risk index based on such methods would enable a consistent comparison to be made between various operating strategies and the economics of such strategies. The acceptable risk level is and must remain a management decision based on economic and social requirements. An estimate of a reasonable risk level can be made by evaluating the probabilistic risk index associated with existing operational reserve assessment methods. Once a risk level has been defined, sufficient generation can be scheduled to satisfy this risk level [101, 107]. All the basic concepts about the probabilistic approach of evaluating the spinning requirements, such as outage replacement rate, unit commitment risk, are extensively discussed in [101, 107].

2.6.3 Spinning Reserve Studies

The assessment of reserve is an important aspect for consideration in power systems. And the scheduling of spinning reserve is very important in the daily operation of power systems. Substantial research work has been conducted in this area. Recently, the probabilistic assessment approach of spinning reserve has been considered for adoption in many markets. Under this approach, the system can schedule a certain amount of reserve to meet a certain criterion, for example, a given system risk index, i.e. the probability of failing to meet demand at some instant in time, a unified reliability level or a predefined maximum *EENS* value.

The criterion that the unit commitment risk should be less than or equal to a specified system risk is illustrated in [5]. A method is proposed for scheduling generation to meet a predefined risk index. The risk index is treated the same as the *LOLP* index. The proper spinning reserve amount is assigned according to this index. An optimal spinning reserve schedule is achieved on the basis of a tradeoff between the total schedule cost and the cost of *EENS*. An approximation method [108] is introduced to integrate a probabilistic criterion into the unit commitment optimization. Bouffard and Galiana *et al* [109] used a mixed integer linear programming approach to satisfy the spinning reserve requirement by making the system operate under a certain *EENS* or *LOLP* requirement. The process also sets a maximum value for *EENS* to meet a predefined system reliability requirement. A zero-sum settlement scheme is implemented in [110] for the payment and compensation for a reserve responsibility share among the online generators via probabilistic reserve scheduling. The system operates under the maximum *EENS* value by considering the influence of various order outages to give a proper reserve amount for the system. A probabilistic dispatch [111] determines the reserve amount by comparing the cost of supplying the reserve with the expected cost of not supplying it.

In a power market, the electricity restructuring is seen as a way of giving more choices to the customers. Customers can decide the spinning reserve capacity and can also participate in the reserve market to provide spinning reserve. This means that the customers not only decide the price of the commodity but also its reliability. This leads to a trade-off between reliability and costs for spinning reserve. This trade-off could lead to a lower, equal or higher reliability than that in the regulated structure.

In [112], a market model is proposed where the demand side submits reserve offers on four reserve markets. In [113], a loading algorithm which incorporates the outage costs into the minimization problem is proposed. A more flexible new formulation of the reserve requirement which replaces the usual rigid emergency reserve criterion is set up. In [114] a flexible operating reserve model is set up and the operating reserve capacity is optimized based on the cost and benefit analysis. A heuristic method with consideration of generation system reliability is used to determine the optimal reserve capacity. A formulation for market-clearing with

stochastic security is proposed in [115, 116]. It is concluded that a probabilistic security criterion has many advantages over the traditional deterministic approaches.

2.7 Market Settlement

Generally, there are two types of market settlement. One is the maximization of social welfare [80, 117, 118] and the other is the minimization of consumer payment [119]. The objective of maximizing social welfare is to minimize the total schedule costs and to obtain the optimum dispatch schedules. It is used in most centralized power pools. The later objective seeks to minimize the market clearing price and hence the price the customers would pay for energy. In this thesis, only the former one is discussed.

2.7.1 Energy Market Settlement

For the energy market, there are two kinds of clearing processes. One is the double auction market, where the market operator receives both supply and demand bids and the system price is obtained by matching the highest priced sale bid to the lowest priced purchase bid [120, 121]. The price-quantity curves of the supply and demand in a double auction market are shown in Figure 2.5. The supply bids are arranged in increasing order of prices while the demand bids are in decreasing order of their prices. Figure 2.5 shows the typical market clearing process in such power pools. The crossing point of these two curves represents the system price and the amount of energy cleared for trading. The shaded area denotes the social welfare which the market operator seeks to maximize.

Figure 2.5 Market settlement in double auction power pools

The other is the single auction market, where only supply bids are received and the system price is obtained by finding the highest priced bid intersecting the system demand forecast. In the single auction market, only suppliers submit bids to the market operator and the system price is obtained by finding the highest priced bid intersecting the system demand forecast as in Figure 2.6. The market operator seeks to minimize the system cost, which is denoted by the shaded area in Figure 2.6.

Figure 2.6 Market settlement in single auction power pools

2.7.2 Problem Formulation of New Market Settlement

With competition in the electricity supply industry, the issue of energy market design becomes a fundamental problem. Choices may be defined by the level of centralization in the system. In a centralized market, the ISO could be responsible for commitment and dispatch of units. Pricing of energy can take the form of least cost scheduling. In a decentralized system where an auction mechanism is used to clear the market, generators submit bids based on the units that are available. Hence they take responsibility for unit constraints such as minimum up and down times and unit maximum and minimum powers. In formulating a bid, a generator should try to ensure that these constraints could be satisfied. If they cannot, then the resulting schedule may be technically infeasible. In some systems, generators have been allowed to alter their bidding so that they can fulfill their requirements.

For a centralized power market in which ISO is responsible for unit commitment scheduling, the purpose is to maximize social welfare. It can be expressed over a day as:

$$\text{Social Welfare} = \text{Total customer benefit} - \text{Total cost to GENCOs}$$

Some constraints, such as the demand-supply balance constraint, start-up price, ramp rate limits and transmission constraints can be included in this optimization problem.

In bilateral markets, a GENCO in principle has no other objective but to produce electricity and sell it with maximum profit. The profit over a day for the GENCO can be expressed as:

$$\text{Profit} = \text{Revenue from [Spot market sale + bilateral power sale]} - \text{Payment for [Spot market purchase + unit operating costs + start-up/shut-down costs]}$$

All the technical constraints such as ramp rate limits and minimum up/down time need to be internalized by the GENCO in its bid price.

2.7.3 Reserve Market Settlement

As discussed before, reserve is very important for the power system to overcome any unforeseen contingencies. The cost of GENCOs includes electricity and ancillary services. The latter are generally referred to as those services that are

essential for ensuring the reliable operation of the electrical grid. The incentive for generators to supply reserve is derived from market settlement. Under the normal operating condition, the electricity price paid by customers is the MCP, which mainly consists of the MW schedule cost of generators. However, what if there are outages and the energy shortfalls happen? How are the price and payment dealt with under this contingency? Basically, there are two approaches prevalent in reserve settlement.

One approach is that the spinning reserve cost is collected from purchasers through an uplift charge. It is believed that accidents are unavoidable and customers need reserves in case of generators' outages. In this situation, the electricity price is modified to include the reserve cost and pass it to customers [122]. This is a popular approach which has been used in many electricity markets around the world.

The other approach holds the opinion that GENCOs should pay for the cost of reserves because they promise to supply the energy at the dispatch time but have the probability of failing to do so. The incentive for the GENCOs to improve the reliability of their plants should be sharpened by charging generators for the cost of unreliability, such as the cost of reserve [123]. Hence it is assumed that GENCOs should be responsible for part of the system reliability by carrying a certain required amount of reserve set by the system. The result is those generators supplying more spinning reserve than the required amount get the compensation and those with reserve deficiencies pay for the deficiency amount. It is also called a zero-sum game among the GENCOs because the sum of the payment and compensation is zero. Since the GENCOs settle the spinning reserve cost among themselves, the second approach would not charge the electricity consumers directly although they can pass on the cost to customers in their energy bid prices. Furthermore, GENCOs are protected as they have various means to prevent a reserve price spike if it hurts them. The electricity market in Singapore has implemented the second approach [124].

The consideration of generators' outage rates in the settlement gives GENCOs motivation to improve the performance of generators. Through regular maintenance, GENCOs can reduce their generators' outage rates although their revenues are affected during maintenance [125]. However, if sustaining a lower outage rate brings

them benefit, GENCOs can balance the loss of revenue during maintenance and the benefit derived from it.

2.8 Summary

The basic concepts and features of the electricity industry before and after the restructuring are presented in this chapter. The market models in different countries around the world are briefly reviewed. As there is no common market structure and no common set of trading rules that suit all the situations in different electricity markets, the form of demand-side participation has to be based on certain requirements according to different markets in different countries. The concepts and implementation of demand-side participation are compared for different country environments. The spinning reserve issues and market settlement including the settlement for reserve markets are stated. Literature review on all these topics of the restructured electricity market is summarized in every section of this chapter.

Chapter 3

Incorporating Demand Reduction Bids

A framework for the incorporation of demand-side reduction bids in a competitive electricity market is modeled in this chapter. The objective function which includes the demand bids is formulated accordingly. Simulation results and cost/benefit analysis are presented as well. Demand-side participation proves to be very efficient for reducing energy price and minimizing the schedule cost compared with those market solutions without considering consumers' response. The influence of demand-side reduction bids to total costs, MCP and the benefit allocation between producers and consumers are illustrated at the end of this chapter.

3.1 Model for Generation Scheduling with DSB

The market structure considered here is a gross pool model with centrally optimized scheduling. MO or PX, according to different market models, accepts bids (for energy) from both the supply and demand side. The costs representing both the supply and demand are included in the objective function of the scheduling algorithm to maximize the social welfare. The objective function will be elaborated in the next section.

3.1.1 Generator Model

Generators have several kinds of supply curves, e.g. linear or quadratic functions. Normally, a generator's offer file comprises the incremental offers curve and the start-up cost curve. Many electric utilities prefer to represent their generator

offered cost functions as single-segment or multiple-segment linear cost functions. The latter form is used in the problem model of this thesis. The offered cost function for each generator can be represented by several piecewise linear curves, while the start-up and no-load cost are spread over the running period. As shown in Figure 3.1, the generator offered cost is taken as the sum of the cost for the operation of the generating set at no-load and the cost for the MW output in each of the three ranges (up to the maximum capacity) of the generating set. The formulations are given as follows:

$$C_i(P_{i,t}) = \begin{cases} NL1_i + INC1_i P_{i,t} & P_i^{\min} \leq P_{i,t} \leq EL1_i \\ NL2_i + INC2_i P_{i,t} & EL1_i \leq P_{i,t} \leq EL2_i \\ NL3_i + INC3_i P_{i,t} & EL2_i \leq P_{i,t} \leq P_i^{\max} \end{cases} \quad (3.1)$$

i = Unit number

t = Time in hours [h]

$C_i(P_{i,t})$ = Unit offered cost as a function of generation output [\$/h]

$P_{i,t}$ = Output power of Unit i at time t [MW]

$P_i^{\max}$ = Maximum power generation by Unit i [MW]

$P_i^{\min}$ = Minimum power generation by Unit i [MW]

$EL1_i / EL2_i$ = Generation elbow point 1 and 2 of Unit i [MW]

$NL1_i / NL2_i / NL3_i$ = No-load cost 1/2/3 of the piece-wise segment of the linear price function for Unit i [\$/h]

$INC1_i / INC2_i / INC3_i$ = Incremental price 1/2/3 of the piece-wise segment of the linear price function for Unit i [\$/MWh]

The bidding files contains three incremental prices ($INC1_i$, $INC2_i$, $INC3_i$), one no-load price ($NL1_i$) and one start-up price. The incremental prices are different as shown in Figure 3.2. Only the first no-load price is actually part of the bidding file. The other two no-load parameters are calculated as follows:

$$NL2_i = NL1_i + (INC1_i - INC2_i)EL1_i \quad (3.2)$$

$$NL3_i = NL2_i + (INC2_i - INC3_i)EL2_i \quad (3.3)$$

Figure 3.1 Generator offered cost function

Figure 3.2 Generator incremental price curve

The start-up cost curve is included in a generator's bid package which states the cost for starting that generator after taking into account the operating point where it is ready to be synchronized with the power system. The curve is a function of the number of the hours from the time the generating unit was previously shut down. Generally, an exponential function is used to represent the relationship between the start-up cost and the shut down time of a generating unit.

$$S_{i,t} = \alpha_i + \beta_i (1 - e^{-X_i^{off}(t)/\eta_i}) \quad (3.4)$$

$S_{i,t}$ = Start-up cost for Unit i in hour t [\$]

α_i = Fixed cost (includes crew expense, maintenance expenses) [\$]

β_i = Cold start-up cost [\$]

η_i = Thermal time constants in the start-up cost function of unit i [h]

$X_i^{off}(t)$ = Time duration for which unit i has been off at hour t [h]

3.1.2 Demand Reduction Model

Traditionally demand has been considered inelastic in the short run. This is still a reasonable assumption for a considerable part of demand, but in electricity markets an increasing part of demand is becoming elastic. The customer has the opportunity to choose their consumption pattern as a response to the spot price. In this thesis the bidding price of the demand side is represented using a demand reduction model as shown in Figure 3.3 (a) and the formulation is given in equation (3.5). With the increase of price, demand is more willing to get interrupted as they can gain more compensation from the pool. The curve of total demand after demand reduction is shown in Figure 3.3 (b), which presents a same bidding curve as that of bulk purchase.

$$B_j = \begin{cases} B1_j & Q_j^{\min} \leq Q_{j,t} \leq EL1_j \\ B2_j & EL1_j \leq Q_{j,t} \leq EL2_j \\ B3_j & EL2_j \leq Q_{j,t} \leq Q_j^{\max} \end{cases} \quad (3.5)$$

B_j = Bidding price of customer j for load reduction [\$/MWh]

$Q_{j,t}$ = Demand reduction amount (a positive value) of consumer j at period t [MW]

$Q_j^{\max}$ = Maximum reduction amount of customer j [MW]

$Q_j^{\min}$ = Minimum reduction amount of customer j [MW]

$EL1_j / EL2_j$ = Demand elbow point 1 and 2 of customer j [MW]

$B1_j / B2_j / B3_j$ = Bidding prices of customer j for the three segments [\$/MWh]

$D_j^{\max}$ = Maximum demand of customer j by load forecast [MW]

Figure 3.3 The demand reduction model

3.2 Problem Formulation

In the restructured electric power system operating with the pool structure used in this thesis, the main objective is to maximize the social welfare. Unlike the traditional cost minimization UC problem, whose objective function is to minimize the operating cost of generators, demand reduction bids are incorporated in the objective function. Both suppliers and consumers participate in the new market.

There are two basic categories of DSB programs, (i) those involving in a bid for the total demand, and (ii) those involving in a bid for a change in demand, which have been discussed in Section 2.5.2. The latter will be presented in this chapter and it is formulated as the demand reduction model in Section 3.1.2. Both of these types of schemes are important as they offer consumers the opportunity to manage their electricity consumption and thus, have an impact on the market operation.

3.2.1 Objective Function

The demand, discussed in Section 3.1.2 of this thesis, is modeled as an elastic load. A price-responsive customer as described in Section 2.5 can actively participate in electricity trading by offering to undertake changes to their normal consumption pattern.

The objective function is formulated to maximize the social welfare, which is defined as the total customer benefit minus the total offered cost of GENCOs. It can be written as:

$$\max \left\{ \sum_{t=1}^T \sum_{j=1}^J B_j D_{j,t} U_{j,t} - \sum_{t=1}^T \sum_{i=1}^N C_i (P_{i,t}) U_{i,t} \right\} \quad (3.6)$$

$D_{j,t}$ = Demand of consumer j at period t [MW]

$U_{j,t}$ = Status of customer j at time t , 0 = customer not selected, 1 = customer selected

$U_{i,t}$ = Status of Unit i at time t , 0 = unit not scheduled, 1 = unit scheduled

T = Number of time periods

N = Number of units

J = Number of demand-side agents

In the description of the above function, the first term in (3.6) denotes the total benefit or utility to the customers and the second term denotes the total offered cost to the GENCOs. If the customer bids for a change in demand, i.e. the demand reduction model given in Section 3.1.2, the customer bids for a load reduction ($Q_{j,t}$) at certain prices ($B1_j, B2_j, B3_j$). This means that the customer is willing to reduce the

consumption by the $Q_{j,t}$ amount at time t . If the load reduction bid is selected by the market clearing system, then the total demand after demand reduction of customer j is:

$$D_{j,t} = D_j^{\max} - Q_{j,t} \quad (3.7)$$

Substituting (3.7) into (3.6), the following can be obtained.

$$\max \left\{ \sum_{t=1}^T \sum_{j=1}^J B_j (D_j^{\max} - Q_{j,t}) U_{j,t} - \sum_{t=1}^T \sum_{i=1}^N C_i (P_{i,t}) U_{i,t} \right\} \Rightarrow \quad (3.8)$$

$$\max \left\{ \sum_{t=1}^T \sum_{j=1}^J (B_j D_j^{\max} U_{j,t} - B_j Q_{j,t} U_{j,t}) - \sum_{t=1}^T \sum_{i=1}^N C_i (P_{i,t}) U_{i,t} \right\} \Rightarrow \quad (3.9)$$

$$\max \left\{ \sum_{t=1}^T \sum_{j=1}^J B_j D_j^{\max} U_{j,t} - \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} - \sum_{t=1}^T \sum_{i=1}^N C_i (P_{i,t}) U_{i,t} \right\} \Rightarrow \quad (3.10)$$

In the above function, the value of $U_{j,t}$ will be decided after the selection of customers' reduction bids has been processed by the market clearing algorithm. Customers are selected if their bid prices are competitive enough. Since $D_j^{\max}$ is a constant, the term $\sum_{t=1}^T \sum_{j=1}^J B_j D_j^{\max} U_{j,t}$ becomes a constant. And the objective function changes to:

$$\max \left\{ - \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} - \sum_{t=1}^T \sum_{i=1}^N C_i (P_{i,t}) U_{i,t} \right\} \Rightarrow \quad (3.11)$$

$$\min \left\{ \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} + \sum_{t=1}^T \sum_{i=1}^N C_i (P_{i,t}) U_{i,t} \right\} \quad (3.12)$$

When the generator start-up price is included in (3.12), the final scheduling problem is formulated as:

$$\min \left\{ \sum_{t=1}^T \sum_{i=1}^N [C_i(P_{i,t})U_{i,t} + S_{i,t} * U_{i,t}(1 - U_{i,t-1})] + \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} \right\} \quad (3.13)$$

In the minimization of the total cost in (3.13), the first part represents the cost of pool to buy the generator MW output to satisfy the consumption of customer. The second part represents the possible compensation for customers for the electricity they did not consume. The compensation will be paid by the pool in settlement.

3.2.2 Demand Reduction Bids

If the customer's demand is price responsive, then when the price rises beyond a specific point, the customer may bid not to purchase, which is so called the demand reduction bid in the Alberta market [51]. The market clearing process is described as in Figure 3.4. There are two stair curves. One is the generator's offer curve, which is in the direction from lower left to upper right. The other is the demand reduction curve, which is in the direction from lower right to upper left.

Figure 3.4 Market clearing process in combined generator's offer and demand reduction bids

As discussed in Section 2.7.1, in the single auction market where the demand reduction bids are absent, the MCP is determined by the market clearing Point 1 at which the highest supply bid intersects with the system load forecast (LF). LF is the summation of $D_j^{\max}$, the maximum demand of customer j as defined earlier.

In the double auction market, the load reduction bids begin from LF and the loads are reduced in small steps as prices increase during peak load periods, which is ordered according to the reduction bids submitted by customers. In the real system, not all of the customers are willing or able to reduce their load in response to prices. The inelastic customers will purchase electricity regardless of the price and the price may be very high as represented by Point 2. Point 3 is the intersection of curves of supply offers and demand reduction bids. The dash line through Point 3 represents the energy cleared by the double auction market. The MCP at Point 3 is much lower than that at Point 1 (single auction market). Area 1 represents the cost saved through demand reduction bids compared with that of the single auction market. Area 2 corresponds to function (3.13), which is the objective function obtained via minimization. Area 2 which falls to the left of the EC dash line represents the first term of function (3.13) and Area 2 which falls to the right of the EC dash line represents the second term.

In Figure 3.4, Area 3 denotes function (3.6), and B_j of (3.6) represents the price that customer j is willing to pay for the bulk purchase, $D_{j,t}$. If the energy cleared by the double auction market (EC) = LF - ER = total bulk purchase, then minimizing Area 2 has the same effect of maximizing Area 3. Hence, the market clearing process in Figure 3.4 based on load reduction bids is the same as that in the bulk purchase market. The only difference is that demand reduction bids are used instead of total demand bids and the market is cleared in a reverse direction. The load reduction method is however easier to implement because the number of load reduction bids is generally small in reverse clearing.

The demand reduction here is different from the traditional load curtailment. The curtailed load is already pre-agreed and will be cut when necessary, while the demand reduction is firmed up after the market clearing engine has been executed. It

is a kind of customer response to the high price and it reflects the actual elasticity of demand.

The demand reduction bid method provides a very flexible and efficient way of meeting the peak load in a MW production schedule. Consequently, if all demand side bids are treated in this manner, then it is clear that a price-responsive demand bid is exactly equivalent to a price-responsive supply bid. Therefore any framework for bidding by a supplier in a competitive electricity market can be used by a consumer in the same market.

3.2.3 Constraints

Due to the fluctuations in consumer demands, outages of generating units, and some natural characteristics of units, the solution of the generation scheduling problem is required to ensure the operational reliability of the power system, without violating any of the governing constraints. Many constraints, which are used in the UC problem, can be placed here together with some other constraints related to changes of the customer load profile.

I) System energy balance

$$\sum_{i=1}^N P_{i,t} U_{i,t} = D_t - \sum_{j=1}^J Q_{j,t} \quad t = 1, \dots, T \quad (3.14)$$

D_t = Inelastic demand portion at time t (without demand reduction bid)

$\sum_{j=1}^J Q_{j,t}$ = Total net reduction (a positive value) in the demand at time t after the load reduction bids are selected. This value is determined by the market clearing engine based on offer bids and load reduction submitted by all the bidders. As a result, the final demand profile at the right-hand side of (3.14) is not known until $Q_{j,t}$ is solved.

II) System spinning reserve requirement

$$\sum_{i=1}^N r_{i,t} U_{i,t} \geq R_t \quad t = 1, \dots, T \quad (3.15)$$

$$r_{i,t} = \min\{P_i^{\max} - P_{i,t}, \tau * UR_t\}$$

$r_{i,t}$ = Unit reserve contribution of Unit i at period t

R_i = Spinning reserve requirement

τ = Reserve response time (which is set to 10 minutes in this thesis)

UR_i = Ramp up rate of Unit i [MW/h]

III) Unit generation limits

$$P_i^{\min} \leq P_{i,t} \leq P_i^{\max} \quad i = 1, \dots, N; t = 1, \dots, T \quad (3.16)$$

IV) Customer load profile change limits

$$Q_j^{\min} \leq Q_{j,t} \leq Q_j^{\max} \quad j = 1, \dots, J; t = 1, \dots, T \quad (3.17)$$

V) Unit minimum up/down time constraints

$$[X_i^{\text{on}}(t-1) - T_i^{\text{on}}] * (U_{i,t-1} - U_{i,t}) \geq 0 \quad i = 1, \dots, N \quad (3.18a)$$

$$[X_i^{\text{off}}(t-1) - T_i^{\text{off}}] * (U_{i,t} - U_{i,t-1}) \geq 0 \quad t = 1, \dots, T \quad (3.18b)$$

$T_i^{\text{on/off}}$ = Minimum up/down time of Unit i

$X_i^{\text{on/off}}$ = Time duration for which Unit i has been on/off at hour t

VI) Ramp rate limits for unit generation changes

$$P_{i,t} - P_{i,t-1} \leq UR_i \quad \text{as generation increases} \quad (3.19a)$$

$$P_{i,t-1} - P_{i,t} \leq DR_i \quad \text{as generation decreases} \quad (3.19b)$$

UR_i = Ramp up rate of Unit i [MW/h]

DR_i = Ramp down rate of Unit i [MW/h]

There are some special constraints for the first on and last on periods. To prevent a newly committed unit from producing more megawatts than its allowable output in its first period on line, some special constraints are incorporated. For the same reason, to ensure the unit to be shut down in the next period, some limits are also imposed on the output of the last period on-line.

- For the first on period

$$\begin{aligned}
 &\text{If } X_{i,t-1} < 0 \text{ and } X_{i,t} > 0 \quad \text{then} \\
 &\quad P_i^{\min} \leq P_{i,t} \leq P_i^{\min} + UR_i \\
 &\quad r_{i,t} = \min\{P_i^{\min} + UR_i - P_{i,t}, \tau * UR_i\}
 \end{aligned} \tag{3.20}$$

- For the last on period

$$\begin{aligned}
 &\text{If } X_{i,t+1} < 0 \text{ and } X_{i,t} > 0 \quad \text{then} \\
 &\quad P_i^{\min} \leq P_{i,t} \leq P_i^{\min} + DR_i \\
 &\quad r_{i,t} = \min\{P_i^{\min} + DR_i - P_{i,t}, \tau * UR_i\}
 \end{aligned} \tag{3.21}$$

$X_{i,t}$ = State of Unit i at time t , denoting number of hours that Unit i has been on (positive values) or off (negative values)

3.2.4 Lagrangian Relaxation Method

The Lagrangian Relaxation optimization method is used to solve this problem. In this problem, the demand constraint, the spinning reserve constraint and the ramp rate constraints are relaxed by using the Lagrange multipliers. Let $\lambda_t, \mu_t, \xi_{i,t}, \zeta_{i,t}$ be the corresponding nonnegative Lagrange multipliers to (3.14), (3.15) and (3.19). The following dual problem can be written.

$$\begin{aligned}
 L = & \sum_{t=1}^T \sum_{i=1}^N [C_i(P_{i,t})U_{i,t} + S_{i,t} * U_{i,t}(1 - U_{i,t-1})] + \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} \\
 & + \sum_{t=1}^T \left[\lambda_t \left(D_t - \sum_{j=1}^J Q_{j,t} - \sum_{i=1}^N P_{i,t} U_{i,t} \right) + \mu_t \left(R_t - \sum_{i=1}^N r_{i,t} U_{i,t} \right) \right] \\
 & + \sum_{t=1}^T \sum_{i=1}^N [\xi_{i,t} (P_{i,t} U_{i,t} - P_{i,t-1} U_{i,t-1} - UR_i) + \zeta_{i,t} (P_{i,t-1} U_{i,t-1} - P_{i,t} U_{i,t} - DR_i)]
 \end{aligned} \tag{3.22}$$

The problem is to minimize the Lagrangian function of (3.22), subject to other constraints (3.16), (3.17), (3.18), (3.20), (3.21) that can be applied to each unit separately. The Lagrangian Relaxation procedure is done through the dual optimization by maximizing the Lagrangian function with respect to the Lagrangian multipliers, while minimizing with respect to the other variables in the problem. Hence, the whole solution methodology just follows that of the traditional UC problem [126].

3.2.5 Load Recovery Scheduling

In addition to a self elasticity effect, it is important to consider suppression of load at one time and reappearance at another, through a cross elasticity effect. This is particularly important because industrial customers, as prospective participants in the demand reduction bid scheme, cannot reduce their load on a regular daily basis without load recovery, otherwise their profits could suffer.

DSB driven load reductions could be followed by load recovery [82], which changes the load profile of the customer either before or after the exercise. But some load may not be recovered because the customers affected are not able or willing to use that part of electricity again in future. Hence, not all of the load reduced in previous hours must be recovered completely in the following hours. Different scenarios with different load reduction and recovery schemes can be set up for study purposes. The conventional Lagrangian Relaxation method is extended to take into account the effects of load recovery on the market clearing price in this chapter.

It is assumed that all the load reduction will be recovered in the following periods after load is reduced and a reduction of one unit of energy in the gross demand over any period of one hour requires an increase in demand over the following two or

four hours. Thus the total energy consumed (say over a day) remains constant. An example is given here. If the amount of load reduction is required in two successive periods, the total change is the sum of the individual load changes A and B (A and B could be thought of as two DSBs), which are depicted in Figure 3.5 A and B. The sum of the load elements in each column over the study time is equal to zero, as the total energy consumed remains unchanged by the assumption. It can be seen that the net reduction is only 3.5 units in gross demand, as a result of the overlap of load reduction of B and load recovery of A shown in Figure 3.5 C. A negative value of the load amount, e.g. -0.5, means the load is reduced by 0.5 MW and a positive value means the load is recovered.

3.3 UC Simulation Results Incorporating DSB

The proposed method has been tested on the 32-unit IEEE reliability test system data listed in Appendix [127]. For simplicity, hydro generators are not considered here. The IEEE reliability test system contains a load model, generation system and transmission network that can be used to test any developed power applications. The UC data in Appendix were obtained from [128, 129].

The unit polynomial cost curves in [128, 129] are replaced by three-segment linear offered cost curves. The P^{min} and P^{max} values are the MW start point of segment 1 and the MW end point of segment 3 respectively. The two elbow points for the three-segment linear curve are computed by dividing the difference between the P^{min} and P^{max} values into three equal segments.

The original demand curve modeled without DSB is given in Appendix. In order to illustrate the effect of DSB, the demand curve was altered during hour 10 and hour 11. The altered demand curve is also given in Appendix. The UC time interval is taken as 1 hour with generation scheduling assumed to be a day ahead. The DSB data are given in Appendix. Due to data confidentiality and difficulties in obtaining the demand reduction bid data from the real market, the DSB data are obtained by referring to DSB prices from limited resources [51, 68], and by creating suitable system operation condition for the study purpose.

The software packages for the proposed problem are written in FORTRAN 90 and tested in Compaq Visual Fortran Developer Studio on PC.

3.3.1 Base Case—Results without DSB

In order to illustrate that DSB has an influence on the Pool market solution, some results without DSB are first presented. Two load profiles are used to test the problem without DSB and with price bids from suppliers.

➤ Results with Original Demand Curve

The UC with all those constraints mentioned in Section 3.2.2 is solved. It takes 2 seconds of computing time to run and a total offered cost of \$764,138.37 is obtained. The feasible solution is found at iteration 61 with a duality gap of 0.49%.

The UC solution for the original demand curve is shown in Table 3.1. The numbers, 1 and 0, in Table 3.1 represent on and off state of units at different hours. Hour 0 represents the initial condition. Units 17-20 and 24-26 in Table 3.1 constitute the base load units that are responsible for a large portion of system generation because of their low incremental price. The peaking units such as Units 1-9 are committed or decommitted to satisfy variable load demands. It can be seen that Unit 9 is not selected at all in the original load case because of its expensive price.

➤ Results with Altered Demand Curve

To study the impact of DSB on the scheduling of units and total cost, an altered demand curve as given in Appendix is used. It is assumed that hours 10 and 11 are the peak load periods. Table 3.1 shows the results with the altered demand if the bold and italic numbers for Unit 9 are changed from 0 to 1 at hours 10 and 11. This time, Unit 9, the most expensive unit, has to be selected to satisfy the increase in load during hours 10 and 11 though it is not used in the original load curve case. At this time the total offered cost increases to \$773,001, which is \$8,863 higher than that of the original load curve case. The UC run with the altered demand curve is referred to as the Base Case in this chapter.

Table 3.1 UC schedule for 26-unit system without DSB

Unit Number	Hour 0	Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
6	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
7	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
8	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
15	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
16	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
22	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
23	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
24	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
25	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
26	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

3.3.2 Results with Single DSB Agent

This section shows the results with only one demand-side agent. This time three different cases are compared. The first case (Case I) includes DSB with load reduction but without load recovery. The second case (Case II) considers load recovery but set the recovery in the next two hours immediately after load reduction. The third case (Case III) makes load recovery follow load reduction immediately in four sequential hours. The total cost, hourly cost, MCP, UC schedule and hourly profit of GENCOs are shown in Tables 3.2 and 3.4.

Table 3.2 gives the UC schedule for Cases I and III. If the status of Unit 8 at hours 10 and 11 are changed to 1 (on) with the others untouched, then the UC schedule for Cases II is obtained. This means that the schedule difference between Case II and Cases I and III is that the status of Unit 8 in Case II is 1, but in Cases I and III it is 0 (off). This indicates that the load recovery in two sequential hours will result in Unit 8, the second most expensive unit, be selected during the peak load period.

This is because of the overlap of load reduction and load recovery. From Table 3.4, under the columns “Load Reduction” and “Load Recovery” for Case II, there is a load reduction of 12 MW at hour 11, while at the same time there is a load recovery of 6 MW following the load reduction at hour 10, so the net reduction at hour 11 is only 6 MW. In Case III, load reduction at hour 11 is 12 MW and load recovery is 3 MW, so the net reduction is 9 MW. It is this 3 MW difference between the Case II and Case III that results in the selection of Unit 8 at hours 10 and 11 in Case II and hence the increase of cost. Comparing Tables 3.1 and 3.2, it can be seen that the status of Units 6-9 will be on for a longer time in the Base Case, i.e. without DSB than those of Cases I-III with DSB. From Table 3.4, the results confirm that the total cost with DSB is lower than that without DSB. And load recovery immediately after load reduction in the next four consecutive hours will result in a lower cost than load recovery immediately after load reduction in the next two consecutive hours. Compared with the results of the Base Case without DSB, the results of Cases I-III with DSB indicate that the profits of GENCOs decrease significantly, together with the decrease of MCP, which explains why the GENCOs’ profits are eroded.

Table 3.2 UC schedule for 26-unit system with single DSB agent

Unit Number	Hour 0	Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
6	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
15	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
16	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
22	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
23	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
24	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
25	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
26	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

In Table 3.4, load changes, hourly costs, profits and MCPs of the Base Case and Cases I-III with single DSB agent over the 24-hour study period are given. The total values of load, cost and profit are calculated and given in the bottom row of Table 3.4. The amount of load reduction and load recovery are also given in Table 3.4.

3.3.3 Results with Multiple DSB Agents

The proposed method in this thesis can yield solutions not only for one demand-side agent as discussed in Section 3.3.2, but also for multiple demand-side agents. Cases I-III as described in Section 3.3.2 are repeated under the same scenarios as three different Cases IV-VI here for multiple demand-side agents. Tables 3.3 and 3.5 give the UC schedule and other load, cost and profit results for all these different cases. Table 3.3 is the UC schedule for Cases IV and VI. And the UC schedule for Case V is obtained by changing the status of Units 7 and 8 at hour 11 from 0 to 1, i.e. they are on in Case V and they are turned off in Cases IV and VI. Comparing Tables 3.1 and 3.3 and as mentioned in Section 3.4.2, Units 6-9 will be on for a longer period in the Base Case than those Cases IV-VI with multiple DSB agents.

Table 3.3 UC schedule for 26-unit system with multiple DSB agents

Unit Number	Hour 0	Hour																							
		1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
1	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
2	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
3	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
4	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
5	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
6	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
11	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
12	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
13	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
14	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
15	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
16	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0
17	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
18	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
19	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
20	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
21	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
22	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
23	0	0	0	0	0	0	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	0	0
24	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
25	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
26	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1

Table 3.4 Load changes, offered cost, profit, MCP comparison with single agent

Hour	Load (MW)			Load Reduction (MW)			Load Recovery (MW)			Offered Cost (\$)			MCP (\$/MWh)			Profit (\$)				
	Base Case	Case I	Case II	Case III	Case I	Case II	Case III	Case I	Case II	Case III	Base Case	Case I	Case II	Case I	Case II	Case III	Base Case	Case I	Case II	Case III
1	1700	1700	1700	1700	0	0	0	0	19120	19008	19008	19008	19008	36	36	36	42392	41816	41816	41816
2	1730	1730	1730	1730	0	0	0	0	19534	19485	19485	19485	19485	36	36	37	43064	43419	43801	43419
3	1690	1690	1690	1690	0	0	0	0	18988	18978	18978	18978	18978	36	36	37	42163	42471	42844	42471
4	1700	1700	1700	1700	0	0	0	0	19120	19099	19151	19099	19099	36	36	37	42392	42714	43037	42714
5	1740	1740	1740	1740	0	0	0	0	19698	19633	19633	19633	19633	36	36	37	43262	43634	44018	43634
6	1900	1900	1900	1900	0	0	0	0	21954	21880	21880	21880	21880	36	36	37	46795	47205	47625	47205
7	2000	2000	2000	2000	0	0	0	0	24385	23868	23868	23868	23868	36	36	37	47983	48853	49294	48853
8	2430	2430	2430	2430	0	0	0	0	36441	35890	35890	35890	35890	62	36	37	113634	52466	53003	52466
9	2540	2540	2540	2540	0	0	0	0	37462	36914	36914	36914	36914	62	36	37	119407	55442	56003	55442
10	2790	2778	2778	2778	12	12	12	0	44004	42862	42888	42862	42862	62	45	45	128305	81343	81711	81343
11	2800	2788	2794	2791	12	12	12	6	44345	43161	44043	43275	43275	62	45	45	128240	81691	81274	81712
12	2590	2590	2602	2596	0	0	0	12	6	38662	38100	39245	38243	62	36	37	121294	56073	55940	56149
13	2590	2590	2596	2596	0	0	0	6	6	38662	38100	38671	38243	62	36	37	121294	56073	56294	56149
14	2550	2550	2550	2556	0	0	0	0	6	37714	37151	37293	37293	62	36	37	119773	55569	56132	55645
15	2620	2620	2620	2623	0	0	0	0	3	39376	38814	38814	38886	62	36	37	122433	56450	57028	56487
16	2650	2650	2650	2650	0	0	0	0	0	40093	39531	39531	39531	62	36	37	123569	56824	57409	56824
17	2550	2550	2550	2550	0	0	0	0	0	37714	37151	37151	37151	62	36	37	119773	55569	56132	55569
18	2530	2530	2530	2530	0	0	0	0	0	37240	36677	36677	36677	62	36	37	119011	55315	55874	55315
19	2500	2500	2500	2500	0	0	0	0	0	36574	36011	36011	36011	62	36	37	117824	54890	55442	54890
20	2550	2550	2550	2550	0	0	0	0	0	37714	37151	37151	37151	62	36	37	119773	55569	56132	55569
21	2600	2600	2600	2600	0	0	0	0	0	38900	38338	38338	38338	62	36	37	121674	56199	56773	56199
22	2480	2480	2480	2480	0	0	0	0	0	36102	35538	35538	35538	62	36	37	117061	54636	55184	54636
23	2200	2200	2200	2200	0	0	0	0	0	28117	27914	27914	27914	36	36	37	51487	52079	52565	52079
24	1840	1840	1840	1840	0	0	0	0	0	21079	21106	21020	21020	36	36	37	45499	45797	46289	45883
Total					24	24	24	24	24	773001	762358	764948	762885				2218100	1292095	1301619	1292466

Table 3.5 Load changes, offered cost, profit, MCP comparison with multiple agents

Hour	Load (MW)			Load Reduction (MW)			Load Recovery (MW)			Offered Cost (\$)			MCP (\$/MWh)			Profit (\$)		
	Base Case	Case IV	Case V	Case VI	Case IV	Case V	Case VI	Case IV	Case V	Case VI	Case IV	Case V	Case IV	Case V	Case VI	Case IV	Case V	Case VI
	Base Case	Case IV	Case V	Case VI	Case IV	Case V	Case VI	Case IV	Case V	Case VI	Case IV	Case V	Case IV	Case V	Case VI	Case IV	Case V	Case VI
1	1700	1700	1700	1700	0	0	0	0	0	19120	19008	19008	36	36	36	42392	41897	41897
2	1730	1730	1730	1730	0	0	0	0	0	19534	19485	19485	36	37	37	43064	43909	43909
3	1690	1690	1690	1690	0	0	0	0	0	18988	18978	19030	36	37	37	42163	42950	42950
4	1700	1700	1700	1700	0	0	0	0	0	19120	19099	19099	36	37	37	42392	43195	43195
5	1740	1740	1740	1740	0	0	0	0	0	19698	19633	19633	36	37	37	43262	44127	44127
6	1900	1900	1900	1900	0	0	0	0	0	21954	21880	21880	36	37	37	46795	47743	47743
7	2000	2000	2000	2000	0	0	0	0	0	24385	23868	23868	36	37	37	47983	49420	49420
8	2430	2430	2430	2430	0	0	0	0	0	36441	35890	35890	62	37	37	113634	53155	53155
9	2540	2540	2540	2540	0	0	0	0	0	37462	36914	36914	62	37	37	119407	56162	56162
10	2790	2766	2766	2766	24	24	24	0	0	44004	42168	42168	62	45	45	128305	81120	81120
11	2800	2776	2788	2782	24	24	24	6	6	44345	42447	43860	62	45	45	128240	81288	81613
12	2590	2590	2602	2596	0	0	0	12	12	38662	38100	39818	62	37	37	121294	56808	56962
13	2590	2590	2596	2596	0	0	0	12	12	38662	38100	38958	62	37	37	121294	56808	56962
14	2550	2550	2550	2556	0	0	0	12	12	37714	37151	37151	62	37	37	119773	56291	56447
15	2620	2620	2620	2623	0	0	0	6	6	39376	38814	38958	62	37	37	122433	57192	57269
16	2650	2650	2650	2650	0	0	0	0	0	40093	39531	39531	62	37	37	123569	57575	57575
17	2550	2550	2550	2550	0	0	0	0	0	37714	37151	37151	62	37	37	119773	56291	56409
18	2530	2530	2530	2530	0	0	0	0	0	37240	36677	36677	62	37	37	119011	56032	56032
19	2500	2500	2500	2500	0	0	0	0	0	36574	36011	36011	62	37	37	117824	55599	55599
20	2550	2550	2550	2550	0	0	0	0	0	37714	37151	37151	62	37	37	119773	56291	56409
21	2600	2600	2600	2600	0	0	0	0	0	38900	38338	38338	62	37	37	121674	56936	56936
22	2480	2480	2480	2480	0	0	0	0	0	36102	35538	35538	62	37	37	117061	55339	55339
23	2200	2200	2200	2200	0	0	0	0	0	28117	27914	27914	36	37	37	51487	52702	52702
24	1840	1840	1840	1840	0	0	0	0	0	21079	21020	21020	36	37	37	45499	46490	46405
Total					48	48	48	48	48	773001	760950	764905	2218100	1305147	1308836			1306099

3.4 Cost/Benefit Analysis of DSB

The benefit of DSB is obviously reflected from the above results. The developed composite DSB model can be used for (i) a comprehensive evaluation of possible scenarios during the implementation of DSB in the electricity market and (ii) the assessment of the impact of DSB on total offered costs, MCP profile and benefit allocation between producers and consumers.

It is noted that DSB is not effective at all times. In the studies, the demand reduction bids are selected only during peak load periods. The reason is during peak load periods the price is very high. The total cost of dispatching the demand reduction bids is lower than that of scheduling the most expensive units to satisfy the demand. Conversely, demand-side agents are not selected at all during non-peak-load periods. The market is cleared as usual and all the customer demands are satisfied without load reduction.

To support the above discussion and to study the efficiency of DSB, both the single demand-side agent and multiple demand-side agents are tested and analyzed. It is assumed that: (i) the DSB can reduce load no less than the maximum output of the marginal generator (in this case is 20 MW, Unit 9's maximum output) that supplies the peak periods (hours 10 and 11); (ii) energy that is reduced during the load reduction period will be recovered by an increased consumption over an assumed period (2 hours and 4 hours after the reduction); and (iii) the total energy not produced at peak is recovered.

3.4.1 Single Demand-Side Agents

In this case, only one demand-side agent is selected to show how DSB affects the generation scheduling, as well as the MCP and profits of GENCOs. The variation of the MW output and cost of each unit between the without and with DSB is also analyzed. Because Case I only includes load reduction and does not include load recovery, the total load over 24 hours, the total cost and profits of GENCOs will certainly be lower than those of the other three cases. Thus only the Base Case, Cases

II and III are compared here. Figure 3.6 shows the comparative results of hourly cost over a 24-hour period for the Base Case, Cases II and III considered earlier. From this Figure, it is obvious that the hourly offered cost with DSB and load recovery during hours 10 and 11 is reduced when compared to that of the Base Case. But it can also be noted that the reduction of hourly cost is not so significant due to the fact that the load reduction is little. In addition, the cost of Case II at hour 12 is higher than that of the Base Case and Case III. The reason is that there is a 12 MW load recovery for Case II. The difference in the hourly cost between the Base Case and Case II is \$8,053.4, while that in Case III is \$10,115.8, as a result of load redistribution. The benefit of DSB is, therefore, \$8,053.4 (Case II) or \$10,115.8 9 (Case III.), which is the amount that the DSB could save due to the reduced cost.

Figure 3.6 Hourly offered costs with and without DSB (single agent)

The changes are substantial with respect to MCP profile and profits of GENCOs, which can be obviously seen from Table 3.4, Figures 3.7 and 3.9. It is noted from Figure 3.7 that the MCP of Base Case (without DSB) is much higher than those of Cases II and III (with DSB) from hour 8 to 22. This can be explained by the UC schedule in Tables 3.1 and 3.2. Units 6 to 8 are all decommitted from hour 8 to 22 in the case with DSB except hours 10 and 11. Hence, MCPs from hour 8 to 22 are reduced drastically because the marginal unit which sets the MCP is no longer those of the most expensive units (Units 6-8) and has since been replaced by cheaper units. It should be noted that the MCP for the with DSB remains fairly high at hours 10 and 11. The load redistribution is depicted in Figure 3.8. From Figure 3.8, the load is reduced during the peak load at hours 10 and 11. And it is recovered in the following periods when the load demand is not so high. The total load over the 24-hour period

remains unchanged. This rearrangement of load not only results in a lower total cost, but also significantly reduces the MCP and profit of GENCOs. Although the load reduction is not large, only 24 MW over the two peak load hours 10 and 11, it removes the most expensive Unit 9 completely, because the generation of Unit 9 is small, 5.747 MW at hour 10 and 10.161 MW at hour 11. Thus the MCP reduces greatly from 61.76 \$/MWh to 44.57 \$/MWh during the peak load periods. The profit here is calculated by revenue minus the cost of GENCOs and the revenue is calculated by MCP times MW output. So the profits of GENCOs are reduced significantly at the same time due to the reduction of MCP. The total cost and profit are reduced after incorporating DSB, which can be seen from the bottom row of Table 3.4.

Figure 3.7 MCP profile with and without DSB (single agent)

Figure 3.8 Hourly loads with and without DSB (single agent)

Table 3.6 shows the comparison for unit's total MW output over 24 hours. For the sake of clarity, only those units with the major MW changes are shown here. Compared with the Base Case, the most expensive Unit 9 is removed completely in the other three cases with DSB. The situation of Unit 8 (the second expensive unit) is a little different. It is removed in Cases I and III, but is selected to produce 8 MW in Case II. This is because of the overlap of load reduction and load recovery at hour 11. The load reduction is 12 MW at hour 11, while the load recovery is 6 MW, so the net reduction is 6 MW in Case II. Similarly, it can be calculated that the net reduction at hour 11 is 12 MW in Case I and 9 MW in Case III. This very little MW difference results in the selection of Unit 8 and the increase of total cost and MCP in Case II. In addition, the generation of each unit is rearranged due to the load reduction. The outputs of Units 6 and 7 (the other two less expensive units compared to Units 8 and 9) decrease significantly while the output of the cheapest Unit 25 increases. For example, in Case II, the total output reduction of Units 6-9 is 216.58 MW while the increase in output of Unit 25 is 213.05 MW. The same analysis can be done for Cases I and III.

Table 3.6 Unit output comparison with single agent

Unit number	Total output over 24-hour (MWh)			
	Base Case	Case I	Case II	Case III
...	...	...	...	...
6	81.83	24.00	17.42	24.00
7	81.59	17.66	13.33	20.66
8	76.00	0.00	8.00	0.00
9	15.91	0.00	0.00	0.00
...	...	...	...	...
25	8885.80	9088.68	9098.85	9104.68
...	...	...	...	...

For the implementation of the DSB scheme, however, a mechanism for the payment allocation to DSB needs to be defined. In this thesis, a possible scenario that DSBs would be paid their bid prices is suggested. Under the pool operation, the payment would be collected from other customers, by a corresponding increase in uplift over the reduction period, while the MCP would be determined as before by the generator incremental cost and start-up cost as well as the no-load cost which are spread over the whole running period.

The DSB scheme results in a major change in benefit allocation due to the changes in MCP and because generators make the largest proportion of their profit during the peak periods. This situation is depicted in Figure 3.9. The total decrease in profit, as a result of incorporation of DSB, is \$916,481 with load recovery in two hours and \$925,634 with load recovery in four hours. The reduction in profit is significantly larger than the reduction in cost. From the demand-side point of view, the benefit of DSB would correspond to \$916,481 and \$925,634, which resulted from a huge reduction in MCP. And all the customers can benefit from this huge reduction in MCP although the pool cost saving is not so significant.

Figure 3.9 Supply side profits with and without DSB (single agent)

3.4.2 Multiple Demand-Side Agents

In order to study the efficiency of DSB, Cases IV-VI with multiple demand-side agents participation are tested and analyzed too. With the same analysis as in a single agent, similar results can be obtained for multiple agents, and they are shown in Figure 3.10 to Figure 3.13. The difference in total cost between the Base Case and Case V is \$8,096 and \$10,911.5 in Case VI. It can be seen that the reduction of total cost with multiple agents is larger than that of single agent. With more agents participating in DSB, more loads can be reduced during peak periods and recovered in other periods which have lower load demand. In this case, the load reduction is 48 MW. While in the single agent case, it is only 24 MW. As in the single demand-side agent, the reduction in cost is not so significant as that in profit. It can be seen from

Table 3.5, Figure 3.10 and Figure 3.13 that the reduction of profit in cases with multiple demand-side agents is much larger than that with a single demand-side agent.

Table 3.7 shows the total MW output comparison of each unit and it shows only those units with major MW changes. It can be seen that in multiple agents cases, the expensive Units 6-9 produce even less output compared with those units with a single agent in Table 3.6.

Table 3.7 Unit output comparison with multiple agents

Unit number	Total output over 24-hour (MWh)			
	Base Case	Case IV	Case V	Case VI
...	...	...	...	...
6	81.83	12.92	8.00	18.92
7	81.59	0.00	4.00	0.00
8	76.00	0.00	4.00	0.00
9	15.91	0.00	0.00	0.00
...	...	...	...	...
25	8885.80	9098.51	9101.79	9114.51
...	...	...	...	...

Figure 3.10 Hourly costs with and without DSB (multiple agents)

Figure 3.11 Load changes with and without DSB (multiple agents)

Of course, not all of the load which was reduced in previous hours must be recovered completely in the following hours. Some load need not be recovered because some customers may not use that part of electricity again in future. It is possible that only 80 percent or even 50 percent of load reduction needs to be recovered and/or load recovery can occur before load reduction. Hence, different scenarios with different load reduction and recovery schemes can be set up.

Figure 3.12 MCP profile with and without DSB (multiple agents)

Figure 3.13 Supply side profits with and without DSB (multiple agents)

3.5 Extended Analysis for Effect of DSB on MCP

Following the description of the market clearing process in Section 3.2.2, a market clearing study is examined further in this section. Even more case studies performed demonstrate that, in general, DSB aids in reducing MCP but there are times the value of DSB is affected when offers of inflexible units are replaced by higher demand reduction bids. The results also indicate that while load recovery addresses customer needs, it reduces the value of DSB. Hence, the influence of DSB on MCP, GENCOs' profits, and pool cost including the effects of load recovery, unit minimum output and minimum up time on MCP is analyzed in this section extensively.

3.5.1 Effect of Minimum Output (P^{min}) and Minimum Up Time (T^{on})

It is understood that not every deregulated market requires the submission of the unit operating limits, such as minimum output and/or minimum up time, as part of the generator's bid data. However, in the UK power pool and NYISO, minimum up time is still required for the market operator, and minimum output bids are also required by PJM-ISO. Hence, the effect of minimum output and minimum up time on the market clearing process is examined further in this section because they can impact MCP significantly.

As observed before, DSB may bring customers benefits by reducing market price. However, when DSB agents are selected to replace generators with high minimum output [79] or high minimum up time, DSB could increase market price on the contrary. These high minimum output and/or high minimum up time can make the generator very inflexible. DSB is flexible since it does not have these constraints and hence may be selected by the full Lagrangian Relaxation scheduling program to replace an inflexible generator even though the bid price of DSB is high. The developed scheduling tool is used to demonstrate (i) how a flexible DSB may compete favorably with an inflexible generator and (ii) that minimizing the cost of a schedule does not always result in a minimum price. Figure 3.14 shows the market clearing process under this scenario.

Figure 3.14 Market cleared with high DSB price

If the minimum output or minimum up time constraints are not violated, then the market clearing process in Figure 3.14 is the same as that of Figure 3.4, i.e. MCP will be at Point 3. If the constraints are violated, the market may be cleared at Point 4. The stair dash curve in Figure 3.14 denotes the original composite bids from generators with high minimum output/up time. Based on the objective function, load reduction is performed to obtain the optimal solution, but this time these generators' minimum output/up time constraints could not be satisfied. Hence, to ensure a feasible

MCP solution without the minimum output/up time constraint violation, the price offers of those inflexible generators are not selected by the scheduling process and the new supply bid curve is set up as in Figure 3.14 with other generators bids which satisfy the minimum output/up time requirement. This new supply curve intersects with the DSB curve at Point 4. The marginal inflexible generators with high minimum output/up time are replaced by the selected DSB agents. The removal of inflexible generators results in the MCP at Point 4, which is much higher than that at Point 3 and even higher than that at Point 1 without DSB. Note that when the MCP is cleared at Point 4 instead of Point 3, the global social welfare is reduced by the size of Area 4. For the load reduction to proceed, the size of Area 4 must be less than that of Area 1 in Figure 3.14. This results in a lower pool cost.

Another possible solution is to commit the next generator in the priority list to produce electricity and to balance the supply and demand. Of course, this happens if the bid price of this generator is lower than that of demand-side agent selected at Point 4 of Figure 3.14. The market will be cleared at Point 5 in Figure 3.15, and again the load reduction can only be performed if the size of Area 4 is less than that of Area 1.

Figure 3.15 Market cleared with high generator price

3.5.2 Simulation Results

Some results have been given in Section 3.3 as well as the cost/benefit analysis of the effect of DSB. Proceeding with this study, more cases are further carried out and compared in this section. The Base Case here is the same as that in Section 3.3, which is the without DSB.

To test the effect of P^{min} and T^{on} , Cases VII, VIII, IX and Cases X and XI are run respectively. Tables 3.8-3.9 provide the DSB data and data that are modified from the original input case given in Appendix, while Tables 3.10-3.13 show the output results.

Table 3.8 Demand-side bidding data

DSA	Q_j^{min} (MW)	$EL1_j$ (MW)	$EL2_j$ (MW)	Q_j^{max} (MW)
1	0	8	16	24
2	0	10	20	30
Demand-side bids (\$/MWh)				
Base Case	DSA1	97.4830	97.7670	97.9010
	DSA2	102.0340	102.6530	103.1100
Case VII	DSA1	97.4830	97.7670	97.9010
	DSA2	102.0340	102.6530	103.1100
Case VIII	DSA1	77.4830	77.7670	77.9010
	DSA2	87.4830	87.7670	87.9010
Case IX	DSA1	104.0210	104.5670	104.9010
	DSA2	112.0340	112.6530	113.1100
Case X	DSA1	56.7918	56.9673	57.2012
	DSA2	65.4839	74.7673	74.9012
Case XI	DSA1	57.4218	65.5673	65.9012
	DSA2	65.4839	74.7673	74.9012

Table 3.9 P^{min} and T^{on} of different cases

Unit Number	P^{min} (MW)				T^{on} (h)		
	Base Case	Case VII	Case VIII	Case IX	Base Case	Case X	Case XI
8	4	4	4	4	0	0	3
9	4	6	6	8	0	3	3

In the Base Case in Table 3.9, the P^{min} of Units 8 and 9 is 4 MW. Both Units 8 and 9 in Table 3.10 are scheduled at hours 10 and 11. In Case VII of Table 3.9, the P^{min} of Unit 9 is increased to 6 MW with all the other input data unchanged. This results in the removal of Unit 9 at hours 10 and 11 in Table 3.10 and the selection of DSA at hour 11 in Table 3.11.

Table 3.10 UC schedule of different cases

Unit Number	UC schedule of hours 10 & 11					
	Base Case	Case VII	Case VIII	Case IX	Case X	Case XI
8	1 1	1 1	1 1	1 1	1 1	0 0
9	1 1	0 0	0 0	0 0	0 0	0 0

1-Scheduled 0-Not Scheduled

Table 3.11 DSA selection of different cases

DSA	DSA selection of hours 10 & 11					
	Base Case	Case VII	Case VIII	Case IX	Case X	Case XI
1	0 0	0 1	1 1	1 1	1 1	1 1
2	0 0	0 0	0 0	0 0	0 0	0 0

As shown in Table 3.12, the marginal unit at hour 10 in Case VII is Unit 8 and in Table 3.13 the corresponding MCP (44.93 \$/MWh) is a little lower than that of the Base Case (44.99 \$/MWh). This is because MCP here is calculated as the hourly marginal highest bid price accepted by the pool plus the start-up and no-load price spread over the running time. Since Unit 9 is not scheduled at hour 10 in Case VII due to the high P^{min} , so the start-up price of Unit 9 is not included. Hence, this results in a little lower MCP at hour 10. But at hour 11, the marginal price is determined by DSA1 and the MCP increases to 97.48 \$/MWh.

When DSA1 bids at a lower price as in Case VIII of Table 3.8, it will be selected at both hours 10 and 11. The MCP is 77.77 \$/MWh which is lower than 97.48 \$/MWh but still much higher than 44.99 \$/MWh of the Base Case. DSAs may bid into the pool strategically and result in a sharp and unwarranted price increase. If the generator has a high P^{min} , it may be removed from the schedule by a marginal DSA. DSAs may actually increase MCP, although the overall pool cost is reduced. For

example, in Case IX of Table 3.9, the high P^{min} of Unit 9 (8 MW) makes it rather inflexible and it is eventually replaced by DSA1. Hence, the MCP in Table 3.13 reaches an even higher value of 104.02 \$/MWh as dictated by DSA1 of Table 3.8.

Table 3.12 Marginal unit of different cases

Hour	Base Case	Case VII	Case VIII	Case IX	Case X	Case XI
10	9	8	DSA1	DSA1	DSA1	DSA1
11	9	DSA1	DSA1	DSA1	DSA1	DSA1

Table 3.13 SMP of different cases

Hour	Base Case	Case VII	Case VIII	Case IX	Case X	Case XI
10	44.99	44.93	77.77	104.02	56.79	57.42
11	44.99	97.48	77.77	104.02	56.79	57.42

Similarly, when T^{on} of Unit 9 is increased to 3 hours in Case X of Table 3.9, it is replaced by DSA1 as in Table 3.12. Both Units 8 and 9 are removed in Case XI of Table 3.10 when their T^{on} is increased to 3 hours. But the MCP (56.79 \$/MWh in Case X and 57.42 \$/MWh in Case XI) are higher than that of the Base Case (44.99 \$/MWh). All these results confirm the belief that sometimes DSB may cause an unwarranted increase of MCP. Although the price of the inflexible generator may be lower than that of DSB, it cannot be selected by the market clearing algorithm due to other unit physical constraints. Hence, the value of DSB should be carefully assessed in the actual operation of power markets.

3.6 Summary

Restructuring of the electricity industry involves a transition from natural monopolies with centralized planning to markets that are subject to competition. Although the benefits come with some turmoil in the process of restructuring, it can be safely said that deregulation of the electric power industry has come to stay and the way the power industry is operated will never be the same again. This raises a whole new set of problems and issues that will be a challenge especially in the area of generation scheduling and market pricing.

In addition, new market solution analysis tools need to be developed to include the uncertainties of the market and to enable the application of generation scheduling techniques for the benefit of both the customers and suppliers.

In this chapter, a market clearing study is examined by incorporating DSB where customers are allowed to submit load reduction bids. The relationship between the bulk purchase and load reduction bids is presented. A Lagrangian Relaxation optimization method is developed to simultaneously clear generation and demand reduction bids, while maximizing the overall benefits for market participants. With the proposed model and methodology, the influence of DSB on generation scheduling, total offered cost, profit of GENCOs and MCP are analyzed. Figure 3.16 illustrates the effect of DSB on the MCP determination process. It can be seen that DSB effectively introduces elasticity into the demand side in the price determination process, leading to the MCP of P_{dsb} , which is lower than the P_{mcp} set by an inelastic demand. This has been proven by the results shown in Tables 3.4 and 3.5.

The effect of load recovery is analyzed in this chapter. It is pointed out that conventional scheduling programs ignore the impact of load recovery. Since producing this recovered energy has a cost, load reduction of DSB without consideration of load recovery may artificially enhance the value of the demand-side bids from the scheduler's perspective. The results also indicate that while load recovery addresses customer needs, it reduces the value of DSB.

Figure 3.16 The effect of DSB on the MCP

Furthermore, it is demonstrated in this chapter that flexible DSB is likely to be competitive when compared with inflexible generators from the total cost minimization point of view. The effects of P^{min} and T^{on} are analyzed. Some demand-side bids will be selected even if their actual value (i.e. their contribution to the global social welfare) is smaller than the value of competing generation bids. This means that due to some unit physical constraints such as P^{min} and T^{on} , the demand reduction bids may be selected. This will cause sharp and unwarranted increases in electricity prices if the UC schedule is based on minimization of the total schedule costs. This is not necessarily in the best interest of consumers. Hence, it is concluded that under certain conditions the value of DSB should be quantified carefully in this regard.

Chapter 4

Probabilistic Reserve with Demand-Side Participation

4.1 Introduction

The assessment and allocation of spinning reserve are important aspects for consideration in short-term generation scheduling. Spinning reserve is required for a power system to handle unforeseen sudden increases in load and any possible outages of generating units. There are two techniques for reserve management. One is the widely used deterministic criterion. The other is the probabilistic criterion, which takes different unit order outages (multiple unit contingencies) into consideration by calculating the *LOLP* or the *EENS* [130]. Scheduling spinning reserve based on a deterministic approach is easy to implement, however, it does not match the stochastic nature of the problem and does not provide a means to assess the system risk.

In the restructuring competitive electricity market, risk assessment is increasingly used to reflect the electricity price and the risk that the customer is exposed to. The probabilistic approach is normally used due to forecast uncertainties and the random nature of outage events. In order to achieve a high reliable power system, an increase in schedule cost is expected to maintain a substantial amount of spinning reserve in the system. But this does not mean that it is always worth to keep a substantial amount of reserve at the expense of the benefit it provides to customers. The purpose of reserve is not to reduce the risk of loss of load below some arbitrary level but to minimize customer outages at an acceptable and justifiable cost. Reserve

should be increased until its marginal cost exceeds the benefit it provides. The marginal cost of reserve should therefore be compared to the cost *EENS*.

In Chapter 2, the concept of probabilistic reliability criteria and the problem of how to balance the reliability cost and reliability worth are reviewed. Based on the market model set up in Chapter 3, a probabilistic reserve assessment was implemented to achieve an optimal scheduling of spinning reserve by a balance between the cost of carrying the reserve and the expected cost of energy not served. This balance point is known as the optimal risk index as far as reserve scheduling is concerned. The risk index denotes system risk. It is calculated as the *LOLP*. The demand reduction bid is incorporated in the market model and the objective function. The influence of demand reduction bid on the optimal scheduling process, the pool schedule cost, *EENS* and the optimal operating point is analyzed in both the with and without demand reduction bid scenarios. The market model is modified by scheduling the hourly reserve and energy simultaneously. The cost of *EENS* is added to the schedule cost to obtain an overall optimal operation point for the system.

4.2 Probabilistic Reserve Assessment

4.2.1 Probabilistic Spinning Reserve Scheduling

An optimal spinning reserve scheduling which integrates a probabilistic reserve assessment in the UC function has been proposed in [5]. The reliability of individual scheduled units and the uncertainties of the load forecast are considered for the price-based UC. The generation is scheduled to meet a given risk index. Based on this study [5], DSB is incorporated in the market clearing process.

The probabilistic reserve assessment begins after a feasible UC schedule at minimum cost has been found. Figure 4.1 illustrates the algorithm for the probabilistic spinning reserve scheduling. It is separately considered for each scheduling interval. According to the units committed in this interval, the COPT is formed [101]. The system risk is calculated for each commitment pattern in the schedule and it is then

compared to the given acceptable risk index. The spinning reserve requirement is updated when necessary. Further iterations of UC are performed until the risk indices for each interval satisfies the given acceptable risk index.

Figure 4.1 Probabilistic reserve assessment

4.2.2 Capacity Outage Probability Table

As initially defined in [101], COPT is simply an array of capacity levels and the associated probabilities of existence. Theoretically the capacity outage probability table incorporates all the unit capacities. The probability of the actual load being less than the scheduled system capacity due to the failure or deration of Unit i depends on the unit's failure rate and the time taken to replace the lost capacity. The probability that a unit fails and is not replaced during the lead time T is known as the *ORR*. This probability is the sum of all the unit's failure or derated state probabilities. The calculation of COPT and the hourly spinning reserve schedule are using the same way as described in [5].

4.2.3 Expected Energy Not Supplied

The concept of *EENS* was originally formulated for long-term planning studies. It is used in this study to determine how many MWs would have to be disconnected in the event of capacity outage, and for how long that disconnection would take place. Hence, *EENS* for the commitment period must first be quantified.

Assuming that the scheduled units are actually running at the beginning of each hour and that the demand was constant for the lead time of the marginal unit, *EENS* for each hour of the schedule is calculated independently.

EENS is calculated by convolution of the MW capacity outage probability distribution function with the number of MWs of energy that would have to be shed for the duration of the MW shortfall [5, 101]. *EENS* is obtained for each interval of the UC schedule as follows:

$$EENS_t = \sum_{k=1}^m E_k * p_k \quad (E_k : \text{energy not supplied for state } k; p_k : \text{probability for state } k)$$

where

m = All the possible states for different unit capacity at period t .

E_k = Energy that might be on outage for state k .

p_k = Probability for state k in which this amount of energy will not be supplied. Its value is obtained from the capacity outage probability table (COPT) [5].

4.2.4 Optimal Risk Index

A system will suffer considerably when units fail, and spinning reserve becomes very important at this time. But to maintain a substantial amount of spinning reserve in the system, the schedule cost is expected to increase. This does not mean

that it is always worth to keep a substantial amount of reserve at the expense of the benefit it provides to customers.

The purpose of reserve is not to reduce the risk of loss of load below some arbitrary level but to minimize customer outages at an acceptable and justifiable cost. Reserve should be increased until its marginal cost exceeds the benefit it provides. The marginal cost of reserve should therefore be compared to the cost of expected energy not supplied [130, 131]. So a probabilistic reserve assessment was implemented to achieve an optimal scheduling of spinning reserve by a balance between the cost of carrying the reserve and the expected cost of energy not served. This balance point is known as the optimal risk index as far as reserve scheduling is concerned.

The cost of energy not supplied is therefore computed by multiplying the *EENS* with a value of lost load (*VOLL*). *VOLL* represents the estimated average value that customers place on the loss of one kWh of electricity. It is a fixed value in this thesis and is normally obtained through customer surveys. The product of *EENS_t* and *VOLL* represents the expected cost of having to shed load due to generation outages during period *t*. The cost of load shedding is a loss to individuals and businesses as they are deprived of electricity usage.

Due to the consideration of compensating the customers for the lost load, the total cost of the pool is calculated by adding the cost of *EENS* to the schedule cost.

$$\text{Total Cost} = \text{UC Schedule Cost} + EENS * VOLL$$

$$\text{Where } EENS = \sum_{t=1}^T EENS_t$$

With the decreasing of the risk index, the UC schedule cost increases as more spinning reserves are required to meet the given risk index. Conversely, the *EENS* decreases as the system becomes more reliable based on a stricter risk index. The total cost is thus a function of the risk index. The optimal value of the risk index is determined at the minimum pool cost. This is done by achieving a balance between the cost of meeting the risk index and the expected cost of energy not served.

4.3 Simulation Results for Effect of DSB on Spinning Reserve

The input data of unit commitment remain unchanged as those in Section 3.3 of Chapter 3. With additional data for probabilistic reserve assessment are obtained from [127], the simulations are conducted for this study. The system is tested under different risk indices with different *VOLL* values. One of the weaknesses of the risk index approach to probabilistic reserve assessment is the lack of an intuitive quantifiable interpretation of the index. A cost and benefit analysis is thus given in this section to illustrate how the optimal risk index is obtained on the basis of a tradeoff between the schedule cost and the expected cost of energy not served.

Table 4.1 shows the comparison of the schedule cost and *EENS* under different risk indices between the with and without DSB. It is obvious that the schedule cost is decreasing with the increase of risk index, whilst the *EENS* is increasing. It is noted that for the without DSB, the spinning reserve requirement at a risk index of 0.019 cannot be satisfied. However, the risk index can be as small as 0.014 for the with DSB.

Table 4.1 Schedule cost and *EENS* comparison between the with and without DSB

Risk index (%)	Without DSB		With DSB	
	Schedule Cost (\$)	<i>EENS</i> (kWh)	Schedule Cost (\$)	<i>EENS</i> (kWh)
1.4	-	-	767705.4	7386.3
1.5	-	-	757144.0	9362.6
1.9	753924.1	11478.2	749268.9	11205.0
2.0	752292.6	11914.9	747357.2	11718.1
2.1	749496.8	12567.2	745836.8	12186.0
2.5	747208.5	13349.4	743364.2	13066.9
2.8	745190.5	13827.7	741726.0	13594.0
3.0	744375.6	14247.8	740945.5	13939.6
3.2	743140.5	14699.6	740037.3	14392.7
3.5	737515.2	18701.2	735637.2	18239.4

Table 4.2 is the total cost of different *VOLLs* under different risk indices for the without DSB case. Total costs in bold numbers denote the optimal balanced points. It is noted that the optimal risk index varies as a function of *VOLL*. If *VOLL* is at \$1/kWh, the optimal risk index should be set at 0.035, whereas for a *VOLL* value of

\$2/kWh, it should be increased to 0.032. It is obvious that the optimal risk index decreases when *VOLL* increases. The system runs out of capacity at a risk index of 0.019, which means that the spinning reserve requirement at this time cannot be satisfied. Hence this explains why the optimal risk index is the same even though the *VOLL*s in the last two columns of Table 4.2 are different.

Table 4.2 Cost/benefit analysis for an optimal risk index without DSB

Risk index (%)	Total cost (\$)					
	<i>VOLL</i> = \$1/kWh	<i>VOLL</i> = \$2/kWh	<i>VOLL</i> = \$3/kWh	<i>VOLL</i> = \$4/kWh	<i>VOLL</i> = \$5/kWh	<i>VOLL</i> = \$6/kWh
1.9	765402.3	776880.5	788358.7	799836.9	811315.1	822793.3
2.0	764207.5	776122.5	788037.4	799952.3	811867.3	823782.2
2.1	762064.0	774631.2	787198.4	799765.5	812332.7	824899.9
2.5	760557.9	773907.2	787256.6	800605.9	813955.3	827304.6
2.8	759018.2	772846.0	786673.7	800501.4	814329.1	828156.8
3.0	758623.4	772871.2	787118.9	801366.7	815614.4	829862.2
3.2	757840.0	772539.6	787239.1	801938.7	816638.2	831337.8
3.5	756216.4	774917.5	793618.7	812319.8	831021.0	849722.1

Table 4.3 Cost/benefit analysis for an optimal risk index with DSB

Risk index (%)	Total cost (\$)					
	<i>VOLL</i> = \$1/kWh	<i>VOLL</i> = \$2/kWh	<i>VOLL</i> = \$3/kWh	<i>VOLL</i> = \$4/kWh	<i>VOLL</i> = \$5/kWh	<i>VOLL</i> = \$6/kWh
1.4	775091.8	782478.1	789864.4	797250.7	804637.0	812023.3
1.5	766506.5	775869.1	785231.7	794594.3	803956.9	813319.5
1.9	760473.9	771678.9	782883.9	794088.9	805293.9	816498.9
2.0	759075.3	770793.4	782511.5	794229.6	805947.6	817665.7
2.1	758022.9	770208.9	782394.9	794580.9	806767.0	818953.0
2.5	756431.1	769498.0	782564.9	795631.8	808698.7	821765.6
2.8	755320.1	768914.1	782508.1	796102.2	809696.2	823290.3
3.0	754885.1	768824.7	782764.3	796704.0	810643.6	824583.2
3.2	754430.0	768822.7	783215.4	797608.1	812000.8	826393.5
3.5	753876.6	772116.1	790355.5	808594.9	826834.3	845073.8

A similar table, Table 4.3, is given below to reveal the results with DSB. This time the table includes two more rows for the cost/benefit analysis at risk indices 0.014 and 0.015. The minimum risk index which can be satisfied to meet the load

demand is 0.019 when DSB is not incorporated as in Table 4.2. After DSB is incorporated, the minimum risk index reduces to 0.014, which implies a more reliable system as a whole. The total cost is reduced when compared to the without DSB as shown in Table 4.1. This is because demand-side agents are selected to reduce their load at the peak load periods and the load reduction alleviates the burden of the system. Hence the system can provide relatively more spinning reserve at cheaper costs to achieve a more reliable system. Similarly, the bold numbers in the total cost columns denote the optimal balanced points of the system after incorporating DSB. With the increase of the *VOLL* value, the optimal risk index decreases due to the increase of the expected cost of energy not served.

In order to analyze the influence of DSB, some figures are given in the following to show the comparison of the schedule cost, *EENS* and total cost of the with and without DSB.

Figure 4.2 shows how the UC schedule cost decreases as the risk index increases. This is a logical consequence of the accompanying decrease in spinning reserve requirement. In a way this graph represents the “cost” side of the proposed cost/benefit analysis. It is obvious that the schedule cost decreases with the increase of risk index, since spinning reserve requirement decreases when risk index becomes higher. It is noticeable that the schedule cost with DSB is much lower than that without DSB, which accords with the earlier discussion in Section 3.4 of Chapter 3.

Figure 4.2 Schedule cost comparison vs. risk index with and without DSB

On the “benefit” side, the *EENS* for each hour of the schedule was calculated independently assuming that the scheduled units were actually running at the beginning of each hour and that the demand was constant for the lead time of the marginal unit. From Figure 4.3, it is noted that the *EENS* values increase with the increase of the risk index. This is because the system is less reliable as the risk index increases and carries less spinning reserve. At the same time, under the same risk index, *EENS* with DSB becomes lower than that of the without DSB. It can be concluded that DSB could reduce the risk (and corresponding payment) of the system for not able to meet the scheduled load.

Figure 4.3 *EENS* comparison vs. risk index with and without DSB

Figure 4.4 *EENS* cost vs. risk index for different values of *VOLL* without DSB

Figure 4.5 EENS cost vs. risk index for different values of $VOLL$ with DSB

The total cost for the system is computed via the cost/benefit analysis. The cost is the sum of the schedule cost of Figure 4.2 and the expected cost of energy not served of Figure 4.4 for the without DSB. Likewise Figure 4.2 and Figure 4.5 are added for the with DSB. The results of the cost/benefit analysis are given by Figures 4.6 and 4.7 for the without and with DSB, respectively. These figures show the total societal cost of the generation schedule for several values of $VOLL$. From these curves, it is observed that the optimal risk index varies significantly with the $VOLL$ value. If $VOLL$ is set at 6\$/kWh, the risk index should be set at 0.019 for the without DSB and 0.014 for the with DSB. For a value of $VOLL$ of 1\$/kWh, it could be increased up to 0.035 for the with/without DSB.

In addition, it is interesting to note from Tables 4.2 and 4.3 and Figures 4.6 and 4.7 that the optimal value of the risk index varies for the same $VOLL$ between the with and without DSB. Two cases are selected to show here for the values of $VOLL$ at 4\$/kWh and 6\$/kWh. From Figure 4.8, it is obvious from the earlier discussion that the total cost with DSB is smaller than that without DSB. At the same time, it is noted from the curve with DSB that the minimum total cost is obtained at the risk index of 0.019, while for the without DSB the optimal risk index is 0.021 when $VOLL$ is set to be 4\$/kWh. It can be concluded that the system reliability is enhanced and the total cost is reduced after incorporating DSB.

Figure 4.6 Total cost vs. risk index for different values of *VOLL* without DSB

Figure 4.7 Total cost vs. risk index for different values of *VOLL* with DSB

Figure 4.8 Total cost comparison vs. risk index with and without DSB when *VOLL* = \$4/kWh

The same conclusion can be obtained from Figure 4.9, when *VOLL* is set at \$6/kWh. The optimal risk index is 0.014 with DSB and 0.019 without DSB. The system is unable to satisfy the reliability requirement to achieve the risk index at 0.014 when DSB is not incorporated. The lower the risk index, the more the spinning reserve is required. As discussed before, demand-side agents can relieve the demand by reducing their load if they are selected to do so. This means that the system can provide more spinning reserve. Hence, the reliability of the system will improve.

Figure 4.9 Total cost comparison vs. risk index with and without DSB when *VOLL* = \$6/kWh

Figure 4.10 Optimal risk index vs. *VOLL* with and without DSB

Figure 4.10 shows the relationship between the risk index and the *VOLL* with and without DSB. It is noted that with the increase of *VOLL*, the system optimal risk index becomes smaller. This is because the cost of *EENS* increases as *VOLL* increases

which leads to an increase in system reserve and a more reliable system. In addition, with the increase of *VOLL*, the optimal risk index of the system with DSB tends to become smaller than that of the without DSB under the same *VOLL*. This can be explained by the decrease of *EENS* under the same *VOLL* shown in Table 4.1.

Table 4.4 Demand-side bidding data

Demand Agents		$Q_j^{\min}$ (MW)	$EL1_j$ (MW)	$EL2_j$ (MW)	$Q_j^{\max}$ (MW)	Demand-side bids (\$/MWh)		
						$B1_j$	$B2_j$	$B3_j$
Case I	1	32.00	35.30	38.60	42.00	35.0218	35.5673	35.9012
	2	32.00	35.00	38.00	41.00	35.0448	35.6663	36.1009
	3	0.00	9.00	13.00	17.00	52.0341	52.6534	53.1107
Case II	1	12.00	15.30	18.60	22.00	35.0218	35.5673	35.9012
	2	12.00	15.00	18.00	21.00	35.0448	35.6663	36.1009
	3	0.00	9.00	13.00	17.00	52.0341	52.6534	53.1107

Besides the simulation results and analysis above, some other situations are also tested to show the effect of DSB. It is found that DSB will only be selected during peak load periods to satisfy a required system risk index of high reliability. Two different DSB cases are compared here. Table 4.4 is the bidding data of these two cases. Keeping the bidding prices unchanged, the only difference between these two cases is that the load reduction amount of Case I is 20 MW larger than that of Case II. The different load reduction amounts of DSB affect the simulation results.

Table 4.5 Selection of demand-side agent under different risk indices

		Hour 10 11	Hour 10 11	Hour 10 11	Hour 10 11	Hour 10 11	Hour 10 11	Hour 10 11	Hour 10 11	Hour 10 11
Demand Agents		Risk index (%)								
		1.4	1.9	2.0	2.1	2.5	3.0	3.2	3.4	3.5
Case I	1	1 1	1 1	1 1	1 1	1 1	1 1	1 1	0 1	0 0
	2	1 1	1 1	0 1	0 0	0 0	0 0	0 0	0 0	0 0
	3	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0
Demand Agents		Risk index (%)								
		2.7	3.0	3.2	3.5	3.8	4.0	4.2	4.4	4.5
Case II	1	1 1	1 1	1 1	1 1	1 1	1 1	1 1	1 1	0 0
	2	1 1	1 1	1 1	0 1	0 1	0 1	0 1	0 1	0 0
	3	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0

Table 4.5 gives the selection results of the demand-side agents for Cases I and II during load periods 9 to 12. It is found that DSB agents will only be selected during peak load periods (hours 10 and 11) to enhance the system reliability. In Case I, DSB agents will not be selected when the risk index is larger than 0.035, while in Case II, DSB can still be selected till the risk index increases to 0.044. In addition, the minimum risk index that can be satisfied for Case I is 0.014, while it is 0.027 for Case II. The reason is that in Case II the load reduction amount is not sufficient to compensate the deficiency in system spinning reserve if the system sets the risk index below 0.027. As mentioned before, the lower the risk index, the more the spinning reserve required. Hence, it is interesting to note that with the increase of risk index, fewer demand-side agents are selected for load reduction. Conversely, more demand-side agents are selected in hour 11 than in hour 10, because the load of hour 11 is larger than that of hour 10.

Of course, not only the load reduction amount of DSB affects the selection of demand-side agents, the bidding prices can affect it too. Only two different cases are compared here. More studies and analysis will be extended further in future to see how the elasticity of demand-side influences both the energy market and reserve market.

4.4 Extended Analysis for Probabilistic Reserve with Demand-Side Participation

Previous work [5, 109, 111, 113] considers only the generator bidding in the energy market without the reserve market. The scheduling of spinning reserve is solved as a constraint for the objective function. In this section, the problem is further developed to include the reserve bidding into the objective function. With the demand-side bids in the energy market, the model also considers reserve offers from the demand side. Furthermore, the cost of *EENS* which denotes the possible load lost is included in the main objective function which describes the total offered cost of carrying reserve and supplying electricity.

An optimal risk index is obtained by balancing the reserve and energy offered cost and the *EENS* cost. The cost of *EENS* incorporates the effect of the unit's *ORR* under different scenarios. An iterated Lagrangian Relaxation algorithm based full UC dispatch over the 24-hour period equipped with the Golden-Section search technique is implemented.

4.4.1 Problem Formulation

Based on the market model set up in Chapter 3, the market structure considered here is still a gross pool with centrally optimized scheduling where all products are traded simultaneously through the pool. However, both energy and reserve are dispatched jointly where the demand-side bids for electricity and demand-side reserve offers are included. The generator model is the same as that used in Chapter 3, which is represented as a three-segment linear cost function. Generators bid in the market with prices, quantities of both energy and spinning reserve, as well as coefficients for the start-up prices, $S_{i,t}$. Similarly, customers submit prices and quantities for demand-side energy and reserve offers.

The market clearing engine is based on a day-ahead market model. The units are dispatched for each hourly period to provide both the energy and reserve. Unlike most unit commitment (UC) objective functions, the cost of *EENS* which represents the product of *EENS* and the value of lost load (*VOLL*) is incorporated into the function. The costs of each hour are added up and the overall optimal solution is obtained by evaluating coupling constraints, such as the ramp rate and minimum up/down time of generators. The new objective function is formulated as follows:

$$\min \left\{ \sum_{t=1}^T \sum_{i=1}^N OC_i(P_{i,t}, U_{i,t}) + \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} \right. \\ \left. + \sum_{t=1}^T \sum_{i=1}^N PR_{i,t}^g R_{i,t}^g U_{i,t}^{gr} + \sum_{t=1}^T \sum_{j=1}^J PR_{j,t}^d R_{j,t}^d U_{j,t}^{dr} + VOLL \sum_{t=1}^T EENS_t \right\} \quad (4.1)$$

where

$$\sum_{t=1}^T \sum_{i=1}^N OC_i(P_{i,t}, U_{i,t}) = \sum_{t=1}^T \sum_{i=1}^N [C_i(P_{i,t}) U_{i,t} + S_{i,t} * U_{i,t} (1 - U_{i,t-1})] \quad (4.2)$$

Although some variables are given earlier in Chapter 3, some new variables are included here. Their definitions are all given below. $OC_i(P_{i,t}, U_{i,t})$ is the offered cost function for each unit as shown in Equation (4.2).

T = Number of time periods.

N = Number of units.

J = Number of demand-side agents.

$P_{i,t}$ = Output power of Unit i at time t [MW].

$U_{i,t}$ = Status of Unit i at time t , 0 = unit not scheduled, 1 = unit scheduled.

B_j = Bidding price of customer j for energy [\$/MWh].

$Q_{j,t}$ = Demand reduction amount (a positive value) of customer j at time t [MW].

$U_{j,t}$ = Status of customer j at time t , 0 = customer not selected, 1 = customer selected.

$PR_{i,t}^s$ = Bidding price offered by Unit i for spinning reserve at time t [\$/MWh].

$R_{i,t}^s$ = Spinning reserve contributed by Unit i at time t [MW].

$U_{i,t}^{sr}$ = A discrete variable which is 1 if Unit i is committed for reserve at time t and 0 otherwise.

$PR_{j,t}^d$ = Bidding price offered by customer j for spinning reserve at time t [\$/MWh].

$R_{j,t}^d$ = Spinning reserve contributed by customer j at time t [MW].

$U_{j,t}^{dr}$ = A discrete variable which is 1 if customer j is committed for reserve at time t and 0 otherwise.

This objective function aims to minimize the total pool cost. The first term of the objective function denotes the total offered cost of the GENCOs; the second term represents the possible cost of customers for the electricity they did not consume at an agreed time; the third and the fourth terms are the cost for the pool to buy reserve from generators and customers, respectively. The last term denotes the cost of *EENS* over the 24 hourly periods. The costs of each hour in (4.1) are added up to obtain the total cost and the optimization problem is subjected to the same constraints as those in Chapter 3 except for the following three constraints:

I) System spinning reserve requirement

$$\sum_{i=1}^N R_{i,t}^g U_{i,t} U_{i,t}^{gr} + \sum_{j=1}^J R_{j,t}^d U_{j,t}^{dr} \geq R_t \quad t = 1, \dots, T \quad (4.3)$$

R_t = Spinning reserve requirement, a variable whose value is determined by probabilistic reserve scheduling in Section 4.4.2.

II) Unit generation limits

$$P_i^{\min} \leq P_{i,t} + R_{i,t}^g \leq P_i^{\max} \quad i = 1, \dots, N; t = 1, \dots, T \quad (4.4)$$

III) Customer load profile changing limits

$$Q_j^{\min} \leq Q_{j,t} + R_{j,t}^d \leq Q_j^{\max} \quad j = 1, \dots, J; t = 1, \dots, T \quad (4.5)$$

The market model considered here is a full scheduling model, which not only dispatches the units to produce the required energy amount, but also deals with the on/off status of the UC problem. Both the energy and reserve are scheduled at the same time. The Lagrange Relaxation optimization algorithm is used. It is based on a dual optimization approach to the minimization of the total cost in (4.1). The coupling constraints such as the power balance constraint, spinning reserve requirement and ramp rate constraints are incorporated in the problem by means of multipliers $\lambda_t, \mu_t, \xi_{i,t}, \zeta_{i,t}$ to form the Lagrangian [5, 105].

$$\begin{aligned} L = & \sum_{t=1}^T \sum_{i=1}^N OC_i(P_{i,t}, U_{i,t}) + \sum_{t=1}^T \sum_{j=1}^J B_j Q_{j,t} U_{j,t} \\ & + \sum_{t=1}^T \sum_{i=1}^N PR_{i,t}^g R_{i,t}^g U_{i,t} U_{i,t}^{gr} + \sum_{t=1}^T \sum_{j=1}^J PR_{j,t}^d R_{j,t}^d U_{j,t}^{dr} + VOLL \sum_{t=1}^T EENS_t \\ & + \sum_{t=1}^T \left[\lambda_t \left(D_t - \sum_{j=1}^J Q_{j,t} - \sum_{i=1}^N P_{i,t} U_{i,t} \right) + \mu_t \left(R_t - \sum_{i=1}^N R_{i,t}^g U_{i,t} U_{i,t}^{gr} - \sum_{j=1}^J R_{j,t}^d U_{j,t}^{dr} \right) \right] \\ & + \sum_{t=1}^T \sum_{i=1}^N \left[\xi_{i,t} (P_{i,t} U_{i,t} - P_{i,t-1} U_{i,t-1} - UR_i) + \zeta_{i,t} (P_{i,t-1} U_{i,t-1} - P_{i,t} U_{i,t} - DR_i) \right] \end{aligned} \quad (4.6)$$

4.4.2 Probabilistic Spinning Reserve Scheduling

In the traditional deterministic criterion, a spinning reserve requirement that is a function of the largest on-line unit capacity or system load is predefined for every system scenario without consideration of the unit's *ORR* and ramp rate. But the probability of failing to meet the demand or the risk index is different for different hourly unit commitment patterns due to load changes. Since the risk index denotes the system unreliability level, the reliability level of a system or the *EENS* for each hour will be different. On the contrary, a uniform system reliability can be achieved by adjusting the *SRR* to adapt to the units' *ORRs* and ramp rates. This results in a uniform risk index under different system scenarios. Hence, the objective of probabilistic spinning reserve is to achieve uniform system reliability regardless of load changes and units committed.

Figure 4.11 Total reliability cost

As shown in Figure 4.11, the total cost (curve 1) is a function of the system risk index and is calculated as the sum of the schedule cost (curve 2) and the expected cost of energy not served (curve 3). The schedule cost includes the offered cost of supplying electricity and the cost of carrying reserve. There is a trade-off between the cost of carrying the reserve and the expected cost of not serving the load. The optimal risk index is obtained when the total cost achieves a minimum. The objective function aims to minimize the total cost of generation scheduling and *EENS* for any unforeseen unit outages. The optimal value will be obtained by simultaneously solving the energy

and reserve schedules in a coordinated manner. The market clearing price is determined based on the bid price of the last marginal unit selected. It is interesting to know that in Figure 4.11, when *VOLL* increases in the arrow direction, the curves denoting the cost of *EENS* tend to move in the upper left direction. Hence the optimal point of the total cost tends to shift in the upper left direction as well.

A probabilistic reserve scheduling scheme has been proposed earlier to determine the *SRR* value and the UC schedule for each hourly load demand using the proposed Lagrange Relaxation algorithm. Lagrange Relaxation is executed and the value of risk index is determined by comparing with the system risk through the construction of the COPT [79]. The algorithm will iterate successively by adjusting the value of risk index to calculate the cost of the objective function. The iterative process will continue until a minimum point is reached. The risk index at this minimum point is the balancing point at which the system is operating most economically. Unlike the deterministic approach, the system can maintain the reliability level based on the risk index used.

Figure 4.12 Calculation of Golden-Section search method at first iteration

As shown in Figure 4.11, the minimum point of the total cost is the solution to a single-variable (risk index) optimization problem. The problem fits very well into a unimodal function, in which there is a unique minimum value. The Golden-Section search method is used to update the risk index for the next iteration and the Lagrange Relaxation optimization method is used to solve the main problem. Figure 4.12 shows the first iteration of the method. The Golden-Section search method starts with a finite

interval between two starting points, a and b . This technique then systematically shrinks the interval around the optimum value until the optimum is confined to within an acceptable tolerance. Evaluating the objective function sequentially at selected points decides the direction of shrinking. Using the unimodal property eliminates portions of the current interval [132].

In this algorithm, the search is based on the number 0.618, known as the golden section. The first two points of the Golden-Section search method are located at $0.618(b - a)$ from the endpoints of the initial interval, e.g. $X_1 = a + 0.618(b - a)$ and $X_2 = b - 0.618(b - a)$. Successive points are considered one at a time and are positioned at $0.618L_i$ from the newest endpoint of the current interval, where L_i denotes the length of the interval. For the first iteration, $L_1 = b - a$. If $F(X_1) > F(X_2)$, then the minimum does not lie in $[X_1, b]$, and the newest endpoints become a and X_1 . Hence the length of the second interval is $L_2 = X_1 - a$ as shown in Figure 4.12. On the contrary, if $F(X_1) < F(X_2)$, then the minimum does not lie in $[a, X_2]$ and $L_2 = b - X_2$.

To begin, the starting points of the risk index here are selected. They can be any non-negative numbers. However, a suitable choice for these two points enhances the performance of the algorithm. A smart selection can reduce the iteration number dramatically and save the execution time substantially. The interval $[0.014, 0.030]$ is chosen as the starting points to prevent the system from running out of spinning reserve or starting from too small a spinning reserve value. Successive points are iterated by the method described earlier and they are shown as in Figure 4.13.

Figure 4.13 Iteration points of Golden-Section search technique

Figure 4.14 Convergence of total cost curve

The first iteration points are calculated as $X_1(0.0239) = 0.014 + 0.618(0.030 - 0.014)$ and $X_2(0.0201) = 0.030 - 0.618(0.030 - 0.014)$. In this program, $F(0.0239) > F(0.0201)$, hence the new interval shrinks to $[0.014, 0.0239]$ and the next point in the search is positioned at $X_3 = 0.0239 - 0.618(0.0239 - 0.014) = 0.01778$. Since $F(0.0239) > F(0.01778)$, it follows from the unimodal property that the minimum must occur to the left of 0.01778. Therefore, $[0.014, 0.01778]$ is the new interval of interest. Similarly, the iterative process is repeated until it reaches the minimum point at $X_7(0.01599)$. Convergence is reached when the difference between this point and any other points in the interval $[0.01544, 0.01689]$ is within 0.001, which is set as the tolerance value ε in the solution algorithm. The iterated points correspond to the results shown in Figure 4.14.

The implementation process of the proposed probabilistic reserve scheme is illustrated in Figure 4.15. Two starting points (a, b) of the risk index are selected. The difference between these two points is compared with a tolerance value ε to see whether they satisfy the convergence tolerance. If a convergence is reached, the algorithm will terminate and output the results. Otherwise, the Lagrange Relaxation optimization is executed to get the total cost ($TCost$) for each of the two risk indices. The smaller cost is stored in a variable, $TCost^{min}$. The iterative process continues with the execution of the Golden-Section search method described in Figure 4.13. The $TCost^{min}$ will be updated after each iteration. The process will stop when the

difference between the two risk indices is less than a preset tolerance value ϵ . At this time a minimum cost is achieved.

Figure 4.15 Optimal scheduling with probabilistic reserve assessment

4.5 Simulation Results for Extended Analysis

Similarly, the proposed method in the above section is tested on the same system as in Section 3.3.3 of Chapter 3. Demand-side traders/customers participate in both the energy and reserve markets. The energy bid prices and quantities are the same as those in Chapter 3. The reserve bid prices are taken as a 10 percent of the highest energy bid price. Hence there is only one segment for the reserve quantity and

bid price. The demand-side bidding data are chosen to create suitable system operation condition for the study purpose. The demand curve is altered as well and it is given in Table 4.6 together with the demand-side MW bid quantities and prices given in Tables 4.7 and 4.8.

Table 4.6 Demand for 24-hour period

Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)
1	1500	7	1800	13	2390	19	2300
2	1530	8	2230	14	2350	20	2350
3	1490	9	2340	15	2420	21	2400
4	1500	10	2400	16	2450	22	2280
5	1540	11	2470	17	2350	23	2000
6	1700	12	2390	18	2330	24	1640

Table 4.7 Demand-side MW bid quantities

Demand Agents	For energy market				Reserve
	$Q_j^{\min}$ (MW)	$EL1_j$ (MW)	$EL2_j$ (MW)	$Q_j^{\max}$ (MW)	$R_{j,t}^d$ (MW)
DSA1	12.00	15.30	18.60	22.00	20.00
DSA2	10.00	14.00	18.00	22.00	20.00
DSA3	5.00	9.00	13.00	17.00	15.00

Table 4.8 Demand-side bid prices

Demand Agents	Demand-side bids for energy (\$/MWh)			Reserve (\$/MWh)
	$B1_j$	$B2_j$	$B3_j$	
DSA1	25.0218	25.5673	25.9012	1.1009
DSA2	10.0448	15.1009	20.6663	2.5218
DSA3	42.0341	42.6534	43.1107	3.0341

4.5.1 Effect of Demand-Side Participation

To illustrate the influence of demand-side participation, the spinning reserve requirement, total cost, reserve cost and *EENS* of the with DSB and without DSB are compared.

Figure 4.16 shows the comparison of the spinning reserve requirement at each period and at the same risk index between the with and without DSB. The load demand for the test over the 24-hour period is shown in Table 4.6. Overall, the spinning reserve requirement without DSB is larger than that with DSB. Hence the reserve cost with DSB is much lower than that without DSB. In the case without DSB, more reserve is scheduled for higher load periods from hours 10 to 16. During hours 8 and 9, the *SRR* of the with DSB is 1 MW higher than that of the without DSB due to the convergence tolerance.

Figure 4.16 Reserve comparison for with and without DSB

Figure 4.17 EENS comparison vs. risk index with and without DSB

From Figure 4.17, it is noted that for the same risk index, *EENS* with DSB becomes lower than that of the without DSB. This is because with DSB, the customer may choose not to consume electricity due to high prices and the load at that time becomes lower than that of the without DSB. Therefore both the spinning reserve and the *EENS* of the with DSB become lower than those of the without DSB. Hence, DSB could reduce the corresponding system payment when the system has limited generation resources to meet the scheduled load. Demand-side agents can relieve the pressure on generation shortage by reducing their load if they are selected to execute load reduction bids. If demand-side agents are selected for dispatch, the demand reduction from these agents can be used to meet the demand needs of other loads. Hence, the pressure for the system to deliver demand is relieved by demand reduction via demand-side agents. This means that the system can provide more spinning reserve relative to the reduced load. Hence, the reliability of the system will improve accordingly and the system will operate at a smaller risk index.

Figure 4.18 Reserve cost comparison vs. risk index with and without DSB

In Figure 4.18, the reserve cost with DSB is much lower than that without DSB. The reserve amount decreases with the increase of risk index. This can be well explained by the increase of *EENS* in Figure 4.17 when the risk index increases.

Figure 4.19 Total cost comparison vs. risk index with and without DSB
when $VOLL = \$3/\text{kWh}$

Figure 4.20 Total cost comparison vs. risk index with and without DSB
when $VOLL = \$5/\text{kWh}$

From Figure 4.19 and Figure 4.20, the total cost with DSB is smaller than that without DSB at $VOLL$ of $\$3/\text{kWh}$ and $\$5/\text{kWh}$. This is because with the selection of DSB in the energy market, the clearing price for energy is reduced drastically, especially over the peak load hours. Hence the schedule cost of the with DSB is largely reduced when compared with that of the without DSB. At the same time, the optimal risk index, denoted by arrow, occurs at 0.021 when $VOLL$ is at $\$3/\text{kWh}$, while

for the without DSB, it is 0.024. It can be concluded that after incorporating DSB the system reliability is enhanced and the total cost is reduced substantially. Similarly in Figure 4.20, when *VOLL* is set at \$5/kWh and the most economically dispatch schedule is obtained when the risk index is 0.0165 for the without DSB and 0.016 for the with DSB. The total cost with DSB is reduced dramatically when DSB is engaged. The shape of the curve and the optimal risk index agree well with the theory presented in Figure 4.11. As *VOLL* increases, the optimal risk index tends to left shift to a lower value.

Figure 4.21 Optimal risk index vs. *VOLL* – with and without DSB

In order to illustrate how the optimal risk index varies as *VOLL* increases, different scenarios are run and compared with different *VOLLs* under different risk indices. Figure 4.21 shows that with the increase of *VOLL*, the optimal risk index of the system with DSB tends to become smaller than that of the without DSB. It is concluded that the system reliability level is enhanced with demand-side participation.

4.5.2 Effect of Unit’s *ORR*

Three cases are run and compared here. All of the three cases are with DSB. Case I is the original case. Case II shows the system situation when the *ORR* of Unit 21 doubles and Case III is when one of the most reliable generators, Unit 5, does not participate in the bidding process. Results are given in the following sections to show the difference among these three scenarios.

Table 4.9 Spinning reserve and unit status comparison of Cases I and II

Hour	SRR		Unit Status of Unit 21	
	Case I	Case II	Case I	Case II
1	444	444	0	0
2	417	417	0	0
3	446	446	0	0
4	446	446	0	0
5	455	455	0	0
6	414	414	0	0
7	458	458	0	0
8	510	527	1	1
9	510	527	1	1
10	533	550	1	1
11	533	550	1	1
12	533	550	1	1
13	533	550	1	1
14	533	550	1	1
15	552	563	1	1
16	552	563	1	1
17	533	482	1	0
18	529	510	1	0
19	529	510	1	0
20	533	510	1	0
21	533	510	1	0
22	529	510	1	0
23	456	456	0	0
24	455	455	0	0

The spinning reserve and unit status comparison between Cases I and II are shown in Table 4.9. Unit 21 will not be committed from hour 17 to hour 22 in Case II after its *ORR* is increased. This is because the system will schedule other generators with lower *ORR* to substitute Unit 21 since its *ORR* increases. At the same time, during hours 8 to 16, the spinning reserves of Case II become larger than those of Case I, while during hours 17 to 22 the spinning reserves of Case II are less than those of Case I when Unit 21 is not committed. All other hours remain unchanged when Unit 21 is not committed in both cases. Since the *ORR* of Unit 21 in Case II is larger than that of Case I, the system needs to provide more spinning reserve to maintain the same reliability level, or risk index. During hours 17 to 22 since Unit 21 is

decommitted, the commitment of units with lower *ORR* results in a decrease of spinning reserves in Case II.

Figure 4.22 *EENS* comparison of three cases

Figure 4.22 presents the comparison of *EENS* among the three cases. It is noted that *EENS* of both Cases II and III are higher than that of Case I. The reason for the increase of the system *EENS* value is because in Case II the *ORR* of Unit 21 is doubled and the probability when the energy is not supplied increases accordingly. Hence the amount of *EENS* increases. For Case III, Unit 5 does not take part in the bidding process so that the system has to commit other generators with higher *ORRs* to substitute it. Hence, the *EENS* value of Case III is higher than that of Case I. For instance, under the risk index of 0.028 the *EENS* value of Case II increases by 837.77 kWh and Case III increases by 700.79 kWh with respect to that of Case I.

Furthermore, the optimal risk index of both Cases II and III becomes smaller than that of Case I since the cost of *EENS* becomes higher and it increases in the total cost. As shown in Figure 4.23, the optimal risk index of Case I is 0.016 and it becomes 0.0155 for both Cases II and III.

Figure 4.23 Optimal risk index of the three cases

4.6 Summary

Based on the work done in Chapter 3, the study is extended to include the reserve market and probabilistic reserve scheduling. Firstly, the effect of DSB on spinning reserve is tested and analyzed further using the market model proposed in Chapter 3. Secondly, with the DSB incorporated as in Chapter 3, optimal spinning reserve scheduling is set up by integrating the probabilistic reserve assessment in the main objective function. It is proposed that different spinning reserves are scheduled for varying load at each period. Some interesting results are achieved to show how DSB influences the schedule cost, *EENS*, the optimal risk index and the total cost. The total cost includes the schedule cost and the expected cost of energy not served. Various scenarios of the with and without DSB are modeled to see how the *EENS*, the optimal risk index and the total cost vary as the scenarios vary.

Demand-side bids can build a price response into the markets, which are used to determine the MCPs of the wholesale electricity and ancillary services. The market model set up in Chapter 3 only includes the energy offers. Both generators and demand-side agents can only bid into the energy market. In reality, demand-side customers can provide reserve offers to contribute to the reserve market as well. So

the market model is extended to include the reserve offers. The customer's response is incorporated not only for energy purchase bids but also for spinning reserve offers.

Furthermore, the cost of *EENS* which denotes the possible load lost is included in the main objective function which has the total offered cost of carrying reserve and supplying electricity. A probabilistic reserve schedule scheme is proposed, whereby the criterion is to make the pool operate optimally via an optimal risk index. A Lagrangian Relaxation based UC equipped with the Golden-Section search technique is implemented to achieve the optimal risk index.

It is concluded that with the demand-side participation in the energy and reserve market, the total cost is reduced significantly together with the reduction of the schedule cost, the *EENS* and reserve cost. It can reduce the system risk of being unable to meet the demand. Accordingly, the system reliability level is markedly improved with the decrease of the optimal risk index. In addition, it is also found that the *EENS* increases with the increase of the unit's *ORR*. The reliability of individual units has impact on the system reliability cost and solutions.

Chapter 5

A Settlement Scheme for Probabilistic Reserve with Interruptible Loads

5.1 Introduction

As described in Chapter 2, under the new restructured environment, separate markets are set up for energy and reserves. Reserve management is an important factor in preventing blackout because investment alone cannot avoid it. For reserve management, two techniques based on the deterministic and probabilistic methods are available. A probabilistic reserve scheduling method is proposed in Chapter 4. An optimal risk index is achieved by balancing the schedule cost and the possible cost of not providing sufficient energy via a Lagrangian Relaxation based UC equipped with the Golden-Section search technique. Hence the spinning reserve is dispatched at an optimal risk index to obtain a minimum total schedule cost.

In the deterministic approach, the reliability of generators is not taken into account when scheduling units. There are good reasons for considering units' reliability in the scheduling process. When a generating unit is forced out, the system dynamics are aggravated which may cause load shedding or put the system in a state where load shedding is more likely to occur. The replacement of energy and reserve that must be procured is costly. If the units' outage probabilities are considered in the scheduling process, the expected impact of contingencies can be lowered thus enhancing the security of the system. To schedule a reasonable amount of reserve, the market rules need to introduce a proper scheme to reflect the possibility of generators'

outages. The incentive for GENCOs to supply reserves is derived from market settlement. Settlement influences the GENCOs' behavior in terms of finance. With the participation of interruptible loads into the reserve market, customers are also responsible for part of the system reliability by contributing reserve via interruption of a certain amount of their load.

In this chapter, a probabilistic reserve scheme is proposed by considering the reliability of each individual generator. The *EENS* is calculated for each unit at each market clearing interval. The possible *EENS* cost is then computed and added into the objective function. It aims to minimize the total cost including the schedule cost, reserve cost and the cost of *EENS*. Interruptible loads are allowed to bid into the market to contribute towards the reserve market. Besides, a settlement scheme with the participation of interruptible loads is proposed to allocate the payment among generators and customers in the reserve market. Interruptible loads share the reserve responsibility along with all the generators in the reserve market. Those with a high reliability level will be paid for their good performance and those which operate poorly will be penalized for the loss they caused. Although interruptible loads do not contribute energy, they may cause energy deficiency if they fail to respond when the system calls the reserve in. Hence, the proposed scheme provides incentives for all the participants of the market to improve their performance and to be responsible for their failures.

5.2 Problem Formulation

5.2.1 Objective Function

Like the market model set up earlier in Chapter 3 and Chapter 4, the market structure is also assumed to be a gross pool. Maintaining security and operating the system at a minimum schedule cost are the overall responsibilities of the ISO. The objective function aims to find an optimal solution for energy and reserve as a whole, and at the same time, takes individual generator reliabilities into account. In addition, interruptible loads bid into the market as reserve providers. These products, i.e. energy, reserve and interruptible loads, are co-optimized for scheduling in the market clearing

process. For simplicity, only spinning reserve is considered here in this chapter and it is assumed that interruptible loads which meet time response requirements can compete for the provision of reserve. But other commodities such as secondary and contingency or tertiary reserves [39] can be taken into consideration as well by modifying the objective function. The objective function is formulated as follows:

$$\min \left\{ \begin{aligned} & \sum_{t=1}^T \sum_{i=1}^N OC_i(P_{i,t}, U_{i,t}) + \sum_{t=1}^T \sum_{i=1}^N PR_{i,t}^s R_{i,t}^s U_{i,t}^{gr} \\ & + \sum_{t=1}^T \sum_{l=1}^L PR_{l,t}^{il} R_{l,t}^{il} U_{l,t}^{il} + VOLL \sum_{t=1}^T \sum_{i=1}^N EENS_{i,t} \\ & + VOLL \sum_{t=1}^T \sum_{l=1}^L EENS_{l,t} \end{aligned} \right\} \quad (5.1)$$

where

T = Number of time periods.

N = Number of units.

L = Number of interruptible loads.

$P_{i,t}$ = Output power of Unit i at time t .

$U_{i,t}$ = Status of Unit i at time t , 0 = unit not scheduled, 1 = unit scheduled.

$PR_{i,t}^s$ = Bidding price offered by Unit i for spinning reserve at time t [\$/MWh].

$R_{i,t}^s$ = Spinning reserve contributed by Unit i at time t [MW].

$U_{i,t}^{gr}$ = A discrete variable which is 1 if Unit i is committed for reserve at time t and 0 otherwise.

$PR_{l,t}^{il}$ = Bidding price offered by customer l for spinning reserve at time t [\$/MWh].

$R_{l,t}^{il}$ = Spinning reserve contributed by customer l at time t [MW].

$U_{l,t}^{il}$ = A discrete variable which is 1 if customer l is committed for reserve at time t and 0 otherwise.

$EENS_{i,t}$ = The $EENS$ caused by Unit i at period t .

$EENS_{l,t}$ = The $EENS$ caused by customer l at period t .

The first term of the objective function in (5.1) is the total offered cost of the GENCOs. The second and the third terms in (5.1) are the cost associated with purchasing reserve from generators and customers. The fourth term in (5.1) accounts for the cost of the risk of energy loss caused by failures of generating units, including failures of interruptible loads. *VOLL* is the value of lost load and is defined as the average constant value that customers attach to the loss of one kWh of energy for one hour [101]. Ideally, an interruptible load may be treated as a reserve participant that never fails to function. But in the real system, interruptible loads can reject the request for calling in the reserve or fail to perform when the system demands. Hence a penalty scheme needs to be set up to deal with non-delivery. The last term in (5.1) is created in this chapter to represent the possible *EENS* cost caused by interruptible loads failing to deliver the scheduled reserve. The scenario that generators fail to increase their MW output when their reserve is needed is not included in the study. Only the scenario with generator outages as given in the fourth term of (5.1) is considered.

This objective function is subjected to many constraints. Most of them remain the same as those in Chapter 3 except for the three constraints in the following.

I) System energy balance

$$\sum_{i=1}^N P_{i,t} U_{i,t} = D_t \quad t = 1, \dots, T \quad (5.2)$$

II) System spinning reserve requirement

$$\sum_{i=1}^N R_{i,t}^g U_{i,t}^{gr} + \sum_{l=1}^L R_{l,t}^{il} U_{l,t}^{il} \geq R_t \quad t = 1, \dots, T \quad (5.3)$$

III) Unit generation limits

$$P_i^{\min} \leq P_{i,t} + R_{i,t}^g \leq P_i^{\max} \quad i = 1, \dots, I; t = 1, \dots, T \quad (5.4)$$

The system energy balance constraint in (5.2) needs to meet the expected gross demand, D_t at time t . The spinning reserve requirement is given as in (5.3), which includes the reserve part provided by interruptible loads. R_t is the required spinning

reserve amount. The level of reserve is adjusted for each hour to maintain a uniform system reliability level and to meet the specified *LOLP* value.

Furthermore, except for the unit generation limits constraints in (5.4), minimum up/down time constraints, and ramp rate limits for unit generation changes are also considered in this chapter. Hence, the unit's ability of providing spinning reserve is constrained by the physical properties of a unit.

5.2.2 Formulation of *EENS* for Generators

EENS is an energy deficiency value that indicates the consequence of an event in terms of reliability influence. In this chapter, *EENS* is used to evaluate the reserve responsibility for each unit and each interruptible load. It represents the unit's/interruptible load's responsibility in those events where energy deficiencies exist. In other words, the system *EENS* is divided into a number of responsibility shares and each unit/interruptible load takes up one of them.

Due to the fact that an interruptible load does not contribute energy, it cannot result in energy deficiency by itself. This means that the energy deficiency caused by interruptible loads involves at least one other unit to share the responsibility. Hence, two possible situations are considered here. One is when only units' outages happen and the *EENS* shares are distributed among the N units. The other is when interruptible loads are involved in the event and the *EENS* shares are among the $N+L$ units and interruptible loads. Based on earlier work in [109, 110], the *EENS* formulations are redeveloped with the incorporation of interruptible loads and the new settlement schemes with interruptible loads.

$EENS_{i,t}$ is the total *EENS* contributed by Unit i at period t . As discussed above, it includes two parts, $EENS_{i,t}^g$ and $EENS_{i,t}^{il}$, as shown in (5.5). $EENS_{i,t}^g$ is caused only by units. As in (5.6), this term represents the expected energy deficiency attributable to Unit i , following its failure at period t . Similarly, the other one, $EENS_{i,t}^{il}$, is the expected energy deficiency contributed by Unit i that includes failures of interruptible

loads to supply the reserve following the outage of Unit i . $EENS_{i,t}^g$ and $EENS_{i,t}^{il}$ are expected energy deficits attributable to Unit i .

$$EENS_{i,t} = EENS_{i,t}^g + EENS_{i,t}^{il} \quad (5.5)$$

where

$$\begin{aligned} EENS_{i,t}^g = & s_{i,t}^1 * EENS_{i,t}^1 + \sum_{j=1, j \neq i}^N s_{i,j,t}^2 * EENS_{i,j,t}^2 \\ & + \sum_{j=1, j \neq i}^N \sum_{k > j, k \neq i}^N s_{i,j,k,t}^3 * EENS_{i,j,k,t}^3 + \dots \end{aligned} \quad (5.6)$$

Note that $EENS_{i,t}^{il}$ component is discussed in (5.19).

In (5.6), $EENS_{i,t}^1$ is the amount of energy deficiency following an outage of a single unit (Unit i). Similarly, energy deficits following simultaneous outages of two units (i and j) and three units (i , j and k) are given by $EENS_{i,j,t}^2$ and $EENS_{i,j,k,t}^3$ respectively. The contribution to $EENS_{i,t}^1$ that can be attributed to Unit i is denoted by $s_{i,t}^1$ (deficit contribution parameter). Similarly, the contribution to $EENS_{i,j,t}^2$ and $EENS_{i,j,k,t}^3$ that can be allocated to Unit i are $s_{i,j,t}^2$ and $s_{i,j,k,t}^3$, respectively. The $EENS$ of the first, second and third order outages due to the failure of units is calculated by using the following equations.

$$EENS_{i,t}^1 = \max \left[0, (P_{i,t} + R_{i,t}^g - R_t) \right] * p_{i,t} \prod_{u=1, u \neq i}^N (1 - p_u) \quad (5.7)$$

$$EENS_{i,j,t}^2 = \max \left[0, (P_{i,t} + R_{i,t}^g + P_{j,t} + R_{j,t}^g - R_t) \right] * p_{i,t} p_{j,t} \prod_{u=1, u \neq i, j}^N (1 - p_u) \quad (5.8)$$

$$\begin{aligned} EENS_{i,j,k,t}^3 = & \max \left[0, (P_{i,t} + R_{i,t}^g + P_{j,t} + R_{j,t}^g + P_{k,t} + R_{k,t}^g - R_t) \right] \\ & * p_{i,t} p_{j,t} p_{k,t} \prod_{u=1, u \neq i, j, k}^N (1 - p_u) \end{aligned} \quad (5.9)$$

For a single unit failure, the number of outage events is N . If the spinning reserve is not sufficient to cover the loss of Unit i , the energy deficiency amount is calculated as $(P_{i,t} + R_{i,t}^g - R_i)$. This part of $EENS$ will be included in the calculation of (5.7). Otherwise, if the spinning reserve amount is larger than the sum of the dispatched energy and reserve of Unit i , then it will not be included in the $EENS$ calculation since energy deficiency does not occur. The ORR of Unit i is $p_{i,t}$ and p_u denotes the ORR of all other units. The $EENS$ calculation of the first order outage (contingency of a single unit outage) is as shown in (5.7). Similarly, the $EENS$ of the second order outage (contingency of simultaneous outage of two units) can be calculated in (5.8). In this case, two random units are outaged at the same time and this results in a larger amount of generation lost and the possibility of energy deficiency increases. The number of the second order outage events raises to $N*(N-1)/2$. The $EENS$ of the third order outage is calculated in a similar way as in (5.9).

Clearly, the energy deficiency for the first order is caused solely by the unit which fails. Hence this unit should be fully responsible for the entire $EENS_{i,t}^1$ and the deficit contribution parameter $s_{i,t}^1$ is equal to 1. The deficit contribution parameters for the second and third order outage, $s_{i,j,t}^2$ and $s_{i,j,k,t}^3$, are formulated as in (5.10) and (5.11), respectively. The deficit contribution parameter is a function of the dispatched MW, amount of reserve allocated and the ORR of Unit i . This is reasonable because larger units (with higher output and higher reserve levels allocated) will contribute more to $EENS$ than smaller units. Furthermore, units with high ORR (more likely to fail) will contribute more to $EENS$. The contribution that Unit i makes to $EENS$ when involved in high order outages will be measured by the deficit contribution parameters, which is proportional to the product of $(P_{i,t} + R_{i,t}^g)$ and $p_{i,t}$ as shown in equations (5.10) and (5.11).

$$s_{i,j,t}^2 = \frac{(P_{i,t} + R_{i,t}^g) * p_{i,t}}{(P_{i,t} + R_{i,t}^g) * p_{i,t} + (P_{j,t} + R_{j,t}^g) * p_{j,t}} \quad (5.10)$$

$$s_{i,j,k,t}^3 = \frac{(P_{i,t} + R_{i,t}^g) * p_{i,t}}{(P_{i,t} + R_{i,t}^g) * p_{i,t} + (P_{j,t} + R_{j,t}^g) * p_{j,t} + (P_{k,t} + R_{k,t}^g) * p_{k,t}} \quad (5.11)$$

5.2.3 Formulation of *EENS* for Interruptible Loads

$EENS_{i,t}$ in the last term of (5.1) is the possible energy loss caused by an interruptible load failing to supply the reserve when requested. This energy deficit can be calculated in a similar way as for generating units.

Generally, interruptible load schemes are set up by the pool with incentives to attract the customers to offer reserve services for the purpose of system security and reliability. Such contracts may be beneficial given that the frequency of providing the service may be relatively low. Even when an outage occurs, load curtailment may not be required every time because spinning reserve provided by part loaded generators may be sufficient. Of course, the customer will be obliged to shed its load when it is called to serve its duty during emergency.

The ILs considered in this paper are mostly industrial and commercial loads which could be office buildings, industrial plants, chiller plants, etc. In this context we consider ILs that may be tripped automatically (instantaneously) via under frequency relays as well as ILs whose load is reduced manually within 10 minutes upon notification.

In Singapore, the restructured power market allows interruptible loads to bid into the real time reserve market directly. It is important however to adequately incentivize interruptible loads to deliver their expected contribution to reserve when required. It would not be appropriate for generators only to take the entire responsibility for outages as interruptible loads may also fail when the system requires that its load be shed. Hence failure rates can be allocated to interruptible loads similar to generators. If an interruptible load never fails, its failure rate can be set to zero. This will allow the development of a settlement scheme that includes interruptible loads in the allocation of reserve costs.

Although the allocation of reserve responsibility for interruptible loads is similar to that of generators, there are some key differences. In contrast to generators, interruptible loads make no energy contribution and so no first order outages are possible. This means that an interruptible load cannot result in energy deficiency by itself and it has to share the responsibility with at least one other generating unit. Following an outage the system could call for reserve services from an interruptible load. If the interruptible load fails to respond, there are two possible situations. One is that this causes no energy deficit provided that remaining generators and/or other interruptible loads are available and have sufficient capacity for meeting the required reserve request. Otherwise, the demand will need to be curtailed. Hence, a penalty will be imposed and/or a compensation will be charged against the interruptible loads for failing to provide reserve. The *EENS* formulation evaluates the reserve responsibility for individual interruptible loads as follows:

$$\begin{aligned}
 EENS_{l,t} = & \sum_{i=1}^N r_{l,i,t}^2 * EENS_{l,i,t}^2 + \sum_{i=1}^N \sum_{j>i}^N r_{l,i,j,t}^3 * EENS_{l,i,j,t}^3 \\
 & + \sum_{m=1, m \neq l}^L \sum_{i=1}^N r_{l,m,i,t}^3 * EENS_{l,m,i,t}^3 + \dots
 \end{aligned} \tag{5.12}$$

As discussed before, an interruptible load will not cause energy deficiency by itself, so the *EENS* caused by the interruptible load begins from the second order outage event as in the first term of (5.12) with one interruptible load and one unit fail. For the *EENS* of the third order, there are two possible situations, denoted by the remaining two terms in (5.12). Clearly, the second term of (5.12) represents the situation of one interruptible load and two units failing simultaneously. On the other hand, the third term applies to the situation of two interruptible loads and one unit failing simultaneously. Both variables l and m represent interruptible loads and i and j represent units. Terms $r_{l,i,t}^2$, $r_{l,i,j,t}^3$ and $r_{l,m,i,t}^3$ represent the deficit contribution parameters which measure the proportion of *EENS* that is attributable to interruptible load (l). Similarly, higher outage orders deficit contribution parameters can be calculated. However only second and third order outages are considered here as the probabilities of higher order outages occurring are very small and can be neglected.

The number of the second order outages is $L*N$, where L is the number of interruptible loads and N is the number of units. The number of events in which only one interruptible load is involved is $L*N(N-1)/2$. Similarly, the number of events involving two interruptible loads is $L(L-1)*N/2$. As it can be found, the number of events increases with the increase of the outage order. On the contrary, the probability of outage events reduces significantly with the outage order given that the failure rates of generators are relatively small. The $EENS$ caused by both interruptible loads and generators for the second and third order outages is computed as in (5.13), (5.14) and (5.15).

$$EENS_{l,i,t}^2 = \max \left[0, (R_{l,t}^{il} + P_{i,t} + R_{i,t}^g - R_t) \right] * p_{l,t}^{il} p_{i,t} \prod_{v=1, v \neq l,i}^{L+N} (1 - p_v) \quad (5.13)$$

$$EENS_{l,i,j,t}^3 = \max \left[0, (R_{l,t}^{il} + P_{i,t} + R_{i,t}^g + P_{j,t} + R_{j,t}^g - R_t) \right] * p_{l,t}^{il} p_{i,t} p_{j,t} \prod_{v=1, v \neq l,i,j}^{L+N} (1 - p_v) \quad (5.14)$$

$$EENS_{l,m,i,t}^3 = \max \left[0, (R_{l,t}^{il} + R_{m,t}^{il} + P_{i,t} + R_{i,t}^g - R_t) \right] * p_{l,t}^{il} p_{m,t}^{il} p_{i,t} \prod_{v=1, v \neq l,m,i}^{L+N} (1 - p_v) \quad (5.15)$$

For the outage event that involves an interruptible load, the deficit contribution parameters are determined in a similar way as for generating units. Note however that the “output” of interruptible loads under normal operating conditions is zero, and that only reserve commitment is relevant for the evaluation.

$$r_{l,i,t}^2 = \frac{R_{l,t}^{il} * p_{l,t}^{il}}{R_{l,t}^{il} * p_{l,t}^{il} + (P_{i,t} + R_{i,t}^g) * p_{i,t}} \quad (5.16)$$

$$r_{l,i,j,t}^3 = \frac{R_{l,t}^{il} * p_{l,t}^{il}}{R_{l,t}^{il} * p_{l,t}^{il} + (P_{i,t} + R_{i,t}^g) * p_{i,t} + (P_{j,t} + R_{j,t}^g) * p_{j,t}} \quad (5.17)$$

$$r_{l,m,i,t}^3 = \frac{R_{l,t}^{il} * P_{l,t}^{il}}{R_{l,t}^{il} * P_{l,t}^{il} + R_{m,t}^{il} * P_{m,t}^{il} + (P_{i,t} + R_{i,t}^g) * P_{i,t}} \quad (5.18)$$

When calculating $EENS_{i,t}^{il}$ in (5.5), the deficit contribution parameters that measure the contribution of each unit $r_{i,l,t}^2, r_{i,l,j,t}^3, r_{i,l,m,t}^3$ to $EENS$ can be obtained by the numerators in (5.16) through (5.18) replaced by the unit MW and reserve contribution of Unit i . The $EENS_{i,t}^{il}$ is computed as in (5.19).

$$\begin{aligned} EENS_{i,t}^{il} = & \sum_{l=1}^L r_{i,l,t}^2 * EENS_{l,i,t}^2 + \sum_{l=1}^L \sum_{j=1, j \neq i}^N r_{i,l,j,t}^3 * EENS_{l,i,j,t}^3 \\ & + \sum_{l=1}^L \sum_{m>l}^L r_{i,l,m,t}^3 * EENS_{l,m,i,t}^3 + \dots \end{aligned} \quad (5.19)$$

$EENS_{i,t}^{il}$ is different from $EENS_{l,t}$ in (5.12) because the former represents the expected energy deficit that can be attributed to Unit i including failure of interruptible loads to respond, while the latter represents the energy deficiency attributed to interruptible loads only.

The total system $EENS$ at period t , considering both the unit and interruptible load outages, can be expressed as follows:

$$EENS(t) = \sum_{i=1}^N EENS_{i,t} + \sum_{l=1}^L EENS_{l,t} \quad (5.20)$$

The relative contribution of each generating unit and interruptible load to the total $EENS$ in period t is given by (5.21) and (5.22) respectively.

$$EENS_{i,t}^{share} = \frac{EENS_{i,t}}{EENS(t)} \quad (5.21)$$

$$EENS_{l,t}^{share} = \frac{EENS_{l,t}}{EENS(t)} \quad (5.22)$$

On the other hand, each participant of the reserve market also has a share of the supply of reserve at each period. The system spinning reserve requirement is the summation of their spinning reserve amount. The relative contribution of each participant (generating unit or interruptible load) in reserve provision is as follows:

$$SR_{i,t}^{share} = \frac{R_{i,t}^g}{\sum_{i=1}^N R_{i,t}^g + \sum_{l=1}^L R_{l,t}^{il}} \quad (5.23)$$

$$SR_{l,t}^{share} = \frac{R_{l,t}^{il}}{\sum_{i=1}^N R_{i,t}^g + \sum_{l=1}^L R_{l,t}^{il}} \quad (5.24)$$

Prior to introducing interruptible loads participation, the payment or compensation of the reserve provision is settled among generating units, while demand customers are not involved in the settlement scheme for the reserve market. Every unit shares all the responsibilities of energy deficiency according to unit outages. If no outage happens, the generator is paid according to the reserve amount scheduled. If outages happen, the generator suffers losses because it needs to pay others for the losses caused by its failure.

Following the proposed approach, this scheme can be extended to interruptible loads, as these are treated in the same way as generators. For each market clearing period, generator payments or charges can be computed as follows:

$$Payment_{i,t} = [EENS_{i,t}^{share} - SR_{i,t}^{share}] * RCP_t * \left[\sum_{i=1}^N R_{i,t}^g + \sum_{l=1}^L R_{l,t}^{il} \right] \quad (5.25)$$

where RCP_t is the reserve market clearing price for each period.

The payments or charges for interruptible loads can be evaluated using (5.25) when the terms representing relative contribution (share) to $EENS$ and reserve provision are substituted by those given by equations (5.22) and (5.24). As can be seen, customers who participate in the market as interruptible loads are also involved

in the payment schedule. If a customer guarantees that it can comply with the system requests, it will surely gain money from the reserve market. If it fails to respond, it needs to compensate the pool. Hence this settlement scheme treats equally all market participants. Each participant benefits from contributing to the reserve and is penalized for their contribution to energy deficits. There is clearly an incentive for generators and interruptible loads to enhance their performance and to avoid failures.

5.3 Simulation Results

The proposed formulation and scheme are tested on the same IEEE reliability test system as those in the earlier chapters without the hydro generation. The energy bid prices and quantities are the same as those in Chapter 3 and are given in Appendix. The reserve bid prices are taken as a 10 percent of the highest energy bid price. Hence there is only one segment for the reserve quantity and bid price. The bidding data of interruptible loads are chosen to create suitable system operation condition for the study purpose and are given in Table A.6 of Appendix. The Lagrangian Relaxation optimization method is used to carry out a number of case studies. Up to third order outages are taken into consideration in all the cases.

5.3.1 Effect of Generator's Reliability

The base case in this study, which performs the objective function in (5.1), is minimized and operates with a uniform system reliability or *LOLP* value of 0.024 for each period. All the other cases are compared with the base case. To show the effect of reliability terms four and five in (5.1), Case I is set up without taking these terms into account in the objective function. All other cases (Cases II-V) however include these terms. Cases II and III illustrate the impact of individual unit characteristics on their financial performance in the market. Cases IV and V show the effect of the proposed settlement scheme.

Three scenarios are run for Case I with different reliability levels: Cases I-A, is characterized by a higher reliability level with *LOLP* of 0.014. Case I-B has the same system reliability level as that of the base case (*LOLP* = 0.024), while a lower

reliability level with *LOLP* of 0.034 is associated with Case I-C. Table I presents the differences between the three scenarios in Case I and the base case. The cost of *EENS* of Case I is also calculated for the comparison purpose. It is calculated when *VOLL* is 3 \$/kWh for all the cases in Table 5.1.

The total cost of the base case is the lowest, although neither its system schedule cost nor *EENS* cost is the lowest among the cases. It turns out that the system characterized with the medium reliability level achieves the lowest total cost. As expected, the generation scheduling cost increases with the level of reliability. The reserve cost in Case I-A is the highest since it requires the largest amount of spinning reserve to maintain the high reliability. Of course, its *EENS* is the smallest. On the other hand, the system with the low reliability level has the lowest generation cost but the highest *EENS*. However, in the base case, the reserve is dispatched by considering unit's and interruptible load's *EENS* (terms 4 and 5) in the objective function of (5.1). The base case achieves the lowest total cost among the four cases in Table 5.1. Note that the total cost of Case I-B is higher than the base case, although both systems deliver the same reliability level. This proves that the incorporation of unit's and interruptible load's *EENS* in the objective function will minimize the overall cost and lead to optimal system operation.

Table 5.1 Effect of *EENS* terms towards costs in (5.1)

	Base Case	Case I		
		Case I-A	Case I-B	Case I-C
Total cost (\$) Terms 1~5	678596.8	694432.2	678721.1	685668.1
System schedule cost (\$) Terms 1~3	638788.2	671720.4	639661.6	632577.8
Reserve cost (\$) Terms 2 & 3	17785.6	20217.1	17890.5	16378.6
<i>EENS</i> (kWh)	13269.5	7570.6	13019.8	17696.8
<i>EENS</i> cost (\$) (<i>VOLL</i> =3\$/kWh) Terms 4 & 5	39808.6	22711.8	39059.5	53090.3
<i>LOLP</i> (%)	2.4	1.4	2.4	3.4

Case I-B with the middle reliability is further tested to show the effect of generators' and interruptible load's reliability terms. As mentioned before, the *LOLP* under this scenario is the same as that of the base case, which is 0.024. Table 5.2 shows the comparison results between the base case and Case I-B. For the simplicity of analysis, only results at Hour 11 when the demand load is the highest are given here to show the effect. The results indicate that units with high *ORR* are scheduled for less operating hours or even not committed, and some of them are dispatched for less MWs during their operating hours in the base case.

Table 5.2 Unit status and energy dispatch at Hour 11

Unit number	Unit status		MW	
	Base Case	Case I-B	Base Case	Case I-B
1	1	1	2.400	2.400
2	1	1	2.400	2.400
3	1	1	2.400	2.400
4	1	1	2.400	2.400
5	1	1	2.400	2.400
6	0	1	0.000	4.000
7	0	1	0.000	4.000
8	0	1	0.000	4.000
9	0	0	0.000	0.000
10	1	1	69.582	69.582
11	1	1	69.582	69.582
12	1	1	69.582	69.582
13	1	1	69.582	69.582
14	1	1	91.498	91.498
15	1	1	91.498	91.498
16	1	1	91.498	91.498
17	1	1	142.081	142.081
18	1	1	142.081	142.081
19	1	1	142.081	142.081
20	1	1	142.081	142.081
21	1	1	68.950	111.630
22	1	1	68.950	89.899
23	1	1	57.832	68.950
24	1	1	341.122	320.827
25	1	1	400.000	366.887
26	1	1	400.000	366.660

(Unit status: 1 = committed, 0 = not committed)

As can be seen in Table 5.2, Units 6-8, which have the highest *ORR* among the 26 units, are uncommitted in the base case but they are committed in Case I-B. Unit 9 is not committed in both cases due to its high bidding price. Furthermore, Units 21-23 in Case I-B dispatch more MWs than the respective values in the base case. This is

because Units 21-23 have high *ORR* values just below those of Units 6-8. The MW dispatches of Units 24-26 become higher in the base case than those in Case I-B due to their lower *ORR* compared with those of Units 6-8 and 21-23. It should be noted that *ORR* is not the only factor that influence the schedule of the system. For some other units, their MW dispatch may remain the same in both cases at Hour 11. Many other parameters and constraints, such as the bidding price, maximum capacity and ramp rate, also influence the schedule. Under the proposed objective function, fewer units are committed in the base case than in Case I-B.

Table 5.3 Unit status comparison for the base case and Case II

Hour	Base Case		Case II	
	Unit 8	Unit 9	Unit 8	Unit 9
1	0	0	0	0
2	0	0	0	0
3	0	0	0	0
4	0	0	0	0
5	0	0	0	0
6	0	0	0	0
7	0	0	0	0
8	1	0	0	1
9	1	0	0	1
10	1	0	0	1
11	1	0	0	1
12	1	0	0	1
13	1	0	0	1
14	1	1	0	1
15	1	1	0	1
16	1	0	0	1
17	1	0	0	1
18	1	0	0	1
19	1	0	0	1
20	1	0	0	1
21	1	0	0	1
22	1	0	0	1
23	0	0	0	0
24	0	0	0	0

(Unit status: 1 = committed, 0 = not committed)

Case II shows the system situation when the *ORR* of Unit 9, which is one of the most unreliable generators, is reduced. As shown in Table 5.3, Unit 9 replaces Unit 8, which is the marginal unit in the base case, although the bidding price of Unit 9 is a little higher than that of Unit 8. This explains that the system tends to commit units with lower *ORR* after the incorporation of individual unit’s reliability into the

objective function. This serves as an incentive for the generators to improve their performance and it enhances the system security and reliability level by balancing the schedule cost and the possible cost of *EENS* when contingencies happen.

Table 5.4 Unit status and energy dispatch comparison for the base case and Case III

Hour	Unit status						MW of Unit 10	
	Base Case			Case III			Base Case	Case III
	Unit 3	Unit 5	Unit 10	Unit 3	Unit 5	Unit 10		
1	0	0	1	1	0	0	15.200	0.000
2	1	0	1	1	1	0	15.200	0.000
3	0	0	1	1	0	0	15.200	0.000
4	0	0	1	1	0	0	15.200	0.000
5	1	0	1	1	1	0	15.200	0.000
6	1	0	1	1	1	1	22.122	15.200
7	1	0	1	1	1	1	55.730	15.200
8	1	1	1	1	1	1	69.582	15.200
9	1	1	1	1	1	1	69.582	15.200
10	1	1	1	1	1	1	69.582	53.700
11	1	1	1	1	1	1	69.582	69.582
12	1	1	1	1	1	1	69.582	45.127
13	1	1	1	1	1	1	69.582	45.127
14	1	1	1	1	1	1	69.582	15.200
15	1	1	1	1	1	1	69.582	53.700
16	1	1	1	1	1	1	69.582	69.582
17	1	1	1	1	1	1	69.582	15.200
18	1	1	1	1	1	1	69.582	15.200
19	1	1	1	1	1	1	69.582	15.200
20	1	1	1	1	1	1	69.582	15.200
21	1	1	1	1	1	1	69.582	53.700
22	1	1	1	1	1	1	69.582	15.200
23	1	1	1	1	1	0	69.582	0.000
24	1	0	1	1	1	0	15.200	0.000

Unit 10 is among the most reliable generators with the lowest *ORR* in the system. In Case III the *ORR* of this unit is doubled. Table 5.4 shows the relevant results of the optimization. Note that Unit 10 is scheduled to run in all periods in the base case, while in Case III this unit operates fewer hours (during hours 1-5 and 23-24 the unit is not committed). Instead, Units 3 and 5 are dispatched for more hours in Case III due to their high reliability. They are committed for a longer period to satisfy the load demand. In Case III, Unit 10 not only is dispatched for fewer hours due to the increased *ORR*, but also the dispatched energy is much lower than that of the base case even during the period it is committed. As can be seen from the last two columns in Table 5.4, the energy dispatched for Unit 10 in Case III becomes lower except at

hours 11 and 16, when the load is at its peak and the output is the same in both cases.

5.3.2 Effect of Settlement Scheme

For the purpose of studying the proposed settlement scheme, two more cases are tested under different scenarios. Case IV excludes the participation of interruptible loads in the reserve market. Case V is with interruptible loads being perfectly reliable. Note that interruptible loads are included in the base case with a non-zero failure rate.

In the process of calculating *EENS*, outages of the third order are considered. In fact, the outages of the second order will be sufficient in the majority of practical cases. In the case study carried out, the *EENS* of the third outage order is about $1.1524279E-41$, clearly a small number that can be ignored. Note that the *EENS* of the first outage order remains zero and will not cause any energy deficits since the amount of reserve will be larger than the capacity of the largest generator.

The settlement process is proposed to cover 24 hours since the reserve prices change in each hour and result in different hourly payment. Hence, the MW dispatch, reserve dispatch, and the reserve settlement are all different every hour. For the convenience of analysis, only selected results that highlight the differences between the cases are given here. Except for the units shown in Tables 5.5, 5.6 and 5.7, the remaining units are not committed either in the energy or reserve market and they are removed from the tables as they have no effects on the settlement scheme. All the results shown in the three tables are at Hour 1.

According to the formulation in Section 5.2, the reserve responsibility share in expressions 5.21 and 5.22, the reserve supply share in expressions 5.23 and 5.24, *EENS* and corresponding payment are calculated for each unit. The sum of the values representing the reserve responsibility share or reserve supply share is 1. Table 5.5 shows the settlement for reserve and the payment among units in Case IV. Positive values in the payment column mean that the corresponding generator/interruptible load should pay others, while negative values indicate that the generator/interruptible load would get paid.

Furthermore, the payments of Units 24-26 are positive due to the fact that they contribute mostly the energy and very little reserve. They are generators with the largest capacity (400 MW) in the system, hence outages of these units cause largest energy deficits. The *EENS* values in Table 5.5 reflect the consequence. Note that the values of *EENS* associated with Units 24-26 are significantly larger than those corresponding to any other unit.

Table 5.5 Reserve settlement and payment among units in Case IV at Hour 1
(Interruptible loads not participated)

Unit number	Reserve (MW)	Reserve responsibility share	Reserve supply share	<i>EENS</i> (kWh)	Payment (\$)
10	38.000	0.0000	0.0854	0.00	-55.40
11	38.000	0.0000	0.0854	0.00	-55.40
12	31.000	0.0000	0.0697	0.00	-45.20
17	33.580	0.0009	0.0755	2.00	-48.35
18	35.606	0.0009	0.0800	2.00	-51.30
19	67.170	0.0009	0.1509	2.00	-97.32
20	67.170	0.0009	0.1509	2.00	-97.32
24	70.000	0.2544	0.1573	544.20	63.02
25	31.134	0.3709	0.0700	793.10	195.24
26	33.340	0.3709	0.0749	793.10	192.02

Table 5.6 Reserve settlement and payment among units and interruptible loads in Case V at Hour 1 (Perfectly reliable interruptible loads)

Unit number	Reserve (MW)	Reserve responsibility share	Reserve supply share	<i>EENS</i> (kWh)	Payment (\$)
10	27.000	0.0000	0.0607	0.00	-39.10
11	0.000	0.0000	0.0000	0.00	0.00
12	0.000	0.0000	0.0000	0.00	0.00
17	33.580	0.0009	0.0755	1.70	-48.02
18	35.606	0.0009	0.0800	1.70	-50.96
19	67.170	0.0009	0.1509	1.70	-96.67
20	67.170	0.0009	0.1509	1.70	-96.67
24	70.000	0.2546	0.1573	468.40	62.63
25	31.134	0.3709	0.0700	684.80	193.91
26	33.340	0.3709	0.0749	684.80	190.72
IL Agent					
1	80.000	0.0000	0.1798	0.00	-115.85
2	0.000	0.0000	0.0000	0.00	0.00
3	0.000	0.0000	0.0000	0.00	0.00

Table 5.6 shows the results of Case V that includes interruptible loads that are 100% reliable. Given more competitive reserve prices offered by interruptible loads, the reserve supplied by the marginal units (Units 11 and 12 in Case IV), is replaced by IL Agent 1. Furthermore, the reserve provided by Unit 10 is reduced for the same reason. Hence the reserve supply share of Unit 10 and the corresponding payment are reduced. It can also be noted that both the charges to Units 24-26 and the payments to Units 17-20 are reduced. The reason is that IL Agent 1 shares a certain amount of reserve with units and it would not result in any energy deficiency. It relieves the burden of units to provide reserve. So the participation of interruptible loads enhances the competition in provision of reserve. Clearly, generators need to improve their reliability performance and reduce (control) their cost in order to effectively compete in the reserve market.

Furthermore, $EENS$ values in Table 5.6 are reduced greatly compared with those in Table 5.5. These results accord with the concept of the settlement scheme set up in this chapter. For Case V, IL Agents are assumed to be 100% reliable, so $EENS_{i,t}$ and $EENS_{i,t}^H$ are zero. Given that the IL agents contribute to the provision of reserve the amount of reserve allocated to Unit i , $R_{i,t}^g$, becomes smaller. Hence the $EENS_{i,t}^g$ attributable to each unit will become lower according to (5.7)-(5.9). This explains well that the participation of interruptible loads helps to improve the system reliability, especially when the interrupted loads are in 100 percent compliance when the system requests. This conclusion is further strengthened in the following study.

Simulation results with interruptible loads having a certain failure rate (as in the base case) are as shown in Table 5.7. As expected Units 24-26 pay even less to others in the base case when compared with those of Case V. Similarly, IL Agent 1 receives \$3.6 (\$115.85 - \$112.25) less in the base case. This is because IL Agent 1 now contributes to $EENS$ (9.30 kWh). This means that it will cause energy deficiency if it fails to respond upon request. The reserve responsibility share of IL Agent 1 in the base case is 0.0058 and it is 0 in Case V. According to the payment formulation in (5.25), IL Agent 1 will gain less as predicted.

Table 5.7 Reserve settlement and payment among units and interruptible loads in the base case at Hour 1 (Interruptible loads with non-zero failure rates)

Unit number	Reserve (MW)	Reserve responsibility share	Reserve supply share	EENS (kWh)	Payment (\$)
10	27.000	0.0000	0.0607	0.00	-39.10
11	0.000	0.0000	0.0000	0.00	0.00
12	0.000	0.0000	0.0000	0.00	0.00
17	33.580	0.0009	0.0755	2.00	-48.02
18	35.606	0.0009	0.0800	2.00	-50.96
19	67.170	0.0009	0.1509	2.00	-96.67
20	67.170	0.0009	0.1509	2.00	-96.67
24	70.000	0.2526	0.1573	541.50	61.43
25	31.134	0.3690	0.0700	789.30	192.72
26	33.340	0.3690	0.0749	789.30	189.53
IL Agent					
1	80.000	0.0058	0.1798	9.30	-112.25
2	0.000	0.0000	0.0000	0.00	0.00
3	0.000	0.0000	0.0000	0.00	0.00

However, the *EENS* value for each unit or the IL Agent in Table 5.7 increases in the base case. It increases from 468.40 kWh to 541.50 kWh for Unit 24 and from 684.8 kWh to 789.3 kWh for Units 25 and 26. Overall, the total *EENS* value for the base case is still lower than that of Case IV that has no interruptible loads participation. This is because the $EENS_{i,t}$ and $EENS_{i,t}^{\#}$ are not zero anymore compared with those of Case IV. But the increase of the $\sum EENS_{i,t}$ and $\sum EENS_{i,t}^{\#}$ may be less than the decrease of $\sum EENS_{i,t}$ due to the decrease of the reserve dispatched for units. Again, this indicates that the participation of interruptible loads is useful to the whole system. But interruptible load will also cause problems if it cannot respond to system request for load interruption. Hence, to safeguard system reliability and security, it is necessary to set up the settlement scheme and make customers take a share of responsibility.

Although the differences in hourly payments between the cases are relatively small, they may be more substantial in the course of a day as demonstrated in Figure 5.1. The payments to some units, such as generators 1-7 are very small when compared with charges for large units like Units 24-26. When compared to Case IV, the charges for Units 24-26 are reduced greatly following the participation of IL Agents in Case V and the base case. For one day, Unit 26 saves \$1,663.48 in Case V

and \$1,675.33 in the base case. If it is committed to operate for say 300 days in a year, the total reduction payment will be \$499,044 and \$502,599 respectively. For IL Agent 1, its gain in Case V is \$30.88 (\$4,111.71 - \$4,080.83) more than that in the base case per day. If the interruptible load were to supply the reserve with 100% reliability, some $\$30.88 \times 365 = \$11,271.2$ more will be gained.

In addition, *EENS* is mainly caused by Units 24-26, which have the largest capacity in the system and these units are the major providers of energy. The *EENS* value of IL Agent 1 in a whole day is 65.94 kWh, and it is 6.83kWh for IL Agent 2. The responsibility shares for the IL Agents of the market are not significant since they only provide reserve and the amount they bid into the reserve market is not very large. However they still affect the dispatch and settlement of the reserve market with their low bidding prices.

Figure 5.1 Payment comparison for the reserve market

From the above analysis of the payment scheme, it can be concluded that the participation of IL Agents enhances the competition in the reserve market. Generators/IL Agents will be encouraged to improve their performance if they want to be dispatched for a longer time and to gain more revenue from the market. The probabilistic reserve scheme also improves the system reliability in addition to ensure economic operation of the system.

5.4 Summary

Interruptible loads, a kind of potential reserve provider to compete with generators, have been widely considered and implemented in many power markets all over the world. Interruptible load contracts are prevalently set up for reserve markets in many countries in the world. They usually involve commercial and industrial consumers. They may reduce the total pool cost and reserve price, especially at hours when a contingency happens. Interruptible loads in the reserve market can also help to maintain the system security and to control the market power in a power market.

In a competitive electricity market, the security of the system is influenced by the level of ancillary services that are produced. Reserve management is an important aspect to be considered in the restructured electricity market. The incentive for GENCOs to supply reserves is derived from market settlement. Settlement influences the GENCOs' behavior in terms of finance. Hence, the settlement scheme has to provide enough stimuli for these GENCOs to supply reserves.

Compared to the earlier work in Chapter 3 and Chapter 4, the market structure and problem formulation are altered in this chapter for the purpose of studying the effect of interruptible load's and generator's reliability. Demand side customers only provide interruptible loads as a kind of reserve and bid into the real time reserve market, but do not participate in the energy market. A probabilistic reserve dispatch is implemented by taking the individual unit's and interruptible load's reliability into account. Those with high outage replacement rate will be dispatched for fewer hours and less MWs by the system. A uniform system risk is achieved by balancing the schedule cost and the cost of *EENS* as a whole optimization problem in the objective function.

Following the settlement scheme for the reserve market set up in Singapore, the participation of interruptible loads is included into the proposed settlement scheme. It rewards participants with low failure rates and penalizes those with high failure rates. Interruptible loads also share the responsibility with generators for supplying the reserve and for converting into energy when requested. From the simulation results, it

is concluded that the incorporation of interruptible loads not only improves the security and reliability of the system, but also relieves the burden of generators to provide reserve. Interruptible loads also compete with units to bring down the reserve price.

Chapter 6

Conclusions and Future Works

6.1 Conclusions

The move towards competitive electricity markets has changed how electricity is traded, and thereby opens the door for demand-side participation. Demand-side participation offers consumers the opportunity to receive financial compensation for making short-term changes to their electricity consumption. By rescheduling loads or agreeing to load reductions, consumers help to maintain a balance between electricity supply and demand and to ensure the quality and security of supply.

A market model by incorporating demand-side participation into a pool-based electricity market is examined in this thesis. In order to illustrate the effect of demand-side participation on a fair basis, load recovery is considered such that the total demand remains unchanged over the whole operating periods. Two models for *EENS* evaluation are proposed. One is evaluating *EENS* for each interval of the unit commitment schedule by the convolution of the MW capacity outage probability distribution function and the number of MWhs of energy shed. The total *EENS* is the sum of the *EENS* values for each interval of the schedule. The other one calculates *EENS* for each involved individual unit when an outage happens at that period. Up to third outage order is considered when computing the *EENS* value. The total *EENS* is the summation of *EENS* of all the units in the system. Each of these two *EENS* costs under the two models mentioned above is included in the objective function together with the schedule cost. A probabilistic spinning reserve schedule is obtained based on

the minimization of the total cost by balancing the cost of providing reserve and the cost of energy not supplied.

Finally, a settlement scheme for reserve market is proposed. It argues that it may no longer be true that all consumers should pay the cost of reserve on the basis of their consumption. The only way to reduce the cost of reserve is to give an incentive to both the generators and consumers to minimize the purchase price. Generators already have an incentive to improve the reliability of their plants because a plant that is not available cannot generate energy, and of course, will not get any revenue. But this incentive should be sharpened through charging generators for the cost of unreliability, e.g. the cost of reserve. In the long term, improving the reliability of the generating units will reduce the optimal amount of reserve. The settlement proposed in this thesis makes generators share reserve responsibility and pay for the reserve market. Interruptible load is also considered in the market. It is assumed that interruptible loads have a failure rate when they respond to reserve just like that of generators. So it shares reserve responsibility along with all the generators.

Various scenarios for case studies are set up and compared to illustrate the effect of demand-side participation, probabilistic reserve on generation scheduling, and the settlement scheme with interruptible loads. With the participation of the demand side, the schedule cost and the total cost are reduced. The profits of GENCOs are eroded, and the MCP generally becomes lower. In general, the market operates more efficiently. However, this is not always true. Demand-side bidding may also result in a higher MCP under some situations. High MCPs result when offers from generators are so inflexible that demand-side bids are selected instead, although the contribution of the demand side to the global social welfare is smaller than the value of competing generation bids. Hence, the actual value of demand-side bidding should be carefully examined in the light of these findings.

The probabilistic reserve assessment can effectively control the spinning reserve and it can result in substantial cost reductions in a large power system. Excess spinning reserve is reduced where possible in view of unit constraints. Through the probabilistic approach, the system operates more economically. The settlement scheme also provides an incentive for all market participants to improve their

performance and to be responsible for their failures. It is concluded that the participation of interruptible loads in the reserve market and the settlement scheme not only improve the security and reliability of the system, but also relieve the burden of generators to provide reserve. Interruptible loads also compete with units to bring down the reserve price. As a whole, the schemes proposed in this thesis improve the security and reliability of the system and enhance the efficiency of system operation. In the long run, the adoption of the proposed schemes helps to achieve a more economical, reliable, efficient electricity supply system and market.

6.2 Suggestions for Future Works

Power system operation is exposed to many uncertainties. With the deregulation of power systems, it becomes more challenging than ever to find a better way to solve existent problems. As discussed before, power markets will definitely be more open to customers though most countries have not considered the DSB yet. Many countries are planning to do so before long in the future. So a lot of works need to be explored further.

Demand-side bids can build a price response into the market, which is used to determine the MCPs of the wholesale electricity and ancillary services. Demand-side bidding is only used in the energy and spinning reserve market in this thesis. This work can be generalized to incorporate standing reserve in which the response time is longer than spinning reserve as discussed in the thesis. The reliability of standing reserve is far from 100%. System operators need to allocate the overall reserve requirement between the spinning and standing reserve. This is done by balancing the cost associated with loss in efficiency of part loaded plant that provides spinning reserve and the need to start a plant with relatively high fuel costs.

Furthermore, another issue could be studied is the payment to standing reserves. Different forms of standing reserve may be provided by different kinds of generating units. The reliability levels of these generating units which successfully respond to supply reserve upon system requests are different. But they are paid almost the same for a long time. So a more complete market model can be further researched

to incorporate all kinds of reserve products in the market. The cost redistribution among all the energy and ancillary service markets and its impact on the whole market management can be discussed further. At the same time, the decision of how much reserve should be purchased from each of the providers with consideration of different levels of availability could be explored.

In addition, a secondary risk unit is one that has a recognized likelihood of tripping following the tripping of the primary risk unit. There are no secondary risk units modeled in the thesis. However, a secondary risk unit directly impacts on the reserve requirement presented by all other units except itself. Hence, it is effectively adding a statistical component to the secondary risk calculation if this work is studied further on this topic. Of course, some factors need be considered to differentiate the risk of different units.

Demand-side participation can neutralize market power and eliminate price spikes by involving physical curtailments and inter-temporal shifts in electricity consumption. Peak demand can be interrupted voluntarily by the wholesale buyers. Hence, further work can be done in this area to see how the demand side influences the market solution and how it contributes to control market power towards the setting up of a perfect power market. In addition, transmission constraints greatly influence the market clearing solution and market power is likely to occur in a congested system. New algorithms and methods could be developed in the future for determining a measure of market concentration in a congested transmission system.

Appendix

Table A.1 Generator operational parameters

Unit	$P_i^{\min}$ (MW)	$EL1_i$ (MW)	$EL2_i$ (MW)	$P_i^{\max}$ (MW)	T_i^{on} (h)	T_i^{off} (h)	Initial Status (h)	MTTF (h)	UR_i (MW/h)	DR_i (MW/h)
1	2.40	5.60	8.80	12.00	0	0	-1	2940.0	48.0	60.0
2	2.40	5.60	8.80	12.00	0	0	-1	2940.0	48.0	60.0
3	2.40	5.60	8.80	12.00	0	0	-1	2940.0	48.0	60.0
4	2.40	5.60	8.80	12.00	0	0	-1	2940.0	48.0	60.0
5	2.40	5.60	8.80	12.00	0	0	-1	2940.0	48.0	60.0
6	4.00	9.33	14.67	20.00	0	0	-1	450.0	30.5	70.0
7	4.00	9.33	14.67	20.00	0	0	-1	450.0	30.5	70.0
8	4.00	9.33	14.67	20.00	0	0	-1	450.0	30.5	70.0
9	4.00	9.33	14.67	20.00	0	0	-1	450.0	30.5	70.0
10	15.20	35.47	55.73	76.00	3	2	3	1960.0	38.5	80.0
11	15.20	35.47	55.73	76.00	3	2	3	1960.0	38.5	80.0
12	15.20	35.47	55.73	76.00	3	2	3	1960.0	38.5	80.0
13	15.20	35.47	55.73	76.00	3	2	3	1960.0	38.5	80.0
14	25.00	50.00	75.00	100.00	4	2	-3	1200.0	51.0	74.0
15	25.00	50.00	75.00	100.00	4	2	-3	1200.0	51.0	74.0
16	25.00	50.00	75.00	100.00	4	2	-3	1200.0	51.0	74.0
17	54.25	87.83	121.42	155.00	5	3	5	960.0	77.5	77.5
18	54.25	87.83	121.42	155.00	5	3	5	960.0	77.5	77.5
19	54.25	87.83	121.42	155.00	5	3	5	960.0	77.5	77.5
20	54.25	87.83	121.42	155.00	5	3	5	960.0	77.5	77.5
21	68.95	111.63	154.32	197.00	5	4	-4	950.0	98.5	98.5
22	68.95	111.63	154.32	197.00	5	4	-4	950.0	98.5	98.5
23	68.95	111.63	154.32	197.00	5	4	-4	950.0	98.5	98.5
24	140.00	210.00	280.00	350.00	8	5	10	1150.0	175.0	175.0
25	100.00	200.00	300.00	400.00	8	5	10	1100.0	200.0	200.0
26	100.00	200.00	300.00	400.00	8	5	10	1100.0	200.0	200.0

MTTF: Mean Time To Failure

Table A.2 Original load demand for a 24-hour period

Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)
1	1700	7	2000	13	2590	19	2500
2	1730	8	2430	14	2550	20	2550
3	1690	9	2540	15	2620	21	2600
4	1700	10	2600	16	2650	22	2480
5	1740	11	2670	17	2550	23	2200
6	1900	12	2590	18	2530	24	1840

Table A.3 Generator offer data

Unit	$INC1_i$ (\$/MWh)	$INC2_i$ (\$/MWh)	$INC3_i$ (\$/MWh)	$NL1_i$ (\$/h)	α_i (\$)	β_i (\$)	η_i (\$)
1	25.7498	25.9119	26.0741	24.0487	0	0	1
2	25.8872	26.0568	26.2263	24.0550	0	0	1
3	26.0268	26.2060	26.3853	24.2617	0	0	1
4	26.1592	26.3411	26.5229	24.3785	0	0	1
5	26.2895	26.4722	26.6549	24.5045	0	0	1
6	37.7109	37.8388	37.9667	117.3074	20	20	2
7	37.8318	37.9663	38.1009	117.6375	20	20	2
8	37.9582	38.1032	38.2481	117.9503	20	20	2
9	38.0807	38.2335	38.3864	118.2856	20	20	2
10	13.7710	14.1261	14.4812	76.4139	50	50	3
11	13.8073	14.1700	14.5328	76.4731	50	50	3
12	13.8416	14.2104	14.5793	76.5583	50	50	3
13	13.8795	14.2573	14.6351	76.6015	50	50	3
14	18.4673	18.7787	19.0903	210.1077	70	70	4
15	18.5590	18.8650	19.1710	210.6851	70	70	4
16	18.6485	18.9475	19.2465	211.3002	70	70	4
17	11.3518	11.6628	11.9738	120.6731	150	150	6
18	11.3875	11.7052	12.0229	120.4906	150	150	6
19	11.4201	11.7432	12.0663	120.3985	150	150	6
20	11.4502	11.7773	12.1045	120.3918	150	150	6
21	23.4677	23.6888	23.9099	239.1956	200	200	8
22	23.5695	23.7915	24.0134	239.6819	200	200	8
23	23.6749	23.8994	24.1240	239.9326	200	200	8
24	11.3971	11.6113	11.8255	132.0757	300	200	8
25	8.0741	8.4621	8.8501	271.2020	500	500	8
26	8.0881	8.4781	8.8681	272.9100	500	500	10

Table A.4 Altered load demand for a 24-hour period

Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)
1	1700	7	2000	13	2590	19	2500
2	1730	8	2430	14	2550	20	2550
3	1690	9	2540	15	2620	21	2600
4	1700	10	2790	16	2650	22	2480
5	1740	11	2800	17	2550	23	2200
6	1900	12	2590	18	2530	24	1840

Table A.5 Demand-side bidding data

Demand Agents		$Q_j^{\min}$	$EL1_j$	$EL2_j$	$Q_j^{\max}$	$B1_j$	$B2_j$	$B3_j$
		(MW)	(MW)	(MW)	(MW)	(\$/MWh)	(\$/MWh)	(\$/MWh)
Single Agent		12.00	15.30	18.60	22.00	44.0218	44.5673	44.9012
Multiple Agents	1	12.00	15.30	18.60	22.00	44.0218	44.5673	44.9012
	2	12.00	15.00	18.00	21.00	44.0448	44.6663	45.1009
	3	0.00	9.00	13.00	17.00	62.0341	62.6534	63.1107

Table A.6 Interruptible load bidding data in reserve market

Interruptible Load Agent	Bidding Price (\$/MWh)	Bidding MW (MW)	Failure Rate
1	1.1009	20.00	0.002
2	2.5218	25.00	0.005
3	3.0341	15.00	0.011

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Curriculum Vitae

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