Proposed insurance and reserve management scheme for Singapore electricity market

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**A PROPOSED INSURANCE AND RESERVE
MANAGEMENT SCHEME FOR SINGAPORE
ELECTRICITY MARKET**

A PROPOSED INSURANCE AND RESERVE MANAGEMENT
SCHEME FOR SINGAPORE ELECTRICITY MARKET

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SCHOOL OF ELECTRICAL AND ELECTRONIC
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2006**

2006

A Proposed Insurance and Reserve Management Scheme for Singapore Electricity Market

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School of Electrical and Electronic Engineering

A thesis submitted to the Nanyang Technological University
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Doctor of Philosophy

2006

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Summary

The new electricity market has been introduced in Singapore since 2003. Like other electricity markets, the Singapore Electricity Market brings customers choices. However, some problems still persist and there is room to improve the market design.

Blackouts still exist after the introduction of the electricity market. Under the current market environment, consumers are not well protected from financial losses caused by generator outages. Consumers suffering loss of load are not compensated and failed generators causing load curtailments are not penalized either.

The “ $n-1$ security” criterion is used in the Singapore Electricity Market for the determination of the reserve requirement. It is simple and easy to implement, but the emerging probabilistic criterion attracts attention. When scheduling reserve, the probabilistic reserve criterion considers the possibility of generators’ outages. Meanwhile, the system reliability level is uniformly maintained in terms of reliability metrics such as the expected energy not served (EENS).

Currently, the modified runway model is implemented in the reserve settlement of the Singapore Electricity Market. Reserve settlement is where the reserve service providers get payment and therefore influences generation entities’ attitude towards reserve provision. The modified runway model belongs to zero-sum settlement where every generator is financially bundled to provide reserve. The modified runway model encourages every generator to carry reserve and this is critical to system security since Singapore only has around 8,000 MW generation capacity. However, the calculation of the reserve responsibility fraction that each generator is responsible is inaccurate because the modified runway approach only roughly estimates the consequence of generator failures. Contingency analysis of outaged units is not considered.

The objective of the research is to improve the market design in the Singapore Electricity Market. There are three aspects that this thesis tries to improve, i.e. loss of load

Summary

compensation, reserve requirement criterion and reserve market settlement. Three new designs are proposed for incorporation in the Singapore Electricity Market respectively. They are the insurance scheme on the generation side, probabilistic reserve with demand side participation and probabilistic zero-sum settlement.

To start with, an insurance scheme on the generation side is discussed. The consumers are required to pay the insurance premium so that they can avoid financial losses from load curtailment. The premium depends on two factors. One factor is the customers' value of loss of load (VOLL). The more the revenue loss of load curtailment on consumers is, the higher the premium they need to consider paying. The other factor is the system average (standard) reliability metric represented by the yearly expected energy not served, which could be determined by the cost/benefit analysis. As for the compensation amount, it also depends on two factors. One factor is determined in the premium calculation, i.e. value of loss of load. The higher the VOLL consumers choose, the higher the compensation amount is. The other factor is the loss of load amount. It can be computed from the load profile curve and the duration of the load curtailment. In contrast to consumers, the generator side receives the premium and is required to pay the consumers who suffered loss of load. The "causers-pay" criterion is selected to penalize the failed generators and the penalty serves as compensation to consumers. Hence, generation entities under the proposed insurance scheme have a strong motivation to prevent load curtailment.

The market clearing model in the Singapore market is then studied. The objective of the market clearing algorithm is to coordinate energy and reserve allocation such that the minimized offer cost is obtained. The characteristics of generators and system are formulated as constraints. As for the reserve requirement, a probabilistic reserve criterion with the system reliability metric, EENS, is proposed and implemented. The amount of the expected unserved energy is maintained throughout the dispatch period. This means that the system reliability level is uniformly maintained. Particularly, the demand side could also participate as interruptible loads. The probability of noncompliance is also formulated. Mixed integer linear programming (MILP) and iterative linear programming are employed to solve the formulated problem. MILP is simple to understand and accurate in model representation but it suffers curse of dimensionality. Iterative linear programming is a heuristic approach and is more reliable in getting a solution with less computation burden.

Summary

Reserve settlement is then examined. The available reserve settlement approaches are first reviewed and the zero-sum probabilistic reserve settlement is then proposed where the “beneficiaries-pay” criterion is implemented. A contingency analysis is used to calculate the reserve responsibility fraction each generator is responsible for. Multiple contingencies are analyzed and the responsibility represented by the EENS for each unit is computed in every possible event. It could be observed that the system EENS is divided among generators. The probabilistic zero-sum settlement could be deemed as a natural extension of the probabilistic reserve requirement in the market clearing process.

In summary, the incorporation of the proposed insurance scheme on the generation side, probabilistic reserve with demand side participation and probabilistic zero-sum settlement in the Singapore market design would enhance the Singapore market greatly.

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List of Symbols

Symbols in Chapter 1

- Symbols for lost opportunity approach

EBP	Energy bidding price curve
MCP^{LP2}	Energy clearing price with energy and AGC constraints (\$/MWh)
MCP^{LP3}	Energy clearing price with energy, reserve and AGC constraints (\$/MWh)
CE_{LP2}	Scheduled MW output with energy and AGC constraints (MW)
CE_{LP3}	Scheduled MW output with energy, reserve and AGC constraints (MW)
$MRCP$	Reserve price under the lost opportunity approach (\$/MWh)
LOC	Lost opportunity cost (\$)
LOP	Lost opportunity price (\$/MWh)

- Symbols for runway and modified runway approach

i	Unit index sorted according to the descending order of unit MW output
μ_i	Forced outage rate for Unit i
GE_i^{sum}	Scheduled MW output amount for Unit i (MW)
GR_i^{sum}	Scheduled reserve amount for Unit i (MW)
TR_i	MW amount of tier i (MW)
RRF_i^{rw}	Reserve responsibility fraction for Unit i under the runway model
RSF_i^{rw}	Reserve supply fraction for Unit i under the runway model
RRF_i^{mr}	Reserve responsibility fraction for Unit i under the modified runway model

List of symbols

Symbols in Chapter 2

- Symbols for system information

g	Index of the consumer VOLL categories
$VOLL_g$	Value of loss of load in Category g (\$/MWh)
PTG_g	Percentage of participating consumers in Category g
$EENS^{std,yr}$	Yearly standard expected energy not served (MWh)
SEC^{yr}	Yearly system electricity consumption (MWh)
$CPST^{std,yr}$	Compensation amount when the yearly loss of load amount is $EENS^{std,yr}$ (\$)
PM^{yr}	Total amount of premium to be collected (\$)

- Symbols for individual consumers

m	Index of the individual consumer in Category g
CEC_m^{yr}	Yearly m th consumer's electricity consumption (MWh)
$VOLL_{g,m}$	Value of loss of load for consumer m in Category g (\$/MWh)
PM_m^{yr}	Insurance premium consumer m needs to pay (\$)

- Symbols for loss of load process

h	Index of the whole hourly period
H	Number of the whole hourly periods the loss of load lasts
$Prfl(h)$	Load profiling for consumer m , a function of hourly period
H^{blol}	Hourly period index when the consumer starts to suffer loss of load
L_m^{blol}	Energy consumption for consumer m just before the loss of load (MW/h)
$Time^{first}$	Minutes that the loss of load lasts at Period L_m^{blol} (minute)
$Time^{last}$	Minutes that the loss of load in the last hourly period if the loss of load lasts more than one period (minute)
L_m^{lol}	Total loss of load amount for consumer m during the outage (MWh)
$CPST_m^{lol}$	Compensation amount for consumer m for the loss of load (\$)

List of symbols

▪ Symbols for generator outage and generator penalty

v_i	On/off random variable of Unit i , 1 is on and 0 is off
L_g^{out}	Amount of loss of load in Category g (MW)
WTH^{out}	Worth of loss of load (\$)
SHR_i^{out}	Share that Unit i pays due to outage
PNT_i^{out}	Penalty amount Unit i pays due to outage (\$)

Symbols in Chapter 3

▪ Symbols for objective function and constraints other than probabilistic reserve requirement

i,j,k,l	Index of generators
il,s	Index of interruptible loads
gi	Index of MW tranches in the energy offer for generators
ri	Index of MW tranches in the reserve offer for generators
sj	Index of MW tranches in the reserve offer for interruptible loads
t	Index of dispatch periods
N	Number of generators
S	Number of interruptible loads
GE_t	Sum of the generator energy output at Period t (MW)
D_t	System demand at Period t (MW)
V_t^{sum}	Violation penalties (\$)
$ILR_{s,sj,t}$	Selected MW reserve capacity from tranche sj for interruptible load s
$ILRP_{s,sj,t}$	Offer price in tranche sj for interruptible load s (\$/MW)
$ILR_{s,sj,t}^{max}$	Maximum MW reserve capacity that can be scheduled from tranche sj for interruptible load s (MW)
$ILR_{s,t}^{max}$	Maximum amount that could be scheduled for interruptible load s (MW)
$ILR_{s,sj,t}^{ex}$	Excess amounts to be schedule from tranche sj for interruptible load s
$ILR_{s,sj,t}^{ex,pnt}$	Penalty for every one MW of excessive reserve for interruptible load s

List of symbols

$ILR_{s,t}^{sum}$	Selected reserve provision of interruptible load s (MW)
$GE_{i,gi,t}$	Selected generator energy output in tranche gi for Unit i (MW)
$GEP_{i,gi,t}$	Generator energy price offered in tranche gi for Unit i (\$/MW)
$GR_{i,ri,t}$	Selected reserve provision in tranche ri for Unit i (MW)
$GRP_{i,ri,t}$	Generator reserve price offered in tranche ri for Unit i (\$/MW)
$GE_{i,gi,t}^{max}$	Maximum MW amount that can be scheduled in tranche gi for Unit i (MW)
$GR_{i,ri,t}^{max}$	Maximum reserve amount that can be scheduled in tranche ri for Unit i (MW)
$GE_{i,gi,t}^{ex}$	Excess energy to be scheduled in tranche gi for Unit i (MW)
$GR_{i,ri,t}^{ex}$	Excess reserve to be scheduled in tranche ri for Unit i (MW)
$GE_{i,t}^{sum}$	Sum of selected MW offer for Unit i (MW)
$GE_{i,t}^{start}$	MW output when market clearing engine starts to run (MW)
RU_i	Ramp up rate of Unit i (MW/min)
RD_i	Ramp down rate of Unit i (MW/min)
$Time^{slvr}$	Expected running time for the market clearing engine (second)
$Time^{bdptch}$	Time duration between the running point of the market clearing engine and the start point of the dispatch period (second)
$Time^{dptch}$	Time duration between the point when the clearing engine is done and the end of the dispatch period (second)
$RU_{i,t}^{ex}$	Excess ramp up rate for Unit i (MW/min)
$RD_{i,t}^{ex}$	Excess ramp down rate for Unit i (MW/min)
$GE_{i,t}^{end,max}$	Maximum MW output Unit i can get at the end of the dispatch period (MW)
$GE_{i,t}^{end,min}$	Minimum MW output Unit i can get at the end of the dispatch period (MW)
$GR_{i,t}^{sum}$	Reserve amount to be scheduled for Unit i (MW)
GR^{max}	Maximum amount of reserve to be scheduled for any unit in the system (MW)

List of symbols

$GR^{max,ex}$	Excess amount of reserve to be scheduled for Unit i to violate the maximum reserve capacity constraint (MW)
$RPPN_{i,t}$	Reserve proportion ratio limiting the maximum reserve provision according to its energy provision
$RPPN_{i,t}^{ex}$	Excess amount of reserve to be scheduled for Unit i due to the reserve proportion constraint (MW)
GER_i^{max}	Maximum generator energy and reserve amount Unit i can provide (MW)
$GER_{i,t}^{max,ex}$	Excess amount of reserve to be scheduled for Unit i due to maximum reserve generation constraint (MW)
R^{min}	Minimum scheduled system spinning reserve amount (MW)
$VOLL_s$	System average VOLL (\$/MW)
$GE_i^{ex,pnt}$	Penalty amount for 1 MW of $GE_{i,gi,t}^{ex}$ (\$/MW)
$GR_i^{ex,pnt}$	Penalty amount for 1 MW of $GR_{i,gi,t}^{ex}$ (\$/MW)
$ILR_s^{ex,pnt}$	Penalty amount for 1 MW of $ILR_{s,sj,t}^{ex}$ (\$/MW)
$RU_i^{ex,pnt}$	Penalty amount for excess 1 MW/min of $RU_{i,t}^{ex}$ (\$/MW/min)
$RD_i^{ex,pnt}$	Penalty amount for excess 1 MW/min of $RD_{i,t}^{ex}$ (\$/MW/min)
$GR_i^{max,ex,pnt}$	Penalty amount for excess 1 MW of $GR_i^{max,ex}$ (\$/MW)
$RPPN_i^{ex,pnt}$	Penalty amount for excess 1 MW of $RPPN_{i,t}^{ex}$ (\$/MW)
$GER_i^{ex,pnt}$	Penalty amount for excess 1 MW of $GER_{i,t}^{ex}$ (\$/MW)

■ Symbols in MILP

z	Index of system situations
Z	Number of system situations
v_i	On/off random variable of Unit i , 1 is on and 0 is off
v_s	On/off random variable of interruptible load s , 1 is compliance and 0 is noncompliance
μ_k	Forced outage rate for Unit k
μ_s	Noncompliance rate for interruptible load s

List of symbols

θ_z	Binary variable indicating whether or not energy deficiency occurs in contingency z
p_z	Probability of the system contingency z
$\theta_{k,t}^{si}$	Binary variable indicating whether the system suffers energy deficiency when Unit k fails as a single contingency
$p_{k,t}^{si}$	Probability of the system situation where only Unit k fails as a single contingency
$DEF_{k,t}^{si}$	Difference between demand and generation plus reserve when only Unit k fail as single contingency (MW)
$EENS_t^{si}$	Sum of system EENS for the single contingencies (MWh)
$\Omega_{k,t}^{si}$	Energy deficiency amount when only Unit k fails as a single contingency (MW)
$\theta_{k,l,t}^{db}$	Binary variables indicating whether the system suffers energy deficiency when only Unit k and l fail as a double contingency
$p_{k,l,t}^{db}$	Probability of the system situation where only Unit k and l fail as a double contingency
$DEF_{k,l,t}^{db}$	Difference between demand and available generation plus reserve when only Unit k and l fail as a double contingency (MW)
$\theta_{k,s,t}^{db}$	Binary variables indicating whether the system suffers energy deficiency when only Unit k and interruptible load s fail as a double contingency
$p_{k,s,t}^{db}$	Probability of the system situation where only Unit k and interruptible load s fail as a double contingency
$DEF_{k,s,t}^{db}$	Difference between demand and available generation plus reserve when only Unit k and interruptible load s fail as a double contingency (MW)
$EENS_t^{db}$	Sum of system EENS for double contingencies (MWh)
$\Omega_{k,l,t}^{db}$	Energy deficiency amount when Unit k and l fail as double contingency (MW)
$EENS_t$	System EENS amount at Period t (MWh)
$EENS^{std,hr}$	Hourly system EENS requirement (MWh)
$EENS^{tol}$	Tolerance for hourly system EENS requirement (MWh)

List of symbols

- Symbols in iterative LP

SRR	System spinning reserve amount (MW)
SRR^{ini}	SRR value at the starting point (MW)
$EENS_t$	Hourly system EENS amount at Period t (MWh)
Γ_i	Loss of load amount when Unit i fails in contingency analysis (MWh)
$\Gamma_{i,j}$	Loss of load amount when only Unit i and j fail in contingency analysis (MWh)
$\Gamma_{i,j,k}$	Loss of load amount when only Unit i , j and k fail in contingency analysis (MWh)

Symbols in Chapter 4

- Symbols for zero-sum approach

i	Unit index sorted according to the descending order of unit MW output
μ_i	Forced outage rate for Unit i
$GE_{i,t}^{sum}$	MW output amount from Unit i
$GR_{i,t}^{sum}$	Scheduled reserve amount from Unit i
$EENS_i^{cnt}$	EENS that Unit i should be responsible for (MW) in contingency analysis
$EENS_i^{si}$	Energy deficiency amount when only Unit i fails in single contingency (MW)
$EENS_{i,j}^{db}$	Energy deficiency amount when only Unit i and j fail in double contingency
$EENS_{i,j,k}^{tr}$	Energy deficiency amount when only Unit i , j and k fail in triple contingency (MW)
r_i^{si}	Proportion responsibility fraction of Unit i when Unit i fails
r_i^{db}	Proportion responsibility fraction of Unit i when Unit i and j fails simultaneously

List of symbols

r_i^{tr}	Proportion responsibility fraction of Unit i when Unit i , j and k fails simultaneously
RRF_i^{pz}	Reserve responsibility fraction for Unit i under the probabilistic zero-sum approach
RSF_i^{pz}	Reserve supply fraction for Unit i under the probabilistic zero-sum approach
$MRCP$	Reserve market clearing price (\$/MWh)
PAY_i^{pz}	Amount that Unit i needs to pay under the probabilistic zero-sum approach (\$)
RRF_i^{rw}	Reserve responsibility fraction for Unit i under the runway model
RSF_i^{rw}	Reserve supply fraction for Unit i under the runway model
RRF_i^{mr}	Reserve responsibility fraction for Unit i under the modified runway model

Chapter 1

Introduction

1.1 Motivation

The electric power industries all over the world have been undertaking major regulatory and operational changes since 1980s. The power supply is moving from a centralized operation approach to a competitive one. Reregulation has brought forth innovation in the electricity industry. Meanwhile, the probabilistic techniques are gradually attracting attentions in the planning and operation side. Along with the reregulation, a lot of research works have been done to incorporate probabilistic techniques in the electricity market. The motivation of the research in this thesis is to further apply probabilistic techniques in reserve scheduling and settlement as well as to extend the usage of system reliability metrics in loss of load compensation for the Singapore Electricity Market. Some of the market operations in other jurisdictions are also investigated such that good practices and experiences could be borrowed.

1.1.1 Deregulation in Singapore power industry

The electricity industries in Singapore have traditionally been vertically integrated and government-owned. An organization called Public Utilities Board was formed in 1963 to undertake the supply of water, electricity and piped gas to the population of Singapore.

The first phase of the electricity industry reform was in 1995 when the government corporatised the electricity undertakings of the Public Utilities Board. The intention was to gradually introduce competition in electricity generation and retail. Public Utilities

Board was reconstituted to undertake the new role of regulating the electricity and piped gas industries. The second phase of the reform was implemented on 1 April 1998 when the Singapore Electricity Pool commenced operation. The Pool was a “day-ahead” market. The Pool introduced back then incorporated many of the attributes of a modern market without the complications of a real-time market at the wholesale level. In March 2000, the government decided to continue with further reregulation of the industry. The key initiatives included the establishment of a system operator, a market operator as well as a real-time wholesale market. On 1 January 2003, the National Singapore Electricity Market commenced operation. Generation entities have offered to sell electricity into the real-time market since then.

◆ Rationale behind reregulation

Natural monopolies existed in the power industries for many years. It was believed that one firm could serve the market better than two or more. The size of the power plant increases, and its average cost falls. In order to protect the consumers, electricity price is regulated at a fair but not excessive level. However, three problems arise. Firstly, the utilities become indifferent to its cost increase because the cost will automatically be passed on to consumers. If any reduction in the generation cost would be followed by a reduction of price, then the power plants have little incentive to put in their time and efforts to reduce the cost. Secondly, a ban on new entries is a common result of regulation. Entrepreneurs with new ideas have no chance to try them. This kind of creative destruction is an obstacle to the enhancement of social welfare [1]. Thirdly, under monopoly provision of a good or service, profit-maximization results in an electricity price in excess of the marginal cost. It is hard to tell whether the price paid by consumers is at its marginal cost. As could be illustrated in Fig. 1.1, the monopoly price charged to consumers is higher than the real marginal cost.

Fig. 1.1 Monopolist regime in the power industry

Under private ownership of assets, owners have powerful incentives to maintain the assets in such a way as to provide maximum benefits to them. To the extent that private ownership clearly identifies and internalizes the benefits from the assets, the owners will have an incentive to operate and maintain the assets in such a way to maximize these benefits [2]. In addition, the ownership incentives that maximize benefits to the owner also maximize the overall economic efficiency as proved in [1]. If a firm raises its price in a perfectly competitive market, then it will lose its market share and the other competitors would get its share. Thus the competition drives price toward marginal cost. This means that the excess of benefits over cost is maximized because consumers are paying exactly the producer's cost of the last chosen unit.

The reregulation can also improve consumer focus. The consumers have more options or increase control over their energy usage. Although a monopoly-franchise utility has an obligation to serve all consumers, it does not promote the same type of focused, proactive attention to consumer needs that competition does. A monopoly-franchise utility listens to its consumers when they explain their needs and responds to their needs accordingly. A competitive electric service company anticipates their needs and responds in advance of consumers articulating their needs.

The setup of the electricity market aims to economically schedule the generation facilities in the short term, and provides incentives for new power system investment in the long

term. It should be noticed that competition does not necessary provide the lowest price. In the short run, it is possible to design market rules which lower the market price without reducing supply. However, at a lower price producers will not cover their fixed costs. This will make future investors think twice and may result in a risk premium added to the cost of capital which makes future production more costly than it would have been. In the long run, competition guarantees that the suppliers will just cover the long run total costs and no more. It also guarantees that the cheapest suppliers will be the ones producing. Together this means production costs are minimized and producers are paid only enough to cover their cost. In a word, competition minimizes long run average costs of production and long-run average costs to consumers.

◆ Key players in Singapore Electricity Market

In the electricity market, new structures and terminologies have evolved (or are still evolving) in order to handle the changing needs with regards to administration, planning and operation. Inevitably, the structures and terminologies are still emerging and may differ from one area to the other. These terminologies and their functions are briefly summarized [3-6]. Particularly, organizations and corporations in the Singapore Electricity Market are described below.

Regulator: The regulator has the ultimate responsibility of ensuring that the market meets the preset objectives the Singapore Electricity Act specifies [5] . In the Singapore market, the regulator is the Energy Market Authority (EMA).

Market Operator: It is also called PoolCo or Pool Operator in some markets. A market operator (i) operates and administers the wholesale electricity marketplace to ensure fairness to all market participants; (ii) promotes full competition that could lead to the lowest price for electricity supply, consumer services and training support; and (iii) performs the settlement function in the marketplace by ensuring that sellers in the real-time market are paid by purchasers. It also provides information and other services to facilitate decisions for all the participants. Some market operators may track physical and/or financial bilateral contracts between market participants. In the Singapore market, the market operator is Energy Market Company (EMC).

Power System Operator: It is also called Independent System Operator (ISO) in some markets. Its responsibility is to ensure the reliability supply of electricity to consumers and the secure operation of the power system. It controls the dispatch of facilities in the wholesale market; co-ordinates outage and emergency planning, and forecasts the short-term and long-term demand. In addition, it also directs the operation and regulates the tariff of the high-voltage transmission system. The role of ISO widely varies from one market to another [7-12]. In the Singapore market, a division of EMA named power system operator is the system ISO.

Transmission Licensee: It is responsible for the operation and maintenance of the transmission system. It may own one or more transmission lines and other transmission utilities such as FACTS, transformers, dynamic voltage restorers (DVRs) etc. Until now, it is commonly believed that the network operation is a natural monopoly and has to be regulated and supervised by the authorities. Hence the equipments owned by any Transmission Licensee are open for access by all users without any discrimination. In the Singapore market, only the PowerGrid is the transmission licensee.

Generation entity: The economic segregation of the generation system is to split the generation system, which belongs to a vertically integrated system owned by a single company, into a sufficiently large number of smaller independent competing generating companies. A generation entity may own one or more generating plants and provides its consumers with real power, reactive power, capacity reserve for long-term planning and real-time operation. In the Singapore market, generation entities comprise Power Seraya, Senoko Power, Tuas Power, SembCorp Cogen, Island Power Co, Singapore Syngas, ExxonMobil Asia Pacific and Keppel FELS Utilities.

Generation Licensee: A generation entity is required to get an operating license from the regulator when its generator exceeds a certain capacity. The licensed generator may then be registered with the market operator for dispatch or for settlement only. Mandatory participation ensures that all generators of any significant size are subjected to market rules. Thus they can pay their share of system and market cost, such as the regulation and reserve cost accordingly. In the Singapore market, all facilities larger than 10 MW must be registered for dispatch while generators between 1 MW and 10 MW in capacity can

choose to be registered for dispatch or not. Generators or units are the generation licensees in this thesis.

Market Support Service Licensee (MSSL): It provides market support services such as meter reading and meter data management. It facilitates access to the wholesale market for contestable consumers and retailers. In addition, it is responsible for supplying electricity to all non-contestable consumers. In the Singapore market, the incumbent supplier, Power Supply, is the only MSSL. However, there may be more MSSLS in the future.

Retail Electricity Licensee: A retailer is permitted to sell electricity to contestable consumers. In Singapore, there are two kinds of retailers. The first one is called the market participant retailer. It is required to get a license from the regulator and then to be registered as a market participant. It can purchase energy directly from the wholesale market. The second one is the non-market participant retailer. It also needs to get a license from the regulator, but it purchases electricity indirectly from the wholesale market through MSSL. Seraya Energy, Senoko Energy Supply, and Tuas Power Supply are some retailer electricity licensees in the Singapore market.

Consumer: A consumer is the end-user of electricity with certain facilities connected to the distribution system (in the case of small consumers) or connected to the transmission system (in the case of bulk consumers). In the Singapore Electricity Market, consumers are categorized as contestable and non-contestable according to their annual energy consumption. Currently, consumers with energy consumption above 240 MWh per year are contestable. The threshold for contestable consumers may lower progressively until all consumers become contestable. Contestable consumers can purchase electricity from a retailer, a MSSL or directly from the wholesale market while non-contestable consumers are required to be supplied by a MSSL.

The relation among the key players in the Singapore Electricity Market is illustrated in Fig. 1.2. Electricity flows from generators to consumers while the money flows just the contrary. Meanwhile, service providers would charge service receivers. The charges are represented as other settlement in the figure.

Fig. 1.2 Relation among the key players in the Singapore Electricity Market

1.1.2 Evolution of probabilistic techniques

The nature of the electric power system failure is uncertain. Facility failures which occurred randomly in the past will also occur randomly in the future and therefore the electric power system behaves probabilistically. Thus, it is logical that probabilistic techniques should be considered for the assessment of such behavior. However, it remains a fact that most of the operational criteria are based on deterministic techniques. The essential weakness of deterministic techniques is that the likelihood is neglected and the system expected unserved energy cannot be assessed. Recently, probabilistic techniques considering such behavior attract more attention. This is because the main obstacles such as lack of data and limitation of computation resources once preventing the implementation of probabilistic techniques no longer exist [13].

Under the probabilistic technique, system reliability levels could be measured by different metrics. Loss of Load Probability (LOLP) and EENS are widely used metrics. In the literature, Expected Unserved Energy (EUE) is used instead of Expected Energy Not Served. In this thesis, the two terms have the same meaning and they are interchangeable.

The system metric LOLP or EENS is a function of factors such as units' status, possibility and consequence. LOLP or EENS originated from the planning side. LOLP refers to the probability that the system suffers loss of load while EENS refers to the expected energy not served amount within a year. Actually, a little change of the definition of LOLP and EENS in the duration measured makes them suitable for real-time operation. For a one-hour commitment period, LOLP is the probability that the system suffers load curtailment while EENS is the expected energy not served amount in that hour. A system may have three operating conditions as far as reserves and load shedding are concerned. If all the generators continue to run normally, the system does not need to curtail any loads. If a few generators fail but the reserve is enough to cover the MW deficiency, the system can still avoid load shedding. However, under the severe condition where the reserve is not enough, the system has to curtail part of the load to alleviate a more catastrophic event. LOLP is the probability of the last operating condition. The metric EENS considers not only the probability of the contingency but also the consequence of the contingency represented by the MWh loss.

This thesis focuses on the usage of the reliability metric EENS. The history of using EENS in vertically and reregulated power industry is reviewed below. These works are the basis for conducting the research in this thesis.

◆ Probabilistic techniques used in planning side

Probabilistic techniques have been used in power system planning. A better system reliability level benefits the end users, but the users have to pay a high price for it. Fig. 1.3 shows the causal relationship between the risk of electricity interruption and its effects on the end users' payment [14].

Fig. 1.3 Reduction of risk and its effect on end users' payment

Fig. 1.3 shows that the risk of loss of load is reduced by either increasing the investment in the generator/transmission expansion capacity or increasing the operating cost for better utilization of existence resources. The result is an increase in consumer payment. Over-investment and high reliability level may lead to a non-efficient system operation. On the other hand, under-investment and tight generation margins in operation would result in a supply of low reliability. A trade-off between the increase in reliability and the additional cost of keeping the reliability needs to be achieved. Therefore, a cost/benefit analysis is introduced to analyze the loss decreased through the reliability enhancements and the cost incurred.

Many papers concern the probabilistic techniques for investment in generation/transmission expansion [15-19]. In [15], Burns and Gross proposed an evaluation approach that incorporates the value of service reliability into the planning process. In [16], an approach based on the cost/benefit analysis is proposed for the transmission line expansion of the Duke Company's regional transmission system. This approach attempts to balance the costs of improving the transmission network and the benefit that these improvements bring to their consumers. In [17], a cost/benefit analysis is performed on the generation planning aiming to minimize the sum of investment, maintenance, operation cost and worth of outage. A large number of contingencies are enumerated to estimate both the expected outage worth and operation cost. In [18], a case study for Pacific Gas and Electric Company (PG&E) evaluated three options for maintaining reliability in a major load center, involving both the generation and transmission systems. In [19], the impact of the substation transformer outage on the area consumers is evaluated, and the cost effectiveness of adding a second transformer is assessed.

◆ Probabilistic techniques used in reserve management of vertically integrated power industry

Under the real-time electricity market, a proper reserve criterion is required for the reserve schedule. Currently, one of the most widely implemented criteria is " $n-1$ security" where the largest online generator's capacity or a percentage of demands is used as the spinning reserve requirement (SRR) [20]. Under the " $n-1$ security" criterion, regardless of reliability historical records generators hold, the system is able not to shed load after the

loss of a single unit provided the system can arrest the frequency drop in time. However, when two or more generators fail at the same time, the system cannot promise not to shed load. Similarly, “ $n-2$ security” can guarantee continuous supply up to double contingencies. The “ $n-x$ security” schemes are easy 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 [21]. The “ $n-x$ security” criterion does not take into consideration the intrinsic reliability performance of each scheduled generator. Under different unit commitment schedules and/or different load demand levels, “ $n-x$ security” actually results in different system reliability levels for different hours and sometimes their difference in system reliability levels is significant.

Therefore, probabilistic techniques and methods have been developed for reserve management in unit commitment in the past 40 years [13]. The probabilistic reserve criteria consider the probabilistic nature of spinning reserve. LOLP and EENS are widely used system reliability metrics in setting the probabilistic reserve criterion and they can be calculated using a variety of simulation and analytical methods. Based on analytical techniques, a mathematical model is established to calculate the metrics. Analytical techniques generally are able to obtain the values of these metrics in several minutes and their short processing time satisfies the real-time needs. In this thesis, only analytical techniques are discussed.

In [22], a unit commitment risk index, LOLP, is first defined to determine the probability of failing to meet the demand at some instant in time. In [23, 24], the concept of LOLP was integrated with a Lagrangian Relaxation based unit commitment program where the risk index is kept at a given level and the total fuel cost is minimized.

In [20], an integrated unit commitment process which satisfies the LOLP requirement via a Capacity Outage Probability Table (COPT) and a post processor is proposed. As the name suggests, COPT is an array of capacity levels and the associated probabilities of occurrence. The table can be extended through a simple but powerful convolution, in which units are added sequentially to produce the final table. A considerable saving in time taken to assemble the COPT can be achieved if the table is truncated by omitting the MW outage levels for which the cumulative probabilities are less than a pre-specified

amount, e.g. 10^{-8} . A further reduction in computation can be achieved by rounding the MW outage level to a fixed MW increment, e.g. 10 MW.

The post processor could overcome the over-commitment normally observed in the Lagrangian Relaxation based unit commitment. The first step in the post processor is to examine the marginal unit, which refers to the last unit that is scheduled by economic dispatch due to its relative high incremental cost. The post processor then tries to decommit the marginal unit by examining the hourly system spinning reserve. If the unit can be decommitted without violating any constraints, a final adjustment is made to the unit commitment schedule. Otherwise, without reduction in cost or exceeding the preset LOLP, the unit is re-committed.

Several papers further developed the process proposed in [20]. In [25], the ramp rate constraints are added in that process. The consideration of the ramp rate constraint reflects the actual operating condition of the generators where the unit output could not be adjusted instantaneously. The forward dispatch, dispatch modification and backward dispatch are used to satisfy the spinning reserve requirement and ramp rate limits. In [26], Chattopadhyay and Baldick approximated the relation between LOLP and the spinning reserve amount using statistical methods. This could provide a direct and computationally cheaper means to solve the same problem.

In [27], Nitu and Gross presented a systematic approach for the reliability evaluation of power system operational planning with explicit representation of control actions. The approach explicitly incorporates customer outage data and adapts the widely-used frequency and duration method to evaluate the reliability indices of the expected unserved energy. Besides, the frequency and expected duration of interruption with the contribution of the control actions are explicitly represented. The outage cost information is used to determine economically the optimal reserve requirements and to perform a cost-benefit analysis of control actions.

Load uncertainty is also an important topic in the probabilistic area. In [28], Takriti and Birge proposed a stochastic model for unit commitment where load uncertainty was taken into consideration. In [29], Shiina and Birge refined the way to solve the problem in [28]

by the Dantzig-Wolfe reformulation and column generation approach. In [30], the Nash equilibrium point was then derived for the deterministic and stochastic demand.

A cost/benefit analysis could also be used to determine a reasonable real-time operating cost. One of the major methods in improving the system real-time reliability level is to increase the reserve amount. As the system becomes more reliable, the cost of loss of load would decrease. However, both the reserve requirement and the cost for providing the reserve increase. At the other extreme, when no spinning reserve is arranged, the cost of spinning reserve is zero, but the worth of loss of load when generators fail is huge. The optimal reserve quantity can be determined by balancing the purchase cost of the reserve and the expected value of lost load.

◆ Probabilistic techniques used in electricity market operation

It is clear that the restructuring of the electricity industry increases the level of uncertainty that affects power system operation and planning. Building, siting, and scheduling generating plants are no longer centrally planned by the utility but are determined by business opportunities [31]. In [32], demand side participation is considered in the reserve scheduling. It can be seen that demand side bidding can reduce the risk of the system of being unable to meet the demand. Flynn *et al* [33] considered the loss of possible generator failure explicitly in a competitive electricity market. The worth of generator failures is added to the objective function. This means that the cost of arranging reserve and the worth of the generator outages is balanced. The problem is formulated as an augmented Lagrangian dual problem and solved using a new neural network derived from a Hopfield-type network. Bouffard [34] proposed a new way to calculate EENS as a mixed integer linear programming (MILP) problem and it can be incorporated into the optimization process.

1.1.3 Reserve market settlement

One important procedure of the commodity or service trades in the electricity market is settlement. The incentive for generation entities to offer commodities is derived from market settlement. In other words, the way to settle the market can influence the generation entities' behavior.

In the electricity market, every generation entity tries to maximize the profit. It is undoubtedly important for the system regulator to create an economic and regulatory framework for the electricity sector that promotes competitive, fair and efficient market. The reserve services provided by the generation entities need to be reasonably paid. This way, correct signals could be sent to the market participants such that investment would be brought in at the right time and right place.

The major function for the system to carry spinning reserve is to ensure that the loss of one or more units does not cause a substantial system frequency drop and possible loss of load subsequently. Meanwhile scheduling of reserve means that the generator could not make full use of its capacity and thus it incurs cost and needs payment. Broadly, there are two schools of thoughts prevalent in the market for spinning reserve settlement. One school holds the idea that the reserve offering cost is paid by purchasers through uplift charges. The other school believes that generation entities should pay for the offering cost of reserves because they promise to supply the energy at the dispatch time but have the probability of failing to do so. Thus those generators which won their offers in the energy market would pay the reserve providers. In other words, every committed generation entity is assumed to be responsible for a part of the system reliability by carrying reserve or paying others to carry reserve. The result is that those generators supplying more spinning reserve than the required amount get payments and those with reserve deficiencies make payments. It is also called a zero-sum game among the generation entities because the sum of the payment is zero [21].

Currently, the availability payment approach and lost opportunity cost approach belong to the first school of thoughts where the consumers pay the reserve cost. The runway approach and modified runway approach belong to the second school where the generators pay the reserve offering cost.

◆ Availability payment approach

In this payment approach, a generator receives the reserve price per MW for every time period that the reserve is allocated and not used. The reserve clearing price equals to the reserve availability price of the most expensive generators that are designated to supply

reserve. The reserve offering cost is added to the system offering cost and the consumers are charged in terms of uplift.

If outages happen and the reserve is called in, then the generator would receive the clearing price of the real-time market for this additional MW output converted from the reserve. The consumers still pay the electricity they consumed. Thus, the payment originally meant for the failed generators is shifted to the energy converted from reserve. This approach was once used in the England and Wales Power Pool (EWPP) [35].

◆ Lost opportunity cost approach

The three electricity markets in the Northeastern U.S. all have or will have the energy and reserve markets where the lost opportunity costs are explicitly compensated [36]. The lost opportunity cost approach is applicable to the ancillary services in the market, including the reserve. According to the definition of New York ISO, the lost opportunity cost is the foregone profit associated with the provision of ancillary services, which is equal to the product of: (1) the difference between (a) the energy that a generator could have sold at the specific location based market clearing price (LBMP) and (b) the energy sold as a result of reducing the generator's output to provide the ancillary service under the direction of the NYISO; and (2) the existing LBMP at the time the generator was instructed to provide the ancillary service, less the generator's energy offer for the same MW segment [37].

In [38], a hybrid dispatch method which consists of a series of linear programming solutions is used in the interim market of ISO-NE in 1999. It has four linear programming solutions in the configuration for each dispatch run. After that, the lost opportunity cost for AGC, spinning reserve and operating reserve would be computed. The four linear programming solutions are as follows:

- [LP1] Pure energy dispatch honoring the manual operating limit and manual response rate;
- [LP2] Pure energy dispatch honoring the AGC range limit and auto response rate constraints for units selected to be on AGC;
- [LP3] Simultaneous dispatch of the energy and spinning reserve honoring the AGC constraints and AGC capacity reservation for units selected to be on AGC; and

[LP4] Simultaneous dispatch of spinning reserve and operating reserve honoring the previous clearing results of the other markets.

In the settlement, intermediate energy dispatch solutions for $LP2$ are buffered so that they can be compared against that of $LP3$ for the purpose of calculating a lost opportunity cost for the spinning reserve market. The shaded area in Fig. 1.4 represents the lost opportunity cost payment of spinning reserve.

EBP : Energy bidding price as a function of MW

MCP^{LP2} : Energy market clearing price in step $LP2$

MCP^{LP3} : Energy market clearing price in step $LP3$

CE_{LP2} : Clear energy output in step $LP2$

CE_{LP3} : Clear energy output in step $LP3$

Fig. 1.4 Calculation of lost opportunity cost for reserve

The generator is rescheduled when the reserve dispatch is simultaneously co-optimized with energy. Some generator's output MWs may be backed down to provide reserve. As shown in Fig. 1.4, its energy output is decreased from CE_{LP2} to CE_{LP3} . Thus the system would compensate its loss by offering the value of the shaded area, i.e. the profit loss from step $LP2$ to $LP3$. If the clearing energy output increases from Step $LP2$ to Step $LP3$, then the generator would not enjoy the lost opportunity cost. The formulation for the lost opportunity price (LOP) and the lost opportunity cost (LOC) are as follows:

$$LOP = \text{Max} \left\{ 0, MCP^{LP3} - \frac{\int_{CE_{LP3}}^{CE_{LP2}} EBP \cdot dMW}{CE_{LP2} - CE_{LP3}} \right\} \quad (1.1)$$

$$LOC = \text{Max} \left\{ 0, MCP^{LP3} \cdot [CE_{LP3} - CE_{LP2}] - \int_{CE_{LP3}}^{CE_{LP2}} EBP \cdot dMW \right\} \quad (1.2)$$

In [36], both the availability payment and lost opportunity cost can be considered in the reserve settlement. Availability payment refers to the payment to generators that offer the reserve capability in the market. There are three alternatives of possible designs considering the lost opportunity cost:

- generators receive lost opportunity cost payments—Model (L);
- generators receive availability and lost opportunity cost payments—Model (A+L);
- generators receive either availability or lost opportunity cost payment—Model (A|L).

In the three models above, the lost opportunity cost would be paid to the generators. To fully optimize the offering cost consumers pay, the lost opportunity cost is put into the objective function just like the energy and reserve offering cost. However, the final energy price needed to calculate the lost opportunity cost is not known until the problem is solved. In other words, it is a self-referential calculation. In [36], the whole problem is turned into a 0-1 MILP problem, and the standard branch and bound method is used to solve it.

◆ Runway approach

The runway approach is based on the “causers-pay” criterion. This means that the reserve offering cost should be shouldered by all the generators who need reserves. Since the generators are also the providers of reserves, a zero-sum settlement can be implemented for the reserve offering cost. This means that those who contribute more reserve than required will be compensated by receiving payments from those who contribute less. The net effect is that the sum of all compensations (negative payments) and payments is zero.

To begin with, the generators are sorted by their MW provisions. The unit with the largest online MW provision has an index of 1 and the second largest is 2 and so on. The schedule can be obtained from the market clearing engine where GE_i^{sum} and GR_i^{sum} are used to represent the MW output and reserve output for the i th unit in the sequence respectively.

The tiers are then defined. The i th tier is the MW difference between Unit i and Unit $(i+1)$. The last tier or tier n is set to the sole MW generation of Unit N . The MW quantity of the i th tier can be formulated as:

$$TR_i = GE_i^{sum} - GE_{i+1}^{sum} \quad (1.3)$$

Fig. 1.5 illustrates the relationship between the sorted generators and tiers [39].

Fig. 1.5 Tier division in the runway approach

As can be seen in Fig. 1.5, Tier 1 occupies $\frac{TR_1}{GE_1^{sum}}$ in the MW output. Besides, only Unit 1 has MW in this tier. Hence Unit 1 is fully responsible for the cost of this tier. Similarly, Tier 2 occupies $\frac{TR_2}{GE_1^{sum}}$ in the MW output. However, both Unit 1 and Unit 2 have MW in this tier. Then they would share the cost of this tier equally. The portion that Unit 1

should be responsible for is $\frac{TR_2}{GE_1^{sum}} \cdot \frac{1}{2}$. The i th tier can be handled in a similar way. For

Unit i , its reserve responsibility fraction under the runway approach can be formulated as follows:

$$RRF_i^{rw} = \sum_{j=i}^n \left[\frac{TR_j}{GE_1^{sum}} \cdot \frac{1}{j} \right] \quad (1.4)$$

The i th unit has $(n - i)$ tiers to be responsible for. The larger the MW output, the more tiers it has to be responsible for, and thus the larger the value of RRF_i^{rw} . Meanwhile, the sum of RRF_i^{rw} is equal to 1.

The reserve supply fraction for Unit i , RSF_i^{rw} , is the ratio of the reserve Unit i supplies over the total scheduled reserve amount. The payment Unit i will receive is the product of the reserve market value and the difference between RRF_i^{rw} and RSF_i^{rw} .

◆ Modified runway approach

The modified runway approach is the improvement of the runway approach. Besides the factors considered in the runway approach, the modified runway approach takes the generator forced outage rates (FORs) into consideration. The modified runway approach is also a zero-sum settlement [5, 39]. The bottom line for the settlement under this approach is that those generators with higher forced outage rates and/or more energy should take more responsibilities. The implication of this approach is that one reserve provision covers a multitude of generators and all the generators share the cost roughly in proportion to the benefits they received. Under the modified runway approach, the generators are motivated to pay more attention to their availability performance.

The division of the tiers in the modified runway approach is the same as that in the runway model. The generators are sorted by their MW outputs first. Then the largest online unit's MW provision is divided into n tiers while n is the number of successful bidders in the energy market. Every unit has a share of responsibility for the tiers that are below its MW provision. This means that the largest unit has a share in tiers 1 to n and the

second largest has a share in tiers 2 to n and so on. The sum of all the shares is the reserve responsibility fraction RRF_i^{mr} for this unit.

The process of calculating the reserve responsibility fraction for Unit i , RRF_i^{mr} is different. RRF_i^{mr} is not only related to the energy output amount but also in proportion to the forced outage rate μ_i . RRF_i^{mr} can be formulated as follows:

$$RRF_i^{mr} = \sum_{j=i}^n \left[\frac{TR_j}{GE_1^{sum}} \cdot \frac{\mu_i}{\sum_{k=1}^j \mu_k} \right] \quad (1.5)$$

For the first tier, its MW share is $\frac{TR_1}{GE_1^{sum}}$. Only Unit 1 has MW in the first tier. Hence

Unit 1 is solely responsible for this tier. For the second tier, both Unit 1 and 2 share the responsibility in proportion to their respective forced outage rate. For Unit 1, the portion is $\frac{TR_2}{GE_1^{sum}} \cdot \frac{\mu_1}{\sum_{k=1}^2 \mu_k}$. In a similar way, the portions for Unit 1 in other tiers could be obtained

and the sum of the portions is RRF_i^{mr} . For Unit 2, it does not have a share in the first tier.

In the second tier, its portion is $\frac{TR_2}{GE_1^{sum}} \cdot \frac{\mu_2}{\sum_{k=1}^2 \mu_k}$. Likewise, RRF_i^{mr} for each unit can be

computed. Under the same output, a unit with a higher FOR would pay more in the modified runway approach.

As can be seen in Equation (1.5), if the generators have a uniform forced outage rate μ_i , the modified runway approach will become the runway approach.

1.1.4 Load curtailment compensation

In the electricity market, consumers face a lot of financial uncertainties. One of the financial uncertainties is the revenue loss caused by load curtailment. Many studies have

been conducted over the years to quantify the value that consumers place on the energy not served because of unexpected outages. The consensus is that this value is several orders of magnitude larger than the price paid for electricity [40].

There are several strategies to shed load, such as fixed priority strategy and combined fixed/rotating strategy. The fixed priority strategy sheds the least important loads first and the most important last. The last load shed is the first to be restored. The fixed priority strategy has the advantage of keeping high-priority loads supplied almost all the time. The other one is the combined fixed/rotating strategy. This means that part of the loads adopt the fixed priority strategy while the others use the rotating strategy. To avoid such unpredictable revenue losses caused by loss of load, some consumers may install embedded generators. The size of an embedded generator can range from 30 kW to 300 MW. However, not every consumer can afford the embedded generator nor feels justifiable to install the embedded generator.

During system outages, consumers may or may not suffer loss of load. For those consumers having suffered loss of load, no good compensation scheme is offered under the current electricity market operation. Normally, consumers with loss of load would not get any compensation if there are no contracts or schemes specified for loss of load. Hence, consumers with loss of load would complain that they suffered revenue loss.

A possible solution that can protect consumers from revenue loss due to loss of load is through physical bilateral contracts or financial contracts for difference. Assume that a generation entity and a consumer sign a physical bilateral contract that the consumer would get compensation for loss of load due to load curtailment. As a result, the consumer would get financial protection. However, this kind of contract adds extra financial uncertainties to the generation entity in the contract because the consumer's load curtailment may be caused by failures of other generation entities' rather than caused by the one in the contract.

Recently, some pioneering works related to insurance schemes have been done on the loss of load compensation issues. The idea of the insurance is gradually introduced into the reliability of energy service sector. The insurance encompasses premium and compensation. A consumer pays a small amount of premium and subsequently receives a

much larger compensation when curtailed. In [41], an insurance process is applied to the curtailment priority in the transmission network. The consumers pay the strike price first. Different consumers may have different interruption loss so that the strike price can vary from bus to bus. When the congestion happens in the transmission lines, the ISO can implement a proper priority loss of load list so as to minimize the net compensation to the consumers.

In [42], a scheme called the reliability insurance is proposed. The reliability insurance allows for a differentiated reliability service based upon consumer's preference. The implementation of this scheme provides a relatively simple method for unbundling the delivery and reliability service in the distribution grid. In [43], the idea of Quality of Service (QoS) in the distribution grid is further developed. The value of the reliability is explicitly expressed by the insurance premium that one pays. In [44], some problems relating to the unbundling the reliability service are raised, including the systematic institutional solutions in support of the value-based IT technology as well as the way to differentiate between the market-created uncertainties and equipment-related uncertainties.

1.1.5 Issues not covered in previous research works

Reference [5, 45] report about reregulation in the Singapore Electricity Market. However, there are no research works that apply the probabilistic techniques in the Singapore Electricity Market considering its market characteristics. The computation burden should be carefully evaluated because the market clearing time is limited to 5 minutes in the Singapore market. In addition, interruptible loads could participate in the spinning reserve market as long as they could meet the response time requirement. Interruptible loads could also fail to reduce the load when they are called in. Currently, limited research works are available on how to consider interruptible loads in probabilistic reserve requirement for real-time operation.

Research works [20, 25, 33, 34] discuss how to incorporate the probabilistic reserve criteria into the system operation process. However, few research works apply probabilistic techniques in reserve market settlement. For the available zero-sum

settlement approaches, i.e. runway model and modified runway model, contingency analysis is not carried out and the reserve responsibility fractions are not calculated as in (1.4) and (1.5). It is also incoherent that probabilistic techniques are implemented in the reserve scheduling but not used in reserve settlement.

Several research works covered the consumer protection against financial loss arising from loss of load upon failures of the transmission and distribution networks [41-43]. Although loss of load is related to distribution problems in general, generator outages also contribute to load curtailment. For example, both transmission network failures and generator outages lead to the final disaster in the American blackout on August 14 2003. Without the involvement of generation entities, the financial protection for consumers' load curtailments is incomplete. Under the market environment, the transmission network is still regulated but the generation is already open for competition. Two problems arise for generation entities in terms of curtailment penalty due to generator failures. One is how much premiums the consumers need to pay. The other is on how to allocate penalties among the generation entities for consumer compensation. Until now, there are no researchers reporting on how the premium calculation and penalty allocation are done due to generator failures.

1.2 Objective

The first objective of the research work is to develop an insurance scheme that could protect the consumers from financial losses due to generator outages. The second objective of the research work is to design a market clearing algorithm, dealing with the system and unit constraints, interruptible load participation as well as the probabilistic reserve criteria. The third objective of the research work is to develop a probabilistic zero-sum settlement scheme that engages contingency analysis in the reserve responsibility computation. The proposed insurance scheme needs a corresponding market clearing process to satisfy the yearly EENS requirement which is critical in the insurance scheme. The probabilistic zero-sum reserve settlement is a natural extension of the probabilistic reserve requirement. The execution sequence and relations among these processes are shown in Fig. 1.6.

Fig. 1.6 Connection among the execution phases of the proposed work

As can be seen in Fig. 1.6, there are data flows and execution sequence interlinking these processes. Firstly, the annual system reliability needs to be converted into the system reliability requirement for each period for use in the market clearing phase. Meanwhile, the cost/benefit analysis in the market clearing also gives some feedback to the system reliability requirement evaluated in the insurance process. Secondly, the information on the consumers' VOLL category is passed from the insurance phase to the market operation and settlement phase. Thirdly, the outage rates of generators are passed on to the settlement phase. Finally, the energy and reserve schedule produced by the clearing engine are used both in the market operation and market settlement phase.

The specific objectives in the insurance scheme, market clearing and market settlement are presented here.

◆ Insurance scheme

The objective of the insurance scheme is to set up an insurance structure and solve the issues related to premium payment and compensations for consumers and the premium distribution to the generation entities in the Singapore Electricity Market. These issues include premium calculation for each participating consumer, premium distribution for each generator, compensation to each consumer having suffered loss of load, and allocation of penalty responsibilities among generation entities upon load curtailment.

The first specific objective in the insurance scheme is to calculate a premium for each participating consumer. Consumers have different needs for protection against revenue losses as a result of load curtailment and hence the corresponding premiums for each customer would be different. The load consumption amount is also an important factor. Last but not least, system yearly EENS needs to be taken into consideration. A certain amount of load curtailment is allowed in the system. With the factors listed above, a consumer's premium needs to be formulated.

The second specific objective is to distribute the premiums collected from consumers to generation entities. The generator capacity is an important factor considered in this distribution.

The third specific objective is to compute the compensation amount for each consumer who suffered loss of load when energy curtailment occurs. The process of load curtailment needs to be clearly described, and then the loss of load amount can be determined. The revenue losses the consumers reported in the premium calculation needs to be obtained. Finally, the compensation amount could be formulated.

The last specific objective is to allocate the penalties (the total premium collected is the same as the total compensation to consumers) in the load curtailment to the generation entities. This thesis would discuss in detail who will pay for the penalties and how much each generator needs to pay.

After all these specific objectives are achieved, the implementation of the insurance scheme still needs the support of market clearing model. The system reliability metric and yearly EENS need to be incorporated into the clearing process.

◆ Market clearing process

In the market clearing process, the specific objectives are to set up a clearing model in the Singapore Electricity Market, and to incorporate the probabilistic reserve requirement into the model. Demand side participation in the form of interruptible loads is also added to the model. This work is to formulate the objective function, system constraints, and probabilistic reserve requirement.

In the formulation of the objective function, minimizing the offering cost of energy and reserve are implemented. In the formulation of constraints, unit physical characteristics, and unit and system requirements are considered. The tranche MW constraint, energy generation and demand constraint, feasible reserve region constraint, ramp rate constraint, minimum system reserve constraint, and penalty calculation constraint need to be formulated. Besides, the demand side participation in the form of reserve has to be considered in its related constraint.

For the formulation of the probabilistic reserve requirement, the technique used to satisfy the yearly EENS in the insurance scheme needs discussion. Another specific objective is to apply a proper solution method after the system probabilistic reserve requirement is taken into consideration.

◆ Market settlement process

The modified runway model used in the Singapore Electricity Market needs to be further improved. The objective is to develop a probabilistic zero-sum settlement that is suitable to meet the probabilistic reserve requirement. Through the market settlement process, those generators benefiting system security are rewarded while those hurting are charged accordingly for compensating other generators. Formulating the computation of reserve responsibility and reserve supply fractions are the two specific objectives.

The principle of computing reserve responsibility fractions needs to be discussed. The “beneficiaries-pay” criterion is chosen as the basis of the proposed probabilistic zero-sum settlement. Contingency analysis is carried out to carefully compute the reserve responsibility fraction of each unit.

The payment to the reserve providers is the product of the marginal reserve clearing price and system reserve. A reserve supply fraction is used to determine the reserve contributions from each reserve participant. The reserve scheduling costs are then paid according to the reserve supply fractions.

1.3 Major contributions of the thesis

The consumers and generators would achieve a win-win situation under the proposed scheme. The participating consumers are protected from financial uncertainties since they are compensated accordingly. The principle of “causers-pay” criterion is incorporated in the insurance scheme. The “causers-pay” criterion makes the failed generators take the corresponding responsibility as a consequence of their failures. Generators are encouraged to improve their performance and reduce the frequency and amount of loss of load. In this connection, avoiding failures would be more meaningful to the generators.

A market clearing engine is developed to determine the reserve schedule based on a proposed probabilistic reserve criterion. Interruptible loads as well as generator reserve are taken into consideration. Two approaches are proposed as the solution methods. One approach is the MILP. This approach can formulate the probabilistic reserve criterion according to the probabilistic reserve requirement. The second approach is the iterative linear programming based on a heuristic technique and it runs several rounds of linear programming and post linear programming processes to satisfy the probabilistic reserve criterion. The iterative linear programming approach can avoid the curse of dimensionality. It has less computation burden and is suitable for real-time market operation.

A cost/benefit analysis is implemented to determine an optimal operating point where the expected value of loss of load is calculated and then compared with the reserve offering cost. The cost/benefit analysis gives a reference to the annual or hourly system reliability requirement.

The probabilistic zero-sum settlement is developed. The principle of “beneficiaries-pay” criterion is incorporated. Compared to the modified runway approach used in the Singapore Electricity Market [46], contingency analysis is conducted to carefully compute the benefit each participant receives. Besides, the probabilistic zero-sum settlement works very well with the probabilistic reserve requirement.

1.4 Organization of the thesis

The thesis consists of five chapters. Chapter 1 is the introduction of the thesis. The motivation of the research is discussed first. Then the objectives of the research are set up. Three new market designs are to be studied for the Singapore Electricity Market. They include the insurance scheme at the generation side, market clearing with demand side participation and reserve market settlement. Finally, major contributions of the thesis are presented.

Chapter 2 focuses on the insurance scheme for the Singapore Electricity Market. Firstly, the real world example of load curtailment is discussed. Secondly, the conceptual model of the insurance scheme at the generation side is proposed. Thirdly, the structure and mathematical model in the insurance scheme is developed. The premium for individual consumers is formulated and the compensation amount is computed as well. Besides, the penalty is also formulated for the failed generators. Finally, the calculations on insurance premium and compensation payment are illustrated through simulation results.

Chapter 3 studies the market clearing with demand side participation. The probabilistic reserve criterion is chosen for the market clearing. Firstly, the real word example of Singapore market clearing is shown. Secondly, the conceptual model of the proposed market clearing process is discussed while the assumptions and limitations are listed. Thirdly, the mathematical model for the market clearing is developed. The objective function and various constraints are formulated. Two solution techniques, i.e. MILP and iterative LP, are implemented to solve the model. Through some transformation, the probabilistic reserve requirement is converted from mixed integer nonlinear constraints to a mixed integer linear form. The market clearing model is further investigated to explore whether the iterative LP could be used to solve it. Fourthly, a cost/benefit analysis is chosen to determine the optimal operating point. Finally, simulations are conducted to show the results of the model proposed.

Chapter 4 carries out the reserve settlement study. To begin with, the real world examples of reserve settlement in the present Singapore market are discussed. Particularly, the rationale behind the zero-sum settlement is discussed. Then, the conceptual model of the

Chapter 1 Introduction

probabilistic zero-sum settlement is proposed. The proposed market design tries to preserve consideration of FORs in the current Singapore reserve settlement. Meanwhile contingency analysis is implemented and a mathematical model is formulated to calculate the reserve responsibility share more accurately. Finally, simulation results are presented to demonstrate the proposed settlement.

Chapter 5 concludes the research and gives recommendations to future studies.

Chapter 2

Insurance scheme for the electricity market

2.1 Load curtailment

Load curtailment may result from inadequate generation resources or system facility failures. To avoid load curtailment caused by inadequate capacity, PJM, NEPOOL, Texas and New York require load serving entities to maintain capacity reserves for their load requirement plus a fixed capacity margin. In the United States, most states that have employed capacity margins for load serving entities have been able to maintain robust reserve margin. In the New York Electricity Market, if load forecast for the next day shows sign of operating reserve shortage after using up all the available offers, operation staffs will take corrective actions in accordance with the procedures set forth. Some of the load demands (consumers) are called upon to reduce their energy consumption [47].

Another cause of load curtailment is from system facility failures. A reserve requirement is defined on an hour-to-hour basis. At all times, there must be sufficient generation synchronized to the grid to meet the load requirements and to be able to respond to short-term variations in consumer demands, as well as to cover for the loss of generators. This operating reserve is usually allocated among groups of companies who have agreed to jointly maintain these reserves [48]. Following a sudden generation outage, if there is insufficient generation reserve to maintain the frequency within acceptable limits, the only way to restore security is to reduce the load. The implementation of the electricity market does not change the laws of physics and does not eliminate the possibility of loss of load [40]. In the Singapore jurisdiction, the transmission network is very robust. Meanwhile, there are only three main power companies with 2670 MW, 2500 MW and 1567 MW installed capacity, and altogether these three plants account for 80% of the entire installed capacity in Singapore. Loss of generators may lead to loss of load. A

typical example is the massive blackout on June 29, 2004 [49]. The cause of the accident was due to a faulty valve which cut off the gas supply from Indonesia. Six gas turbines of the three power stations (viz Seraya, Tuas and SembCorp Cogen) had to switch from gas to diesel but only one generator succeeded in doing so. Around 300,000 homes plunged into darkness and it took more than an hour and a half to restore electricity to all the households. However, these consumers having suffered blackout did not get any compensation.

The research in this thesis focuses on the load curtailment caused by generator outages. Consumers have several choices to protect themselves from loss of load. One choice is to install embedded generators. The embedded generators like diesel units would start to operate when the energy supply is curtailed. That is why some consumers prefer to install them. However, not every consumer could afford to install the embedded generator. Another alternative is to set up a physical bilateral contract or financial contract for difference. If the contract has a clause that compensates the consumers for the loss of load, the consumer would not worry for the revenue loss due to load curtailment. However, this kind of contract adds extra uncertainties to the generation entity which signed the contract because load curtailment in the system may be caused by other generators and is not controlled by them.

For those consumers whose loss of load only leads to revenue losses, an insurance scheme is also an alternative. In terms of transmission and distribution network failures, an insurance scheme has been proposed to effectively unbundle reliability services and enable consumers to receive differentiated reliability based on their value for this service [43]. This means that different consumers would receive different reliability service levels, i.e. load curtailment duration, frequency and amount. However, the scheme in [43] does not take the generator outages into consideration.

Under the Singapore jurisdiction, generator outages may also lead to load curtailment in actual operation. Under the current market design, the consumers could only install embedded generators or sign a financial bilateral contract to protect them from possible loss due to load curtailment. Therefore, research related to the insurance at the generation side is carried out in this chapter to offer the consumers a possible choice.

2.2 Conceptual model for the insurance scheme

2.2.1 Principles of the insurance scheme

There are four principles in setting up the insurance scheme. The first principle is about the relation between the generation side and consumers. If the load curtailment amount in a year is equal to the preset yearly EENS standard, then the premiums collected should be equal to the expenses for compensating the consumers who suffered loss of load. This means that premiums from some consumers without loss of load are used to compensate others with loss of load. The mechanism is similar to aircraft passenger insurance that some passengers or families of casualties get most of the benefits at the end. On the other hand, if the load curtailment amount in a year is larger than the preset yearly EENS standard, then the generation side suffers revenue loss because of poor performance.

The second principle is about the relationship among the generators. Every generator is given a preset load curtailment amount. After every load curtailment within the yearly insurance period is decided, the responsibility fractions are calculated for generators. If the responsibility fraction for a generator exceeds its preset load curtailment amount, this generator loses revenue under the proposed insurance scheme. This also means that this generator holds an under-average performance. When the responsibility fraction for a generator is under its preset load curtailment amount, this generator gains revenue and holds an above-average performance.

The third principle is about the relationship among the participating consumers. Every participating consumer is calculated and then given a loss of load amount. Similarly, if the amount of load curtailment a consumer suffers during the yearly insurance period is smaller than the given loss of load amount, the sum of the compensation the consumer receives is less than the premium paid. When the load curtailment is larger than the given loss of load amount, the compensation is more than the premium.

The fourth principle is that the proposed insurance scheme should not be a mandatory one. Instead, the scheme makes choices possible to most of the consumers. The consumers

could pick a choice from the embedded generation, physical bilateral contract, contract for difference and insurance scheme to avoid revenue losses due to load curtailment.

2.2.2 Conceptual process of the insurance scheme

The proposed insurance scheme renews every year. The insurance scheme comprises four issues. They are the calculation of insurance premium for each participating consumer, premium distribution for each generator, compensation for each consumer having suffered loss of load, and allocation of load curtailment penalty responsibility among generation entities.

In the premium calculation for each participating consumer, those non-participating consumers do not need to pay the premiums. For the participating consumers, those with more energy consumption and larger VOLL have to pay more.

In the premium distribution, the generating capacity would be the determining factor as to how much each generator would get.

In the compensation for each consumer who suffered loss of loads, the participating consumers with a larger loss of load amount and larger VOLL have to be compensated more. No compensations would be offered to non-participating customers who suffered loss of load.

In the allocation of load curtailment responsibilities among generation entities, the “causers-pay” criterion dominates. Those failed generators are the causers of load curtailment such that they will have to take the full responsibility. Besides, the penalties need to be allocated according to the lost MW output amount.

The real social loss of the load curtailment is revealed in the insurance scheme. When a load curtailment happens due to generator outages, the failed generators not only suffer revenue loss in electricity sale but also have to compensate consumers’ loss of loads. Generators with different performances are differentiated in terms of their competition ability. According to the varying nature of unit availability, generators at the intrinsic

failure period are encouraged to supply energy while those at the early and wearout failure periods are discouraged.

2.2.3 Assumptions in the insurance scheme

Three assumptions are made in the introduction of the insurance scheme. The first assumption is that the system operator applies load curtailment according to system security needs. There is no priority in load curtailment. This means that the probability of load curtailment to each consumer is equal.

The second assumption is that the loss of load amount represents the result of load curtailment. The frequency of loss of load is not considered here. For consumers who suffered load curtailments several times, the loss of load amount each time is added together.

The third assumption is that consumers are offered three VOLL categories to choose although more categories could be added. It is assumed that VOLLs in the categories represent the revenue loss in load curtailment.

Finally, the realization of the insurance scheme also needs the support of the real-time market clearing because the yearly EENS specified in the insurance scheme is required to be turned to hourly EENS and thereafter incorporated in the real-time market clearing model.

2.2.4 Limitations of the proposed insurance scheme

The implementation of the insurance scheme may not physically reduce the amount of loss of load. It only provides financial compensation to consumers and thus it protects consumers from revenue loss in load curtailment.

The proposed insurance scheme requires extra human and computer resources. Premiums need to be computed by adding all the expenses to the acquisition bill. Some calculations are also needed after every large scale load curtailment.

When smart meters are not installed at customer premises, the loss of load amount could be estimated using load profiles. The load profile method could be inaccurate but it is a temporary solution until the smart meters are installed.

The proposed insurance scheme only discusses the outages at the generator side. The consumers are encouraged to participate in the transmission/distribution and generation side insurance scheme at the same time as load curtailment may be caused by both the transmission/distribution failures and generator outages.

The insurance scheme is not suitable for every consumer. Generally speaking, two kinds of consumers are not suitable, i.e. those consumers who could not bear the results of loss of load and those who do not care much about the loss of load. For example, blackouts are not permitted for hospitals because it is a matter of life and death. Obviously, no amount of compensation could not be enough to compensate the loss of a human life. Embedded generators would be a preference. In contrast, a pump-storage reservoir does not need to participate in the scheme because almost zero revenue loss is incurred.

2.3 Structure and mathematical model in the insurance scheme

2.3.1 Structure and characteristics of generation-side insurance scheme

The insurance scheme is renewed yearly. The structure of insurance scheme at the generation side has two financial flows in two opposite directions: one flow for the premium and the other for the penalty/compensation. Fig. 2.1 shows the structure.

Fig. 2.1 Structure of insurance scheme

The involved parties in the insurance scheme are Market Operator, retailers/consumers and generation entities. In this structure, Market Operator is not involved in any generation or retailing service. Hence, Market Operator can act as a central agent to collect and distribute the insurance premium. Retailers buy electricity from the market and then sell it to the consumers. They can be deemed as the agent of the aggregated consumers. Generation entities are the ones who provide the system reliability service.

The process of the insurance scheme is presented below. To begin with, retailers/consumers pay the insurance premium for protection against loss of load, as shown by solid lines in Fig. 2.1. After premiums are collected by the Market Operator, the premiums are then distributed among generation entities. If generators fail and the load is curtailed, the generation entities have the responsibility to compensate the retailers/consumers for the financial loss of the curtailed load. Generation entities would be required to maintain a prudential cover with a bank and the bank will pay on their behalf should they default on their payouts. This can provide some form of guarantee to the market in the event that the generation entities cannot pay up. The generation entity would not be penalized for transmission/distribution failures that occur outside the power generating station because the proposed insurance scheme is only set up between the consumers and generators. In Fig. 2.1, the dash line shows the direction of the financial flow from generators to compensate retailers/consumers due to generator outages.

Comparing with the transmission network and distribution grid, the generation side is already open for competition. For consumers, they need to know the compensations provided by the generators due to their loss of load. The compensations are in the form of penalties to generators. The penalties are allocated among generators. To discuss the allocation, the process of loss of load is studied. Suppose that the operator of units operating at full capacity decides to disconnect them because of some internal problems at the plant. Immediately after disconnection, the system load exceeds total generation such that the frequency starts to drop. This may lead to load curtailment as the power system operator attempts to avoid a complete collapse of the system. As can be seen, the failed generators are the cause of the loss of load. Those units remaining in operation actually help the system in terms of security. Hence a guideline called the “causers-pay” criterion is implemented here. This means that only those failed generators should be responsible for the consumer loss. In other words, those units which remain in operation do not have any responsibility as far as compensation is considered.

The insurance structure can protect the consumers from revenue loss due to generator outages. The consumers face the risk of being curtailed if severe outages happen. Generally, the loss of load would not be compensated in the market. Meanwhile, the consumers have no control of system reliability. As a result, the consumers are absolutely passive recipients of outage consequences. The insurance scheme avoids consumers’ uncertainties. High risk-averse consumers would benefit from it. If some consumers never suffer loss of load throughout the year, then no compensation is made to them. The premium collected ensures that generation entities compensate other consumers who suffered loss of load. The premium may also serve as a reward for generation entities because of their good performance.

The insurance scheme provides an incentive for reliable generators to supply energy through the “causers-pay” criterion. Those reliable generators have a better performance such that their probability of being penalized is small. Conversely, the generators that are just put into operation or are about to retire have a higher failure rate and subsequently will be penalized. To avoid the penalty as much as possible, generation entities would schedule more reliable units to produce energy. When a generation entity feels that its unit is susceptible to failures, the entity could reduce the unit’s energy output. This way, in case the unit fails, it would not be penalized too much under the insurance scheme.

The insurance scheme reveals the overall financial loss due to the generator outages and brings appropriate investment in the generator's performance. Without the insurance scheme, generators lack of incentives to prevent loss of load. It could be argued that failed generators are not able to sell energy. However, the loss of sales of electricity to the failed generators is nearly negligible compared to consumers' loss of loads. In fact, generation entities even enjoy the possible increase of energy price following the outages.

With the insurance, correct price signals are sent to generation entities. There are two factors that would influence the generator's outage rate. One is the time varying nature of unit availability. As the unit becomes older, its availability rate decreases. The other is the maintenance effort put in. Through regular maintenance, generation entities can reduce their unit forced outage rates although their revenues are affected during maintenance. However, if a lower forced outage rate brings them benefit, generation entities can balance the loss of revenue during maintenance and the benefit derived from it. The insurance scheme offers such rewards for maintenance and sends correct signals to generators.

2.3.2 Formulation of premium calculation and distribution

The insurance premium is paid by consumers so that compensation can be given to them later when needed. The premium is computed on a pro rata basis as a function of the annual electricity consumption [50]. Besides, the premium amount that each consumer pays is also influenced by the VOLL category the consumer chooses.

The m th consumer's annual load consumption is represented as CEC_m^{yr} while the total system annual electricity consumption is SEC^{yr} . The system reliability metric $EENS^{std, yr}$ is used to represent the expected energy not served within the yearly insurance period. As has been assumed, the probability that each consumer gets load curtailment is the same. It could be deduced that the loss of load amount for the consumer allocated is

$$EENS^{std, yr} \cdot \frac{CEC_m^{yr}}{SEC^{yr}}.$$

VOLL is used to calculate the value of loss of load per MWh [46]. For simplicity, three categories are provided, i.e. high VOLL, medium VOLL and low VOLL. $VOLL_g$, where $g = 1, 2, 3$, is used to represent the respective VOLL for each category. Each consumer is allowed to choose his respective VOLL category. System VOLL is published first to give the consumers an indicative value of loss of load. System VOLL reflects the average revenue for each consumer loss due to loss of load. Many ISOs investigate the system VOLL. For example, in the England and Wales electricity market, system VOLL was set at £2,816/MWh in 2000/01, while in the Singapore Electricity Market, system VOLL was set at Singapore S\$5,000/MWh in 2003. The VOLL that individual consumer chooses may be different from the system VOLL. The process for the consumers to choose a VOLL category is as follows:

- Step 1: In a given period, say 1 month, they can choose a VOLL category for the next year.
- Step 2: After this given period, no one is allowed to change the category within the year.
- Step 3: At the same time next year, these consumers are allowed to change their categories. Those do not take any action will remain in the same category.

After the VOLL category has been determined, the formulation of the premium that Consumer m has to pay is as follows:

$$PM_m^{yr} = VOLL_{g,m} \cdot EENS^{std, yr} \cdot \frac{CEC_m^{yr}}{SEC^{yr}} \quad (2.1)$$

If the consumer experiences a lost load amount less than $EENS^{std, yr} \cdot \frac{CEC_m^{yr}}{SEC^{yr}}$ MWhs in the yearly insurance period, it can be deemed that this consumer enjoys an above-average reliability level. The compensation the consumer receives would be less than the premium paid. In contrast, if the consumer suffers electricity interruption more than $EENS^{std, yr} \cdot \frac{CEC_m^{yr}}{SEC^{yr}}$ MWh, the consumer's reliability level is below-average and would get compensation higher than the premium paid.

The premium collected serves as an incentive for the generator entities to maintain their generators. The insurance premium would be distributed to the generator entities in proportion to the energy they provide yearly.

2.3.3 Formulation of compensation for consumers

In the compensation process, financial loss to the consumers due to loss of load is reasonably compensated. The compensation paid to an affected consumer depends on two factors, i.e. the VOLL category the consumer chooses and the loss of load amount. The category information can be obtained through the premium records.

To compute the loss of load amount, the first step is to determine the load consumption pattern. Ideally, all consumers in an open electricity market should have time-interval meters with online communication installed. This would ensure accurate billing. In reality, only a portion of electricity consumers (especially large ones) have meters installed. Historical measurements can be obtained to build load patterns for those consumers with meters. However, other consumers (mostly residential and low energy consumers) do not have these meters installed because meter and communication solution are relatively costly. A load profiling solution could be an alternative since it is already widely used in the Europe market [51, 52]. The load profiling solution involves two steps: (i) Determine an estimate of the average load profile of a class of consumers over a given period; (ii) Allocate that load profile to all consumers in that consumer class. This class of consumers can be all those who are not metered on time interval basis within the geographic region covered by a network. With this method, the non-metered consumers constitute the residual profile, which is an adjusted load-profile for the node or for the area under consideration. The other option is grouping consumers with a similar load pattern into classes, where each individual consumer is then associated with a representative of the load profile predetermined.

For each consumer, the load profile function $Prfl(h)$ could be set up to describe the energy consumption pattern. The mapping is done by substituting the index h and a typical energy consumption value $Prfl_h$ (with MWh as unit) will be assigned to each hour.

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The pattern for energy consumption could be obtained by computing the value in each hour. The function is defined as follows:

$$Prfl_h = Prfl(h) \quad h = 1, 2 \dots 24 \quad (2.2)$$

The second step is to obtain the energy consumption just before the load curtailment as represented by L_m^{blol} . For large consumers with time-interval meters, L_m^{blol} could be obtained from the meter readings. For residential and low energy consumers, L_m^{blol} could be obtained from the load profile solution techniques.

The third step is to compute the loss of load amount. Depending on the time periods the load curtailment lasts, the loss of load amount has three stages, i.e. (1) the hourly period indexed h when the load curtailment begins, (2) H whole hourly periods follow, and (3) the last hourly period indexed $(H^{blol} + H + 1)$. In the first stage, load curtailment which lasts 1- 59 minutes in that hourly period is represented by $Time^{first}$. In the second stage, H is set to 0 if load curtailment lasts for only one or two hourly periods since H only counts the whole time periods. In the third stage, load curtailment which lasts minutes in that period is represented by $Time^{last}$, and $Time^{last}$ is set to 0 when the load curtailment ends at the period of $Time^{first}$ or at the end of the hour (60 minutes). The following figure illustrates the process of load curtailment and the corresponding parameters.

Fig. 2.2 Description of loss of load process

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For the loss of load amount, the load profile together with the meter reading at the load curtailment point shows a clear picture. The load profile could be obtained through the historical electricity consumption records. Function $Prfl(h)$ is used to represent the load consumption amount at Period h while the energy consumption just before the loss of load is represented by L_m^{blol} . The loss of load amount can be seen in the shadow area in Fig. 2.3.

Fig. 2.3 Loss of load amount computation

The shadow area L_m^{lol} can be computed as follows:

$$L_m^{lol} = \frac{L_m^{blol}}{Prfl(H^{blol})} \cdot \left\{ Prfl(H^{blol}) \frac{Time^{first}}{60} + \sum_{h=1}^H Prfl(H^{blol} + h) + Prfl(H^{blol} + H + 1) \frac{Time^{last}}{60} \right\} \quad (2.3)$$

If the VOLL of the consumer is $VOLL_{g,m}$, then the compensation amount the consumer can receive is as follows:

$$CPST_m^{lol} = L_m^{lol} \cdot VOLL_{g,m} \quad (2.4)$$

The premium calculation and loss of load compensation encourage consumers to choose the VOLL category based on their actual revenue loss due to load curtailment. The overestimation of the VOLL makes the consumer pay more insurance. For example, if the

consumer belongs to the medium VOLL category but chooses the high reliability category, the premium this consumer has to pay is higher than what it is supposed to pay.

Meanwhile, the underestimation of the VOLL makes the consumer exposed to unnecessary risks. If the consumer belongs to the high VOLL category but chooses the medium one, the compensation would cover only part of its real revenue loss when the loss of load happens. The financial uncertainty due to loss of load is only partially avoided.

In a nutshell, the best choice for the consumers is to choose the VOLL category based on their actual needs.

2.3.4 Formulation of generator penalty

When the generator outages cause load curtailment, the generators have to be penalized and the compensation derived from the penalty is passed on to the consumers who suffered loss of load. The guideline in the sharing of compensation responsibility for generators is the “causers-pay” criterion. This means that only failed generators are responsible for the consumer’s revenue loss due to load curtailment. The reason is that the outages are caused by the failed generators while other operating generators contribute additional MWs towards the system security.

Let L_g^{out} , where $g = 1, 2, 3$, represents the loss of load amount in each of the three consumer VOLL categories. According to the insurance scheme, the consumers would get their total compensation as shown in (2.5).

$$WTH^{out} = \sum_g L_g^{out} \cdot VOLL_g \quad (2.5)$$

According to the “causer-pays” approach, the failed units should be responsible for all the cost incurred. If only one generator is involved, then this unit needs to take the whole responsibility. If more than one generator causes the load curtailment, the cost needs to be allocated among all the failed generators. For those failed generators with higher output,

the system needs more reserve to cover it. Thus, they should pay more a large share for the loss. The share of the penalty for Unit i , SHR_i^{out} , and the penalty amount for Unit i , PNT_i^{out} , under this condition are shown in (2.6) and (2.7) respectively.

$$SHR_i^{out} = \frac{[1 - v_i] \cdot GE_i^{sum}}{\sum_{j=1}^N [1 - v_j] \cdot GE_j^{sum}} \quad (2.6)$$

$$PNT_i^{out} = SHR_i^{out} \cdot WTH^{out} \quad (2.7)$$

where

v_i is on/off random variable of Unit i where 1 is on and 0 is off.

GE_i^{sum} is the scheduled output of Unit i .

The penalty gives incentives to the generators to improve their performance. The generation entities would compare the cost of maintenance and the payment as outage penalty. If the outage penalty is higher than the maintenance cost, the generation entities would improve their generator performance. In contrast, if the penalty cost is lower or if there is no significant difference between the two, the generation entities can wait or slow down the investment on reliability improvement.

2.3.5 Balance between premium and penalty

Efficient pricing of the insurance scheme can be achieved when the expected value of compensation is equal to the premium collected under the condition that the system reliability level remains at the preset level. In this section, the calculation would prove that the sum of compensations equals to total premium collected when the yearly energy curtailment amount is equal to $EENS^{std, yr}$.

As has been assumed in Section 2.2.3, the probability that each consumer would suffer loss of load is the same. It could be deduced that those consumers who do not participate and those who participate in the insurance scheme would suffer equally during the load curtailment in the yearly insurance period. After all the participating consumers choose their VOLL categories, the statistics of the number consumers in each category could be

computed. The symbol PTG_g is used to represent the percentage in each category. The loss of load amount that consumers in each VOLL category suffer is proportional to PTG_g .

The expected compensation amount, $CPST^{std,yr}$, can be obtained by multiplying the expected loss of load amount $PTG_g \cdot EENS^{std,yr}$ and $VOLL_g$ in each category. The formulation is as follows:

$$CPST^{std,yr} = \sum_g (PTG_g \cdot EENS^{std,yr} \cdot VOLL_g) = EENS^{std,yr} \sum_g VOLL_g \cdot PTG_g \quad (2.8)$$

Meanwhile, the sum of the PM_m^{yr} from consumer m , PM^{yr} , can be deduced from (2.1)

$$\begin{aligned} PM^{yr} &= \sum_m PM_m^{yr} \\ &= \sum_m VOLL_{g,m} \cdot EENS^{std,yr} \cdot \frac{CEC_m^{yr}}{SEC^{yr}} \\ &= \frac{EENS^{std,yr}}{SEC^{yr}} \sum_m VOLL_{g,m} \cdot CEC_m^{yr} \end{aligned} \quad (2.9)$$

For consumer m , the value of $VOLL_{g,m}$ is equal to $VOLL_g$. Meanwhile, $\sum_m CEC_m^{yr}$ in category g is equal to $PTG_g \cdot SEC^{yr}$. Hence, (2.9) could be rewritten as follows:

$$PM^{yr} = \frac{EENS^{std,yr}}{SEC^{yr}} \sum_g VOLL_g \cdot PTG_g \cdot SEC^{yr} = EENS^{std,yr} \sum_g VOLL_g \cdot PTG_g \quad (2.10)$$

As can be seen, the $CPST^{yr}$ in (2.8) is exactly the same as the PM^{yr} in (2.10). This means that the collected premium would be fully paid to the affected consumers as compensations if $EENS^{std,yr}$ MWhs of load are curtailed in the yearly insurance period. If the generator entities increase their reliability performances, the exact load curtailment amount may be less than the preset $EENS^{std,yr}$ and the generators would get extra revenue.

The financial flow indicating how the premium and compensation are made is shown in Fig. 2.4. As could be observed in the figure, the compensation for those consumers having suffered loss of load is obtained from the premiums collected from all consumers.

Depending on the loss of load amount, different consumers get different compensations. As can be seen in Fig. 2.4, all participating consumers pay premiums as shown at the top layer but some never receive compensation as in the right part of the bottom layer.

As could be observed, whether a generator gains or loses revenue under the scheme depends on its own performance. If the generator never fails or its failure does not cause any loss of load during the year, it does not need to compensate consumers. Then, the generator gains extra profit for its good performance. As shown in Fig. 2.4, some generators receive the premiums but do not need to pay out. This is a reward to those generators with good performance.

Fig. 2.4 Financial flow between participating consumers and generators

2.4 Illustrative examples

In this section, examples are used to illustrate the premium paid and compensation received for the participating consumers and the penalty allocation among the generators. The proposed scheme is tested on the IEEE 32-unit system [53] where 17,520,000 MWh energy is assumed to be consumed every year. The system reliability metric $EENS^{std, yr}$ is set at 797 MWh, i.e. 0.0909 MWh every hour. The values of $VOLL_g$ in different categories are 8000, 3000, 500 \$/MWh and the PTG_g is 10%, 30% and 60% respectively.

2.4.1 Insurance and compensation calculation examples

The insurance premium, expressed in \$/MWh, that consumers have to pay in different reliability categories is shown in Table 2.1.

Table 2.1 Premium calculations

Reliability category	$VOLL_g$ (\$/MWh)	Premium (\$/MWh)
High	8000	0.3640
Medium	3000	0.1365
Low	500	0.0230

The consumer's load profile is shown in Table 2.2. The time period starts from hour ending 01:00, i.e. Period 1 and ends at hour ending 24:00, i.e. Period 24. The load is expressed in p.u. while the base load is 10 MWh.

Table 2.2 Load profile function

Time period	1	2	3	4	5	6	7	8
Load (MWh)	0.6	0.7	0.7	0.6	0.5	1.6	6.5	9.0
Time period	9	10	11	12	13	14	15	16
Load (MWh)	8.5	7.5	7.0	8.2	7.8	7.0	5.5	2.1
Time period	17	18	19	20	21	22	23	24
Load (MWh)	1.8	1.3	1.2	0.8	1.1	1.1	1.0	0.9

From Table 2.2, the total load per day is 83 MWh. If an annual load consumption of 83×365 MWh is assumed, the consumer would finally consume 30,295 MWh per year. According to the insurance scheme, the premium this consumer needs to pay is \$11,027, \$4,135 or \$697 per year under the high, medium or low reliability category respectively.

For the compensation, two cases are studied. The details of the cases are as follows:

Case 1: The loss of load starts in Period 21 and lasts for half an hour. The last reading

L_m^{blol} before the loss of load is 1.1 MWh.

Case 2: The loss of load starts in the middle of Period 9 and ends in the middle of Period 10. L_m^{blol} before the loss of load is 8.5 MWh.

The compensation amount under different cases and different VOLL categories is shown in Fig. 2.5.

Fig. 2.5 Compensation for different cases

Fig. 2.5 shows that the consumer would receive different amount of compensation. The compensation more or less lets the consumer avoid the financial loss caused by loss of load. If this is the only load curtailment the consumer would suffer within a year, then the consumer receives higher than the standard reliability level in Case 1 while lower than the standard in Case 2. This is because the loss of load amount in Case 2 is more than that in Case 1. The result is that the compensation is lower than the premium paid in Case 1 while higher in Case 2. For example, the consumer gets \$64,000, \$24,000 or \$4,000 compensation compared to \$11,027, \$4,135 or \$697 premium paid in each VOLL category.

At the same time, the consumer will receive a higher compensation amount if a higher VOLL category is chosen. For example, in Case 1 the consumer gets $(\$4,400 - \$275) = \$4,125$ more if an upgrade from a low VOLL category to a high VOLL is chosen.

2.4.2 Penalty allocation examples

This section tests the influence of the penalty allocation among the generators. The hourly system load demand is set at 2,200 MW. The energy and reserve schedule is shown in Table 2.3.

Table 2.3 Energy and reserve schedule

Unit	1	2	3	4	5	6	7
Energy (MW)	2	2	2	2	2	0	0
Reserve (MW)	2	2	2	2	2	0	0
Unit	8	9	10	11	12	13	14
Energy (MW)	0	0	55	55	55	55	75
Reserve (MW)	0	0	21	21	21	21	25
Unit	15	16	17	18	19	20	21
Energy (MW)	66	50	121	121	121	121	56
Reserve (MW)	25	25	34	34	34	34	45
Unit	22	23	24	25	26		
Energy (MW)	45	45	345	400	400		
Reserve (MW)	45	45	5	0	0		

Unit 25 is used to illustrate the impacts of the proposed schemes. Four cases involving the outage of Unit 25 are tested. The detailed information for each case is as follows:

Case 1: Only Unit 25 fails;

Case 2: Unit 25 and Unit 14 fail;

Case 3: Unit 25, Unit 14 and Unit 18 fail; and

Case 4: Unit 25 and Unit 24 fail.

The hourly loss of load amounts in all these cases are shown in Table 2.4. Since the reserve amount is 445 MW while the selected energy and reserve amount of Unit 25 is 400 MW, there is no loss of load in Case 1. For the other three cases, loss of load occurs.

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Table 2.4 Loss of load amount under different cases

	Hourly loss of load amount (MWh)	L_g^{out} (MWh)		
		$g = 1$	$g = 2$	$g = 31$
Case 1	0	0	0	0
Case 2	55	5.5	16.5	33.0
Case 3	210	21.0	63.0	126.0
Case 4	305	30.5	91.5	183.0

The failed generators would be penalized and the penalty imposed is used to compensate the consumers for the lost energy during the outage period. Table 2.5 shows the penalty percentage and payment amount that Unit 25 needs to undertake hourly.

Table 2.5 Payment due to generator outage

	Total compensation amount (WTH^{out})	Payment share (SHR_{25}^{out})	Payment amount (\$) (PNT_{25}^{out})
Case 2	110,000	0.842	92,620
Case 3	420,000	0.671	281,820
Case 4	610,000	0.537	327,570

As could be seen in Table 2.6, the revenue loss due to generator outage is very high, especially several generators fail at the same time such as those in Case 3 and Case 4. This means that the insurance scheme could offer extra incentives for the generators to improve their performances. This kind of incentive comes from possible huge payment.

2.5 Conclusion remarks

In this chapter, an insurance scheme at the generation side is proposed. The participating consumers have to pay premiums and the generation entities would be penalized when their outages lead to load curtailment. The premiums and compensations are formulated. The premiums are based on their annual energy amount and the respective VOLL categories. The penalties are allocated among the failed generators and the penalties

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collected from generators serve as the compensations to the consumers who suffered loss of load. It is proved that the premiums would be equal to the compensations when the energy curtailment amount in the yearly insurance period equals the preset $EENS^{std, yr}$.

The insurance scheme offers the electricity consumers an alternative to an embedded generator and a physical/financial bilateral contract. The implementation of the insurance scheme needs the support of the market clearing scheme. The preset $EENS^{std, yr}$ needs to be converted into hourly EENS requirement where it can be satisfied in real-time.

Chapter 3

Market clearing with probabilistic reserve criterion

3.1 Market clearing

The Singapore Electricity Market comprises two types of markets [5],

- the real-time market for energy, regulation and reserve; and
- the procurement market for ancillary services other than regulation and reserve.

In the procurement market, services such as reactive support, black start capability and fast start service are arranged. Because it is temporally and economically unsuitable to set up a separate market, the system operator signs a long term contract with the service providers to obtain the service. Unless stated otherwise, the remaining part of the thesis describes the real-time market rather than the procurement market.

The real-time market is set up for the trading of energy commodity as well as reserve and regulation service. Regulation refers to the generation capacity that is able to follow the normal variations in load during the dispatch period. Reserve is the unused on-line capacity that is available on a stand-by basis to supply energy during emergency. In the Singapore Electricity Market, interruptible loads could also act as reserves as long as they meet the time response standard imposed by the regulator. Meanwhile, there is no day-ahead market for energy or any services.

The supply of energy, reserve and regulation is specified by means of offers that contain price/quantity pairs indicating how each generator is willing to supply. The offering prices and constraints of generators as well as the system requirement for energy and reserve are formulated in the market clearing model. The market clearing engine is the software module which implements the market clearing model. The market clearing software takes the system information and requirement as inputs and finally produces a generation/load dispatch and reserve schedule as well as the energy and reserve price.

At the first glance, it may seem that the price-based energy dispatch process is very similar to the conventionally cost-based dispatch except the incremental costs of energy production are replaced by offer prices. However, it should be noted that the offered prices can vary according to suppliers' bidding strategies and they may be quite different from the actual incremental costs. To make it clear, the term, offering cost, refers to the scheduling cost based on generators' offers. The offering cost may be different from the operating cost used in the unit commitment of the vertically integrated power industry.

3.1.1 Various aspects in the market clearing process

The market clearing algorithm takes account of all the system constraints, and tries to minimize the offering cost or maximize the social welfare. The inputs of the market clearing algorithm are the offering data, unit parameters and network data. The output of the market clearing engine is the energy and reserve dispatch schedule, as well as the marginal clearing price for energy and reserve.

Various aspects of market clearing processes are investigated in this subsection. These aspects include the demand side participation and commitment procedure. The discussion of these aspects would help to set up the market clearing process in this chapter.

◆ Demand side participation

Demand sides could participate in both the energy and reserve market. Consumers can bid their total demand into an energy market in a similar way to that undertaken by generators. This means that consumers could bid the quantity of the electricity they will consume for a given price and if the price is higher they would rather not consume the electricity.

Consumers could participate in the reserve market in the form of interruptible loads. Many utilities have already realized that interruptible loads could help to reduce the operating/spinning reserve requirement if the owner of these loads could reduce their energy consumption fast enough during contingencies. These interruptible loads are also willing to participate because the interruption would not affect their normal operation

much and they are paid for their contribution. After reregulation, interruptible loads are allowed to take part in the reserve market in many markets around the world. There is a consensus among all stakeholders that increased participation by interruptible loads is essential to a full competitive market. In [54], a chemical process is adapted such that the load could be interrupted and contributes to spinning reserve and the performance of the interruptible load is compared with that of the generator's spinning reserve. However, failure to discharge interruptible load responsibilities faithfully would also get the system into trouble [55].

In the Singapore Electricity Market, a consumer could not participate in the energy market currently but can serve as an interruptible load as long as the consumer is proven to meet the corresponding reserve requirement. A facility called Monitoring, Recording & Activation (MRA) device is installed to automatically interrupt the load when the frequency drops below 49.4 HZ [56].

◆ Centralized commitment and Self commitment

Unit commitment and dispatch are two major tasks in the market clearing process. Different commitment procedures require the generation entities to submit different types of data. Currently, there are two commitment procedures available, i.e. centralized commitment and self commitment.

Under the centralized commitment, the market operator is needed to collect all the relevant data and make a centralized calculation to determine if the unit start-up time as well as the minimum up/down time imposed by the unit is worth the cost incurred. In some markets, centralized commitment is enhanced by incorporating security constraints known as Security Constrained Unit Commitment (SCUC) [57]. Under the self commitment, the market operator provides enough system information by computing a market clearing price for access by the public. The generation entities can use this information to solve their own unit commitment problems separately. The most talked-about techniques for the solution of the unit commitment problem are priority-list schemes, dynamic programming, Lagrangian Relaxation and MILP. Takriti and Birge implemented integer programming to refine the Lagrangian-based unit commitment solutions [58].

Self commitment means that all generators have to manage their offers in the market such that they would get scheduled. Based on self commitment, the generators do not need to submit unit start-up prices, minimum output and minimum up/down time. The self commitment puts these considerations that are commercial in nature in the hands of generation entities themselves. The market operator is only interested in the prices at which the participants are willing to supply the energy and reserve.

Under the self commitment, offers are the signals from/to generators that enable them to manage their own commitment. If a generator wishes to have its capacity or a portion of the capacity considered as “must-run”, it signals by submitting to the market a low offered price that ensures its dispatch. Under the self commitment, the generation entities also have to solve the multi-period unit commitment problem. They can use a sophisticated unit commitment software package of their own to develop their commitment schedule and corresponding offer curves.

Self commitment can overcome some of the problems in centralized commitment. Firstly, it promotes productive efficiency. It sends a clear price signal to the plants to clarify and redefine minimum MW running levels and energy/reserve relationship. Secondly, there is no longer an ambiguity of parameters in the centralized commitment. The parameters and relationship are decided on a unit basis other than the “best-practice” standard. Thirdly, it reduces the complexity of market design. Linear programming can be implemented, which shortens the computation time to reach results and yield global optimization. Fourthly, it motivates and facilitates the participants in taking responsibility for their commercial decisions in the face of uncertain information.

However, self commitment has its limitation too. Firstly, the result achieved by self commitment may not be feasible in reality. The participants can carefully avoid this problem if they submit their offers properly. An iterative offering process could also be implemented to remove this limitation. Secondly, market participants face challenge to handle their own constraints. They may need to have a period of time to get used to it. Last but not the least, self commitment may produce poor commitment decisions overall.

In the Singapore Electricity Market, self commitment is implemented.

3.1.2 Available market clearing models

Most practical systems including the market clearing are nonlinear in nature. However, some approximations are usually tolerable to certain classes of problems. After the approximations are done, the equations for the models are formulated. Two commonly used methods for solving the model equations are quadratic and linear programming [59]. The quadratic optimization assumes a quadratic objective and linear constraints while the linear optimization assumes linear in both the objective and constraints.

The most general description of the linear programming problem is the resource allocation which maximizes the worth from all the activities. The term “linear” refers to the fact that all the mathematical relationships among the decisions (variables) which allocate resources to activities, the various restrictions applicable therein (constraints), as well as the criterion (objective function) are devoid of any nonlinearity.

A few mathematical algorithms are also available to solve the market clearing problem. For the market clearing model formulated by linear programming, the commonly adopted approaches are the graphical, simplex and revised simplex method [59, 60]. Sometimes, the formulated linear programming problem is very large and sparse. The large dimension stems from the vast participants and constraints. In [61], an interior point method for linear programming is used to solve the market clearing model.

Avery et al [62] and Ma et al [63] described the algorithms that have been implemented for the New Zealand and Australian Electricity Market respectively. In [64-68], the operation of the Singapore Electricity Market is analyzed in detail. In [38, 69], Cheung discusses the clearing process in the New England Power Pool. A linear programming based clearing framework is presented and a combined sequential and simultaneous dispatch method is proposed to solve the electricity market dispatch problem with reserve service.

In [70], a mixed-integer linear model for a static (1 hour) electricity market for power, spinning reserve and frequency regulation is formulated. In [71], Lagrangian Relaxation

is used to perform market clearing where reserve is scheduled to provide sufficient flexibility to allow the system to survive during a set of credible contingencies.

3.2 Conceptual model for market clearing

3.2.1 Market structure

The power pool has emerged as a popular form of system operation to organize electricity trading in the current market. For study purposes, a power pool similar to the Singapore Electricity Market is used here.

Every MW of energy and reserve would be traded in the pool. There is no day-ahead market but only the real-time market for the energy and reserve. The bilateral contracts are purely financial arrangements whereby participants sell and buy via the real-time market. This means that the buyers and sellers settle any financial differences agreed by the bilateral contracts between them. In other words, the financial bilateral contract has no direct impact on the clearing system. The overall market structure is shown in Fig. 3.1.

Fig. 3.1 Market structure

In the pool, “sellers” (generators, interruptible loads) submit a set of offers separately.

A trading day begins at 00:00 midnight and there are 24 hourly trading periods every day. Trading is based on the offers submitted by generators and interruptible loads. A staircase offering curve is the only format allowed for submission as offers by the generation entities in the energy and reserve market and by interruptible loads in the reserve market. The offer is a staircase curve or Willans line [72, 73]. This means that each offer for the commodities are divided into several tranches with monotonously non-decreasing price. The {quantity, price} tranche in each offer indicates the quantity of energy/reserve that each dispatchable generator is willing to supply at the corresponding energy/reserve price. The offer curve can be formed by arranging in ascending price order for each generator. Fig. 3.2 illustrates the staircase offering curve in the energy market. The offers in the reserve market could be formed in a similar manner.

Fig. 3.2 Staircase offer curve

Self commitment is engaged in scheduling generators. This means that all generating units have to offer into the market such that they would get scheduled. The trick for the generators in self commitment is through their offering price. If a generator does not want to provide a certain commodity or service, its offering price for this commodity or service would be set very high. In fact, it should be set high enough such that it is profitable to provide energy based on that price. In contrast, if a generator wants to be scheduled for a commodity or service, the price should be set low. Sometimes the generator would even offer as low as zero to get itself scheduled. However, because the system would pay a

uniform clearing price based on the last selected marginal unit, these generators which offer a zero price are usually not paid at zero.

However, self commitment may cause physically impossible commitment. A possible solution is to allow the generators to re-submit their offers. In this study, the generators can re-submit 4 hours before the real-time execution. For example, for the 11:00 am - 12:00 am dispatch period, the generators are not allowed to change their offers after 7:00 am. The 4 hours before the real-time execution, is also called the gate closure. Before the gate closure, the system would have run the market clearing engine several times and published the schedules based on the generators' offering data. These schedules are not for dispatch purpose but for providing information to the participants. Therefore, the generators can still take the time to change the unit commitment schedules to avoid physically impossible operating conditions.

The final schedule is determined 10 minutes before each real-time operation period by the market clearing engine and is used for the dispatch and the subsequent settlement. When multiple periods are to be scheduled, the market clearing engine would clear the market period by period. The first period needs the dispatch information (unit status, unit MW dispatch, etc) in the previous hour. After the market clearing engine completes, all the MWs are assigned to the successful bidders and the system marginal clearing price will be computed for this period. Each subsequent period will then use the schedule in its previous hour that has just been determined. Finally, the schedule and clearing price for each of the multiple periods are decided.

3.2.2 Conceptual model of market clearing system

The market clearing model simultaneously optimizes the energy and reserve schedule by considering both the energy and reserve offers.

The market clearing model has an objective function and several constraints. The objective function is to minimizing the offering costs of energy and reserve. The constraints comprise the tranche MW constraints, energy generation and demand constraint, feasible reserve region constraint, ramp rate constraints, minimum system

reserve constraint, penalty calculation constraint and probabilistic reserve requirement. The simultaneous dispatch is based on formulating the problem in the context of constrained optimization. The coupling between the energy and reserve amount are embedded in the constraints. Thus, the results can satisfy physical limits of the units and achieve the best tradeoff between the allocation of energy and ancillary service. The deterministic system reliability metric $EENS^{std, yr}$ specified in the insurance scheme of the previous chapter is converted into an hourly reserve requirement which needs to be satisfied in the clearing process.

This process could be naturally formulated as a MILP problem and the branch and bound approach is used to solve the problem. Due to the deficiency of the computation burden problem found in the MILP when handling the EENS requirement, a heuristic method called iterative linear programming is proposed. With several iterative rounds of linear programming and a post processing, the energy and reserve schedule could be obtained.

The cost/benefit analysis could also be implemented to determine an optimal hourly EENS value $EENS^{std, hr}$ where the sum of the offering cost and the worth of loss of load is minimized.

3.2.3 Assumptions in the market clearing model

The assumption is made that only the energy commodity and spinning reserve service are traded in the market. Similarly, regulation services and other types of reserve could be added, but are not considered here.

The assumption is made that consumers would not participate in the energy market. They are only allowed to participate in the reserve market in the form of interruptible loads.

A perfect network is assumed. The system could choose the offers without considering the transmission line capacity constraints. Power flow has no transmission loss.

The reserve is converted into energy only during generator failures. Load forecasting, environment and weather impacts, and consumer behaviors are assumed not to affect the spinning reserve calculation.

All the generators are assumed independent and the FORs are constant throughout the study period.

Strategic behaviors of the participant or market power are not considered in the analysis.

3.2.4 Limitation of the market clearing model

Using the MILP approach, the computation burden for solving the market clearing model is heavy, especially for large systems.

3.3 Mathematical model for market clearing

3.3.1 Objective function

In the market clearing process, a simultaneous dispatch is used such that the Market Operator can coordinate all the commodities and services. This means that the energy commodity and other services are co-optimized. Here, only the energy commodity and spinning reserve service are considered. In the remaining part of the thesis, reserve and spinning reserve are used interchangeably. Reserve also refers to the spinning reserve. The objective function in a single time period is formulated as follows:

$$\text{Min} \left[\sum_{i=1}^N \sum_{gi} GE_{i,gi,t} \cdot GEP_{i,gi,t} + \sum_{i=1}^N \sum_{ri} GR_{i,ri,t} \cdot GRP_{i,ri,t} + \sum_{s=1}^S \sum_{sj} ILR_{s,sj,t} \cdot ILRP_{s,sj,t} + V_t^{sum} \right] \quad (3.1)$$

where

N is the number of the generators.

S is the number of interruptible loads.

i is the index for the generators.

s is the index for interruptible loads.

t is the period index.

gi is the index of MW tranches in the energy offer.

ri is the index of MW tranches in the generator reserve offer.

sj is the index of MW tranches in the interruptible load reserve offer.

$GE_{i,gi,t}$ is the selected energy output in tranche gi for Unit i .

$GR_{i,ri,t}$ is the selected reserve provision in tranche ri for Unit i .

$ILR_{s,sj,t}$ is the selected reserve provision in tranche sj for interruptible load s .

$GEP_{i,gi,t}$ is the offer price for energy in tranche gi for Unit i .

$GRP_{i,ri,t}$ is the offer price for spinning reserve in tranche ri for Unit i .

$ILRP_{s,sj,t}$ is the offer price for spinning reserve in tranche sj for interruptible load s .

The objective function aims to minimize the offering cost for energy and reserve. The offering cost refers to the system scheduling cost from generators' offers. The first term represents the total offering cost for all the scheduled energy at period t while the second term is the total offering cost for all the scheduled spinning reserve in the same period. The generator can offer in the energy and reserve markets simultaneously. The market clearing engine would make sure that the sum of energy and reserve amount would not exceed the system capacity.

The third term, V_t^{sum} , is the sum of the penalties applied to all the violations of the constraints. Under the normal clearing process, the constraints are not supposed to be violated. However, sometimes the clearing model could not converge if all the constraints have to be satisfied due to stringent system conditions or wrong offering data. Thus the respective violation penalties are set up for most of the constraints. Whether there are constraint violations or not after the execution of market clearing could be observed through V_t^{sum} . A zero value of V_t^{sum} means no violation while a positive value means that one or more violations have occurred. If a violation has occurred, the market operator

would decide whether to execute the energy and reserve schedule or check the input data for errors and run the clearing engine again after fixing the error.

The objective function would coordinate the allocation of energy and reserve based on the offers submitted by the generation entities. The working mechanism of the objective function without reserve and demand side bidding is shown in Fig. 3.3.

Fig. 3.3 Objective function without reserve and demand side bidding

3.3.2 Constraints in the market clearing model

The objective function is minimized subject to the tranche MW constraints, energy generation and demand constraints, feasible reserve region constraints, ramp rate constraints, minimum system reserve constraints, penalty calculation constraints and probabilistic reserve requirement constraint [46]. The targets of these constraints are presented in Table 3.1.

Table 3.1 Target of the constraints

Name of the constraints	Target of the constraints
Tranche MW:	Unit and interruptible load's MW range for the offers
Energy generation and demand	Balance of system demand and generation
Feasible reserve region	Level of reserve a generator can provide at various levels of energy output
Ramp rate	Unit's ability to change (ramp up/down) energy and reserve provision
Minimum system reserve	Minimum MW amount of system reserve
Probabilistic reserve requirement	System reserve requirement based on probabilistic approach
Violation penalty calculation	Constraint violation cost

A. Tranche MW constraint

This constraint deals with the variable bounds in the market clearing model. For each energy or reserve offer tranche, the quantity that the market clearing engine can select should be less than the generator's offer in that tranche.

$$GE_{i,gi,t} \leq GE_{i,gi,t}^{max} + GE_{i,gi,t}^{ex} \quad (3.2)$$

$$GR_{i,ri,t} \leq GR_{i,ri,t}^{max} + GR_{i,ri,t}^{ex}, \quad ILR_{s,sj,t} \leq ILR_{s,sj,t}^{max} + ILR_{s,sj,t}^{ex} \quad (3.3)$$

where

$GE_{i,gi,t}^{max}$ is the maximum MW which can be scheduled from tranche gi of Unit i .

$GR_{i,ri,t}^{max}$ is the maximum reserve which can be scheduled from tranche ri of Unit i .

$ILR_{s,sj,t}^{max}$ is the maximum reserve which can be scheduled from tranche s_j of interruptible load s .

The values of $GE_{i,gi,t}^{max}$, $GR_{i,ri,t}^{max}$ and $ILR_{s,sj,t}^{max}$ are set from the offering staircase curves of Unit i and interruptible load s . $GE_{i,gi,t}^{ex}$ and $GR_{i,ri,t}^{ex}$ are the violation (deficiency) amount for the energy and reserve tranche respectively while $ILR_{s,sj,t}^{ex}$ is for the interruptible load reserve tranche. Their function is to provide an indication of the violation amount towards the solution quality when the system could not meet the demand and reserve requirement.

When the constraints are violated, they are set to a positive value. A zero value in $GE_{i,gi,t}^{ex}$ means that all the energy amounts selected are within the bound of the generator offers.

B. Energy generation and demand constraint

This constraint deals with the balance between the demand and supply. The summation of selected MWs for Unit i , $GE_{i,gi,t}$, is the MW output scheduled for this unit.

$$GE_{i,t}^{sum} = \sum_{gi} GE_{i,gi,t} \quad (3.4)$$

The total generation at Period t can then be formulated. It is obtained by summing up the MW output scheduled for each generator as follows:

$$GE_t = \sum_i GE_{i,t}^{sum} \quad (3.5)$$

As assumed, transmission constraints are not considered. Hence, for Period t , the forecasted demand must be equal to the generation,

$$GE_t = D_t \quad (3.6)$$

C. Ramp rate constraints

The ramp rate constraints handle the unit's ability to increase and decrease the output within a certain time period. Ramp rates include the ramp up and ramp down rate. The ramp up rate refers to the speed that the generator can increase its output. The constraint is formulated as follows:

$$GE_{i,t}^{sum} - RU_{i,t}^{ex} * 60 \leq GE_{i,t}^{end,max} \quad (3.7)$$

$$GE_{i,t}^{end,max} = GE_{i,t}^{start} + [RU_i / 60] * Time^{dptch} \quad (3.8)$$

where

$GE_{i,t}^{start}$ is Unit i 's MW output at the time when market clearing engine runs.

$GE_{i,t}^{end,max}$ is Unit i 's maximum output at the end of the dispatch period.

RU_i is the ramp up rate of Unit i in MW per minute.

$Time^{dptch}$ is the duration of the dispatch period in seconds.

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As could be seen from (3.8), $GE_{i,t}^{end,max}$ is decided by $GE_{i,t}^{start}$, RU_i and $Time^{dptch}$. $Time^{dptch}$ is related to the time when the market clearing engine runs. The normal dispatch period is 1 hour such that $Time^{dptch}$ is set at 3600 seconds. Under some unexpected conditions, e.g. the market clearing engine has to re-run, the dispatch period for the energy and reserve schedule may be shorter than 3600 seconds. Considering both the normal and unexpected conditions, $Time^{dptch}$ could be formulated as follows:

$$Time^{dptch} = \text{Min}(3600, 3600 + Time^{bdptch} - Time^{slvr}) \quad (3.9)$$

where

$Time^{bdptch}$ is dynamically determined based on the actual starting point of the run. It could be a negative value.

$Time^{slvr}$ is the parameter reflecting the average time needed to complete one run.

For the sake of validating the robustness of the market clearing solution, the variable $RU_{i,t}^{ex}$ is introduced in this constraint. If the value of $RU_{i,t}^{ex}$ is not zero, this means that the normal ramp rate has been violated in the solution process. In other words, the clearing engine schedules the generator output larger than $GE_{i,t}^{end,max}$.

The ramp down rate refers to the generator's ability to reduce its output. The constraint related to the ramp down rate needs to be satisfied too. It is formulated as follows:

$$GE_{i,t}^{sum} + RD_{i,t}^{ex} \geq GE_{i,t}^{end,min} \quad (3.10)$$

where

$$GE_{i,t}^{end,min} = GE_{i,t}^{start} - [RD_i / 60] * Time^{dptch} \quad (3.11)$$

$GE_{i,t}^{end,min}$ is the minimum output associated with Unit i at the end of Period t . RD_i in (3.11) is the ramp down rate of Unit i , in MW per minute. The ramp down rate constraint also faces a possible late start similar to that of the ramp up rate. The determination of $GE_{i,t}^{start}$ and the calculation for the $Time^{dptch}$ in (3.11) are the same as those for the ramp up constraint.

If $RD_{i,t}^{ex}$ is not zero, this means that the clearing engine schedules the generator output lower than $GE_{i,t}^{end,min}$.

As can be seen from (3.2), (3.4) and (3.7), the upper bound of $GE_{i,t}^{sum}$ is confined simultaneously by the tranche MW constraint and the ramp up rate constraint. The tranche MW constraint reflects the MW amount the generator is willing to offer. If the energy clearing price is low, the generator may choose to reduce the energy amount offered. Then the generator could set a very high price in one tranche and a relatively low price in another tranche. The energy amount in the tranche where the price is very high is the amount the generator does not want to be selected. The ramp up rate constraint reflects the speed the energy can be offered in terms of the unit's physical ability. The higher the ramp up rate, the more energy the unit can offer in each time period.

Meanwhile, the lower bound of $GE_{i,t}^{sum}$ is zero in the tranche MW constraint while it is also confined by ramp down rate constraint in (3.10). This means that the lowest amount that each generator could be selected is zero. However, it takes time for the generator to reduce its output. The generator could not go beyond its physical ability in reducing the MW output to zero instantly. According to self commitment, the generators need to take care of the ramp rate constraints themselves so as not to schedule physically unreachable MW.

D. Feasible reserve region

The feasible reserve region constraints in Fig. 3.4 guarantee that the generator would not provide the reserve beyond its capability at various energy output levels [46]. Otherwise, the actual system reserve may be insufficient to meet the system contingency and a potential loss of load may occur. The feasible reserve region constraints comprise the maximum reserve capacity constraint, the reserve proportion constraint and the maximum reserve generation constraint.

To begin with, the reserve to be scheduled for Unit i is formulated. It is the summation of the selected reserve amount in each tranche,

$$GR_{i,t}^{sum} = \sum_{ri} GR_{i,ri,t} \quad (3.12)$$

The first margin, the maximum reserve capacity GR^{max} , limits the maximum reserve that a generator can provide. This margin caps the reserve amount to be scheduled. GR^{max} is a fixed value for all generators and periods. This constraint forces the reserve to be scattered in a number of generators. It is formulated as follows:

$$GR_{i,t}^{sum} - GR_{i,t}^{max,ex} \leq GR^{max} \quad (3.13)$$

where $GR^{max,ex}$ is used to compute the violation amount of a possible solution if this constraint is violated.

The second margin, the reserve proportion, $RPPN_{i,t}$, confines the reserve a generator can provide. It is proportional to its energy output and is formulated as follows:

$$GR_{i,t}^{sum} - RPPN_{i,t}^{ex} \leq RPPN_{i,t} \cdot GE_{i,t}^{sum} \quad (3.14)$$

where

$RPPN_{i,t}^{ex}$ is used to detect a possible solution of $GR_{i,t}^{sum}$ if $RPPN_{i,t}$ is violated.

Due to the generator physical characteristics, the generator reserve provision ability may vary from minimum to maximum output. In some techniques, the minimum up time is considered and an on/off integer variable is used. However, this may increase the computation time. In the market clearing model here, a reserve proportion ratio, $RPPN_{i,t}$, is introduced to solve the problem. $RPPN_{i,t}$ is the ratio limiting the amount of reserve that Unit i can provide given its energy provision. Generators are allowed to submit a different $RPPN_{i,t}$ value during different periods. According to the self commitment scheme, the generation entities have the duty of not supplying impractical $RPPN_{i,t}$. When the unit is disconnected, $GE_{i,t}^{sum}$ is set to zero. This means that Unit i would not be scheduled for reserve in the market clearing engine. This corresponds to the fact that a disconnected unit without MW output is not capable of providing reserve. When the unit is running initially to take up load, it traverses the range from zero to the minimum MW limit where the unit has little ability to provide reserve. During this moment, $RPPN_{i,t}$ the generator submits in its offer should be a small value. As can be seen in Fig. 3.4, the feasible reserve area from zero to the maximum MW limit is a small triangle and there is

little room for reserve provision. From the minimum output to the maximum output, the energy output is not a significant factor influencing the reserve provision ability. Hence the $RPPN_{i,t}$ submitted could be a large value. As could be seen in Fig. 3.4, the feasible reserve region is a quadrangle where the generator has room for reserve provision.

The third margin is the maximum reserve generation constraint. This constraint limits the combined MW production and available reserve. For one MW that a generator's output is below its maximum generation, the generator has one MW available for reserve. This constraint is activated when the generator's output is at a high level. It is formulated as follows:

$$GE_{i,t}^{sum} + GR_{i,t}^{sum} - GER_{i,t}^{max,ex} \leq GER_i^{max} \quad (3.15)$$

where

$GER_{i,t}^{max,ex}$ is used to detect possible solution if GER_i^{max} is violated.

Normally, the value of GER_i^{max} is the generator's rated capacity. However, sometimes the value of GER_i^{max} is not exactly the same as the generator's rated capacity. For example, when the unit is de-rated, the value of GER_i^{max} could be smaller than the rated capacity.

With the three constraints for reserve, i.e. maximum reserve capacity constraint, the reserve proportion constraint and the maximum reserve generation constraint, the feasible reserve region can be drawn. In Fig. 3.4, the shadowed quadrangle area shows the available reserve region from minimum to maximum output, while the shadowed triangle area is the available reserve margin for the unit from zero to minimum output.

Fig. 3.4 Feasible reserve region

E. Minimum system reserve constraint

The minimum system reserve constraint guarantees the minimum scheduled system reserve amount. It is formulated as follows:

$$\sum_i GR_{i,t}^{sum} + \sum_s ILR_{s,t}^{sum} \geq R^{min} \quad (3.16)$$

Where

$$ILR_{s,t}^{sum} = \sum_{sj} ILR_{s,sj,t} \quad (3.17)$$

Under different system conditions, the amount for reserve may be different. However, there is a minimum reserve requirement, i.e. the lowest amount of spinning reserve the system would carry.

The minimum system reserve constraint could be used as an “*n*-1 security” reserve requirement when its value is set at the largest online generator’s capacity. Together with the probabilistic reserve requirement in the next section, a hybrid reserve requirement can be developed. This means that the system would satisfy the “*n*-1 security” or the probabilistic reserve criterion measured by the EENS metric whichever is more stringent.

F. Probabilistic reserve requirement

The system EENS requirement at each period should agree with the system EENS requirement within a year. In other words, the summation of system EENS requirement at

each period would be equal to the system EENS requirement within a year. The system EENS requirement within a year is already defined in the insurance scheme. The value of the system EENS of each period, $EENS^{std,hr}$, can be computed as follows:

$$EENS^{std,hr} = \frac{EENS^{std,yr}}{8760} \quad (3.18)$$

By dividing 8760, the yearly system reliability requirement is converted into the hourly system reliability requirement. It is true that the hourly value is too tight for the majority of the 8760 hours that do not contribute to the loss of load but far too relaxed for those hours that do contribute to the loss of load. However, the formulation of (3.17) is effective for the model as it is difficult to forecast which period the loss of load would occur due to generator failures. When the system reliability metric remains at $EENS^{std,hr}$ for all the dispatch periods, the system would operate under the same reliability level.

Given a pre-determined $EENS^{std,hr}$ value, the probabilistic system spinning reserve requirement is formulated using the following constraint.

$$EENS^{std,hr} - EENS^{tol} \leq EENS_t \leq EENS^{std,hr} \quad (3.19)$$

G. Penalty calculation constraint

The violation variables, e.g. $GE_{i,gi,t}^{ex}$ or $RU_{i,t}^{ex}$, are incorporated into the corresponding constraints so as to help the clearing algorithm to converge. The penalty worth is formulated as follows:

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$$\begin{aligned}
V_t^{sum} = & \sum_i \sum_{gi} GE_{i,gi,t}^{ex} * GE_i^{ex,pnt} + \\
& \sum_i \sum_{ri} GR_{i,ri,t}^{ex} * GR_i^{ex,pnt} + \\
& \sum_i \sum_{sj} ILR_{s,sj,t}^{ex} * ILR_s^{ex,pnt} + \\
& \sum_i RU_{i,t}^{ex} * RU_i^{ex,pnt} + \\
& \sum_i RD_{i,t}^{ex} * RD_i^{ex,pnt} + \\
& \sum_i GR_{i,t}^{max,ex} * GR_i^{max,ex,pnt} + \\
& \sum_i RPPN_{i,t}^{ex} * RPPN_i^{ex,pnt} + \\
& \sum_i GER_{i,t}^{max,ex} * GER_i^{max,ex,pnt}
\end{aligned} \tag{3.20}$$

The introduction of the violation penalty for each violation can arrange the violated constraints in a carefully defined priority order. The violation penalties indicate the per MW (or MW/min) violation cost of the constraints and they are expressed by multiples of system VOLL, $VOLL_s$. The higher the violation penalty, the less likely the constraint would get violated, and vice versa. The violation penalties are shown in the following table.

Table 3.2 Violation variables and penalties

Violation variable	Violating object	Penalty	Violation penalty
$GE_{i,gi,t}^{ex}$	Energy tranche	$GE_i^{ex,pnt}$	$20 * VOLL_s$
$GR_{i,ri,t}^{ex}$	Reserve tranche	$GR_i^{ex,pnt}$	$20 * VOLL_s$
$ILR_{s,sj,t}^{ex}$	Interruptible load reserve tranche	$ILR_s^{ex,pnt}$	$20 * VOLL_s$
$GR_{i,t}^{max,ex}$	Maximum reserve a unit could have	$GR^{max,ex,pnt}$	$0.6 * VOLL_s$
$GER_{i,t}^{max,ex}$	Energy and Reserve provision upper bound	$GER_i^{max,ex,pnt}$	$2.2 * VOLL_s$
$RU_{i,t}^{ex}$	Ramp up rate	$RU_i^{ex,pnt}$	$20 * VOLL_s$
$RD_{i,t}^{ex}$	Ramp down rate	$RD_i^{ex,pnt}$	$20 * VOLL_s$
$RPPN_{i,t}^{ex}$	Reserve proportion	$RPPN_i^{ex,pnt}$	$20 * VOLL_s$

Three values are selected here, i.e. $0.6*VOLL_s$, $2.2*VOLL_s$ and $20*VOLL_s$. The value of $0.6*VOLL_s$ is the maximum reserve price a generator could offer in the Singapore Electricity Market. Since $2.2*VOLL_s$ has exceeded the system average VOLL, load demand would be reduced first before the constraint is violated. A very high price of $20*VOLL_s$ is set for the associated violated constraints because most of these constraints are related to the physical characteristics of the unit. The high price ensures that the related constraints are violated as the last resort.

The introduction of violation variables which hold the violated amount also helps the system to spot errors. A preset tolerance, say 10^{-4} , would be set for V_t^{sum} . If the value of V_t^{sum} exceeds the tolerance, the input data could be in error somewhere and/or the unit/system constraint is violated, e.g. the reserve is not enough. Furthermore, the source of the errors could be traced by analyzing which constraint is violated. If it is because of input data errors, then the market operator could check the input data. This mechanism enables the system not to dispatch generation based on wrong inputs.

3.3.3 Solving the probabilistic reserve requirement via MILP

In this section, the probabilistic system spinning reserve requirement is studied. This constraint satisfies system security needs by scheduling the required spinning reserve at Period t .

To start with, the forced outage rate for each unit is determined. The symbol μ_i is used to represent FOR of Unit i . μ_i is a constant value and can be obtained from historical records, i.e. the moving average of hourly historical data during the past years.

The noncompliance rate (NCR) for each interruptible load could be defined similarly [74]. The symbol μ_s represents the NCR of interruptible load s . There are many factors why an interruptible load fails to respond. Some factors may originate from the failure of equipments, but human factors are the main reasons. According to the operation records, some customers may disconnect the load later or restore the load earlier. These actions

disobey system operator's instructions. The interruption without the request of the system operator is excluded, though an extra penalty would be imposed if the interruption would influence the customer's ability to supply reserve.

After the FORs and NCRs have been determined, the hourly system EENS can be computed. The hourly system EENS refers to the expected energy not served within the hour. When the system reliability metric $EENS^{std,hr}$ remains the same during each dispatch period, the system reliability level is uniformly maintained. The value of hourly system $EENS_t$ is determined by the reliability performance of the committed generators as well as the system demand level. Theoretically, $EENS_t$ could be calculated as follows:

$$EENS_t = \sum_{z=1}^Z \theta_z \cdot \left[D_t - \sum_i v_i (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_s v_s ILR_{s,t}^{sum} \right] \cdot p_z \quad (3.21)$$

where

z is the index of system contingencies.

Z is the number of system contingencies.

p_z refers to the probability of the system contingency indexed by z .

For contingency indexed by z , the generators' statuses at Period t are represented by on/off random variable v_i , i.e. 0 and 1 for the failed and normal status respectively while the interruptible load's statuses are represented by v_s . If the available generation plus reserve, $\sum_i v_i (GE_{i,t}^{sum} + GR_{i,t}^{sum}) + \sum_s v_s ILR_{s,t}^{sum}$, is higher than the demand D_t , the system would not suffer loss of load and the binary variable θ_z is set to 0. Otherwise, θ_z is set to 1 and the square bracket in (3.21) represents the EENS that contingency z contributes to $EENS_t$ before its probability p_z is considered.

The number of system contingencies is unusually huge. The larger the number of the generators N and the interruptible loads S are, the higher the number of contingencies. According to the number of the failed generators in the system, the events are divided into different categories. A single contingency means that only one unit fails. An interruptible load could not fail itself. An n th multiple contingency means that n units and interruptible

loads fail. The number of the generators and interruptible loads in the contingency can be used as a criterion to reduce the number of the system events considered.

As has been assumed, reserve is only called in when some generators fail. No interruptible loads would be called in unless generators fail. This means that the noncompliance of interruptible loads without generator failure at the same time would not cause loss of load [74].

For the single contingencies, a set of binary variables $\theta_{k,t}^{si}$, $k=1, \dots, N$, is used to represent whether an energy deficiency has occurred when Unit k fails. As long as $\theta_{k,t}^{si}$ satisfies the following two constraints, its value is uniquely determined to be 0 or 1.

$$\theta_{k,t}^{si} \geq \frac{D_t - \sum_{\substack{i=1 \\ i \neq k}}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}}{D_t} \quad (3.22)$$

$$\theta_{k,t}^{si} \leq 1 + \frac{D_t - \sum_{\substack{i=1 \\ i \neq k}}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}}{D_t} \quad (3.23)$$

If the loss of Unit k causes energy deficiency, the numerator on the right hand side of inequality (3.22) would be a positive value. Because the denominator on the right hand side of inequality (3.22) is larger than the absolute value of numerator, the right hand side of inequality (3.22) would be a positive value smaller than 1 and the symbol pv is used to represent it. Considering (3.22) and (3.23), $\theta_{k,t}^{si}$ has a range $[pv, 1 + pv]$. Meanwhile, $\theta_{k,t}^{si}$ is a binary variable as defined. Therefore the only value that $\theta_{k,t}^{si}$ can take is 1. Conversely, under the situation where there is no energy deficiency. The right hand side of (3.22) would be a negative value larger than -1 and the symbol nv is used to represent it. Combining the constraints in (3.22) and (3.23), $\theta_{k,t}^{si}$ has a range $[nv, 1 + nv]$. Hence, the final value for $\theta_{k,t}^{si}$ is 0.

The corresponding EENS for single contingencies, $EENS_t^{si}$, can then be formulated as follows:

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$$EENS_t^{si} = \sum_{k=1}^N \theta_{k,t}^{si} p_{k,t}^{si} DEF_{k,t}^{si} \quad (3.24)$$

where

$$p_{k,t}^{si} = \mu_k \cdot \prod_{i=1, i \neq k}^N (1 - \mu_i) \cdot \prod_{il=1}^S (1 - \mu_{il}) \quad (3.25)$$

$$DEF_{k,t}^{si} = D_t - \sum_{\substack{i=1 \\ i \neq k}}^N [GE_{i,t}^{sum} + GR_{i,t}^{sum}] - \sum_{il=1}^S ILR_{il,t}^{sum} \quad (3.26)$$

$p_{k,t}^{si}$ represents the probability of the contingency, i.e. Unit k fails while all the other units operate normally at Period t . $DEF_{k,t}^{si}$ is the difference between the system load forecast and the available energy plus reserve. $DEF_{k,t}^{si}$ could be a negative value.

For the double contingencies, just like single contingencies, loss of load could not be caused by noncompliance of two interruptible loads unless some generators fail. Hence, there are two conditions for loss of load: (i) two generator outages (ii) one generator outage and one noncompliance of interruptible load.

For the first double contingency condition, binary variables, $\theta_{k,l,t}^{db}$ are introduced. The constraints for $\theta_{k,l,t}^{db}$ are as follows:

$$\theta_{k,l,t}^{db} \geq \frac{D_t - \sum_{\substack{i=1 \\ i \neq k,l}}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}}{D_t} \quad (3.27)$$

$$\theta_{k,l,t}^{db} \leq 1 + \frac{D_t - \sum_{\substack{i=1 \\ i \neq k,l}}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}}{D_t} \quad (3.28)$$

For the second double contingency condition, binary variables, $\theta_{k,s,t}^{db}$ are introduced. The constraints for $\theta_{k,s,t}^{db}$ are as follows:

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$$\theta_{k,s,t}^{db} \geq \frac{D_t - \sum_{\substack{i=1 \\ i \neq k}}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{\substack{il=1 \\ il \neq s}}^S ILR_{il,t}^{sum}}{D_t} \quad (3.29)$$

$$\theta_{k,s,t}^{db} \leq 1 + \frac{D_t - \sum_{\substack{i=1 \\ i \neq k}}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{\substack{il=1 \\ il \neq s}}^S ILR_{il,t}^{sum}}{D_t} \quad (3.30)$$

The calculations of $p_{k,s,t}^{db}$ and $DEF_{k,s,t}^{db}$ in the double contingencies are similar to those in the single contingencies. The $EENS_t^{db}$ can be formulated as follows:

$$EENS_t^{db} = \sum_{k=1}^N \sum_{l>k}^N \theta_{k,l,t}^{db} p_{k,l,t}^{db} DEF_{k,l,t}^{db} + \sum_{k=1}^N \sum_{s=1}^S \theta_{k,s,t}^{db} p_{k,s,t}^{db} DEF_{k,s,t}^{db} \quad (3.31)$$

where

$$p_{k,l,t}^{db} = \mu_k \cdot \prod_{i=1, i \neq k, l}^N (1 - \mu_i) \cdot \prod_{il=1}^S (1 - \mu_{il}) \quad (3.32)$$

$$DEF_{k,l,t}^{db} = D_t - \sum_{\substack{i=1 \\ i \neq k, l}}^N [GE_{i,t}^{sum} + GR_{i,t}^{sum}] - \sum_{il=1}^S ILR_{il,t}^{sum} \quad (3.33)$$

$$p_{k,s,t}^{db} = \mu_k \cdot \prod_{i=1, i \neq k}^N (1 - \mu_i) \cdot \mu_s \cdot \prod_{il=1, il \neq s}^S (1 - \mu_{il}) \quad (3.34)$$

$$DEF_{k,s,t}^{db} = D_t - \sum_{\substack{i=1 \\ i \neq k}}^N [GE_{i,t}^{sum} + GR_{i,t}^{sum}] - \sum_{\substack{il=1 \\ il \neq s}}^S ILR_{il,t}^{sum} \quad (3.35)$$

Equation (3.24) and (3.31) are not purely linear expressions because the expression encompasses a product of a continuous variable and a binary variable. For example, in (3.24), the continuous variable is $DEF_{k,t}^{si}$ while the binary variable is $\theta_{k,t}^{si}$. Through some transformation [34, 75], the two variables can be separated and the expression would be converted into several integer constraints and linear constraints. For the single contingency, the following constraints (3.36) to (3.40) are the new constraints substituting constraint (3.24).

$$EENS_t^{si} = \sum_{k=1}^N \Omega_{k,t}^{si} p_{k,t}^{si} \quad (3.36)$$

$$\Omega_{k,t}^{si} \leq \theta_{k,t}^{si} \cdot D_t \quad (3.37)$$

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$$\Omega_{k,t}^{si} \geq -1 \cdot \theta_{k,t}^{si} \cdot \left[\sum_{i=1, i \neq k}^N GER_i^{max} + \sum_{il=1}^S ILR_{il,t}^{max} \right] \quad (3.38)$$

$$\Omega_{k,t}^{si} \leq \left[D_t - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum} \right] + \left[\sum_{i=1, i \neq k}^N GER_i^{max} + \sum_{il=1}^S ILR_{il}^{max} \right] \cdot (1 - \theta_{k,t}^{si}) \quad (3.39)$$

$$\Omega_{k,t}^{si} \geq \left[D_t - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum} \right] - D_t \cdot (1 - \theta_{k,t}^{si}) \quad (3.40)$$

$\Omega_{k,t}^{si}$ is a newly introduced continuous variable, representing the unserved energy amount when only Unit k fails. In the case that the system available spinning reserve from other generators can cover the loss of Unit k , i.e. $\theta_{k,t}^{si}$ equaling to 0, constraints (3.37) to (3.40) can be simplified as follows:

$$\Omega_{k,t}^{si} \leq 0$$

$$\Omega_{k,t}^{si} \geq 0$$

$$\Omega_{k,t}^{si} \leq \left[D_t - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum} \right] + \left[\sum_{i=1, i \neq k}^N GER_i^{max} + \sum_{il=1}^S ILR_{il}^{max} \right]$$

$$\Omega_{k,t}^{si} \geq - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{max}$$

With the four expressions above, the only value $\Omega_{k,t}^{si}$ could have is 0.

In the case that the system available spinning reserve from other generators cannot cover the loss of Unit k , i.e. $\theta_{k,t}^{si}$ equaling to 1, constraints (3.37) to (3.40) can be simplified as follow:

$$\Omega_{k,t}^{si} \leq D_t$$

$$\Omega_{k,t}^{si} \geq -1 \cdot \left[\sum_{i=1, i \neq k}^N GER_i^{max} + \sum_{il=1}^S ILR_{il}^{max} \right]$$

$$\Omega_{k,t}^{si} \leq D_t - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}$$

$$\Omega_{k,t}^{si} \geq D_t - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}$$

With the four expressions above, the only value $\Omega_{k,t}^{si}$ could have is the loss of load value,

$$\text{i.e. } D_t - \sum_{i=1, i \neq k}^N (GE_{i,t}^{sum} + GR_{i,t}^{sum}) - \sum_{il=1}^S ILR_{il,t}^{sum}.$$

Similarly, the expression of double contingencies in (3.31) could be converted to integer or linear constraints. After the EENS for each contingency is calculated, the system EENS can be computed as the summation of EENS in all single and multiple contingencies. The formulation is as follows:

$$EENS_t = EENS_t^{si} + EENS_t^{db} + \dots \quad (3.41)$$

3.3.4 Solving the probabilistic reserve requirement via iterative LP

The linear programming based clearing process is adopted in the Australia, Ontario, New Zealand, and Singapore electricity market [26, 45]. The linear programming technique has a very good performance in terms of speed. However, the technique is not able to handle some complex constraints such as the probabilistic reserve requirement. A heuristic approach called the iterative linear programming technique is thus proposed to handle the probabilistic reserve criterion.

As the name indicates, the iterative linear programming algorithm encompasses many rounds of linear programming processes. After every round of linear programming gets a dispatch schedule, the clearing engine adjusts the reserve requirement in the former linear programming condition. The clearing engine will run again and the adjustment process continues until the reserve requirement is satisfied.

◆ An initial linear programming clearing process

To start with, an initial linear programming process is set up. The objective function as well as the tranche MW constraints, energy generation and demand constraints, feasible reserve region constraints, ramp rate constraints, minimum system reserve constraint and penalty calculation constraints remain the same. As for the probabilistic reserve

requirement, a deterministic spinning reserve constraint is substituted in the linear programming process. The formulation is as follows:

$$\sum_{i=1}^N GR_{i,t}^{sum} + \sum_{il=1}^S ILR_{il,t}^{sum} = SRR \quad (3.42)$$

where

SRR is the system spinning reserve amount

After the objective function and the constraints mentioned above are set up, the linear programming problem can be solved. The energy and spinning reserve schedules are then determined. The next step is the post linear programming process where the system EENS is calculated.

◆ A post linear programming process

In the post linear programming process, the system EENS is computed. The system EENS comprises the EENS for the single contingency, double contingencies and high order multiple contingencies. The calculation of the system EENS is represented as follows:

$$\begin{aligned} EENS_t = & \sum_{i=1}^N \left[\Gamma_i \cdot \mu_i \cdot \prod_{l=1, l \neq i}^N (1 - \mu_l) \cdot \prod_{il=1}^S (1 - \mu_{il}) \right] \\ & + \sum_{i=1}^N \sum_{j=i+1}^N \left[\Gamma_{i,j} \cdot \mu_i \cdot \mu_j \cdot \prod_{l=1, l \neq i, j}^N (1 - \mu_l) \cdot \prod_{il=1}^S (1 - \mu_{il}) \right] \\ & + \sum_{i=1}^N \sum_{il=1}^S \left[\Gamma_{i,s} \cdot \mu_i \cdot \prod_{l=1, l \neq i}^N (1 - \mu_l) \cdot \mu_s \cdot \prod_{il=1, il \neq s}^S (1 - \mu_{il}) \right] \\ & + \sum_{i=1}^N \sum_{j=i+1}^N \sum_{k=j+1}^N \left[\Gamma_{i,j,k} \cdot \mu_i \cdot \mu_j \cdot \mu_k \cdot \prod_{l=1, l \neq i, j, k}^N (1 - \mu_l) \cdot \prod_{il=1}^S (1 - \mu_{il}) \right] \\ & + \dots \end{aligned} \quad (3.43)$$

where

$$\Gamma_i = \max[0, GE_{i,t}^{sum} + GR_{i,t}^{sum} - SRR] \quad (3.44)$$

$$\Gamma_{i,j} = \max[0, GE_{i,t}^{sum} + GR_{i,t}^{sum} + GE_{j,t}^{sum} + GR_{j,t}^{sum} - SRR] \quad (3.45)$$

$$\Gamma_{i,s} = \max[0, GE_{i,t}^{sum} + GR_{i,t}^{sum} + ILR_{s,t}^{sum} - SRR] \quad (3.46)$$

$$\Gamma_{i,j,k} = \max \left[0, GE_{i,t}^{sum} + GR_{i,t}^{sum} + GE_{j,t}^{sum} + GR_{j,t}^{sum} + GE_{k,t}^{sum} + GR_{k,t}^{sum} - SRR \right] \quad (3.47)$$

For the single contingency, the number is N and the parameter Γ_i represents the MW to be curtailed when a single unit, Unit i fails. If the outage of Unit i causes energy deficiency, i.e. the spinning reserve is not enough to cover the loss of this unit, the expression $GE_{i,t}^{sum} + GR_{i,t}^{sum} - SRR$ would be a positive value and consequently Γ_i is set at this value as in (3.44). This means that the expected outage probability and deficiency amount are included in the EENS calculation. In the case where the spinning reserve is enough to cover the loss of Unit i , the expression $GE_{i,t}^{sum} + GR_{i,t}^{sum} - SRR$ would be a negative value and then Γ_i is set at 0. For example, if the spinning reserve amount is larger than the largest online generator's capacity, then Γ_i is zero for each selected unit. This means that the sum of EENS contribution from the single contingency is zero.

For double contingencies, it could be two generators or one generator plus one interruptible load. The process to determine $\Gamma_{i,j}$ is similarly done except that the contingency number increases to $N*(N-1)/2$ while the process to determine $\Gamma_{i,s}$ is $N*S$. The triple and even higher order multiple contingencies can be taken into consideration in a similar way.

Compared to those calculations in MILP, the post linear programming process does not solve a large number of binary variables and equation sets. Therefore, the calculation of EENS requires very little time and multiple contingencies could easily be taken into consideration.

◆ Iterative linear programming process

If the spinning reserve requirement SRR is fixed under any system condition, the system reliability metric EENS is different from period to period and consequently the system reliability level varies. In contrast, through the adjustment of the SRR , the system reliability level can be maintained uniformly, i.e. kept constant at a predefined value under different system conditions. The iterative linear programming process is designed

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to adjust the system *SRR* until the system EENS value is within the pre-assigned tolerance value.

Fig. 3.5 shows an overview of the scheme where several iterations of linear programming are conducted and a predefined system reliability level $EENS^{std,hr}$ is achieved. To begin with, the program chooses a starting point for the system *SRR*. Then a linear programming optimization is conducted and the system EENS is calculated as shown in the previous section. If the reliability level is not satisfied or over satisfied, the algorithm will increase or decrease the reserve accordingly while other constraints would remain the same during the iterative process. The linear programming based clearing process would be conducted again. If the system has sufficient spinning reserve, it will iterate up to a point where the $EENS_t$ is within the tolerance value ($EENS^{tol}$) of $EENS^{std,hr}$. The final schedule is the one where the predefined system reliability level is obtained.

Fig. 3.5 Process to reach a proper reserve amount

A sequential search can be used to determine the proper system reserve amount. The starting point for the SRR can be any non-negative number, such as the largest capacity of an online generator. However, a smart selection of the starting point can decrease the iteration number and help the program to reach the converged SRR more quickly. Here the largest online generator capacity is chosen because the final hourly SRR is usually a value in that neighborhood. A bisection search could also get a suitable system reserve requirement and can speed up the search process. Firstly, the system has to determine SRR^{ini} , i.e. the initialized system reserve value that can provide more than enough reserve to meet the system reliability. Secondly, the middle value, $0.5 * SRR^{ini}$, is set as the system spinning reserve amount. Thirdly, the market clearing engine is run and the corresponding system $EENS_t$ is calculated. The value of $EENS_t$ is then compared to $EENS^{std,hr}$. If the

difference is within the tolerance, the process is terminated. Otherwise, if the value of $EENS_t$ under this reserve amount exceeds the preset value, the next reserve amount is $0.75 * SRR^{ini}$. Otherwise the amount is $0.25 * SRR^{ini}$. Fourthly, the process will continue and the range of the reserve amount is gradually decreased until $EENS_t$ is within the tolerance. On average, the bisection search has a better performance than the sequential search.

If the number of units committed for reserve must be made as few as possible, then it can be best handled by a decommitment post-processor [76] after the solution has converged. A criterion for reserve decommitment must be designed. For example, the unit which contributed the least reserve amount should be decommitted first followed by the unit with the second least reserve amount and so on. Of course when the unit's reserve amount is decommitted, other units that contributed to the reserve must increase their contributions further to make up the shortfall. The decommitment process ceases when further decommitment will result in a violation of SRR . It is assumed that the decommitment process does not affect the energy and reserve clearing prices. Otherwise they would need to be recomputed.

3.3.5 Cost/benefit analysis for an optimal operating point

Regardless of the adoption of very rigorous probabilistic criteria, it should be noted that due to severe contingencies the reserve amount may be inadequate at some period. This means that the loads will have to be curtailed when a highly unlikely combination of events does happen. The implementation of the probabilistic reserve criterion is not to eliminate the loss of load completely. In some cases when the value of $EENS^{std,hr}$ is too high, it can be observed that the probability of loss of load may still be unacceptable given the random availability of generating units. In some other cases when the value of $EENS^{std,hr}$ is too low, it is possible that the cost to avoid loss of load is uneconomic. In other words, it is better to maintain just an acceptable system reliability level with a certain reserve requirement. Therefore, the determination of the system reliability metric $EENS$ is critical to meeting the probabilistic reserve criteria.

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A cost/benefit analysis could be used to choose the $EENS^{std,yr}$ and $EENS^{std,hr}$ values. The cost/benefit analysis can consider the reliability from an economic viewpoint and it can reveal the real system reliability needs better.

After the market clearing engine completes its run, the energy and reserve schedule is decided and the offering cost can then be obtained. The benefit comes from the reduction of the loss of load amount. For example, at an extreme condition where no reserve is scheduled, imposing the system $EENS^{std,yr}$ requirement to the system would result in a higher reserve and would reduce the expected energy not served. This brings more benefit to the system.

One of the commonly used approaches in quantifying the worth of the benefit is the explicit cost technique [13]. The explicit cost approach of the reliability worth assessment can be used in a more direct and practical fashion during the decision-making process.

The explicit cost technique can use subjective and objective measures of consumer monetary losses arising from the curtailment of electric energy. The explicit cost technique incorporates reliability in the costing process by comparing the overall costs. The explicit cost approach computes the system unreliability loss from $EENS^{std,hr}$. The cost of losses due to energy not supplied is a composite parameter formed from the various classes of consumers affected by a given interruption.

Before the insurance scheme is implemented, system VOLL can be used as an indicator for every MW loss of load. System VOLL is an estimated average cost of interruption to consumers. Several methods with varying degrees of complexity have been proposed for calculating the cost of loss of load [77-79].

Under the insurance scheme, the reliability profile is revealed. The system average VOLL can be deduced from the consumers' VOLL and consumers' percentages in each category. By multiplying the system average VOLL and $EENS^{std,hr}$ together, the expected worth of the load not served for the entire system can be determined.

With the system operated under a reliability level measured by $EENS^{std,hr}$, the offering cost (scheduling cost) and the worth of load loss can be obtained. The total cost can then be computed by adding them together. The relation of the schedule cost, the worth of loss of load and the total cost is illustrated in Fig. 3.6.

Fig. 3.6 Cost and benefit analysis

As can be seen in Fig. 3.6, the higher the system reliability level is, the higher the offering cost would be. This is because the system has to schedule more reserve or even more generators. However, a high reserve amount reduces the expected unserved energy. The optimal system operation is the point where the total cost is minimized.

The cost/benefit analysis could be done off-line. The system condition varies from period to period. More generators may be selected under the peak load than the valley load period. In addition, some generator may be temporarily unavailable due to maintenance. These factors would lead to the fluctuation of the offering cost. Since the profile of the consumers' reliability requirements is updated yearly, the system average VOLL may change as well. This will then influence the worth of loss of load. The optimal operation point would shift under the impact of these factors.

After having a comprehensive study on numerous system samples, the distribution of the optimal $EENS^{std,hr}$ values could be obtained. The most frequent optimal $EENS^{std,hr}$ value could be set as the final system optimal operating value.

3.4 Simulation results

3.4.1 Simulation results for model solved via MILP

A system of 6 units is studied to examine the impacts of the probabilistic reserve criterion on the system reliability and marginal price. These 6 units are extracted from the 32-unit IEEE reliability test system [53]. The probabilistic reserve requirement modeled by MILP is coded under the commercial optimization software GAMS and is solved by the solver CPLEX 8.0 [80]. Each generator submits a 3-band offer curve in the energy market and 1-band offer curve to the spinning reserve market.

The offering data of generators in the energy market are shown in Fig. 3.7. Each generator offer curve encompasses three tranches represented by the MW quantity $GE_{i,gi,t}^{max}$ and price $GEP_{i,gi,t}$. As can be seen, some generators offer very low price or even zero to get selected.

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Fig. 3.7 Offering data of Unit 1-6 in energy market

The generator's offering data in the spinning reserve market and the related parameters are shown in Table 3.3. The generator reserve offers here are set at 10% of their maximum energy offers. The reserve proportion factor $RPPN_{i,t}$ for each generator is set according to the common value in the Singapore market.

Table 3.3 Offering data and FOR of units in spinning reserve market

Unit index i	1	2	3	4	5	6
$GR_{i,1,t}^{max}$ (MW)	20	70	30	40	170	170
$GRP_{i,1,t}$ (\$/MWh)	4.2	1.9	2.4	0.9	2.2	1.0
$RU_{i,t}$ (MW/min)	2	7	3	4	20	20
$RD_{i,t}$ (MW/min)	2	7	3	4	20	20
$RPPN_{i,t}$	1.4	1.4	1.5	1.6	2	2
μ_i	0.003	0.009	0.006	0.012	0.0075	0.006

The interruptible load's offering data and NCR, μ_s , is shown in Table 3.4.

Table 3.4 Offering data and NCR of interruptible loads

Interruptible load s	1	2
$ILR_{s,1,t}^{max}$ (MW)	10	15
$ILRP_{s,1,t}$ (\$/MWh)	0.7	1.7
μ_s	0.003	0.003

To reduce the computation burden in calculating EENS, only single and double contingencies are considered. In other words, at most two units/interruptible loads (2 units or 1 unit and 1 interruptible load) may fail simultaneously. The market clearing engine is assumed to run on time. Since the market clearing engine produces energy and reserve schedule every hour, the parameter $Time^{dptch}$ in (3.8) and (3.11) is set to 3600 seconds.

◆ Energy and reserve schedule test

This simulation test is conducted on a system which operates under a load of 500 MW and an hourly EENS requirement of 0.04 MWh. The maximum amount of reserve GR^{max} that each generator can carry is set at 150 MW. The commitment schedule and dispatch for the generators are shown in Table 3.5. For these generators with zero energy selected, the unit status is off. For those generators with energy selected, the unit status is on and the dispatch amount is the total selected MWs.

Table 3.5 System schedule under 500 MW load demand

Participant index	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	IL 1	IL2
Energy tranche 1 $GE_{i,1,t}$	0	0	0	140	100	100	N/A	N/A
Energy tranche 2 $GE_{i,2,t}$	0	0	0	0	100	13	N/A	N/A
Energy tranche 3 $GE_{i,3,t}$	0	0	0	0	47	0	N/A	N/A
Total Energy $GE_{i,t}^{sum}$	0	0	0	140	247	113	N/A	N/A
Total reserve $GR_{i,t}^{sum} / ILR_{s,t}^{sum}$	0	0	0	130	0	103	10	0

(IL1: interruptible load participant 1; IL2: interruptible load participant 2)

As can be seen, the offers with relatively low price are selected first. Since Unit 4, 5 and 6 offer their first energy tranches zero \$/MW, these tranches are fully selected. Meanwhile, energy and reserve offering costs are co-optimized. The market clearing engine balances the energy and reserve offering cost. Although some energy tranches have relative low prices, they are scheduled as reserve. An interesting phenomenon is that the clearing engine does not allocate a lot of reserve in one unit just because its reserve price is low. This is because the probabilistic reserve requirement needs to be satisfied and the scattering of reserve benefits the system reliability. Interruptible loads could be selected when the offer is low enough. The reserve price the first interruptible load participant offers is 0.7 \$/MW, which is the lowest among the reserve providers.

◆ Violation penalty test

This simulation tests the violation penalties. The load demand remains at 500 MW. The maximum reserve, GR^{max} , each generator can carry is reduced to 15 MW. The EENS is set at 0.04 MWh. Based on the reliability profile data revealed in the previous chapter, the system VOLL is 2,000 \$/MWh. The energy and reserve schedule is shown in Table 3.6.

Table 3.6 System schedule with violations

Participant index	Unit 1	Unit 2	Unit 3	Unit 4	Unit 5	Unit 6	IL 1	IL2
Energy tranche 1 $GE_{i,1,t}$	16	14	30	111	100	100	N/A	N/A
Energy tranche 2 $GE_{i,2,t}$	16	25	69	0	10	10	N/A	N/A
Energy tranche 3 $GE_{i,3,t}$	0	0	0	0	0	0	N/A	N/A
Total Energy $GE_{i,t}^{sum}$	32	39	99	111	110	110	N/A	N/A
Total reserve $GR_{i,t}^{sum} / ILR_{s,t}^{sum}$	25	15	15	15	15	15	10	15

(IL1: interruptible load participant 1; IL2: interruptible load participant 2)

An interesting phenomenon observed is the reduction of the system reserve amount. Comparing to Table 3.5 where the reserve amount is 243 MW, the total reserve amount in Table 3.6 is 125 MW. This is because the GR^{max} is only 15 MW. To satisfy the

probabilistic reserve requirement, the system clearing engine has to scatter the reserve among the participants.

However, the reserve is still not enough to meet the system reliability requirement even when each generator carries 15 MW. This could be observed from Table 3.6 where the reserve that Unit 1 carries is 25 MW. In other words, the violation of GR^{max} is activated. The total violation amount reaches 10 MW ($= 25 - 15$) and the value of V_t^{sum} is \$12,000 ($= 10 \times 0.6 \times 2,000$). Comparing to the penalty, the energy and reserve offering cost calculated (\$4,524) is very small.

The constraints are not violated normally. If the system could not reach a dispatch schedule without violating the constraints, the constraints would be violated in a designated order. This can be observed in Table 3.6, only the maximum reserve capacity of the feasible reserve region is violated.

The computing platform is a 1 GHz Pentium III PC with a 128-MB RAM. When the load demand is moderate and $EENS^{std,hr}$ is not stringent, the execution time for the case studies could be less than 0.1 second. Sometimes, especially when the load demand is high, the execution time would reach 0.5 second. When the $EENS^{std,hr}$ becomes stringent, the time required would reach as high as 30 seconds. It is also observed that several minutes have passed by and the solver still could not finish due to “curse of dimensionality”. It can be concluded that the speed of MILP in solving the proposed model may be too slow sometimes and this could pose a problem for the real-time operation.

3.4.2 Simulation results for model solved via iterative LP

The IEEE 32-unit system [24, 53, 81, 82] is used to test the proposed market clearing engine via iterative linear programming. For simplicity, hydro generators are not considered here. The unit polynomial cost curves in [78, 79] are replaced by the four-segment staircase offering curves. The reserve prices are set to 5% of the highest energy bid price. The interruptible loads are the same as those in the model solved via MILP as

shown in Table 3.4. The offering curves are assumed to be unchanged during the dispatch periods. The multiple study period is from the first to the eighth hour. The $EENS^{std,hr}$ is set at 0.0909 MWh and the error tolerance $EENS^{tol}$ is 1.5% of $EENS^{std,hr}$ throughout the operation period. The interruptible load has a noncompliance rate of 0.003. Other detailed data are shown in Appendix A. The program is coded under the Matlab environment [83]. The computation time for the clearing process is around 13 seconds, and it satisfies the requirement of the Singapore real-time market where as much as 5 minutes is given.

◆ Energy and reserve dispatch

The energy and reserve dispatch schedule is shown in Table 3.7. As could be seen, Unit 10 to 26 are always selected because their offering prices are low. When the system demand reaches 2430 MW, the MW dispatch is assigned to Unit 1 to 5 after the capacities of Unit 10 to 26 are all used up.

The reserve provided by interruptible load participant 1 is always fully scheduled while participant 2 gets more reserve when demand increases. As the demand varies, energy and reserve may be rescheduled because the system co-optimizes the energy and reserve offers over the study period. Taking Unit 24 as an example, 280 MW is dispatched for energy and 70 MW for reserve when the demand is 1700 MW at Hour 1. When the demand is 2430 MW at Hour 8, Unit 24 is fully scheduled as energy.

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Table 3.7 Energy and reserve dispatch in a multiple study period

Unit /IL index	Hour 1		Hour 2		Hour 3		Hour 4		Hour 5		Hour 6		Hour 7		Hour 8	
	Demand (MW)															
	1, 700		1, 730		1, 690		1, 700		1, 740		1, 900		2, 000		2, 430	
	Schedule (MW)															
	MW	RV	MW	RV	MW	RV	MW	RV	MW	RV	MW	RV	MW	RV	MW	RV
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	3
6	0	0	0	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
8	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
10	15	15	15	15	15	15	15	15	15	15	55	21	55	21	55	21
11	15	15	15	15	15	15	15	15	15	15	45	21	45	21	55	21
12	15	15	15	15	15	15	15	15	15	15	35	21	35	21	55	21
13	15	15	15	15	15	15	15	15	15	15	35	21	35	21	55	21
14	17	17	17	17	17	17	17	17	17	17	17	17	17	17	75	25
15	17	17	17	17	17	17	17	17	17	17	17	17	17	17	75	25
16	17	17	17	17	17	17	17	17	17	17	17	17	17	17	75	25
17	121	34	121	34	121	34	121	34	121	34	121	34	121	34	126	29
18	119	34	121	34	109	34	119	34	121	34	121	34	121	34	121	34
19	88	34	116	34	88	34	88	34	121	34	121	34	121	34	121	34
20	88	34	88	34	88	34	88	34	93	34	121	34	121	34	121	34
21	56	45	56	45	56	45	56	45	56	45	56	45	56	45	112	45
22	22	22	22	22	22	22	22	22	22	22	22	22	22	22	112	45
23	13	13	13	13	13	13	13	13	13	13	13	13	13	13	107	45
24	280	70	280	70	280	70	280	70	280	70	300	50	300	50	350	0
25	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0
26	400	0	400	0	400	0	400	0	400	0	400	0	400	0	400	0
IL1	N/A	10	N/A	10	N/A	10	N/A	10	N/A	10	N/A	10	N/A	10	N/A	10
IL2	N/A	5	N/A	8	N/A	4	N/A	5	N/A	9	N/A	15	N/A	15	N/A	15

(IL1: interruptible load participant 1; IL2: interruptible load participant 2; MW: generator energy output scheduled; RV: MW reserve scheduled)

◆ EENS of multiple contingencies

In Table 3.8, the impact of units and interruptible loads up to triple contingencies is shown.

Table 3.8 EENS attributable to units and interruptible loads

Contingency composition	Demand (MW)				
	1,600	1,800	2,000	2,200	2,400
1 unit	0.0000	0.0000	0.0000	0.0000	0.0000
2 unit	0.0831	0.0831	0.0819	0.0801	0.0798
1 unit + 1 IL	0.0002	0.0000	0.0000	0.0000	0.0000
3 units	0.0065	0.0072	0.0076	0.0090	0.0096
2 units + 1 IL	0.0003	0.0003	0.0006	0.0006	0.0006
1 unit + 2 IL	0.0000	0.0000	0.0000	0.0000	0.0000

(IL: interruptible load participant)

As shown in Table 3.8, the EENS of the single contingency remains zero because the spinning reserve requirement is larger than the largest generator's capacity in all cases. The EENS contributed by double contingencies dominates the entire system EENS. The triple contingencies can also impact the system EENS, but to a lesser extent. For example, the double contingencies account for 92% ($= (0.0831 + 0.0002) / (0.0831 + 0.0002 + 0.0065 + 0.0003)$) of the system EENS while triple contingencies 8%.

When the system load demand becomes higher, the influence of the double contingencies decreases while the influence of the triple contingencies increases. For example, double contingencies contribute 0.0833 ($= 0.0831 + 0.0002$) MWh of EENS when the system load is 1600 MW, while they contribute only 0.0798 ($= 0.0798 + 0.0000$) MWh when the system load is 2400 MW. Meanwhile, the EENS of the triple contingencies increases by 0.0034 MWh ($0.0096 + 0.0006 - 0.0065 - 0.0003 - 0.0000$).

As also could be seen, the EENS contribution from interruptible loads is so small that it could nearly be ignored. This is because the amount of the interruptible loads scheduled (see Table 3.7) is not much. Besides, the non-compliance rates of interruptible loads is low since the value is only 0.003.

◆ Reserve amount under different case studies

Six cases are set up to test how the system would operate with varying generator forced outage rates and/or when some generators are unavailable. To avoid the influence of interruptible loads, they are not considered in these cases. The detail of these cases is as follows:

- Case 1: All the generators are available in the system operation.
- Case 2: Unit 10 decreases its forced outage rate by 0.25 times, i.e. from 0.0031 to 0.002325.
- Case 3: Unit 10 increases its forced outage rate by 0.25 times, i.e. from 0.0031 to 0.003875. Other generator forced outage rates remain the same.
- Case 4: Unit 25 decreases its forced outage rate by 0.25 times, i.e. from 0.0055 to 0.004125. Other generator forced outage rates remain the same.
- Case 5: Unit 25 increases its forced outage rate by 0.25 times, i.e. from 0.0055 to 0.006875. Other generator forced outage rates remain the same.
- Case 6: Unit 10, one of the most reliable units with a forced outage rate of 0.0031, with a capacity of 76 MW is unavailable. Other generators remain the same.

To start off, the “ $n-1$ security” criterion, i.e. the maximum online generator’s capacity of 400 MW is used as the system spinning reserve requirement. The system unreliability levels measured by EENS are calculated and shown in Table 3.9.

Table 3.9 System EENS value under different cases and load demands

EENS value (MWh)	Load demand (MW)				
	1,600	1,800	2,000	2,200	2,400
Case 1	0.0909	0.1135	0.1232	0.1394	0.1579
Case 2	0.0907	0.1131	0.1224	0.1386	0.1571
Case 3	0.0912	0.1138	0.1240	0.1401	0.1586
Case 4	0.0788	0.0998	0.1085	0.1233	0.1402
Case 5	0.1031	0.1272	0.1378	0.1555	0.1755
Case 6	0.0909	0.1137	0.1271	0.1425	0.1629

As can be seen in Table 3.9, although the “ $n-1$ security” criterion can cover loss of load (MW) caused by the outage of a single unit, the system EENS value varies as the load demand, generator participation and submitted outage probabilities vary.

Along with the increase of load demand, the system EENS increases as well. For example, the EENS value in Case 1 increases about 74% when the load demand increases from 1600 MW to 2400 MW. This means that the system unreliability level measured by EENS increases about 74%. The system EENS value increases because more generation MWs are scheduled while the reserve remains the same.

Comparing Case 1 and Case 6 in Table 3.9, the system EENS value at load demand of 2400 MW increases from 0.1579 MWh to 0.1629 MWh due to the non-participation of Unit 10. Hence, it can be deduced that to a certain extent the reliability of the participated generators can also influence the system reliability level.

The system EENS value varies as the forced outage rates of the generators are changed. As can be seen in Fig. 3.8, the curves of Case 1, 2, 3 are somewhat in the middle, while the curve of Case 4 is at the bottom and that of Case 5 at the top. This distribution of the curves implies that Unit 25 has a bigger influence on the system EENS than Unit 10. This is because the capacity of Unit 25 is much larger than that of Unit 10 and the bid price of Unit 25 is so low that the capacity of the unit is fully scheduled. Another phenomenon is also interesting. The curves of Case 2 and Case 4 are both below the curve of Case 1. This means that the system EENS value would decrease when a unit reduces its FOR.

Fig. 3.8 System reliability levels for “ $n-1$ security” under Case 1-5

If a uniform system reliability level needs to be maintained, then the spinning reserve requirement should be adjusted. In Table 3.10, the system EENS value is maintained for

all the cases at 0.0909 MWh, i.e. the EENS value at 1600 MW demand under Case 1. The iterative linear programming reserve scheme is implemented to obtain the proper system spinning reserve amount.

Table 3.10 Spinning reserve amount under different cases

Case index	Load demand (MW)				
	1,600	1,800	2,000	2,200	2,400
	Reserve amount (MW)				
Case 1	400	424	434	445	464
Case 2	400	424	433	445	464
Case 3	401	424	434	446	464
Case 4	400	411	420	433	451
Case 5	410	435	445	456	474
Case 6	401	426	437	450	472

As can be seen in Table 3.10, the difference between the lowest spinning reserve amount and the highest is 74 MW (474 – 400). It can be deduced that the reserve amount would change even more if more than one generator increase or decrease their outage probabilities.

There is an interesting phenomenon when comparing Table 3.9 and Table 3.10. In Table 3.9, system spinning reserve amount remains at 400 MW when the system EENS varies. In Table 3.10, the system EENS remains constant when the system spinning reserve amount varies. It can be found that a high EENS value under the “ $n-1$ security” criterion corresponds to a high spinning reserve requirement under the uniform EENS scheme although they are not proportional. This is because more reserve has to be scheduled for those systems with low system reliability levels.

◆ Cost/benefit analysis to determine the EENS value

The flexibility of the probabilistic approach lies in its choice of the EENS. However, this brings in another problem, i.e. how to choose an appropriate EENS value. Case 7 is set up to find the optimal operating point. A cost/benefit analysis can be used to analyze the

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system needs. The system demand is set at 2000 MW if not mentioned in the remaining chapter.

In Table 3.11 and 3.12, the energy and reserve offering cost, worth of loss of load and total cost are obtained under different system $EENS^{std,hr}$ requirement while the system is tested with or without interruptible loads respectively. The energy offering cost is the sum of the products of the generator's energy offering price and the selected quantity while the reserve offering cost is the sum of the products of the generator/interruptible load's reserve offering price and the selected quantity.

Table 3.11 System performance in Case 7 without interruptible loads

EENS (MWh)	Energy offering cost (\$)	Reserve offering cost (\$)	Total cost (\$)
0.3000	22001	600	22601
0.2000	22032	400	22432
0.0909	22276	182	22458
0.0700	22423	140	22563
0.0300	22950	60	23010
0.0100	24311	20	24331

Table 3.12 System performance in Case 7 with interruptible loads

EENS (MWh)	Energy and reserve offering cost (\$)	Loss of load worth (\$)	Total cost (\$)
0.3000	21947	600	22547
0.2000	21978	400	22378
0.0909	22145	182	22327
0.0700	22297	140	22437
0.0300	22767	60	22827
0.0100	24072	20	24092

As can be seen from Table 3.11, the energy and reserve offering cost increases as the system $EENS^{std,hr}$ becomes more stringent. For example, when $EENS^{std,hr}$ varies from 0.030 to 0.010, the energy and reserve offering cost increases by \$1,321 (24,331 – 23,010) without interruptible loads and \$1,265 (24,092 – 22,827) with interruptible loads. Fig. 3.9 plots all the costs shown in Table 3.12.

Fig. 3.9 Total cost under different EENS values with interruptible loads

As can be seen from Fig. 3.9, the loss of load worth decreases along with the decrease of the system $EENS^{std,hr}$. The optimal operating point is found when EENS is at 0.0909 MWh since the total cost at this point is the lowest.

The optimal operating point is affected by three factors, i.e. the system offering data, the system average VOLL and the load demand level. Three case studies are set up to analyze the influence of the factors.

If all bidders increase their offers 50% higher than their original ones, the optimal point shifts to the point where $EENS^{std,hr} = 0.2$ MWh as in Fig. 3.10. When all bidders increase their offers, the loss of load worth remains at \$218 (\$400 – \$182) but the offering cost

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gap between the two points where $EENS^{std,hr}$ is equal to 0.2 MWh and 0.0909 MWh increases by \$251 (\$33,218 – \$32,967). Since \$251 which represents the schedule cost is larger than \$218 which represents the loss of load worth, it is worthwhile for the system to operate at a higher EENS value of $EENS^{std,hr} = 0.2$ MWh. This means that the optimal operating point is sensitive to the offering cost in this case.

Fig. 3.10 Optimal operating point under different offering data

If the system average VOLL increases from 2,000 \$/MWh to 3,000 \$/MWh, the loss of load value would change as well. Fig. 3.11 shows the new case. Firstly, the two cases where $EENS^{std,hr}$ is equal to 0.0909 MW and 0.2 MW is compared. The energy and reserve offering cost gap between the two points is \$167 (\$22,145 – \$21,978). Meanwhile, the gap of the loss of load worth increases from \$218 (\$400 – \$182) in Fig. 3.9 to \$327 (\$600 – \$273) in Fig. 3.11. Obviously, the point where $EENS^{std,hr} = 0.2$ MWh could not be the optimal one because the loss of load worth gap increases.

Secondly, the two cases where $EENS^{std,hr}$ is equal to 0.0909 and 0.07 is compared. The gap of the loss of load worth increases from \$42 (\$182 – \$140) in Fig. 9 to \$63 (\$273 – \$210) in Fig. 11. However, the offering cost difference where $EENS^{std,hr}$ is equal to 0.0909 and 0.07 is \$152 (\$22,297 – \$22,145). The offering cost gap is much larger even when the gap of the loss of load worth increases. The result is that the optimal point remains at $EENS^{std,hr} = 0.0909$ MWh.

Fig. 3.11 Optimal operating point under different system VOLL

If the load demand increases from 2,000 MW to 2,200 MW, the system energy and reserve schedule would change. The total cost would change as well. Fig. 3.12 gives the system results under the 2,200 MW demand. As can be seen, the optimal point remains where $EENS^{std,hr}$ is equal to 0.2 MWh.

Fig. 3.12 Optimal operating point under different load demands

Through the analysis of different offering data, system average VOLL and load demand values, the point where $EENS^{std,hr}$ is 0.2 MWh or 0.0909 MWh may be the optimal operating point. The frequency that 0.909 MWh is the optimal operating point is large than that of 0.2 MWh. Therefore, the point where $EENS^{std,hr}$ is 0.0909 MWh is picked as the final $EENS^{std,hr}$ in our studies.

3.5 Conclusion remarks

In this chapter, a market clearing model suitable for application to the Singapore market is developed. In this model, consumers could participate in the reserve market in the form of interruptible loads. The objective function and constraints are formulated. Particularly, the market clearing engine could satisfy the need of the proposed insurance scheme because the probabilistic reserve requirement considering both the generators and interruptible loads is also a constraint. The model can be solved by two approaches. MILP seems natural and is easy to understand, but its performance is not good for real-time

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operation. The iterative LP obtains the system spinning reserve amount through several rounds of linear programming and post processes. The iterative LP fully makes use of the available LP clearing engine in the Singapore Electricity Market and could also meet the time requirement for real-time operation. In addition, the cost/benefit analysis is studied to find an optimal operating point where the sum of the offering cost and loss of load worth is minimized.

Chapter 4

Settlement in reserve market

4.1 Reserve settlement

4.1.1 Market settlement in Singapore Electricity Market

The energy and reserve providers recover the offering cost in the settlement. In every dispatch period, a certain amount of MWhs are delivered from the generators to the consumers. The value of these MWhs is recovered in the settlement. For generators who provide reserve, extra operating costs are needed. Providing reserve requires those generators, which otherwise would be generating at full load, to generate less and set aside some margin, restricting their production and increasing operating cost. The reserve providers will recover the extra cost in the settlement.

In addition to the energy and reserve cost, there are some other costs to be recovered by means of uplift. The uplift includes the monthly uplift and the yearly uplift. The yearly uplift is the administrative cost for paying any given market operator and system operator. The monthly energy uplift amount (MEUA) comprises the monthly compensation and other payments (MACP), monthly miscellaneous costs (MISC) and monthly energy uplift shortfall (MEUS).

In the Singapore Electricity Market, settlement is done on a rolling daily basis. The settlement phase begins at the time of dispatch when the price is available, and ends when the payment is made to the participants. The Singapore Electricity Market has four stages at the settlement phase, i.e. preliminary settlement, final settlement, payment made to the

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market operator and payment made to the market participants. The settlement timetable is shown in Fig. 4.1.

摘 ? refers to the trading day

Fig. 4.1 Timetable of electricity market settlement in Singapore

The preliminary settlement statement for each trading day in the real-time market would be issued six business days after the trading day. For the consumers or purchasers, the aggregate energy withdrawn is recorded from the meters in each dispatch period on that trading day. For the generation entities, the energy produced from each generator is also metered. These values should be within the tolerance of the scheduled output. Otherwise certain penalties may be issued. In addition, the monthly and hourly uplift charges such as the reserve costs are also applied to each settlement period in that trading day.

The preliminary settlement statement would be sent to each participant. Each market participant is given some time to notify the market operator of any errors in the preliminary settlement statement. The market operator should validate inquiries submitted by any participant in time. Ten business days after each trading day, the final settlement statement for each trading day in the real-time market should be issued reflecting the outcome of the participant's enquiries. After that, invoices for participants in each dispatch period are generated. The basis of the invoicing and billing is the final settlement statement.

Thirty days after the dispatch period, each market participant shall initiate the electronic funds transfer process so as to ensure that the market participant's payments for each

invoice reach the market operation. Thirty two days after the dispatch period, the market operator would transfer the money to each receiving end.

4.1.2 Rationale of zero-sum settlement

This thesis focuses on the reserve market settlement. The reserve settlement results would be part of the preliminary settlement statement. In principle, the reserve cost should be paid by those requiring reserve to those supplying it. According to the direct payers in the reserve settlement, either consumers or generators pay the reserve cost. In the current electricity markets around the world, availability payment and lost opportunity cost approaches are on the basis that consumers pay the reserve cost. In contrast, the runway and modified runway approaches are on the basis that generators pay the reserve cost.

In Singapore, reserves are required to cover for generation units deemed to impose contingencies. In other words, generators are the buyers of the reserves. The modified runway model is implemented in the Singapore Electricity Market.

In the modified runway model, a significant degree of cost sharing is needed, not only between units that are assumed to jointly set the largest single contingency, but also with other smaller units. If the larger units were not failing, some reserve would still be required to cover breakdown of those smaller units. Thus it seems that all generators dispatched should pay for the reserves. Particularly, the modified runway model weighs the cost more heavily on the units generating higher quantities, and on those with a poor reliability record.

In the modified runway model, no unit should pay for reserves necessary to protect against loss of a unit larger than itself. In other words, each unit should pay a cost fraction of each “tier” in the reserve requirement that is protecting against loss of units with its MW output. The reserve responsibility fraction for each generator is determined as follows [45]: The first tier of the total reserve requirement (in MWh) is defined as the difference between the MW output of the largest and the second largest generators. The largest generator is allocated the first tier of reserves on the grounds that this tier is necessary only because the largest unit is producing more than the second largest unit.

The second tier of reserve is defined as the difference between the MW outputs of the second and the third largest units. The largest two units share the costs of this tier x on the grounds that this tier of reserves is necessary only because these two units are larger than the third largest unit. The reserve cost sharing is shown in Fig. 4.2.

Fig. 4.2 Reserve cost sharing in modified runway model

That generators pay the reserves based on a zero-sum approach may provide a price signal to the market which would not otherwise present in the current market [39]. An example where the “ $n-1$ security” reserve criterion is presented to illustrate this price signal. A new entry (generator) might find that it has two options for its new 500-MW CCGT (Combined Cycle Gas Turbine). They are (i) a single unit that would increase the outage of the system single contingency to 500 MW or (ii) two 250-MW units that would not increase the single contingency outage capacity. A zero-sum approach to recover the costs of additional reserves may cause the investor to opt for the 2 x 250-MW design, adding to system security rather than reducing it.

4. 2 Conceptual model of probabilistic zero-sum reserve settlement

4.2.1 Conceptual process of probabilistic zero-sum reserve settlement

The data used in the reserve settlement are the reserve offers, energy and reserve dispatch schedules, reserve clearing price and FOR of each generator. The output of the reserve settlement is the payments to be made to and by the generators.

The first step for probabilistic reserve zero-sum settlement is to determine the reserve responsibility fraction. A contingency analysis is implemented so that the responsibility of each contingency is allocated to every generator. Eventually, the expected unserved energy responsibility attributable to each unit is as shown in Fig. 4.3.

Fig. 4.3 Loss of load responsibility allocation

The second step is to compute the reserve supply fraction, which comes from the reserve schedule. The third step is to get the reserve market value, which could be obtained from the reserve quantity and reserve marginal clearing price. Finally, the amount each generator needs to pay could be calculated with the reserve responsibility fraction and reserve supply fraction.

4.2.2 Characteristic of probabilistic zero-sum reserve settlement

The probabilistic zero-sum settlement approach builds on the merit of the modified runway approach. It ensures a zero-sum of hourly compensations and payments. It also recognizes the influence of the MW provision amounts, forced outage rates and reserve amounts in the reserve settlement. The more MW amount a generator provides, the higher the probability the system would suffer energy deficiency when this unit fails almost simultaneously with other units. Hence generators with high MW provision should be

allocated more responsibility fractions in the reserve scheduling cost. For a unit with a high forced outage rate, there is a high probability the unit may fail. Hence units with higher forced outage rates should be allocated a higher responsibility fraction in the reserve scheduling cost.

The probabilistic zero-sum settlement approach complements the deficiencies in the modified runway approach. In the modified runway approach, the calculation of the reserve responsibility fraction each generator allocated is not accurate. The modified runway approach is based on single contingencies. The responsibility of each unit in multiple contingencies is not well analyzed. In the probabilistic zero-sum approach, contingency analysis is used. The probability and the expected unserved energy amount of each contingency are computed and the involved generators are allocated their corresponding responsibility fractions. After that, the responsibility fractions for each generator in different contingencies are added together to obtain the final reserve responsibility fraction for each generator.

In essence, the probabilistic zero-sum reserve settlement scheme is well suited to the realization of the probabilistic reserve criterion. The settlement and reserve requirement have the internal connections via the reliability metric EENS. The value of $EENS_i$ in the reserve requirement is decomposed into many components, one for each generator in the settlement. The reserve requirement and reserve settlement look at the system $EENS_i$ from different angles. In meeting the reserve requirement, the system $EENS_i$ is the total contribution of multiple contingencies. In reserve settlement, the system $EENS_i$ is the sum of the EENS attributable to each generator which may be involved in different contingencies.

When an interruptible load participates in the reserve market, its settlement could also be treated under the same zero-sum framework. The principle is that the interruptible load will be assigned a reserve responsibility fraction if it has a non-zero failure probability. Bai *et al* has reported the settlement of interruptible loads [84] based on the work in this chapter.

4.2.3 Assumptions in reserve settlement

The reserve is assumed to be converted to energy only during generator failures. In this work, reserve would not be called in when transmission network fails or load forecasting error occurs.

4.3 Mathematical model of probabilistic zero-sum reserve settlement

EENS is used to allocate the reserve responsibility of each unit. It shows the unit responsibility in those contingencies with energy deficiencies. In other words, the system EENS is divided into N responsibility fractions and each unit takes up one of them. The reserve responsibility that Unit i takes up in a specified period can be formulated as follows:

$$EENS_i^{cnt} = r_i^{si} EENS_i^{si} + \sum_{j=1, j \neq i}^N r_i^{db} * EENS_{i,j}^{db} + \sum_{\substack{j=1, k > j, \\ j \neq i, k \neq i}}^N \sum_{k=1}^N r_i^{tr} * EENS_{i,j,k}^{tr} + \dots \quad (4.1)$$

where

$EENS_i^{si}$ is the energy deficiency amount when Unit i fails.

$EENS_{i,j}^{db}$ is the energy deficiency amount when both Unit i and Unit j fail almost simultaneously.

$EENS_{i,j,k}^{tr}$ is the energy deficiency amount when Unit i , Unit j and Unit k fail almost simultaneously.

r_i^{si} is the proportion responsibility fraction of Unit i when Unit i fails.

r_i^{db} is the proportion responsibility fraction of Unit i when both Unit i and Unit j fail simultaneously.

r_i^{tr} is the proportion responsibility fraction of Unit i when Unit i , Unit j and Unit k fail simultaneously.

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Due to the failure of Unit i , the EENS caused by Unit i for the single, double and triple contingencies can be calculated in (4.2), (4.3) and (4.4) respectively. When the number of generators involved in the contingency increases, the number of events that Unit i involves increases. Unit i is involved in one event in the single contingency, $(N - 1)$ events in the double contingency and $(N - 1) \cdot (N - 2) / 2$ events in the triple contingency. As the number of generators involved in the contingency increases, the consequence measured by EENS becomes severe because more units are lost. At the same time, the probability of each contingency becomes smaller because the probability that a generator fails is much smaller than that when it operates normally and the product of these numbers becomes very small when many of them are multiplied together.

$$EENS_i^{si} = \Gamma_i \cdot \mu_k \cdot \prod_{l=1, l \neq k}^N (1 - \mu_l) \quad (4.2)$$

$$EENS_{i,j}^{db} = \Gamma_{i,j} \cdot \mu_i \cdot \mu_j \cdot \prod_{l=1, l \neq k, l}^N (1 - \mu_l) \quad (4.3)$$

$$EENS_{i,j,k}^{tr} = \Gamma_{i,j,k} \cdot \mu_i \cdot \mu_j \cdot \mu_k \cdot \prod_{l=1, l \neq i, j, k}^N (1 - \mu_l) \quad (4.4)$$

If the expected energy deficiency is solely caused by Unit i , obviously this unit should be fully responsible for this part of EENS. Hence, the proportion parameter $r_i(i)$ for $EENS_1(i)$ is set to 1. When two or more generators fail at the same time and cause energy deficiency, each involved unit is allocated a fraction of the responsibility. The proportion that Unit i needs to be responsible for in the double and triple contingencies are formulated as follows:

$$r_i^{db} = \frac{GE_i^{sum} * \mu_i}{GE_i^{sum} * \mu_i + GE_j^{sum} * \mu_j} \quad (4.5)$$

$$r_i^{tr} = \frac{GE_i^{sum} * \mu_i}{GE_i^{sum} * \mu_i + GE_j^{sum} * \mu_j + GE_k^{sum} * \mu_k} \quad (4.6)$$

1) Reserve responsibility fraction

According to (4.1), the reserve responsibility $EENS_i^{cnt}$ can be calculated for every unit.

The summation of the $EENS_i^{cnt}$ is equal to the system predefined level, or $EENS^{std,hr}$

which meets the probabilistic spinning reserve requirement if the tolerance error is ignored. The reserve responsibility fraction that Unit i should be attributable to can be formulated as follows:

$$RRF_i^{pz} = \frac{EENS_i^{cnt}}{\sum_{j=1}^N EENS_j^{cnt}} = \frac{EENS_i^{cnt}}{EENS^{std,hr}} \quad (4.7)$$

2) Reserve supply fraction

On the other hand, each unit must also share out in the supply of spinning reserve. The summation of the spinning reserve each unit provides is the system spinning reserve amount. The spinning reserve supply fraction for Unit i is as follows:

$$RSF_i^{pz} = \frac{GR_i^{sum}}{\sum_{j=1}^N GR_j^{sum}} \quad (4.8)$$

The total market value of the spinning reserve is the product of the marginal reserve clearing price ($MRCP$) and the total spinning reserve amount. The payment that a unit needs to make is the total reserve value multiplied by the difference of the unit reserve responsibility fraction and the unit reserve supply fraction. If the payment value is negative, this means that the generator gets compensation from others, i.e. the generator gains by receiving payments from others. The payment that Unit i makes is,

$$PAY_i^{pz} = [RRF_i^{pz} - RSF_i^{pz}] \cdot MRCP \cdot \sum_{j=1}^N GR_j^{sum} \quad (4.9)$$

As can be seen in (4.7), the sum of the RRF_i^{pz} is equal to 1. From (4.8), the sum of RSF_i^{pz} is also equal to 1. Therefore, the sum of PAY_i^{pz} is equal to 0. This means that the generators are both the payers and payees of the reserve and consumers do not need to pay any money for the reserve in settlement.

The probabilistic zero-sum approach uses the EENS metric to compute the unit's responsibility. Through the analysis, every system contingency is considered. The responsibility of each involved generator is related to the consequence, number of

involved generators, output of the generators and forced outage rates. The contingency analysis ensures that the settlement is equitable to all the participants.

4.4 Simulation results

The test case used is the IEEE 32-unit system. The offering data for the energy and reserve are given in Chapter 3. The market clearing is through the iterative linear programming as discussed in Chapter 3. The case definition (Case 1-6) is also the same as that in Chapter 3.

The runway approach, modified runway approach and probabilistic zero-sum approach engage the zero-sum settlement scheme. To study their performances, the load demand is fixed at 1800 MW while the reliability level measured by the system EENS is maintained at 0.0909 MWh. Table 4.1 shows the payment amount under these settlement schemes. A negative payment in the table means that the generator gets compensation from others while a positive one means it pays others.

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Table 4.1 Settlement under three zero-sum settlement approaches

	Energy and reserve schedule		Settlement approaches					
			Runway		Modified Runway		Probabilistic zero-sum	
	(MW)	(MW)	RRF_i^{rw}	Payment (\$)	RRF_i^{mr}	Payment (\$)	RRF_i^{pz}	Payment (\$)
12-MW generator								
1-5	0.0	0.0	0.0000	0.0000	0.00	0.00	0.00	0.00
20-MW generator								
6-9	0.0	0.0	0.0000	0.0000	0.00	0.00	0.00	0.00
76-MW generator								
10	28.2	21.0	0.0052	-22.65	0.0031	-23.77	0.0005	-25.08
11	21.0	21.0	0.0033	-23.66	0.0020	-24.32	0.0003	-25.18
12	21.0	21.0	0.0033	-23.66	0.0020	-24.32	0.0003	-25.18
13	21.0	21.0	0.0033	-23.66	0.0020	-24.32	0.0003	-25.18
100-MW generator								
14	18.8	18.8	0.0029	-21.27	0.0028	-21.31	0.0005	-22.45
15	17.5	17.5	0.0026	-19.77	0.0025	-19.80	0.0004	-20.88
16	17.5	17.5	0.0026	-19.77	0.0025	-19.80	0.0004	-20.88
155-MW generator								
17	121.0	34.0	0.0372	-22.01	0.0401	-20.49	0.0374	-21.90
18	121.0	34.0	0.0372	-22.01	0.0401	-20.49	0.0374	-21.90
19	121.0	34.0	0.0372	-22.01	0.0401	-20.49	0.0374	-21.90
20	121.0	34.0	0.0372	-22.01	0.0401	-20.49	0.0374	-21.90
176-MW generator								
21	55.8	45.0	0.0139	-47.18	0.0153	-46.43	0.0108	-48.73
22	22.0	22.0	0.0035	-24.76	0.0043	-24.37	0.0013	-25.91
23	13.1	13.1	0.0019	-14.85	0.0024	-14.63	0.0003	-15.69
350-MW generator								
24	280.0	70.0	0.1697	+2.33	0.1607	-2.24	0.1693	+2.13
400-MW generator								
25	400.0	0.0	0.3197	+163.45	0.3200	+163.62	0.3331	+170.32
26	400.0	0.0	0.3197	+163.45	0.3200	+163.62	0.3331	+170.32

Basically, the three approaches yield more or less similar results in a broad sense. Unit 1 to 9 do not pay or receive any money because they have neither energy nor reserve scheduled. Unit 25 and 26 have to pay others while Unit 10 to 23 receive payments.

As could be observed, there are some minor differences. The forced outage rate is not taken into consideration in the runway approach while it is considered in the modified runway and probabilistic zero-sum approach. Therefore, units with low forced outage

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rates benefit in the modified runway and probabilistic zero-sum approach. For example, Unit 10 is one of the most reliable scheduled units. Unit 10 only receives \$22.65 under the runway approach, while the amount increases to \$23.77 under the modified runway approach and \$25.08 under the probabilistic zero-sum approach. In contrast, for the most unreliable units, say Unit 17, the compensation is \$22.01, \$20.49 and \$21.90 under the runway, modified runway and probabilistic zero-sum approach respectively.

Comparing the two approaches where the forced outage rates are considered, the probabilistic approach put more responsibility on the units with large capacities than the modified runway approach. For example, Unit 25 pays \$170.32 under the probabilistic zero-sum approach, compared to \$163.62 under the modified runway approach. As for Unit 24, it receives \$2.24 under the modified runway approach but has to pay \$2.13 under the probabilistic zero-sum approach. This means that the reserve analysis proves that Unit 24's reserve is not enough. In a word, the probabilistic zero-sum approach does not favor those generators with large output.

When the unit's forced outage rate changes, the system energy and reserve schedule would change as well. The settlement would then vary accordingly. Table 4.2 and 4.3 show the probabilistic zero-sum settlement under Case 4 and 5 respectively.

When the forced outage rate of Unit 25 increases from 0.004125 in Case 4 to 0.006875 in Case 5, some of the generators are rescheduled to achieve the minimum offering cost since more spinning reserve is needed. The payment amount of the spinning reserve market increases from \$332.24 to \$362.07 accordingly.

As can be seen, the energy and reserve schedule for Unit 25 does not change but its payment increases from \$129.79 to \$206.66. This \$76.87 is the penalty for its increase in the forced outage rate. If 8,000 operating hours in a year are assumed, it needs to pay $\$76.87 \times 8,000 = \$614,960$ more a year. This payment plus the lost revenue in electricity sale represents the loss for Unit 25 in a year. The generation entity can compare this loss with the maintenance cost and then decide the route that it should choose. Obviously, the route that saves money for the generation entity and/or increases its revenue should be chosen. Hence, the proposed settlement scheme can provide the necessary incentive for the generation entities to enhance the performance of their units.

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Table 4.2 Schedule and settlement under Case 4

	Energy and reserve schedule		Settlement		
	Energy (MW)	Reserve (MW)	RRF_i^{pz}	RSF_i^{pz}	Payment(\$)
12-MW generator					
1-5	0.0	0.0	0.0000	0.0000	0.00
20-MW generator					
6-9	0.0	0.0	0.0000	0.0000	0.00
76-MW generator					
10	21.0	21.0	0.0004	0.0511	-25.12
11	21.0	21.0	0.0004	0.0511	-25.12
12	21.0	21.0	0.0004	0.0511	-25.12
13	19.5	19.5	0.0004	0.0473	-23.26
100-MW generator					
14	17.5	17.5	0.0007	0.0426	-20.74
15	17.5	17.5	0.0007	0.0426	-20.74
16	17.5	17.5	0.0007	0.0426	-20.74
155-MW generator					
17	121.4	33.6	0.0402	0.0817	-20.57
18	121.4	33.6	0.0402	0.0817	-20.57
19	121.4	33.6	0.0402	0.0817	-20.57
20	121.4	33.6	0.0402	0.0817	-20.57
176-MW generator					
21	55.8	45.0	0.0128	0.1095	-47.94
22	22.0	22.0	0.0018	0.0536	-25.65
23	13.1	13.1	0.0006	0.0319	-15.52
350-MW generator					
24	288.4	61.6	0.1858	0.1499	+17.82
400-MW generator					
25	400.0	0.0	0.2618	0.0000	+129.79
26	400.0	0.0	0.3725	0.0000	+184.63

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Table 4.3 Schedule and settlement under Case 5

	Energy and reserve schedule		Settlement		
	Energy (MW)	Reserve (MW)	RRF_i^{pz}	RSF_i^{pz}	Payment(\$)
12-MW generator					
1-5	0.0	0.0	0.0000	0.0000	0.00
20-MW generator					
6-9	0.0	0.0	0.0000	0.0000	0.00
76-MW generator					
10	21.0	21.0	0.0002	0.0483	-25.24
11	21.0	21.0	0.0002	0.0483	-25.24
12	21.0	21.0	0.0002	0.0483	-25.24
13	21.0	21.0	0.0002	0.0483	-25.24
100-MW generator					
14	25.0	25.0	0.0008	0.0575	-29.75
15	20.4	20.4	0.0004	0.0470	-24.44
16	17.5	17.5	0.0002	0.0404	-21.00
155-MW generator					
17	121.0	34.0	0.0344	0.0782	-22.96
18	121.0	34.0	0.0344	0.0782	-22.96
19	121.0	34.0	0.0344	0.0782	-22.96
20	121.0	34.0	0.0344	0.0782	-22.96
176-MW generator					
21	55.8	45.0	0.0090	0.1034	-49.54
22	22.0	22.0	0.0008	0.0506	-26.16
23	13.1	13.1	0.0002	0.0302	-15.73
350-MW generator					
24	280.0	70.0	0.1558	0.1609	-2.66
400-MW generator					
25	400.0	0.0	0.3939	0.0000	+206.66
26	398.1	1.9	0.3006	0.0044	+155.41

When a new entrant wants to invest in MW generation, it can choose to install a large capacity generator or two or more small capacity generators. Larger capacity generators have better efficiency. However, two or more small capacity generators may benefit the system in terms of reliability. Therefore, the system needs to offer some stimuli to encourage the need for installing smaller generators. Case 7 and 8 is used to analyze the influence of probabilistic zero-sum approach on this issue. The detail of Case 7 and 8 is,

Case 7: Unit 25 is split into two 200-MW capacity generators. Assume that other characteristics of Unit 25 remain the same. The other 25 units remain unchanged.

Case 8: Unit 25 is split into two 150-MW generators and one 100-MW

generator. Assume that the split units have the same characteristics as Unit 25. The other 25 units remain unchanged.

Since the energy bidding price of Unit 25 is the lowest among the participants, the system schedules the entire capacity, i.e. 400 MW under Case 1, 7 and 8. This gives us a fair basis of comparison. Under the probabilistic zero-sum approach, Unit 25 under Case 1 needs to pay \$170.32. The unit with a capacity of 200 MW needs to pay \$22.97 each under Case 7. The unit with capacity of 150 MW needs to pay \$12.88 each while the unit with capacity of 100 MW needs to pay \$5.83 under Case 8. The total amount these 400 MW needs to pay is shown in Fig. 4.4.

Fig. 4.4 Payment for 400 MW under different cases

It is clear that the payment under Case 7 or 8 is smaller than that under Case 1. This means that the system reliability favors more units with less MW capacity. Consequently, split generators also get benefits in reserve settlement, i.e. paying less although the same amount of energy and spinning reserve is scheduled.

4.5 Conclusion remarks

This chapter focuses on reserve settlement. The reserve settlement in Singapore is reviewed and the rationale for zero-sum settlement scheme is discussed. The probabilistic zero-sum settlement is proposed to remove the deficiencies in the modified runway approach. Contingency analysis is used while EENS contributed by each generator is computed. The reserve responsibility fraction RRF_i^{pz} could then be calculated. For each generator, when its reserve responsibility fraction is larger than its reserve supply fraction, the unit has to pay others, and vice versa.

Chapter 5

Conclusions and recommendations

5.1 Conclusions

In this thesis, three possible aspects of Singapore Electricity Market are discussed. They are the insurance scheme, reserve requirement and reserve settlement. The introduction of the insurance scheme on the generation side in the market protects consumers from financial loss due to load curtailment. The insurance scheme offers consumers an alternative choice other than embedded generators and physical/financial bilateral contracts. The realization of the insurance scheme could not be obtained without the support of a suitable market clearing model.

The system reliability EENS metric links all these three aspects of market designs. The yearly EENS requirement in the insurance scheme needs to be converted to an hourly EENS requirement in the real-time operation and needs to be satisfied in the market clearing process. The probabilistic zero-sum settlement is a natural extension of the reserve requirement represented by EENS. Contingency analysis is conducted for the reserve settlement process and where system EENS is decomposed and each generator carries one fraction.

Some major research works and the contributions are further presented here.

- Insurance scheme

In the electricity market, loss of load is not completely avoidable in actual operation. Most consumers obtain their supply without a proper bilateral contract or installing

Chapter 5 Conclusions and recommendations

embedded generators. Hence, an insurance scheme is proposed for consumers to avoid possible financial losses due to generator failures. Under the insurance scheme, the consumers who are willing to participate are categorized according to their value of loss of load. Based on their annual energy consumptions, the consumers would pay the corresponding premiums to the generators.

After paying the insurance premium, these consumers who suffered loss of load would get proper compensation. The compensation amount is determined by the loss of load amount as well as the value of loss of load. The loss of load amount could be obtained from the load curtailment process while the value of loss of load could be retrieved from the premium calculation.

When the loss of load is caused by generator outages, the failed generators are penalized and the penalty serves as the compensation to the consumers who suffered loss of load. The principle of the penalty calculation is the “causers-pay” criterion. Every failed generator has to take up a share of penalty.

The insurance scheme can avoid the uncertainty of financial loss faced by the participating consumers. These consumers only need to pay a small insurance premium and thereafter do not worry about load curtailment. In addition, each generator has strong incentives to improve its performance since good performance brings extra revenue while its outage may cause a big revenue loss as it needs to compensate consumers.

- Market clearing model with probabilistic reserve requirement

The market clearing model is set up to imitate features of the Singapore Electricity Market. The model encompasses the objective function and constraints. The objective function is to schedule the energy and reserve with the minimum offering cost. The constraints include the purchase and generation constraints, reserve-generation constraints, ramp constraints, minimum system reserve constraint and probabilistic reserve requirement. The hourly EENS in the probabilistic reserve requirement constraint is derived from the annual EENS requirement of the insurance scheme. Particularly, the demand side could participate in the reserve market in the form of interruptible loads. The computation of system EENS also takes interruptible loads into consideration

The market clearing model could be solved by either MILP or iterative LP. MILP is a natural representation and could get a theoretically global optimization, but the computation time is excessive and hence not suitable for real-time operation.

The proposed iterative LP is a heuristic approach. It adds an extra post processing in the current LP implemented in the Singapore Electricity Market. Iterative LP comprises several rounds of linear programming and post linear programming processes. The linear programming determines the energy and reserve schedule under a fixed system reserve amount while the post linear programming process is to compute the system EENS under that schedule. A sequential search or bisection search can be used to obtain the system reserve amount in each iteration until the system EENS is within the tolerance. The advantage of iterative LP, as compared with MILP, is that not much modification is needed to suit the current Singapore market clearing engine while the computation time is still acceptable for the real-time operation.

In addition, a cost/benefit analysis is used to provide the regulator an indication as to how much EENS requirement is needed. A stringent EENS requirement leads to a high scheduling cost as well as a low probability of loss of load. The balancing point could be obtained via the cost/benefit analysis. Since the system situation varies, system studies may be performed to obtain the most suitable operating point.

- Reserve settlement

A probabilistic zero-sum settlement is proposed for the reserve settlement. It holds the same idea that generators need to pay the reserve cost as in the current modified runway approach implemented for the Singapore Electricity Market. The probabilistic zero-sum settlement improves the current modified runway approach in the sense that the reserve cost allocated through contingency analysis is more reasonable. The system reliability metric EENS calculated in each dispatch period is decomposed into fractions for distribution among generators. The generator entities are encouraged to keep the units in good shape and thus they pay less in reserve settlement.

5.2 Recommendations

There are some areas that the research work can be expanded to further improve the schemes proposed in this thesis.

- ❖ Load forecast uncertainties would influence the schedule of reserve. The energy and reserve schedule is based on the forecasted load. If some generators fail during the dispatch, an under-estimation of load may worsen the loss of load problem while an over-estimation of the load may ease the problem to a certain degree but may lead to a high schedule cost. Both are undesirable as they either under or over commit the units. Load forecast uncertainties could be modeled as a normal distribution and taken into consideration in the EENS calculation.
- ❖ Frequency drop may be caused by generator failures. The drop of the frequency leads to the reduction of electricity consumption. In a sense, this benefits the system operation. On the other hand, the sudden drop of the frequency may force some generators disconnected from the power grid, like the old steam sets with poor governor response or some new efficient combined cycle gas turbines which are frequency sensitive. Hence, it would make sense to consider the impact of frequency drops in reserve scheduling.
- ❖ Transmission line constraints have an impact on the energy and reserve price. Due to the capacity limit of some lines, higher offers on energy and reserve have to be accepted. This would also cause the increase of offering cost and thus the optimal operating point may shift.
- ❖ The relation of the insurance scheme at the generation and distribution levels can be further investigated. If failures of both the generator and network contribute to loss of load, the technique to compute the responsibility fraction for each party is worth studying.

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- ❖ The implication for bidding behavior and capital formation of the proposed payment schemes could be further studied in market clearing and market settlement.

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Appendix

Appendix: Test data used in Chapter 3 and 4

The demand levels from Hour 1 to 8 are shown in Table A.1.

Table A.1 Demand level

Hour	1	2	3	4	5	6	7	8
Load (MW)	1,700	1,730	1,690	1,700	1,740	1,900	2,000	2,430

If the price that two or more units submit is the same, the market clearing engine would automatically adjust it slightly. For simplicity, the prices have already been adjusted here for the generators. Table A.2 shows the offering data for the 12-MW capacity generators indexed from 1 to 5.

Table A.2 Offering data (Unit 1-5)

Parameters	Unit index				
	1	2	3	4	5
$GE_{i,1,t}^{max}$ (MW)	2.4	2.4	2.4	2.4	2.4
$GEP_{i,1,t}$ (\$/MWh)	24.05	24.06	24.26	24.38	24.50
$GE_{i,2,t}^{max}$ (MW)	3.2	3.2	3.2	3.2	3.2
$GEP_{i,2,t}$ (\$/MWh)	25.75	25.89	26.03	26.16	26.29
$GE_{i,3,t}^{max}$ (MW)	3.2	3.2	3.2	3.2	3.2
$GEP_{i,3,t}$ (\$/MWh)	25.91	26.06	26.20	26.34	26.47
$GE_{i,4,t}^{max}$ (MW)	3.2	3.2	3.2	3.2	3.2
$GEP_{i,4,t}$ (\$/MWh)	26.07	26.23	26.39	26.52	26.65
$GR_{i,1,t}^{max}$ (MW)	3	3	3	3	3
$GRP_{i,1,t}$ (\$/MWh)	2.61	2.62	2.64	2.65	2.66

Appendix

Table A.3 shows the offering data for the 20-MW capacity generators indexed from 6 to 9.

Table A.3 Offering data (Unit 6-9)

Parameters	Unit index i			
	6	7	8	9
$GE_{i,1,t}^{max}$ (MW)	4.00	4.00	4.00	4.00
$GEP_{i,1,t}$ (\$/MWh)	35.10	35.20	35.30	35.40
$GE_{i,2,t}^{max}$ (MW)	5.33	5.33	5.33	5.33
$GEP_{i,2,t}$ (\$/MWh)	37.71	37.83	37.96	38.08
$GE_{i,3,t}^{max}$ (MW)	5.34	5.34	5.34	5.34
$GEP_{i,3,t}$ (\$/MWh)	37.84	37.97	38.10	38.23
$GE_{i,4,t}^{max}$ (MW)	5.33	5.33	5.33	5.33
$GEP_{i,4,t}$ (\$/MWh)	37.97	38.10	38.25	38.39
$GR_{i,1,t}^{max}$ (MW)	5	5	5	5
$GRP_{i,1,t}$ (\$/MWh)	3.80	3.81	3.82	3.84

Appendix

Table A.4 shows the offering data for the 76-MW capacity generators indexed from 10 to 13.

Table A.4 Offering data (Unit 10-13)

Parameters	Unit index i			
	10	11	12	13
$GE_{i,1,t}^{max}$ (MW)	15.20	15.20	15.20	15.20
$GEP_{i,1,t}$ (\$/MWh)	12.10	12.20	12.30	12.40
$GE_{i,2,t}^{max}$ (MW)	20.27	20.27	20.27	20.27
$GEP_{i,2,t}$ (\$/MWh)	13.71	13.81	13.84	13.88
$GE_{i,3,t}^{max}$ (MW)	20.27	20.27	20.27	20.27
$GEP_{i,3,t}$ (\$/MWh)	14.13	14.17	14.21	14.26
$GE_{i,4,t}^{max}$ (MW)	20.27	20.27	20.27	20.27
$GEP_{i,4,t}$ (\$/MWh)	14.48	14.53	14.58	14.64
$GR_{i,1,t}^{max}$ (MW)	21	21	21	21
$GRP_{i,1,t}$ (\$/MWh)	1.44	1.45	1.46	1.47

Appendix

Table A.5 shows the offering data for the 100-MW capacity generators indexed from 14 to 16.

Table A.5 Offering data (Unit 14-16)

Parameters	Unit index i		
	14	15	16
$GE_{i,1,t}^{max}$ (MW)	25	25	25
$GEP_{i,1,t}$ (\$/MWh)	17.10	17.20	17.30
$GE_{i,2,t}^{max}$ (MW)	25	25	25
$GEP_{i,2,t}$ (\$/MWh)	18.47	18.56	18.65
$GE_{i,3,t}^{max}$ (MW)	25	25	25
$GEP_{i,3,t}$ (\$/MWh)	18.78	18.87	18.95
$GE_{i,4,t}^{max}$ (MW)	25	25	25
$GEP_{i,4,t}$ (\$/MWh)	19.09	19.17	19.25
$GR_{i,1,t}^{max}$ (MW)	25	25	25
$GRP_{i,1,t}$ (\$/MWh)	1.91	1.92	1.93

Appendix

Table A.6 shows the offering data for the 155-MW capacity generators indexed from 17 to 20.

Table A.6 Offering data (Unit 17-20)

Parameters	Unit index i			
	17	18	19	20
$GE_{i,1,t}^{max}$ (MW)	54.25	54.25	54.25	54.25
$GEP_{i,1,t}$ (\$/MWh)	10.10	10.20	10.30	10.40
$GE_{i,2,t}^{max}$ (MW)	33.58	33.58	33.58	33.58
$GEP_{i,2,t}$ (\$/MWh)	11.35	11.39	11.42	11.45
$GE_{i,3,t}^{max}$ (MW)	33.59	33.59	33.59	33.59
$GEP_{i,3,t}$ (\$/MWh)	11.66	11.71	11.74	11.78
$GE_{i,4,t}^{max}$ (MW)	33.58	33.58	33.58	33.58
$GEP_{i,4,t}$ (\$/MWh)	11.97	12.02	12.07	12.10
$GR_{i,1,t}^{max}$ (MW)	34	34	34	34
$GRP_{i,1,t}$ (\$/MWh)	1.19	1.20	1.21	1.22

Appendix

Table A.7 shows the offering data for the 197-MW capacity generators indexed from 21 to 23.

Table A.7 Offering data (Unit 21-23)

Parameters	Unit index i		
	21	22	23
$GE_{i,1,t}^{max}$ (MW)	68.95	68.95	68.95
$GEP_{i,1,t}$ (\$/MWh)	22.10	22.20	22.30
$GE_{i,2,t}^{max}$ (MW)	42.68	42.68	42.68
$GEP_{i,2,t}$ (\$/MWh)	23.47	23.57	23.67
$GE_{i,3,t}^{max}$ (MW)	42.69	42.69	42.69
$GEP_{i,3,t}$ (\$/MWh)	23.69	23.79	23.90
$GE_{i,4,t}^{max}$ (MW)	42.68	42.68	42.68
$GEP_{i,4,t}$ (\$/MWh)	23.91	24.01	24.12
$GR_{i,1,t}^{max}$ (MW)	45	45	45
$GRP_{i,1,t}$ (\$/MWh)	2.39	2.40	2.41

Appendix

Table A.8 shows the Offering data for the 350-MW capacity and 400-MW capacity generators indexed 24 to 26.

Table A.8 Offering data (Unit 24-26)

Parameters	Unit index i		
	24	25	26
$GE_{i,1,t}^{max}$ (MW)	140	100	100
$GEP_{i,1,t}$ (\$/MWh)	10.10	7.10	7.20
$GE_{i,2,t}^{max}$ (MW)	70	100	100
$GEP_{i,2,t}$ (\$/MWh)	11.40	8.07	8.09
$GE_{i,3,t}^{max}$ (MW)	70	100	100
$GEP_{i,3,t}$ (\$/MWh)	11.61	8.46	8.48
$GE_{i,4,t}^{max}$ (MW)	70	100	100
$GEP_{i,4,t}$ (\$/MWh)	11.83	8.85	8.87
$GR_{i,1,t}^{max}$ (MW)	70	100	100
$GRP_{i,1,t}$ (\$/MWh)	1.18	0.86	0.88

Appendix

The feasible reserve region has three parameters, i.e. the maximum amount of reserve that each unit can carry, the reserve proportion ratio and the maximum energy, and reserve the unit can provide. These three parameters are represented by GR^{max} , $RPPN_{i,t}$ and GER_i^{max} respectively.

GR^{max} is set at 100 MW for all the units. According to the data in the Singapore Electricity Market, $RPPN_{i,t}$ is assumed to be 1 for all the units. The parameter GER_i^{max} that each unit submits is set at its capacity. Table A.9 shows GER_i^{max} each unit submits.

Table A.9 *ReserveGenMax(i)* from each unit

Unit index i	GER_i^{max} (MW)
1-5	12
6-9	20
10-13	76
14-16	100
17-20	155
21-23	197
24	350
25-26	400

The ramp up rate and ramp down rate represented by RU_i and DU_i are shown in Table A.10.

Table A.10 Ramp up rate and ramp down rate from the units

Unit index i	RU_i (MW/h)	DU_i (MW/h)
1-5	48	60
6-9	30	72
10-13	40	80
14-16	50	75
17-20	80	80
21-23	100	100
24	175	175
25-26	200	400

VITA

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L. M. Xia, H. B. Gooi and J. Bai, "A probabilistic reserve with zero-sum settlement scheme", IEEE Transactions on Power Systems, vol. 20, no. 2, pp. 993-1000, May 2005.

J. Bai, H. B. Gooi, L. M. Xia, G. Strbac and B. Venkatesh, "A probabilistic reserve market incorporating interruptible load", IEEE Transactions on Power Systems, vol. 21, no. 3, pp. 1079-1087, Aug. 2006.

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