VALUATION MODEL FOR GENERATION INVESTMENT IN LIBERALISED ELECTRICITY MARKET

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Abstract

The introduction of a liberalised electricity market has brought a new challenge to generating companies as well as system regulators. Under this more competitive environment, generating companies are exposed to various risks that might compromise their investment return. Moreover, the various risks in the market affect each type of generation technology in a different way; hence influence the technology choice. Furthermore, it is not yet clear whether the investment cycles in a liberalised electricity market will take place in an orderly fashion or whether 'boom and bust' cycles may arise. As a consequence various market designs, investment incentives and policies have been implemented by system regulators to try to ensure the security of supply. Investment decisions under a market with incentive mechanism are even more complicated to model because the generating company needs to forecast the revenue that the new investment will make from both the energy market and the mechanism.

This thesis develops some models that could be used by system regulators to study the performance of market designs and by generating companies to assess a new investment under a liberalised electricity market. Three main models have been developed to serve these purposes.

A generation expansion model has been developed using Agent-based modelling approach. In this model each generating company makes investment decision taking into account their competitors' investment strategies and the interactions between them. Several incentive mechanisms are also modelled to study their impacts on the generating companies' investment decision and the dynamic of the investments.

A more comprehensive investment framework for a generating company to evaluate an investment in a new power plant has also been developed. The framework consists of two stages: 1) it first models the expected future investments and retirements from all the companies in the market and 2) then calculates the market prices and revenues of the new investment against the future system expansion obtained in the first stage. Two investment models have been developed using this framework. The first model is a probabilistic valuation model to assess investment considering risks and uncertainties. The second model is developed to evaluate investment in an oligopoly electricity market taking into account various risk characteristics of different technologies.

The investment framework for a generating company to evaluate an investment is also extended so that the generating company can evaluate investments in a market with an incentive mechanism.

Declaration

No portion of the work referred to in the thesis has been submitted in support of an application for another degree or qualification of this or any other university or other institute of learning.

Copyright Statement

List of Symbols

Indices

i	index of generating unit running from 1 to I
j	index of generating unit that belong to a given generating company from 1 to J
t	index of time periods running from 1 to T, years
z	index for elements in the capacity on outage probability table (COPT) from 1 to Z, MW
m	index of generating unit participating in capacity market from 1 to M
n	index of n stage process of optimal discretized LDC from 1 to $S-1$

Sets

S	set of segments in load duration curve (LDC)
I	set of generating units participating in the energy market
J	set of generating units that belong to a given generating company
T	set of time periods (lifetime of new investment plant), years
Z	set of elements in COPT
M	set of generating units participating in the capacity market

Functions

$F(x)$	function of LDC
$p(e(x))$	penalty to be paid per unit of mismatch of discretized LDC
$e(x)$	amount of mismatch at x of discretized LDC
$CM\ (X_t, l_{max,t})$	total payment from the capacity mechanism as a function of the system available capacity, X_t, and the peak load, $l_{max,t}$, $

Parameters

pd_s	system demand at segment s, MW
rd_s	spinning reserve requirement for segment s, MW
m_i	slope of the linearized input-output characteristic of generating unit i, MBTU/MWh

b_i	y-offset of the linearized input-output characteristic of generating unit i, MBTU/h
f_c	fuel cost, \$/MBTU
P_i^{min}	minimum stable generation of unit i, MW
P_j^{max}	capacity of generating unit j, MW
$MARR$	minimum acceptable rate of return of new investment, %
$VOLL$	system's value of loss load, \$/MWh
FOR_j	forced outage rate of generating unit j
uf_m	utilization factor of generating unit m that participating in capacity market
lt	lifetime of generating unit, years
K_t	capacity retirement in year t, MW
μ_d	expected value of demand in segment s of LDC, MW
σ_d	standard deviation of demand in segment s of LDC
μ_f	expected fuel cost, \$/MBTU
σ^2_f	variance of fuel cost
IC_t	total investment cost of the new investments in year t, \$
$FOM_{all, t}$	total fixed O&M cost of all the generating units at year t, \$
$VOM_{all, t}$	total variable O&M cost of all the generating units at year t, \$
NWC_t	total nuclear waste cost of nuclear technologies at year t, \$
CC_t	total carbon emission cost of coal and combined cycle technologies at year t, \$
WF	nuclear waste fee per MWh of energy produced, \$/MWh
CO_2	amount of carbon dioxide emission per MWh of energy produced, \$/MWh
CT	carbon tax, \$/tC
$CONE$	Cost of new entry, \$
IRM_T	Installed reserve margin target for capacity market, %

Variables

MCb_i	bidding price of generating unit I, \$/MWh
$p_{i,s}$	power produced by generating unit i at segment s, MW
d_s	duration in hours of segment s, h
P_{GenCo}	Net revenue of generating company, \$

ER_j	yearly revenue of generating unit *j* from the energy market, \$
SR_j	yearly revenue of generating unit *j* from providing spinning reserve, \$
PC_j	yearly production cost of generating unit *j*,\$
$\pi_{clear,s}$	market clearing prices for energy at segment s of the LDC, \$/MWh
π_{SR}	market clearing prices for spinning reserve at segment *s* of the LDC, \$/MWh
FWV	future worth value of new investment plant, \$
r	rate of return of new investment, %
CF_t	net cash-flow at year *t,* \$
$LOLP_s$	system's loss of load probability at segment *s* of LDC
AC_s	actual committed capacity at segment s, MW
CA_z	capacity on outage for element *z* in COPT, MW
CMb_m	bidding price of generating units in capacity market, \$/MW
$A_{revenue,m}$	projected annual revenue of generating unit *m* that participating in capacity market, \$
$A_{prod\_cost,m}$	projected annual production cost of generating unit *m* that participating in capacity market, \$
$A_{investment,m}$	present worth value of the initial investment of generating unit *m* that participating in capacity market, \$
I_{PWV}	present worth value of the investment, \$
TC	total cost of expansion over the prototype of system expansion simulation horizon (lifetime of the new investment plant), \$
$PC_{all,t}$	total production cost of all the generating units in the system at year *t,* \$
X_t	cumulative capacity vector in year *t*, MW
U_t	capacity addition vector in year *t,* MW
t_n	breaking points of optimal discretized LDC at *n* stage process of the optimization, h
g_n	corresponding height of t_n, p.u
$P_{new,t}$	net revenue of the new investment plant at year *t*, \$
CF_t	ratio of the available generation capacity X_t, to the peak load $l_{max,t}$
CPr_{new}	revenue of the new plant from the capacity payment, \$
CM_{price}	capacity market clearing price, \$/MW

List of Abbreviations

CCGT	Combined Cycle Gas Turbine
CONE	Cost of New Entry
COPT	Capacity on Outage Probability Table
CVAR	Conditional Value at Risk
DP	Dynamic Programming
FWV	Future Worth Value
GENCO	Generating Company
ICAP	Installed Capacity
IEA	International Energy Agency
IRM	Installed Reserve Margin
IRR	Internal Rate of Return
ISO	Independent System Operator
ISO-NE	Independent System Operator New England
LDC	Load Duration Curve
LOLP	Loss of Load Probability
LSE	Load Serving Entity
MARR	Minimum Acceptable Rate of Return
NEPOOL	New England Power Pool
NPV	Net Present Value
NYISO	New York Independent System Operator
NYPP	New York Power Pool
OCGT	Open Cycle Gas Turbine
O&M	Operation and Maintenance
PDC	Price Duration Curve
PJM	Pennsylvania New Jersey Maryland Interconnection

RPM	Reliability Pricing Model
VAR	Value at Risk
VOLL	Value of Loss Load
VRR	Variable Resource Requirement

List of Publications

1. Nofri Yenita Dahlan, Daniel S. Kirschen, "Valuation Model for Generation Investment in an Oligopoly Electricity Market", in 8th Young Energy Engineers and Economist Seminar, University of Cambridge, 8-9 April 2010
   http://www.eprg.group.cam.ac.uk/wp-content/uploads/2010/03/Nofri-Dahlan-2.pdf

2. Nofri Yenita Dahlan, Daniel S. Kirschen, "Generation Investment Evaluation Under Uncertainty in a Competitive Environment", in PMAPS 2010 IEEE Singapore, 14-17 June 2010

3. Nofri Yenita Dahlan, Daniel S. Kirschen, "Valuation Model for Generation Investment in an Oligopoly Electricity Market", in MedPower 2010 IET Cyprus, November 2010

4. Nofri Yenita Dahlan, Daniel S. Kirschen, "Valuation Model for Generation Investment in an Oligopoly Electricity Market with Capacity Payment", in PSCC2011 in Sweden, August 2011

About the Author

Nofri Yenita Dahlan was born in Kuala Lumpur, Malaysia in 1979. She received BSc in Electrical Power Engineering from the Universiti Tenaga Nasional (Uniten), Malaysia, and MSc in Electrical Power Engineering from the University of Manchester Institute of Science and Technology (UMIST) in 2002 and 2003 respectively. After completing her MSc degree, she worked with Motorola Technology Malaysia as an electronic engineer for two years and after that with Universiti Teknologi Mara (UiTM), Malaysia as a lecturer. In April 2008 she joined The University of Manchester, UK to pursue her PhD degree.

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Chapter 1 Introduction

Summary

This introductory chapter begins with a brief description of the restructured electricity supply industry compared to the previous largely vertically integrated centralised industry. Then it identifies the main drivers that contribute to the changes in the electricity supply industry. An overview of the new structure and the competition model, the dramatis personae and their specific roles are then presented. This chapter also discusses the challenges faced by the participants, particularly by the generating companies in this new competitive electricity market. Finally the scope and contribution of the research described in this thesis are identified and an outline of the thesis highlighting the main contents of each chapter is presented.

1.1 RESTRUCTURING OF THE ELECTRICITY SUPPLY INDUSTRY

For many years, the electricity supply industry was owned by vertically integrated monopoly utilities. During that time, there were three distinct components to this industry, i.e. generation, transmission and distribution which were typically tied together under the same management. Electrical energy generated by power plants was sent through high voltage transmission lines and distributed at lower voltage levels to the consumers. The introduction of competition in the electricity supply industry in the early 1980s changed this paradigm based on a centralized process into a competitive electricity market. The utilities who previously organized the generation and sale of electrical energy were broken up into independent entities, i.e. generating companies and retailers.

This reform of the electricity supply industry has taken place in many countries around the world. Some countries (such as Australia, Norway and the United Kingdom and several regions of the United States) are well advanced in this restructuring. However, many other countries are still in the design and early implementation stages. Each country has its own unique structure of power system organization that suits its economic, geographical, historical and political conditions.

1.1.1 Why Restructure? What Are the Drivers for Change?

There are three fundamental factors in society that drive the change in the electricity supply industry, i.e. economic, environmental, and technological. Cost efficiency is one of the economical drivers when people in the society become more sensitive to economics but demand a better quality of life. A monopoly electricity industry which has been in existence for a long time has less incentive to global welfare maximisation and may operate inefficiently and make unnecessary investments. These economic factors have created a demand for a more competitive market to bring down the cost of electricity. At the same time, consumers also expect that the quality and security of the supply will not deteriorate.

The increased public awareness of the environmental impact of energy production is the second factor for the change. This factor drives the society to be more innovative in the search and use of green technologies to generate electricity. Finally, the improved technological performance of peaking units, and the development of combined cycle gas turbines that have lower capital costs, shorter construction times and quicker payback periods has also had an effect on the development of electricity markets. Both the environmental and technological factors also lead to the diversification of generation technology in the restructured electricity industry.

1.1.2 Organization and Competition Model in the Restructured Electricity Supply Industry

The liberalisation of the electricity supply industry has led to a major reorganization of the industry. Since electricity is an essential good for the society, and has unique characteristics (continuous supply to meet demand, non-storable and large variations in the load), the process is very complex because it needs to consider the national energy strategies and policies, macroeconomic developments and national conditions [1]. It is important to understand that there is no ideal solution that is applicable to all countries. However the objective of restructuring is similar: to develop an organization that improves the economic efficiency of the industry.

Hunt and Shuttleworth in [2] have defined four models of competition spanning the evolution of the electricity supply industry from a regulated monopoly to full competition: monopoly, purchasing agency, wholesale competition and retail competition. However this thesis will discuss only the retail competition model where competition exists both at the generation and retail levels as shown in Figure 1-1. In this model, generating companies sell their electrical energy to the retailers through a wholesale market. Then the retailers re-price the electricity and sell it to consumers. This wholesale market can take the form of a pool market or of bilateral transactions. Since the competition also exists at the retail level, consumers can choose the supplier who offers the best price. The only functions that remain centralized are the operation of the spot market, and of the transmission and distribution networks.

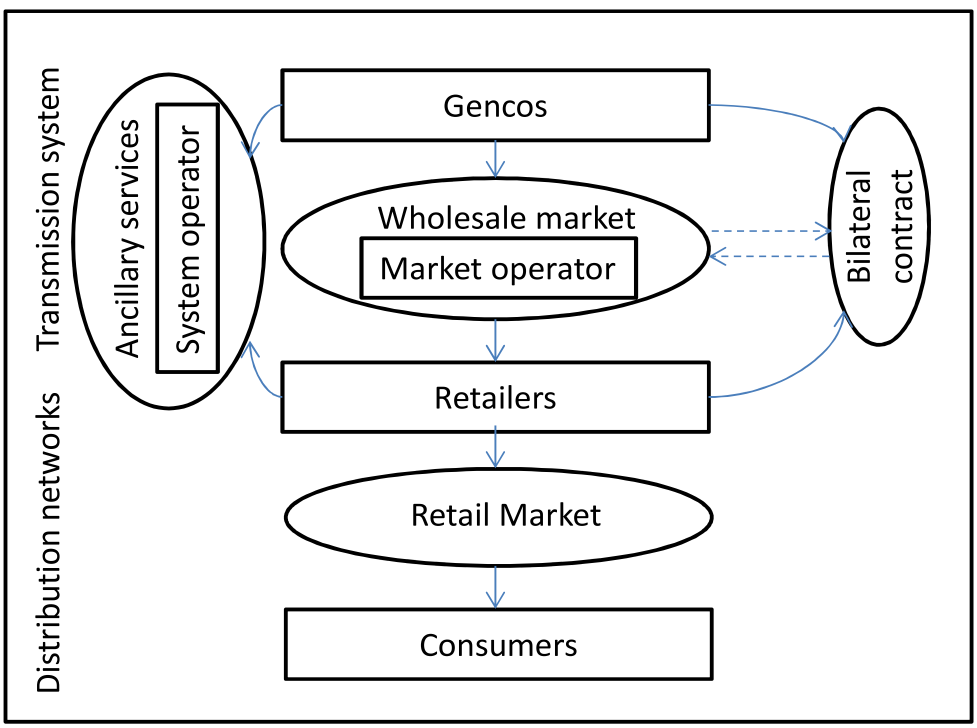


Figure 1-1 Retail competition model in the restructured electricity industry

The companies and organizations involved in this model are described below along with their specific roles.

Generating companies (gencos) produce and sell electrical energy. They bid their power generation into a market, either through an organized electricity market such as pool market or through bilateral contracts or trading. They may also provide reserves when it is needed by the system operator to maintain the security of the electricity supply.

Transmission companies (transcos) own the high voltage transmission grid in their region. They operate the network based on the instruction from independent system operator (ISO). To avoid duplicating huge investment and to maintain system security, transmission and distribution networks are a natural monopoly.

Distribution companies (discos) own and operate the low voltage distribution network. They provide access for the electricity to be delivered to the end users.

The *Independent System Operator (ISO)* plays an important role to balance the load and generation in a real time market under normal and contingency conditions. They are also responsible for maintaining the security of the power system by purchasing ancillary services from generating companies.

The *Market Operator (MO)* is in charge of market coordination by matching the bids and offers submitted by sellers and buyers in the wholesale market for the expected supply and demand. It is also responsible for the settlements of the accepted bids and offers following the delivery of electrical energy.

The *Retailers* buy energy at a variable price in the wholesale market and sale it to small consumers in the form of a tariff. This fixed price to consumers is adjusted at most a few times in a year.

1.1.3 Markets for Electrical Energy and Ancillary Services

A market is a public place (real or virtual) for buyers and sellers to interact and agree on their transactions. This activity can be performed directly between the two parties or indirectly through a power exchange. There are two types of electrical energy markets. Bilateral trading is a market that involves only two parties i.e. a buyer and a seller without interference from a third party. This kind of market is organized between the traders to manage risks associated with the volatility of electricity spot prices. In bilateral trading, the traders enter into a contract that specifies the price, the quantity and the delivery date of the electrical energy.

An electricity pool is another form of market which exists from the early days of the introduction of competition in the electricity supply industry. This market is operated in a centralized manner and provides a mechanism to find market equilibrium in a systematic way. In electricity pools, generating companies submit bids to a market operator to supply a certain amount of electrical energy at a certain time. These bids are then ranked in order of increasing prices. Using these bids, a supply curve is constructed showing the bid prices as a function of cumulative bid quantity. On the other hand, since the electricity demand is highly inelastic, the demand curve is usually assumed to be constant at the forecasted load. The demand curve is then a vertical line. The market equilibrium is the intersection of these two curves and defines the market clearing price. All the bids lower than or equal to the market clearing price are accepted and scheduled for production.

Both types of market operate in advance of the delivery date. This ranges from about a day ahead in the pool market to several years into the future for forward contract in bilateral trading.

However, according to [3], in practice, neither buyer nor seller can fulfil its contractual obligations perfectly. This is first because the electricity commodity exhibits large variations in demand. The actual demand is very unlikely be exactly equal to the forecasted load made earlier in the trading process. Second, unforeseeable technical problems often prevent generating companies from delivering the amount of energy that has been contracted. For these reasons, a managed spot market is needed to provide a mechanism to correct the imbalance between supply and demand. This market of last resort is the responsibility of the system operator, which uses it to match the residual demand by purchasing ancillary services from generating companies and curtailing the demand. Ancillary services are the services provided by generators besides electrical energy such as reserve capacity (spinning and supplementary reserves), load following, frequency and voltage regulation. Different market mechanisms exist for ancillary services, such as long term contract and spot trading for balancing energy. In the early days of electricity restructuring, the market of ancillary services was traded separately from the energy market. However economists agree that the provision of reserve cannot be decoupled from the procurement of electrical energy [3]. A joint market that simultaneously clears energy and reserve can, and probably should, be organized to minimize the overall cost of providing electrical energy and reserve while maintaining the security of the supply.

1.1.4 Capacity Mechanisms for System Adequacy

Regulators in some countries are concerned that the energy prices in the restructured electricity industry are not high or stable enough to convince companies to make enough investments in generation capacity [4]. Economic theory says that the spot market itself can provide enough incentive for investment in new generation [5], however this is not always the case in actual markets. The price spikes that occur in the spot market when the supply is short and which are supposed to provide a signal for investment are produced not only by the normal scarcity rent but by the ability of some of the generating companies to exert market power or practising hockey stick bidding, where participants in the market submit extremely high offers to raise the prices. This scarcity rent increases in the condition of a shortage in capacity producing excess profit that should cover the amortized costs, on the other hand an excess of capacity eliminates the scarcity rent, making it difficult for generators to recover their investment costs.

As a result, some regulators implement various mechanisms to provide additional payments to generating companies for the provision of capacity and hence maintain an adequate generation margin. Examples of such mechanisms include capacity payments such as the ones that existed under the now defunct Electricity Pool of England and Wales, and still exist in Spain and several Latin American countries. Under the capacity payment mechanism, generators receive a payment per MW as long as their generating units are available, whether they get dispatched or not. Another form of capacity incentive is capacity markets. In this mechanism, rather than pay for capacity on the basis of a price per MW set administratively, some regulatory authorities set a reserve target based on the reliability requirement and determine the amount of generation needed to achieve this target. All the entities (retailers and large consumers) that buy energy are obligated to buy a prescribed amount of capacity to meet the target reserve from an organized capacity market. This type of capacity mechanism has been implemented in the United States (example in the PJM, NYPP, NEPOOL markets).

1.1.5 Challenges of Power Generation Investment in Competitive Markets

Since the operation of the electricity market is relatively new in most countries, the participants in the restructured electricity industry are facing great challenges to adapt to this new context. Each company or organization experiences different challenges depending on its function in the market. For example, the biggest challenge for a regulator is to design a robust electricity market that is able to maintain the security of supply while keeping prices at an economically rational level. Generating companies must not only bid in a way that yields maximum profits but must also make wise investment decisions in this much riskier environment. On the other hand, the challenge for the transmission and distribution companies is to plan their expansion considering the uncertainty about the location and capacity of future generation. However, this thesis will focus particularly on the challenges that are faced by generating companies in making their investment decisions.

Prior to the restructuring of the electricity supply industry, all the costs of producing electricity were passed to the consumers under the form of fixed tariffs set by the utility. Investments were less risky as the investors were guaranteed a fixed return on their investment. Unexpected risks associated with the investment could be covered by increasing the prices to consumers. However, this is not the case in a competitive electricity market. The introduction of liberalisation exposes generating companies to various risks that might compromise their investment return. They are no longer guaranteed to recover their investment cost from the consumers. The future electricity prices are unpredictable and influenced by the many uncertainties that affect a competitive market. The decision to build a new power plant can be taken by any participating company in the market independently of what its competitors might decide to do. As a consequence, generation investment decisions in a restructured electricity market become more complex to model than in a traditional centralized industry. Since each generating company has limited information on its competitors' investment strategy, it has to anticipate what they might do in the future. Their investment decisions are influenced by and influence each other. Moreover, each generating company also has to forecast what is likely to happen over the lifetime of the investment plant in terms of demand, fuel cost and the bidding strategies of its competitors.

The various risks that affect generators in the restructured electricity supply industry affect generating companies' choice of technology for power generation. Technologies with higher investment costs but lower fuel costs are more affected by the risk of volatile prices, because there is less they can do to respond [6]. The uncertainty in future prices also exposes technologies that have a long construction time to additional risks. The cost of fuel is another significant risk for generators, particularly the technologies which have fuel cost as a main contribution to the total generating cost, for example technologies that use natural gas as a fuel. The regulatory risk can also be an important risk to the investor. For example the introduction of a carbon tax would increase the cost of coal and natural gas power plants. On the other hand, nuclear power plants are restricted in their emission of radioactive waste.

Modelling generation investment decisions in a market with a capacity mechanism is even more complex because the potential investor has to forecast the expected revenue that the new investment will generate not only from the energy market but also from the capacity mechanism and the interplay between the two prices. Furthermore the exact form of the capacity mechanism also has an effect on the investment decision and technology choice of generating companies.

The traditional approaches to estimate the profitability of a new power plant are no longer suitable in a competitive electricity market. A company which is comparing different power generation options needs to quantify and internalize the investment risks posed by different technologies into its investment decision-making. The investor needs an investment assessment model that is able to explicitly represent the market process, the interactions of generating companies in the market, the investment risks, the volatility of future demand and fuel prices, and also future expected generation capacity expansion and retirements. Furthermore, the model should also be able to show the interrelated dynamics of the spot prices and the investments under various market designs. This is important because all the factors mentioned above will affect the electricity prices, hence the profitability of the new investment and technology choice of a generating company.

1.2 SCOPE OF THE THESIS

As illustrated briefly above, the operation and development of a power system in a liberalised electricity supply industry are very complex. It is difficult to model all the challenges faced by the participants in a single computer program. Therefore, this thesis will focus only on the competition amongst generators as shown in Figure 1-1. Two main aspects will be examined in this thesis. First, the system is viewed as a whole and develops a generation expansion planning model where the competition between multiple generating companies is represented using agent-based modelling. In this model the interactions of these companies, who interact through the market to maximize their profit, are developed. Then, the way in which different scenarios in the market can trigger different degrees of investments is analysed. The interrelated dynamics of the energy prices and the investment decision of generating companies are also studied. The possibility that 'boom and bust' investment cycles, similar to those that have been experienced with other commodities, might emerge under different electricity market designs are also observed.

However, the agent-based simulation of generation expansion planning was not pursued much further because the study came to the conclusion that this type of simulation does not make much sense when considering investment decisions. This is because there are not enough opportunities for interactions and 'learning' between market players. Agent-based modelling is based on the premise that participants use a 'learning by doing' paradigm. However, generation expansion planning is more realistically described as 'learning by thinking'. In generation planning, investors will not wait and learn from the investment mistakes that they might have made before deciding to make a new investment.

For that reason, the study then moves to the second aspect which focuses on a single generating company and develops a more comprehensive approach of assessing an individual investment decision. In estimating the profitability of an investment, this model explicitly takes into account the dynamic of expected system changes in terms of generation expansion and retirement over the lifetime of the investment under evaluation. Two investment evaluation models will be presented within this framework. The first model proposes a probabilistic assessment technique to consider uncertainty in the load growth and the fuel cost using Monte Carlo simulation. A risk analysis is carried out to complement the comparison between two different investments.

The second model takes into account risk characteristics posed by different technologies into the investment evaluation model. The model also considers the behaviour of electricity prices such as in an oligopoly electricity market. This is because, in a competitive electricity market with a small number of firms dominating the market a generating company is facing an oligopoly rather than perfect competition [7]. The price in an oligopoly market is usually higher than the perfect competition as the participants in that market may collude to increase the prices hence favour the investment. Since the expected profitability of investment plant is closely depend on the shape of discretized load duration cure (LDC), an optimal step-function approximation to fit the LDC is presented. In the analysis, the effect of environmental regulations (carbon tax, nuclear waste fee, incentives for development of wind generation) and uncertainty in the technical and cost parameters on the profitability of different generation technologies are examined.

The second model is then extended to consider investment in a market with capacity incentive mechanisms i.e. capacity payment or capacity market. A sensitivity analysis is performed to see the effect of different types of capacity payments and various slopes of demand curve in a capacity market on the profitability of several investment alternatives.

In all the simulation models presented in this thesis, the generating companies make revenues by selling energy and providing spinning reserve. A co-optimization of energy and spinning reserve in a centralized electricity market is modelled to simultaneously clear the energy and reserve markets.

However, due to the limited amount of time available, some interesting topics have not been addressed in this thesis. For example participants in the market are only considered to interact in the pool but not in the bilateral trading. How the financial structure of the generating company might affect its investment decisions is also not considered. Furthermore, it is assumed that the generating company has access to sufficient capital for all investment options. This thesis also did not take into account the taxes that might influence the profitability of the investment. The retirement of generating units is not treated as a strategic decision variable that is part of a generating company's business strategy. Instead, generating units are assumed to be retired when they reach their expected technical lifetime. Transmission and distribution constraints are ignored, even though they can affect the prices at constrained locations in the grid. However, the decision framework presented in this thesis is sufficiently flexible and open that it could be extended in the future to consider some of the aspects that are not included in this thesis.

In summary, this thesis addresses five main objectives:

1. To model generation expansion planning using an agent-based modelling framework that is able to represent the interaction between the generating companies and its effect on the dynamic of system expansion, as well as to study the influence of investment signals on the investment decision of generating companies

2. To develop a realistic investment model that can be used to evaluate different power generation technologies considering risks and uncertainties

3. To take into account the prices in oligopoly market which is usually higher than the perfect competition market in assessing generation investments

4. To model capacity payments or capacity markets in these assessments and to study their impacts on the system and the profitability of the investment technologies

5. To study how sensitive these results are to the unavoidable uncertainties on the various parameters of the models.

1.3 THESIS CONTRIBUTION

The main contribution of this thesis is that it provides a realistic framework for generating companies to make investment decisions and for system regulators to study power investments in a liberalised electricity market. This is possible due to its explicit representation of the elements in the models and the process involved in generation investment activity in the market. Furthermore, this thesis uses a multi-disciplinary approach combining economic theory, agent-based modelling from computer science, dynamic programming and probabilistic analysis from mathematics, and risk analysis from financial theory, hence brings a different original contribution to the state of the art.

The long-term generation expansion model in a restructured electricity industry using agent-based modelling provides system regulators a model that can be used to assess the performance of market design in ensuring adequate generation in the long-term. This bottom up approach is also useful to study the investment strategy of generating companies, the interactions between them, hence their impact on the system expansion.

The probabilistic assessment model for a generating company to value an investment under uncertainties provides a framework that is able to incorporate risk assessment analysis in the evaluation. This analysis is useful for generating companies to compare different investments taking into account the riskiness of the project. On the other hand, the investment evaluation model in an oligopoly electricity market enables generating companies to value their investment under realistic electricity prices. This model which also considers the risk characteristics of various power generation technologies in the financial model helps investors to quantify the risks of different technologies.

Finally, the extension of the generation investment evaluation model in an oligopoly market to include capacity payment or capacity market allows generating companies to estimate the revenue that the new investment will make from both the energy market and the capacity mechanism.

1.4 OUTLINE OF THE THESIS

Chapter 2: Generation Expansion Modelling Techniques in Liberalised Electricity Market

In this chapter generation expansion planning approaches and investment assessment models that have been developed by other researchers are reviewed. Other techniques that are used to support the modelling of generation expansion under uncertainties are also discussed. The approaches proposed in this thesis to model generation expansion planning and assessing generation investment in a competitive electricity industry are described and compared with the previous works.

Chapter 3: Analysis of Long-Term Generation Expansion Planning in a Restructured Electricity Supply Industry Using Agent-Based Modelling

This chapter presents a long-term generation expansion planning framework where generating companies make investment decisions in a market environment taking into account their competitors' strategic investment and the complex interactions among them. Factors that contribute to the dynamic of the investments such as imperfect foresight of generating company in forecasting the price and delay in the construction of the new plants [5] are included in the model. The effects of several capacity incentive mechanisms such as energy-only market, capacity payment and capacity market on the investment decision of generating company and the dynamic cycle of the investments are also analysed.

Chapter 4: Valuation Model for Generation Investment in Liberalised Electricity Market

This chapter is devoted to a new explicit approach for a generating company to evaluate investments in a liberalised electricity market. The investment framework consists of two levels of investment problems. The upper problem is an optimization problem which models the expected future investments and retirements from all the companies in the market. The lower problem corresponds to the profit evaluation of the new investment plant against the expected future system expansion obtained in the upper problem. Two investment models have been developed within this framework. The first model uses a probabilistic approach to assess investments considering uncertainties. The second model is developed to evaluate investment in an oligopoly market considering various risk characteristics of different power generation technologies. Using sensitivity analysis, the effects of uncertainty in the regulatory risks, environmental constraints and various technical and cost parameters of the new investment on its profitability are examined.

Chapter 5: Generation Investment Evaluation Model in Oligopoly Market with Capacity Mechanisms

Chapter 5 presents an extension of the proposed investment evaluation model from Chapter 4 to consider capacity mechanisms in an oligopoly electricity market. Two types of capacity mechanisms are presented, i.e. capacity payment and capacity market. Analyses have been carried out to explore the effects of different capacity payments and various demand curves in the capacity market on the profitability of the investment technologies as well as on the system as a whole.

Chapter 6: Conclusions and Suggestions for Further Research

This chapter summarizes the main achievement of this research. It also discusses and suggests some potentially interesting directions for future research in this general area.

Appendices

A number of appendices to complement the presentation of this thesis are included. Appendix A presents the data for the test system used in the analyses and Appendix B presents the formulation of optimal step-function approximation of load duration curve.

Chapter 2 Generation Expansion Modelling Techniques in Liberalised Electricity Markets

Summary

This chapter presents the approaches that are presented in the literature to model generation expansion planning in liberalised electricity markets. The classification of these approaches is made considering: 1) generation expansion models that are developed from the system perspective and 2) models that focus on individual companies in formulating long-term expansion planning or evaluating an investment. Other techniques that are used to support the modelling of generation expansion in the context of modelling the electricity price and managing risk under uncertainty are also discussed. The models that are developed in the literature to study the influence of capacity mechanism in the investment decision and power system are then presented. Finally, the approaches proposed in this thesis to model generation expansion planning and to evaluate an investment under different market designs are described.

2.1 THE EMERGENCE OF VARIOUS GENERATION EXPANSION TECHNIQUES IN LIBERALISED ELECTRICITY MARKETS

Anna Ku [8] in her PhD thesis states that generation expansion planning is influenced by three types of investment decisions: 1) the choice of technology, 2) the capacity of the plant and 3) the suitable time for making the expansion. The choice of technology depends on the financial risk posed by the different technologies such as the technical and cost characteristics, the economic life time, the construction time and the fuel cost. On the other hand, the capacity and the time to build are influenced by projections about the demand growth, the retirement of existing plants in the system, the installed capacity, the forecasted future market price and the expansion decision of other generating companies. The results of generation expansion planning are the schedule of investments that indicates the time of building a new plant, retiring old and non-profitable plants and the possible mothballing of existing plants over a long planning horizon. It can also be described as a process where the generating company makes a choice over known technologies for new plants, after evaluating the expected benefit of the investment on their profitability.

Modelling generation expansion planning in a restructured electricity supply industry is more complex than in the traditional problem. This is because of the different generating companies competing with each other to maximise their profits and the need to model the interactions between these conflicting objectives. A decision to build a new plant can be taken by any company that participates in the market. Since there is no central decision, the expansion decision involves more uncertainties. Apart from the generating company, the regulatory body also faces major challenges in liberalised markets because it may view the electrical planning objectives from a different perspective. The regulator plays an important role in maintaining system reliability, stabilising the market by preventing under- or over-capacity investment and designing incentive mechanisms to promote the development of an adequate generation system, while generating companies are only concerned about making more money. Furthermore, it is not yet clears whether the expansion of generation capacity will take place in an orderly fashion or whether ‘boom and bust’ cycles may arise as has been observed in other markets. This cyclical behaviour of investments is not only a threat for the regulator but also for the generating companies as the cycles will lead to uncertain prices and hence unstable profits for the companies.

The traditional generation expansion planning approaches are not able to represent the complex phenomenon that arises in liberalised markets. Therefore some models have been developed and published to solve the issues related to the generation expansion problem. In this thesis, the reviewed literature is classified into two groups:

1. Generation expansion models that consist of multiple players in the market and represent the whole system expansion. This model is usually developed to analyse the dynamics of generation investments and the oligopolistic behaviour of participants in the market.

2. Models that focus on the investments of a single generating company. This model is developed for the company to formulate an optimal long-term expansion plan, to develop an optimal portfolio allocation and to determine the profitability and optimal timing of an investment.

Since modelling generation expansion and assessing an investment requires information about future electricity prices, some techniques have also been proposed to forecast these prices. The volatility of the prices and the nature of power generation investments, which require large amounts of capital, create a risky environment and have led to the development of some risk management techniques to support the modelling of generation expansion under uncertainty.

Figure 2-1 shows the organization of the literature review presented in this chapter. The generation expansion models are grouped into two issues according to the classification mentioned earlier i.e. 1) models of system generation expansion and 2) models for individual companies. Three main techniques that have been described in the literature to model generation expansion planning considering all the companies in the market are Game theory, System dynamics and Agent-based modelling. On the other hand, models that represent a single company can be divided into long-term optimal planning and techniques for project valuation such as traditional levelised cost, and to consider uncertainty such as probabilistic analysis and real option theory.

Electricity market models are required in generation expansion planning to model the activities of the participants and to calculate the electricity prices. Extensive studies have been found in the literature to study the behaviour of the participants in oligopoly markets and its effect on market prices. Other issues related to the implementation of capacity mechanisms such as energy-only market, capacity payment and capacity market, and their influence on generation expansion planning and investment decisions are also a major topic that has been discussed in the literature. When estimating the profitability of an investment, some researchers model future market prices as exogenous variables, while others represent the prices as a function of demand and installed capacity in the system. In order to assist generating companies in dealing with uncertainties, some risk assessment techniques have also been adopted in the literature.

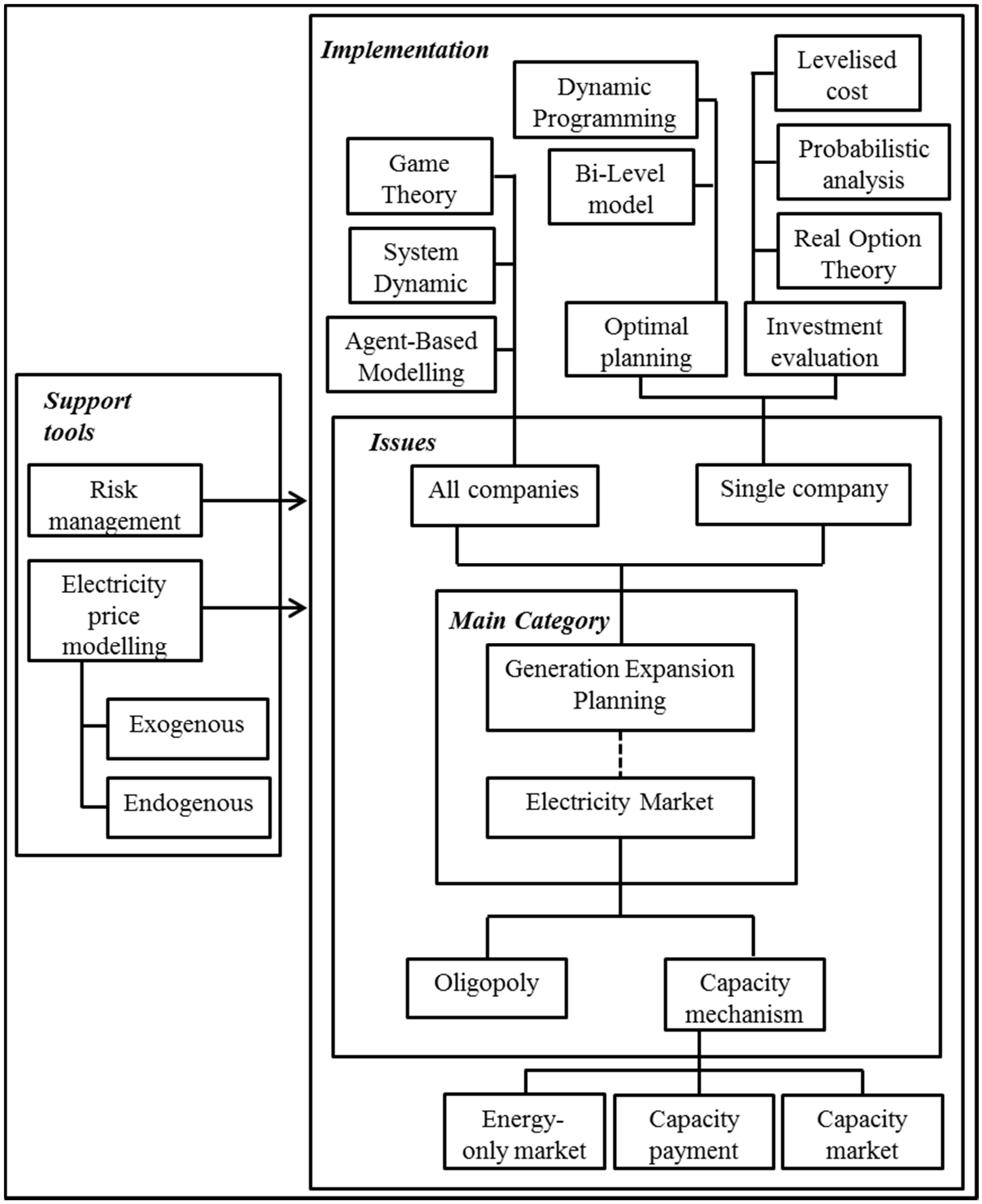


Figure 2-1 Schematic representation of the literature on generation expansion planning and related topics

2.2 TECHNIQUES TO MODEL SYSTEM GENERATION EXPANSION PLANNING

Models to represent generation investment activities in liberalised markets have been developed since the beginning of the restructuring of the electricity supply industry. Three main techniques that are usually presented in the literature to model generation expansion planning in the system are: 1) Game theory, 2) System dynamics and 3) Agent-based modelling.

2.2.1 Game Theory

Game theory has been widely used to model oligopolistic competition in microeconomic theory. This technique models mathematically the strategic interactions of the participants in the market, where each decision of a company is interrelated with the decisions of the other companies. In this game, the model attempts to find an equilibrium point where at the equilibrium (the Nash Equilibrium), none of the companies will get further benefit from changing its strategy. In game theory, there are three decision variables that are commonly used to determine the investment, i.e. the price in Bertrand competition, the quantity in Cournot competition and the relation between price and quantity in Supply Function Equilibrium. The application of the game theory in the context of generation expansion planning was pioneered by [9] who compares three different competitive game scenarios: 1) each company acts independently to maximize its profits (Cournot competition), 2) all companies collude to maximize profits (Cartel) and 3) a single player competes against a coalition of the remaining players (Cournot duopoly). Murphy and Smeers in [10] present three competition models: 1) perfect competitive market, 2) open-loop Cournot game where commitments are simultaneously made on investments and sales contracts with Power Purchase Agreement and 3) closed-loop Cournot game where investments are decided in the first stage and sales in a spot market are carried out in the second stage. The authors of [11] compare the Cournot game with a Stackelberg game where in the Stackelberg model there is a leader firm that first decides its optimal capacity and is then followed by the other firms. However the capacity expansion equilibrium models described above do not evolve over time.

Centeno et al. in [12] present a long-term generation expansion model based on two stages Cournot market equilibrium. The authors of [13] tackle the continuous Cournot equilibrium problem considering a discrete dynamic generation expansion model exploring the whole planning horizon. Gilotte and Finon in [14] present an open-loop Cournot model as in [10] but consider a long expansion horizon (30 years) and the interdependency between existing capacities and investments. Tesser and Nabona in [15] model an open-loop dynamic game but the evolution of competitors' decision is not considered by the generating companies and [16] with a 3-tier matrix game model to solve a multi-year and multi-player generation expansion planning.

Although game theory has been extensively used in the literature for modelling competition in liberalised markets, the problem of dimensionality for N-player applications still exists [17]. A static model where the expansion decision is not influenced by the installed capacity has the advantage of being able to model a bigger problem. It is, however, more suitable for short and medium planning problem. For these reasons, game theory is not considered in modelling generation expansion in this thesis. Game theory has also been used to study how generating companies can raise prices in an oligopoly electricity market. More literatures related to this issue will be described in Chapter 4.

2.2.2 System Dynamics

The system dynamic technique is useful and widely used to model long-term generation expansion planning in liberalised markets. This methodology is used to frame a complex process and to understand the behaviour of complex systems over time. Its main characteristic lies in the way it can represent internal feedback loops and time delays that affect the dynamic behaviour of the system. Andrew Ford uses system dynamics to study the dynamic pattern of building power plants in the western United States electricity market. In the study, he argues that the competitive electricity markets are prone to boom and bust cycles similar to those that have been observed in other markets. Ford also argues that a generating company's imperfect anticipation of the future market situation and the delays in permit approval and construction are the key factors that lead to cyclic investment patterns. The articles by Andrew Ford in this area can be found in [18-20]. Sanchez [21] also proposes a system dynamic model to model the long-term generation expansion planning. However an improvement is made to differentiate the companies' expected profitability by combining system dynamics with credit risk theory. On the other hand [22] focuses on the causal relationship that determines the choice of technology and [23] studies the effect of placing three different constraints i.e. 1) reducing gas plants quota in system planning, 2) setting tax for gas and 3) providing subsidies to wind power generation for generation expansion on the development of gas power plants. A stochastic system dynamic technique is presented in [24] where the uncertainty in demand growth is modelled using a mean-reverting process.

The concept of system dynamics is based on top-down approach where the overview of the system is first presented, then the fundamental elements in the models is specified but not in detail. For that reason it is less favourable to be adopted in this thesis which focuses on developing an explicit decision process of generating company in the market.

2.2.3 Agent-Based Modelling

Agent-based modelling is a computational technique for simulating the actions and interactions of autonomous agents in a complex system. In agent-based modelling, each agent assesses its situation in the environment and makes decisions to achieve its target using a set of rules. In generation expansion planning, the agents are generating companies who are seeking a better strategy in the market to maximize their profits. These agents are reactive, proactive and have social abilities that allow them to interact with other agents and their environment in making decisions. Like the system dynamic approach, agent-based modelling can be used to model the dynamic nature of long-term generation expansion planning by incorporating delays and representing causal relationships. In contrast to the top-down approach taken by system dynamics in modelling complex systems, agent-based modelling uses a bottom-up approach in which the individual elements of the system are first defined in an explicit way and then linked together to form a larger system. Moreover, agent-based modelling provides agents the ability to learn from the past and modify their strategy in the future. With regards to the drawback of game theory that only can represent a small size problem, the agent-based modelling offers the possibility to solve larger problems. These characteristics make agent-based modelling more suitable to represent the complexity of generation expansion planning in liberalised markets and have therefore been considered in this thesis.

Agent-based modelling has been widely applied in modelling and analysing the performance of electricity market which will be discussed in Chapter 3. However, very limited literature can be found on its application to representing long-term generation expansion planning in liberalised markets. Works available in the open literature include the model developed by Argonne National Laboratory [25] and The University of Manchester [26]. The generation expansion model developed by [25] takes into account two stages: 1) the stage where each generating company forecasts the expected profit of its investment and 2) the stage where the actual market clearing is performed after all the companies have made their investment decisions. However, capacity mechanisms are not considered in the analysis. On the other hand, the model proposed by [26] analyses the effect of capacity mechanisms on investment decisions; however the effect of the investment decisions by all the companies on the actual market is not modelled. The agent-based generation expansion planning proposed in this thesis considers these two elements. A detailed description and comparison of the work by [25, 26] and the agent-based generation expansion planning developed in this thesis will be presented in Chapter 3.

2.3 GENERATION EXPANSION TECHNIQUES FOR A SINGLE GENERATING COMPANY

The techniques that focus on a single generating company can be categorized into: 1) studies that represent optimal expansion over a planning horizon and 2) techniques to assess the profitability and optimal timing of an investment for decision-making. The author of [27] proposes a method for optimal long-term expansion planning by a single company using Dynamic Programming. A similar objective as in [27] is addressed in [28] using a Bi-level model. Yin et al. in [29] propose a model for long-term and short-term optimal portfolio allocation in the market using a Differential Evolution algorithm.

Three techniques that are often used to evaluate an investment in the literature are: 1) time value of money and levelised cost methodology, 2) probabilistic analysis and 3) real option theory.

2.3.1 Time Value of Money and Levelised Cost Methodology

Since investing in a new power plant involves commitment of large capital for an extended period of time, financial techniques such as net present value (NPV), future worth value (FWV) and internal rate of return (IRR) that represent the time value of money have been used extensively in the literature to appraise long-term power plant projects. The time value of money refers to the concept that a dollar today is worth more than a dollar in the future because of the interest or profit that it can earn. The NPV and the FWV convert the expected future cash-flow from the project into their equivalent worth at present time (NPV) and future time (FWV) using an interest rate known as minimum acceptable rate of return (MARR). On the other hand the IRR computes the returns of the investment assuming that the NPV is equal to zero and compares it with the MARR.

The levelised cost methodology has been a useful costing method for comparing investments in different generation technologies. It represents the present value of building and operating a generating plant divided by the plant's expected energy production over its lifetime. This approach has been used by the IEA [30] to study the factors affecting the economics of generation technologies. However this technique alone does not provide the investors with an analytical method that can measure the riskiness of an investment under uncertainty. Therefore, it needs to be complemented by approaches that account for risks and uncertainty.

Since investing in a power generation requires a long period of time, the financial technique to consider the time value of money is still a useful technique to assess an investment hence is used in this thesis; however the implementation is extended to consider risk assessments under various uncertainties.

2.3.2 Probabilistic Analysis

The introduction of probabilistic analysis extends the classic economic theory to take into account the risk and uncertainty in valuing an investment plant. In this technique, the input parameters to the financial model are defined as statistical distributions to represent uncertainties. A Monte-Carlo simulation can be used to determine the profitability distribution of an investment. This technique provides a generating company with a wider analytical framework for assessing an investment while considering the risk. The authors of [31] use probabilistic analysis to compare three base-load technologies i.e. nuclear, coal and combined cycle gas turbine (CCGT). Reference [32] uses a Probabilistic Production Simulation algorithm considering uncertainty in market prices. The authors of [33] model uncertainty in fuel and carbon prices and study the impact on the expected generation cost of coal-fired generation, CCGTs and open cycle gas turbines (OCGT). On the other hand, a stochastic dominance relationship between the distributions is applied in [34]. Feretic and Tomsic in [35] introduce the concept of probability to calculate the levelised cost of different power plant technologies considering uncertainty.

The probabilistic investment evaluation model in this thesis models the uncertainty in load growth and fuel costs as a Gaussian distribution function. The time value of money approach combined with the probabilistic technique is developed to capture the rate of return distribution of an investment.

2.3.3 Real Option Theory

Real option theory is a technique that has been developed recently to overcome the drawback of static classical economic theory that is claimed fails to incorporate the management flexibility and uncertainty in the evaluation process. In real option theory the new investment is regarded as an option. The possible options include the options to defer the project, to expand, to abandon and to alter the operating schedule. With these managerial options, the investor has the opportunity to invest strategically in the event of favourable investment conditions.

The authors of [36] present a comparison between the classic NPV and the real option approach for power generation investment. They argue that managerial flexibility in real option would give positive value to a project than the NPV approach. The authors of [37] model real options using Binomial Lattice for two interrelated generating units. [38] examines the effect of two different stochastic price models on the optimal investment in a power plant, where the real option is modelled using differential equations. [39] extends the real option based on the Binomial Lattice approach to consider multiple options. However the works presented above model the electricity prices as exogenous variables. The authors of [40] use stochastic dynamic programming to analyse the value of waiting and calculate the electricity prices endogenously in the model. On the other hand [41, 42] extend the NPV methodology to consider real option valuation.

Nevertheless, the real option technique has two drawbacks: 1) its implementation requires a high level of technical simplification in representing a power plant as a financial asset, and 2) the representation of electricity prices as exogenous stochastic variables may not be realistic [21].

2.4 MODELIING PRICES IN LIBERALISED MARKETS

To evaluate an investment in a liberalised market one must carefully consider the dynamic of the electricity prices as they will affect the expected profitability of the investment under consideration. Different approaches have been proposed in the literature to model the electricity prices. These approaches can be classified into three groups as shown in Figure 2-2. This classification is based on the scheme presented in [43]. However the literatures discussed here also include some more recent techniques. The model approaches are grouped into:

1. Optimization and investment valuation models for a generating company
2. Market equilibrium using game theory considering all the companies in the system
3. Simulation models with a complex representation of the power system.

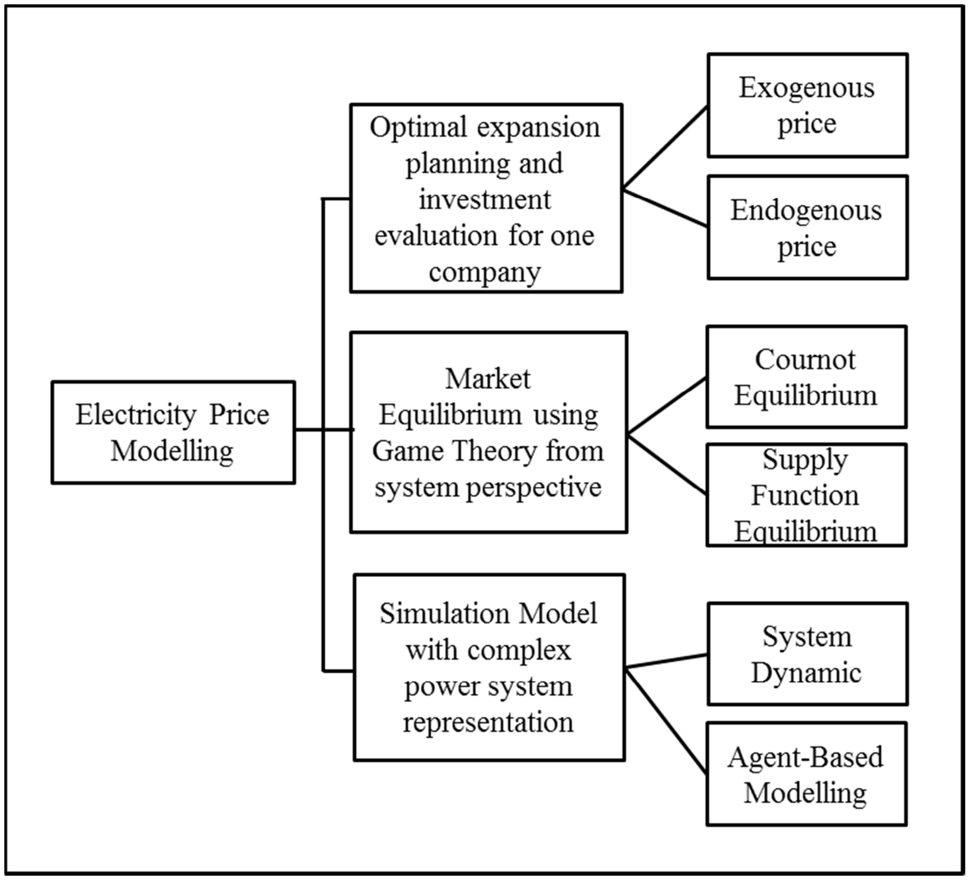


Figure 2-2 Classification of price modelling techniques in the literature based on Ventosa et al. [43]

2.4.1 Optimization and Valuation Model for a Generating Company

In the context of optimizing generation expansion and assessing an investment for a single generating company, two trends in price modelling have been observed in the literature. The first approach consists in treating the price as an exogenous variable that is calculated outside the model and is not affected by the factors in the model. For example, [31, 32] model the electricity price as a normal distribution with a specified mean and standard deviation in their probabilistic assessment model. On the other hand, [38] models the electricity price fluctuation by a mean reverting process and [37] by a geometric Brownian motion in their real option valuation model. Zhe Lu et al. in [36] assumed a fixed electricity price in the classical NPV and NPV with real option.

In the second approach the price is an endogenous variable which is calculated as a function of the demand, the installed capacity and the bid prices of the units in the system. For example, the electricity price in the spot market is obtained by the intersection of the demand and the supply curve in [27], where the market is represented by a multi-agent system and the competitors' bidding strategy is modelled using a conjectural variation model. Unlike the real option approach in [37, 38], Botterud and Korpas in [40] model the electricity prices endogenously considering the expected demand and installed capacity in the system. Meanwhile, the effect of the competitors' investments is considered by adding a price cap in the sense that their investments will reduce the prices in the market hence the profit of the company that is evaluating an investment. On the other hand, Yong Wang et al. [44] model the relationship between the electricity prices and the system installed capacity as a cubic function using historical data from PJM electricity market.

However none of the works described above explicitly modelled the future electricity prices as a function of available technologies in the system resulting from investment strategy of all generating companies in the market under various uncertainties. This will be the focus of the investment evaluation model proposed in this thesis.

2.4.2 Market Equilibrium Using Game Theory

The two types of market equilibrium that are commonly used in the literature to represent competition in liberalised markets are the Cournot model and the Supply Function model. In the Cournot model, where the firms compete on quantity, the equilibrium price is determined by the demand function and is set at a level where demand is equal to the quantity produced by all the companies. Since the company strategy in Cournot model is only based on the quantity, the equilibrium price is very dependent on the demand representation and usually higher than in the real market [43]. This drawback is tackled by the introduction of the Supply Function model where the competition is based on both quantity and price i.e. the offer curve of each firm. This is usually considered a better, but more complex, approach to representing competition in liberalised markets [45]. However the mathematical structure of the

Supply Function which is characterized by a set of differential equations makes it difficult to solve compared to the Cournot model [43].

2.4.3 Simulation Models

Approaches that represent the complex process of generation expansion, such as system dynamics and agent-based modelling, are grouped under the simulation model category. In system dynamics, the relationship between electricity prices and other factors that influence the price is expressed using a causal loop diagram. The electricity prices are represented with a positive influence from the demand (exogenous variable); where under the condition of a higher demand, a higher electricity price will be observed. On the other hand total capacity in the system is modelled as a negative feedback to the prices; in the sense that when the total capacity in the system decreases, the prices increase. Most of the studies on generation expansions using system dynamics have a common representation of the power system; however [22] improves the representation of electricity demand by introducing feedback from the price to demand. Unlike system dynamics where the prices are modelled by the causal relationship, the electricity prices in an agent-based model can be computed by explicitly modelling the market clearing process taking into account the decision and the interaction of the agents in the market such as in [26]. On the other hand the authors of [25] model the prices in their multi-agent simulation model using a probabilistic dispatch algorithm.

2.5 RISK MANAGEMENT TECHNIQUES

The high volatility of electricity prices in the market has prompted the study of how various risk assessment and management techniques could be used to mitigate the risks in generation investments. These techniques are proposed to complement the investment evaluation model to value the investments under uncertainty. One of the techniques is mean variance optimization. This technique was proposed by [46]. This tool is developed for the company to optimally allocate the investments in order to maximize its return subject to several risks. The approach allows the company to make decisions regarding the allocation of its resources considering the trade-off between return and risk, where variance is used as a risk measure. [47] has adopted this approach for portfolio optimization in power systems.

Another technique for risk assessment is sensitivity analysis. This technique is used for examining risks where the variation of the output can be characterized by changing the input variables in the model. Performing a sensitivity analysis on different investment technologies requires a model that can internalise the risks associated with the technologies. The authors of [31] uses sensitivity analysis to identify the key parameters to be modelled by probability distribution in comparing the profit distribution of nuclear, coal and CCGT. This approach has also been adopted in this thesis to study the effect of uncertainty of various parameters in the models on the profitability of different technologies.

An approach proposed recently by [48] has become a popular tool in generation investment analysis. Value at Risk (VaR) and its improved for, conditional value at risk (CVAR), are widely used risk measures in financial theory to calculate the probability of losses based on statistical analysis. VaR is defined as the maximum amount that an investment may possibly lose at a specified probability known as the confidence level, over a given period of time. CVaR measures how bad it could be when the loss exceeds the VaR. The VaR is a coherent measure only when the underlying probability distribution of the loss is a normal distribution function [49], on the other hand CVaR is always a coherent measure. For that reason CVaR has been accepted as the standard tool for measuring risk. A series of VaR and CVaR with respect to different payoff confident levels of a generating company are obtained in [50] to manage the risk of a project. The authors of [15] use CVaR to represent risk-averse generating companies in an equilibrium model for medium-term generation planning. On the other hand [51] uses it to find bidding prices in an auction for long-term electricity contracts. Similar to the approach presented in [51], instead of finding the VaR at a specified confidence level, the probabilistic model in this thesis calculates the expected confidence level of investing in a power plant by setting the VaR at MARR.

2.6 MODELLING CAPACITY MECHANISM IN THE MARKET

Some studies have been conducted to study and compare the effectiveness of several capacity mechanisms such as energy-only market, capacity payment and capacity market in promoting generation investments as well as to propose a better mechanism. [5] discusses alternative approaches to capacity mechanisms and argues that an energy-only market with premium call options is the best way to meet the system adequacy requirements. [52] discusses the uses and abuses of capacity payments and recommends mechanisms that incorporate consumers' participation as a better way of improving reliability. [53] compares the design of capacity payment and capacity market in several countries while [54] and [55] examine the installed capacity market (ICAP) reform in the United States. However the literatures described above discuss and compare the mechanisms in a qualitative way.

The authors of [56] quantitatively study the dynamic capacity payment applied in the old power pool of England and Wales. The investment model is developed using system dynamics. They assumed that the investment decisions are influenced by capacity payment and the fixed cost of new generating unit. Results show that the capacity payment hence the investment is more sensitive to the LOLP than VOLL. In the analysis, they found that the cycles of investment are very much dependent on the generating company's foresight about future demand, supply and market price. They also argue that the LOLP function in the model needs to be improved in term of its explicit relationship to the evolution of capacity mix before it could be used to provide more accurate policy analyses. The author of [57] also uses system dynamics to simulate the construction cycles of power generation in the western United States. Investments are considered if a forecasted spot price is higher than the total levelised cost of new power plants. In the simulation, it is shown that fixed capacity payment helps to dampen the investment cycles. Visudhipan et al. in [58] present a dynamic investment model considering two scenarios: 1) A system comprising a spot market and a forward market and 2) A system comprising a spot market and an ICAP market. The backward (historic price) or forward (future price) is used to determine the investment decision variable. In the analysis, they argue that the future market provides timely information on the potential value of new investments. In contrast, the ICAP market signals for investment can be rather distorting and misleading. However investment decisions in the ICAP scenario are modelled as a function of

ICAP price only, but not the interrelation between the spot price and the ICAP price. De Vries in [59] takes into account the price relationship between the two markets in his simulation model. The study focuses on the effect of several capacity mechanisms in Netherland's power system. He concludes that the capacity mechanisms that administrate the capacity of generation required in the system are more effective than those that use price incentives in promoting investment. Researches that concentrate on the PJM capacity market are given by [60, 61]. A simple dynamic model that could represent the effects of the PJM demand curve on the reserve margin, generator profitability and consumer cost are presented. From the analysis, [60] argues that a sloping demand curve could reduce the risk to investors and simultaneously lower the cost to consumers as well as increase the investments. [61] extends the analysis to consider the demand curve adjustments that are implemented in the real PJM market and suggests that these adjustments provide a higher system reserve margin and lower consumer payments.

The literature described above models power generation investments as an aggregate point of view and studies the effect of capacity mechanisms on system adequacy. The studies do not focus explicitly on how individual generating companies formulate an investment strategy under the market with capacity mechanism. [62] calculates the optimal investment strategies of a generating company under centralised and decentralised electricity industries using real option approach. Analysis shows that a price cap set below the value of loss load will result in further postponement of investment decisions. The introduction of capacity payments in the model induces earlier investment. The analysis is extended in [40] to calculate the optimal timing of investment in a new power plant in a Nordic electricity market. Comparing two different types of capacity mechanisms (i.e. fixed and variable capacity payments), they conclude that the variable capacity payment contributes to an increase in the uncertainty and hence increases the value of waiting and the expected profit. The authors of [63] also model the optimal investment decisions based on the real option approach. In the model, the capacity payment is assumed constant over the planning horizon. On the other hand, the ICAP price as a function of installed capacity is modelled as a quadratic equation using historical price data from the PJM electricity market. In the analysis, they argue that a capacity market could be more effective at reflecting the generation capacity adequacy hence provide a greater reliability level than capacity payment.

Other capacity mechanisms have also been proposed, such as reliability options by [64] where reliability contracts based on financial call options are auctioned through a competitive framework. [5] and [65] also propose a similar approach. [66] proposes a new mechanism called capacity subscription. This mechanism is based on a self-rationing concept that requires customers to subscribe for capacity during system peak conditions. [67] proposes operating reserve pricing for system operators to ensure adequate capacity in the system. In this approach, the system operator buys operating reserve capacity and determines the price of this reserve in the spot market. [68] examines and proposes possible improvements to the Greek Capacity Adequacy Mechanism.

In reality the prices of capacity mechanisms are not only dependent on the reserve capacity in the system but are also influenced by the technology mix resulting from investment strategy of all the generating companies in the market. For example, the LOLP calculation used in the formulation of capacity payment price is closely related to the available technologies in the system. On the other hand, the price of the capacity market is dependent on the bidding price of the technologies. None of the works discussed above models the capacity mechanisms as a function of available technologies in the system. This aspect is considered in this thesis in modelling capacity mechanisms in a liberalised electricity market.

2.7 GENERATION EXPANSION MODELS IN THIS THESIS

In order to consider and study the various factors that could affect the dynamic behaviour of power systems and the profitability of the investments, the complexity of the market and the investment decision process of the generating company are explicitly modelled in this thesis. This requires a combination of some techniques that stem from various other approaches. The generation expansion and investment evaluation models proposed in this thesis are thus a blend of some techniques that are presented in the literature. This section describes the approaches used in the models identifying the gap that they attempt to address.

2.7.1 Chapter 3: Long-term Generation Expansion Planning Using Agent-Based Modelling

In Chapter 3, agent-based modelling is chosen for developing a long-term generation expansion planning model which consists of several agents i.e. generating companies competing in the market to maximize their profit. This is due to the characteristic of agent-based modelling that allows the explicit representation of the generating companies' interactions and the activities in the power market. The market clearing process is modelled as an optimization process to simultaneously clear the energy and spinning reserve market in a way that minimizes the total yearly operating cost. The prices resulting from the market clearing are a function of demand, installed capacity, bidding prices and investment strategy of the generating companies in the market. In the investment evaluation process, the competitors' expected investments are modelled using a scenario tree. Given the long-term nature of the investment in power generation, the discounted cash-flow methodology is an effective technique to estimate the attractiveness of an investment opportunity, and is therefore used in the model. The descriptive aspect and explicit representation of the fundamental elements in the agent-based expansion model make it possible to incorporate delays in the construction of new power plants to simulate the dynamic behaviour of investments and to include regulatory policy such as capacity mechanism in the market. Unlike the literature previously described in modelling the dynamic spot prices and the capacity mechanism prices, the agent-based generation expansion model in this thesis takes a step insight to also model these prices as a function of available power plant technologies in the system.

2.7.2 Chapter 4: Valuation Model for Generation Investment in a Liberalised Electricity Market

In Chapter 4, two different models for a single generating company to evaluate an investment are presented. The models are rooted in a basic investment evaluation framework that consists of two stages. This basic framework combines the two perspectives described earlier when classifying the generation expansion modelling techniques in the literature i.e. from the system and the individual company's perspective. The first stage of the basic framework is the expected future investment and retirement from all the companies in the system (i.e. the system perspective) each year over the lifetime of the investment that the company is evaluating, which is referred to as the 'prototype future system expansion' in this thesis. This optimal prototype plan is defined using dynamic programming to minimize the total cost of system expansion. The dynamic programming has been broadly used to model generation expansion planning in a regulated electricity industry and the assumption that the objective is to minimize the total cost is typically used in a centralised electricity industry. However, since the objective of market liberalisation is to improve the economic efficiency of the electricity supply by reducing the costs, the minimisation of total cost is still valid to represent the whole system expansion under liberalised markets. Furthermore, most of the electricity markets around the world are not completely free in nature but subject to government regulations to ensure power availability and system security as well as to protect customers from high prices. Profit maximisation is often used as an objective for individual companies in a competitive electricity market; however it is not suitable to represent the objective of system expansion.

The second stage of the model calculates the expected profit that the new investment under evaluation will make each year assuming that the system will exhibit the prototype system expansion obtained in the first stage. Instead of considering electricity price as an exogenous variable, the model adopts an explicit representation of the market and computes the market clearing price based on the expected investments and retirements that will occur in the system (as defined in the prototype plan), the demand and the bidding strategies of the market participants. The model is then used to compare several investments involving different technologies and the company might choose to invest in the technology that could provide the highest profit (i.e. company perspective).

The basic model described above is extended in the first model (Model 1) to consider uncertainty in the load growth and the fuel costs. A probabilistic analysis using Monte Carlo simulation is applied in the model to characterise the rate of return distributions of the investments. In order to calculate the confidence level of investing in different investments considering risk, the VaR technique is incorporated in the model.

Model 2 takes into account the risk characteristics of different technologies in the financial model. It also addresses the fact that the new investment needs to be evaluated considering the price in oligopoly electricity market which is missing in the literature. An empirical approach is developed to model the price in an oligopoly market based on a shape of the price duration curve derived from an actual market. Since the profitability of an investment is sensitive to the shape of the load duration curve (LDC), an optimal approach to discretise the LDC is introduced prior to the investment evaluation using dynamic programming.

The novelty of these models lies in their explicit representation of the future electricity prices which is not only a function of load and installed capacity but also the available technologies in the system. A sensitivity analysis is used as a risk assessment technique to study the effects of uncertainty in the regulatory policy hence technology mix on the profitability of the new investment.

2.7.3 Chapter 5: Generation Investment Evaluation Model in an Oligopoly Market with Capacity Mechanism

In Chapter 5, two types of capacity mechanisms i.e. capacity payments and capacity markets are modelled and included in the first and second stage of the proposed investment evaluation framework in Chapter 4. The cost of the capacity mechanism is considered as an extra cost in the objective function of the prototype system expansion as its implementation will increase the total cost of generating electricity. The effect of capacity mechanism in the prototype expansion is modelled in such a way that a lower reserve margin in the system will increase the price of capacity mechanism hence more plants will be built by the dynamic programming to reduce the total cost of expansion. The energy and capacity mechanism prices are calculated based on this prototype plan, and then used to determine the net revenue of the new investment plant that the company is considering.

Two types of capacity payments are presented. The first is a linear capacity payment where the payment is inversely proportional to the installed capacity in the system. The second is a capacity payment which is a function of value of loss load (VOLL) and loss of load probability (LOLP). A capacity market similar to the one implemented by the New York Independent System Operator (NYISO) is considered in the model. Sensitivity analysis is also used as a risk assessment technique to study the effects of various VOLLs on the capacity payments and of different shapes of demand curves in capacity market on the profitability of the investment technologies.

Similar to the models in Chapter 4, this model represents an insight into the fundamental process of assessing an investment which could be used to study the combined effect of energy market prices and capacity mechanism prices on the profitability of the new investment.

Chapter 3 Analysis of Long-Term Generation Expansion Planning in a Restructured Electricity Supply Industry Using Agent-Based Modelling

Summary

This chapter presents a new approach to modelling long-term generation expansion planning in a restructured electricity industry using agent-based modelling. The model simulates generation investment decisions taken by the generating companies in a market environment taking into account their competitors' strategic investment and the complex interactions among them. The investment decision of the companies is modelled considering that the companies have imperfect foresight on the future prices. Another factor that contributes to the dynamic of the investment i.e. the delay in the construction of new plants is also included. Additional to the conventional energy market, several capacity incentive mechanisms such as capacity payment and capacity market to promote a healthy investment for generation expansion are modelled. In the presented results one can appreciate the effect of these incentives on the investment decisions taken by the various agents (generating companies). The results also provide insight on the investment cycles as well as dynamic system behaviour of long-term generation expansion planning in a competitive electricity industry.

3.1 INTRODUCTION

Generation expansion in a competitive electricity market involves a very complex process. In this new environment, the generation expansion planning that was previously based on a centralized decision process has been replaced by individual profit maximizations. In this situation, in formulating the strategy to invest in a new power plant, the generating company has to use its own judgment in forecasting what is likely to happen in the future regarding the demand, fuel cost and bidding strategies of its competitors. Since the generating company has limited information on its competitors' business strategy, it has to anticipate what they might do. The traditional approaches are no longer suitable to represent the complex generation expansion process. Therefore there is a need for a new model that will be able to model the complex interactions of the participants in the market. Agent-based modelling which is a new computational modelling technique offers this possibility, and has therefore been adopted in this chapter to model generation expansion planning in a liberalised electricity market. Agent-based modelling uses a bottom-up approach which enables the agent developers first to specify explicitly the individual components of the system, i.e. the decision-making process of each of the generating companies in the context of modeling generation expansion. Then these decision processes are linked together to represent the whole system and describe the interactions between the companies hence support the study of generation expansion.

In a liberalised electricity market, the generating companies' lack of perfect foresight in making an investment decision, combined with delays in construction and permit approval could result in potentially unstable dynamics in capacity investments [18, 57]. Using this descriptive approach those aspects that contribute to the 'boom' and 'bust' patterns of investment cycles are able to be incorporated in the generation expansion model and hence represent the dynamic behaviour of generation investment. This dynamic investment cycle could represent a major threat to electricity security and a risk to the generating company as the prices in such a situation are uncertain. As a consequence some of the regulatory authorities have imposed capacity mechanisms to stabilize system reserves and to provide generating companies an opportunity to earn extra revenue by making generation investment. Three types of capacity mechanisms are presented in this chapter and tested using the proposed agent-based generation expansion model to see the impact on the system performance as well as on the investment decisions of the generating companies. The objectives of this study are as follows:

1. First to develop a long-term generation expansion planning using agent-based modelling that is able to represent the complex interactions between the agents (generating companies) in the market
2. Second, to simulate the dynamic investment cycles in the liberalised electricity market by modeling the imperfect foresight of the generating

company in making investment decision as well as incorporating the construction delays of the new plants into the model

3. Third, to model the capacity mechanisms that provide investment incentives to the generating companies
4. Finally, to study the impact of these mechanisms on the investment choice of the generating companies and the dynamic system behaviour of long-term generation expansion.

3.2 THE CONCEPT OF AGENT-BASED MODELLING

In agent-based modelling, a system is represented as a collection of autonomous agents who individually assess their situation in an environment and make decisions using a set of decision rules. Each agent has the capability to learn and adapt to its environment in a social, communicative and intelligent way to achieve its target. Agent-based modelling repetitively simulates the decision process and the interactions of the agents and can thus be used to study the dynamics of complex systems.

A spread sheet or mathematical software such as Mathematica or MatLab can be used to develop agent-based modelling; however with those tools the applications can only represent a small number of agents [69]. Large-scale agent models are usually developed using specialised agent simulation environments such as Repast, Swarm and NetLogo. These environments support several features useful to agent modellers including the provision of communication mechanisms, various agent architectures and flexible interaction topologies.

3.3 APPLICATION OF AGENT-BASED MODELLING FOR THE STUDY OF LIBERALISED ELECTRCITY MARKET

Several researchers have proposed models of activities in the liberalised electricity markets using agent-based approaches. These can be broadly grouped as: 1) operation of electricity market and 2) generation expansion planning.

Bower and Bunn [70] were the first to use agent-based modelling to represent electricity trading. They applied the technique to compare the Electricity Pool of England and Wales with the New Electricity Trading Arrangement (NETA) in terms of market price and generators' bidding strategy. Bunn and Oliveira [71] presented the first detailed study of the relationship between bilateral trading and the balancing market in NETA. Bunn and Martoccia [72] analyzed generator market power in the electricity pool of England and Wales. A recent study by [73] developed an Agent-based Modelling of Electricity Supply (AMES) using Repast to model the wholesale electricity market run by the New England Independent System Operator and the Midwest Independent System Operator (MISO). The papers mentioned above focused on the electricity markets in Britain and in the United States. More general electricity market simulators, EMCAS [74] and MASCEM [75] also use agent-based modelling approaches to simulate the operation of other electricity markets. Bagnall and Smith focus on improving agent decision through learning [76] and agent architecture [77].

Since modelling generation expansion using agent-based modelling is a relatively new area of research, only a few specific studies can be found in the open literature. Among these works, the team from Argonne National Laboratory proposed a multi-agent model for generation expansion that simulates investment decisions of generating companies considering the interactions among the various participants [25]. The model framework includes two stages: 1) the stage where each generating company forecasts the expected profitability and makes decision on the new investment and 2) the stage where the actual market clearing is performed after all the companies have made their investment decision. The competitors' investment expectation in the current decision year and into the future is modelled using scenarios. However, they do not take into account the various mechanisms that can be enforced to promote an adequate generation expansion. This problem is tackled by Ortega_Vazquez and Kirschen in [26]. However Ortega-Vazquez and Kirschen make some assumptions to avert the circularities that arise when assessing the decisions taken by a participant, when relying on guesses about the other participants' decisions. In the model, they do not consider the effect of investment decisions by all the generating companies on the actual market.

The agent-based expansion model proposed in this chapter extends and refines the methodology presented by Ortega-Vazquez and Kirschen. In this model, to overcome the circularities that arise when anticipating competitors' investment strategy in their model, the competitors' expansion expectation is represented using scenarios. The competitors' expansion strategy is only considered for the current decision years in order to simulate the imperfect foresight of the generating company in evaluating a new investment. The agent-based framework presented in this model not only considers the market clearing process in the forecasting years but also calculates the market prices in each actual year after all the companies have taken their decisions about the expansion. Using this extensive framework and the imperfect competitors' investment expectation, dynamic behaviour of the generation expansion in the long-term can be modelled. The properties of the model developed by Ortega-Vazquez and Kirschen, Argonne National Laboratory and the new model presented in this thesis are summarised in Table 3-1.

It is beyond the scope of this chapter to use a sophisticated agent-based environment to develop an agent-based generation expansion model. Instead, the model was built from scratch in order to learn the process of agent-based development and also to understand the complex interactions between the agents in the restructured electricity industry. The agent-based generation expansion planning model in this chapter was developed using MatLab.

Properties	Vazquez and Kirschen (2008)	Argonne National Laboratory (2007)	Model in this thesis
Planning horizon (years)	4	15	12
Electricity Market	Minimize the total yearly operating cost	Probabilistic dispatch to calculate market prices	Minimize the total yearly operating cost
Bidding strategies	Bid at price covers variable and quasi-fixed production cost	Bid at marginal cost	Bid at price covers variable and quasi-fixed production cost
Competitors' expectation	Maximize competitors' profit considering static system Imperfect foresight	Modelled using scenario Imperfect foresight	Modelled using scenario Imperfect foresight
Decision-Making	To choose the alternative with the highest profit	Multi-attribute utility theory to choose the alternative with the highest expected utility	To choose the alternative with the highest average profit considering the competitors' expansion scenarios
Capacity Mechanisms	Energy-only market, capacity payment, capacity market	None	Energy-only market, capacity payment, capacity market
Test system	IEEE Reliability test system -26 Units	Real data from Korean power system	IEEE Reliability test system -26 Units
Analyses	The effects of capacity mechanisms on the investment choice of the generating companies	The effect of energy price cap, competitors' expansion and new entrants on the generation expansion and market prices	Generation expansion under different scenarios that could trigger investments, dynamic analysis of the generation investment under the capacity mechanisms

Table 3-1 Properties of the existing models and the new model of agent-based generation expansion planning

3.4 OVERVIEW OF GENERATION EXPANSION PLANNING USING AGENT-BASED MODELLING

Figure 3-1 shows the overall framework of generation expansion planning using agent-based modelling. In this approach, the generating company is modelled as an independent agent who reacts through its environment (in this case the market) to maximize its profits. In general, the framework is divided into two parts: 1) forecasting model, 2) actual market model. In the forecasting model, while evaluating an investment, each generating company forecasts the future load growth, the fuel costs and the competitors' investment strategy. Using these values, the generating company calculates the expected energy prices by clearing the market each year, and then estimates the revenue of the generating plants over their lifetime. It is assumed that to establish its forecast, each generating company has access to initial system information such as load, system capacity, fuel costs and spinning reserve requirement. If the generating company evaluates more than one possible plant, it will compare the profit of the different investment options and will choose to build the most profitable one. In this model, it is assumed that the generating companies make expansion decisions on a yearly basis.

After all the generating companies have decided on which plant to invest in that year (if any), the actual market clearing is performed based on the new system capacity. The actual market model is used to calculate the actual energy prices and the spinning reserve prices in the current year. The new power plants decided by all the companies in that year enter the system only after their construction has been completed. Finally, at the end of each year, the model updates the new system information regarding the load, capacity additions and capacity retirements. The generating companies then use this information to make decisions about the next round of investments the following year.

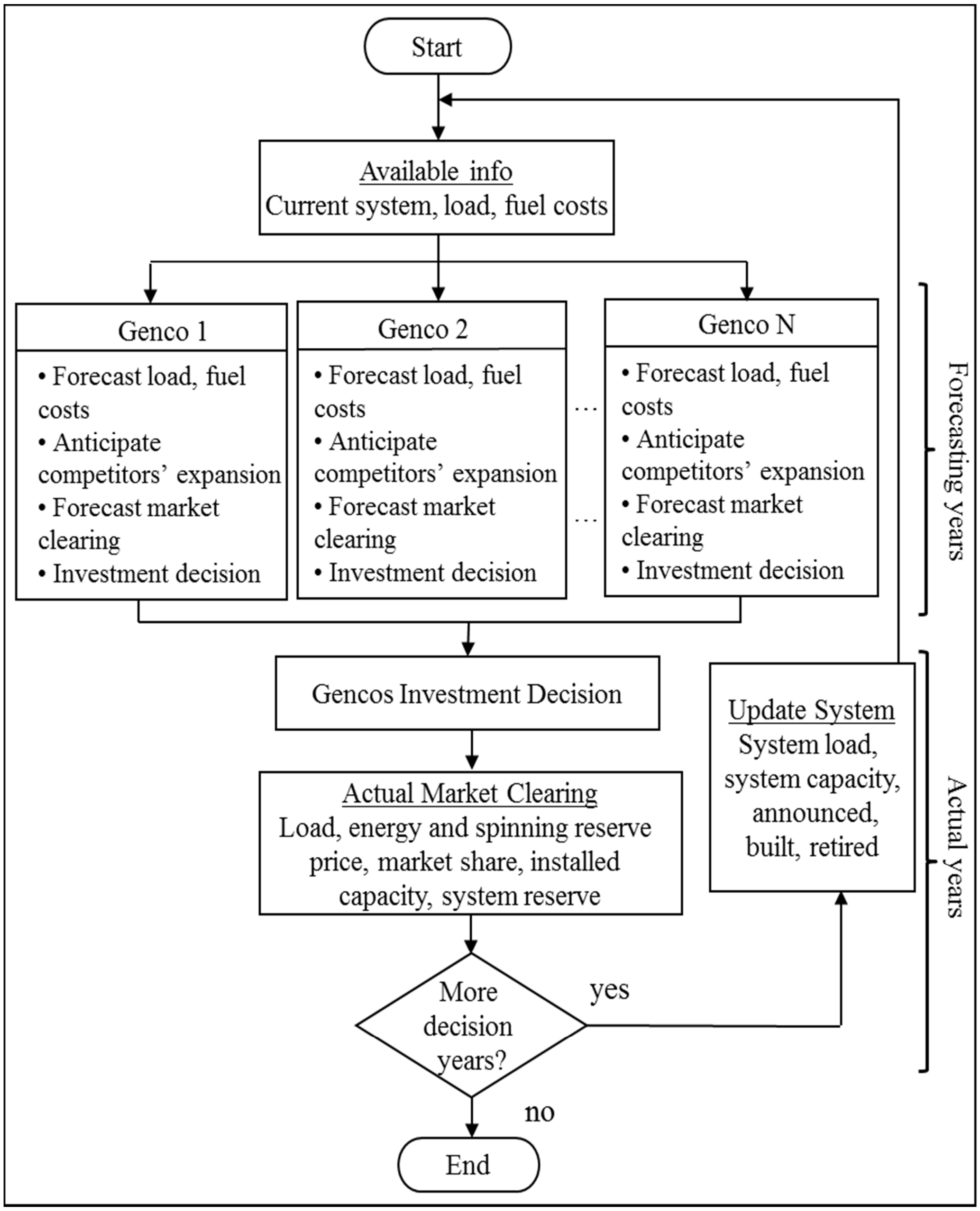


Figure 3-1 Framework of generation expansion planning using agent-based modelling

In this model, all the generating companies use a similar investment evaluation model to make a decision on a new investment. However, while making expansion decisions, each generating company also takes into account the effect of a new investment on the profitability of its existing portfolio. Since each generating company has a different generating portfolio, they may come out with different investment strategies to maximize their overall profit.

3.5 ELECTRICITY MARKET DESIGN

The market model simultaneously clears the energy and spinning reserve markets in each segment of the load duration curve (LDC) of each year as in [26]. Figure 3-2 shows the five-segment discretized load duration curve used in this model. The market clearing process is modelled as an optimization problem in which the total yearly operating cost is minimized:

$$\min\left\{\sum_{s=1}^{S}\sum_{i=1}^{I}\left(MCb_i\ p_{i,s}\ d_s\right)\right\} \tag{3.1}$$

where S is the number of segments in the LDC, I is the number of generating units participating in the market, MCb_i is the bidding price of generating unit i, $p_{i,s}$ is the power produced by generating unit i at segment s and d_s is the duration in hours of segment s.

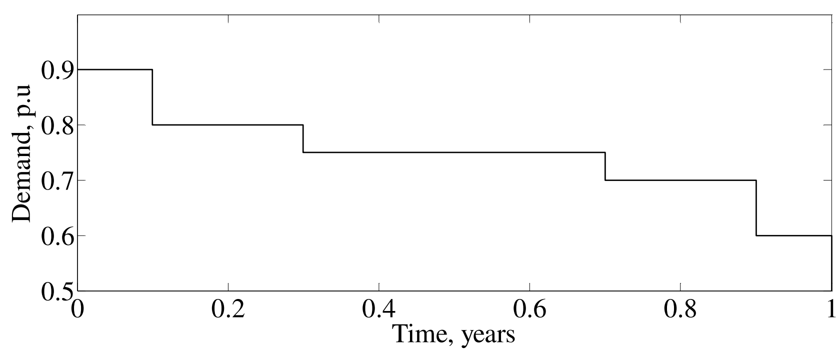


Figure 3-2 Five segments of discretized LDC

The optimization is carried out subject to several constraints:

$$\sum_{i=1}^{I} p_{i,s} = pd_s \tag{3.2}$$

$$P_i^{\min} \leq p_{i,s} \leq P_i^{\max} \tag{3.3}$$

$$\sum_{i=1}^{I} r_{i,s} \geq rd_s \tag{3.4}$$

where pd_s is the system demand at segment s and rd_s is the spinning reserve requirement for segment s.

The first constraint is enforced so that the selected generation meets the load demand for each segment *s;* as in equation (3.2). Each generating unit is also constrained by its minimum stable generation and its maximum capacity as in equation (3.3). Since the market clears simultaneously energy and spinning reserve, constraint (3.4) also needs to be enforced.

The model assumes that each generating company bids at a price that covers both its variable and quasi-fixed production costs. Variable costs are the costs that depend on the amount of energy the power plant produces, for example fuel costs and some aspects of maintenance costs. On the other hand, quasi-fixed costs are the costs that the plant incurs if it produces any amount of energy but does not incur if the plant does not produces anything, such as the start-up cost. Since the actual power produced by each generator is not known prior to the actual clearing process, it is assumed that the generators bids hedge for the minimum stable generation [26] as follows:

$$MCb_i = f_c m_i + \frac{f_c b_i}{P_i^{\min}} \tag{3.5}$$

where m_i is the slope of the linearized input-output characteristic of generating unit i (MBTU/MWh), b_i is the y-offset of the linearized input-output characteristic of generating unit i (MBTU/h), f_c is the fuel cost (\$/MBTU) and P_i^{min} is the minimum stable generation of generating unit i (MW).

The market-clearing price is the cost of providing an additional megawatt of energy, and is thus assumed to be the marginal cost of the marginal energy producer. On the other hand the spinning reserve price is the net cost of getting an additional megawatt of reserve in the system. The calculation of energy and spinning reserve prices in this model at a given load is illustrated using test data from the IEEE Reliability Test System [78] as shown in Table 3-2.

For this simple example, it is assumed that the market is cleared for a demand of 2173.5MW and for a minimum spinning reserve requirement of 400MW. The generating units are first sorted in increasing order of bidding price. To meet the given load at the minimum operating cost, units 24, 25, 26, 17, 18, 19, 20, 10 and 11 must produce at their maximum output. If the reserve constraint is not imposed, Unit 14 is the marginal producer. However, in order to meet the minimum reserve requirement in the system more plants must be operated. In this situation, since the bid prices of unit 13, 14, 21, 15 and 22 are higher than that of unit 12 and these units are constrained by their minimum stable generation, their energy outputs are kept at minimum. The remaining capacities of these units are then scheduled to provide reserve. Unit 12 becomes the marginal producer to balance the remaining load and reserve requirement and the price of energy is thus set at its bid price, which is 19.09$/MWh. These are shown in Table 3-2. In order to make one more megawatt of reserve available, the energy output from unit 12 must be reduced and the production of unit 22 increased by the same amount. The cost of this marginal re-dispatch sets the price of the reserve at 27.06 - 19.09 = 7.97 $/MWh. Figure 3-3 illustrates the market clearing, and the energy and spinning reserve price at the given load. More examples of co-optimization of energy and reserve can be found in [3].

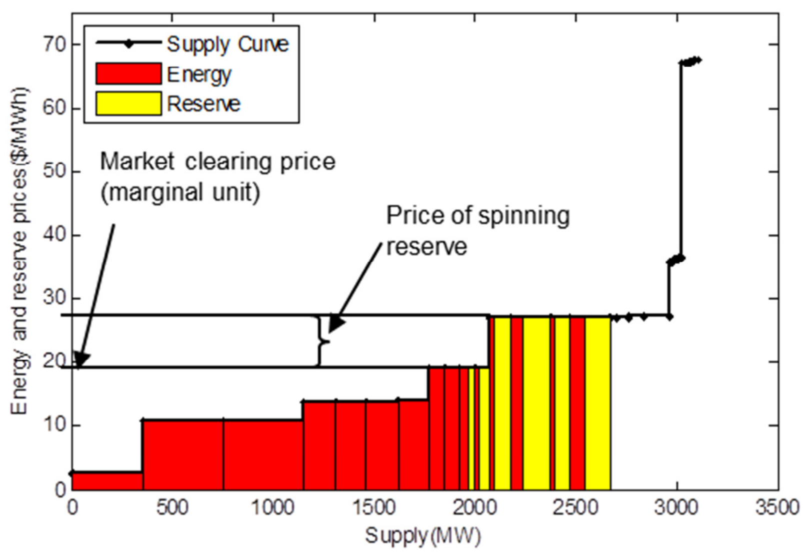


Figure 3-3 Example of market clearing and spinning reserve price at a load equal to 2173.5MW

Units	Max capacity (MW)	Min capacity (MW)	Bidding prices ($/MWh)	Power produces (MW)	Cumulative power produces (MW)	Spinning reserve (MW)
Unit 24	350	140	2.37	350	350	0
Unit 25	400	100	10.78	400	750	0
Unit 26	400	100	10.81	400	1150	0
Unit 17	155	54.24	13.73	155	1305	0
Unit 18	155	54.24	13.77	155	1460	0
Unit 19	155	54.24	13.80	155	1615	0
Unit 20	155	54.24	13.83	155	1770	0
Unit 10	76	15.2	19.01	76	1846	0
Unit 11	76	15.2	19.05	76	1922	0
Unit 12	76	15.2	19.09	48.4	1970.4	27.6
Unit 13	76	15.2	19.14	15.2	1985.6	60.8
Unit 14	100	25	26.89	25	2010.6	75
Unit 21	197	68.95	26.95	68.95	2079.6	128.05
Unit 15	100	25	27.00	25	2104.6	75
Unit 22	197	68.95	27.06	68.95	2173.5	128.05
Unit 16	100	25	27.12	0	2173.5	0
Unit 23	197	68.95	27.17	0	2173.5	0
Unit 01	12	2.4	35.79	0	2173.5	0
Unit 02	12	2.4	35.93	0	2173.5	0
Unit 03	12	2.4	36.16	0	2173.5	0
Unit 04	12	2.4	36.34	0	2173.5	0
Unit 05	12	2.4	36.52	0	2173.5	0
Unit 06	20	4	67.08	0	2173.5	0
Unit 07	20	4	67.28	0	2173.5	0
Unit 08	20	4	67.48	0	2173.5	0
Unit 09	20	4	67.69	0	2173.5	0

Table 3-2 Illustrative data for calculating the price of energy and spinning reserve to meet demand equal to 2173.5MW

3.6 ANTICIPATING COMPETITORS' INVESTMENTS

In the generation expansion model presented by Ortega-Vazquez and Kirschen, the generating company anticipates its competitor's investment strategy considering that its competitor will choose the investment plan that would maximize its overall profit. The optimization process for each of the competitors requires the information of what the first generating company and the other competitors might decide to do. To avoid this circularity, the anticipating process for the competitors is performed assuming that no generation would be built by the first generating company or the rest of the competitors. To overcome this 'static' process, a new technique to anticipate competitors' investment strategy is developed in this model. The anticipated investments from other competitors in each decision year are modelled as a scenario. The representation of each competitor's investment scenario consists of investment options; that is, a list of expected new power plants that might be chosen by the competitor. It is assumed that since all the generating companies are in the same business, they can make a good guess about their competitors' investment options. Since investing in power generation requires large investments, it is also assumed that the competitors only choose to build a single plant each year. The result of all the competitors' investment is a scenario tree structure where each layer represents the investment options that each competitor has. The probabilities of selecting the options are specified individually for each competitor over the layers of the scenario trees. This is shown in Figure 3-4 where Company A is evaluating an investment and Company B, Company C and others are its competitors. Once all the competitors' investment scenarios are obtained and the probability of each scenario is determined, the revenues of the new plant under evaluation are calculated for each scenario's realization. The average expected revenue is then computed considering the uncertainty in the competitors' investment strategy. By using this technique the generating companies are able to consider all the possible investments that might be taken by the competitors while evaluating their investment.

To simulate the imperfect foresight of the generating company in making investment decision, the competitors' investment expectation is considered only in calculating the expected revenue of the new power plant in the current decision year but not in the future.

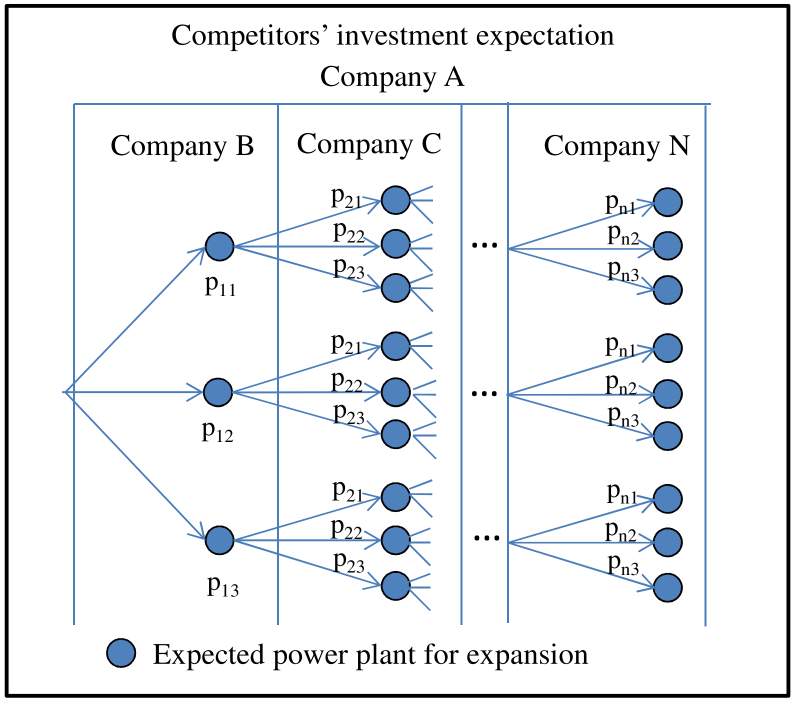


Figure 3-4 Scenario trees of competitors' investment expectation

3.7 DECISION MAKING PROCESS

Decision making is the most important stage in the evaluation of investments. This process consists of determining which investment option is the most profitable. To estimate the profit, the generating company must first acquire the expected revenue and the cost of each plant. This is done by clearing the market for each year of the plant's lifetime. The net revenue of each generating company is then computed using the following equation:

$$P_{GenCo} = \sum_{\forall j \in J} (ER_j + SR_j - PC_j) \tag{3.6}$$

where J is the set of generating units that belong to a given generating company, ER_j is the yearly revenue from the energy market, SR_j is the yearly revenue from providing spinning reserve and PC_j is the yearly production cost of generating unit j.

The yearly energy revenues, revenues from providing spinning reserve and production cost are given respectively by:

$$ER_j = \sum_{s=1}^{S} \pi_{clear,s} \; P_{j,s} \; d_s \tag{3.7}$$

$$SR_j = \sum_{s=1}^{S} (\pi_{SR})(P_j^{\max} - p_j) d_s \tag{3.8}$$

$$PC_j = \sum_{s=1}^{S} \left(f_c m_j + \frac{f_c b_j}{p_{j,s}} \right) p_{j,s} \; d_s \tag{3.9}$$

where $\pi_{clear,s}$ and π_{SR} are the market clearing prices for energy and reserve at segment s of the LDC. This approach therefore does take into account the effect that a new plant might have on the revenues generated by other plants in the generating company's portfolio.

For the example of section 3.5, the revenues from the sale of energy and reserve, the cost incurred and the profit obtained by Unit 17 are calculated for each segment of the LDC in Figure 3-2. The demand data for each of the segments is shown in Table 3-3. The energy and spinning reserve prices which are cleared in each segment of the LDC are shown in Figure 3-5.

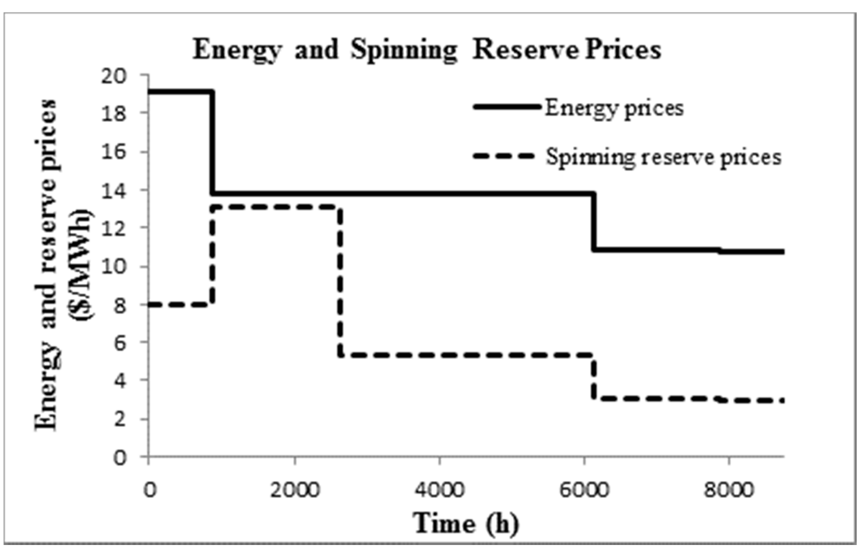


Figure 3-5 Energy and reserve prices in each segment of the LDC

Segment	1	2	3	4	5
Demand (MW)	2173.5	1800.9	1552.5	1304.1	931.5
Duration (h)	876	1752	3504	1752	876

Table 3-3 Demand data for each segment of the LDC

For the peak and intermediate load segments of the LDC (i.e. segments 1, 2 and 3), Unit 17 is one of the main energy producers and operates at its maximum output. During these hours the profit of Unit 17 is dependent only on the price of energy. Since the energy market is cleared just above the production cost of Unit 17 in segment 2 and 3, Unit 17 only makes a very small profit in these segments. On the other hand, at the lower load segments, Unit 17 provides more reserve while producing energy at its minimum output. Although the energy prices at these segments are lower than the cost of producing energy of Unit 17, the revenue that Unit 17 received from the provision of reserve is more than enough to cover its operating cost. This makes it more profitable than selling energy at segment 2 and 3. These results are illustrated in Figure 3-6.

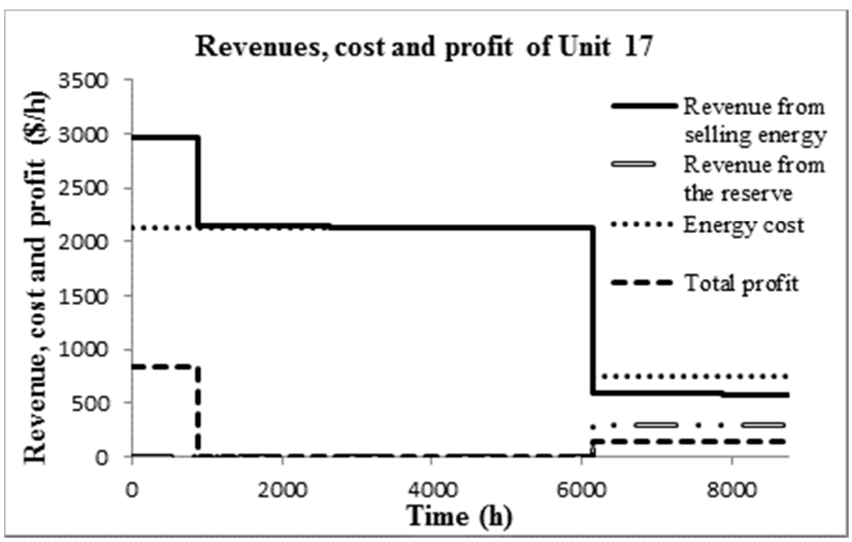


Figure 3-6 Revenues, cost and profit of Unit 17 in the segments of the LDC

Once the revenues and costs have been computed for each year of the lifetime of a given possible new plant and the initial investments is assumed paid uniformly throughout the building time, the FWV (the value of cash in the future) at a minimum acceptable rate of return (MARR), and the IRR (the rate of return that gives a NPV of zero) of the generated cash-flow is calculated. The IRR and FWV are expressed mathematically as follows:

$$0 = \sum_{t=0}^{T} \frac{CF_t}{(1+r)^t} \tag{3.10}$$

$$FWV = \sum_{t=0}^{T} CF_t (1 + MARR)^t \tag{3.11}$$

where CF_t is the net cash-flow at year t, T is the number of years of cash-flow in the investment's life, t is the year in which the cash-flow CF_t occurs and r is the IRR of the investment.

If a given generating company is evaluating two power plants for expansion, the selected plant must have positive FWV and IRR higher than MARR. If both plants have IRR greater than MARR, the one with the greater FWV will be selected. If more than one plant meets these criteria, then the one with the higher expected increment on the overall profits is selected. On the other hand, if none of the plants meets these criteria, the generating company chooses not to build anything in that year.

3.8 CAPACITY MECHANISMS

The possibility that the investment cycles may emerge in the electricity market mimicking the 'boom' and 'bust' patterns has always been discussed as a major risk in the liberalised electricity market. The cycles which represent the uncertainty of reserve in the system, are a threat to energy security. These investment cycles are also a risk to the investors since the cycles could lead to unsustainable energy prices. Some capacity mechanisms have therefore been proposed by regulatory authorities to procure some reserves and to stabilize the prices. These mechanisms also reward investments in generation capacity to promote a "healthy" amount of investments.

A perfectly competitive power market should in theory and in the long run, provide the correct signals to attract investments from generating companies, several researchers have argued that this might not happen in the real world [5, 79]. The difficulties that prevent the practical realization of this theory may come from both generators' and consumers' sides. [64] suggests that there are three factors that discourage generating companies from making investments in the energy market alone. The first factor is the introduction of price caps in some of the reformed markets to help consumers reduce the risk of high prices. Such caps obviously limit the revenues that the generators receive from the market during periods of peak prices, which is exactly when they collect enough money to pay their investment costs. Second, the volatility of electricity market prices has caused the risk adverse generators to invest conservatively to avoid risks. The third factor is related to the oligopolistic behaviour of some generating companies in the market who under-invest and use anti-competitive bidding strategy to raise prices when the barriers to entry are high for the potential new entrance. [64] also specifies that the lack of demand response is also a major contributor to the failure of optimal investment in the perfect competitive market.

Stoft [67] argues that two demand-side flaws exist in electricity markets that hamper the market's ability to operate successfully on its own. The first flaw is a lack of real time metering and billing for the customers that causes the demand to be unresponsive to the wholesale market price. Second, the lack of real time control to specific consumers restricts the physical enforcement of bilateral contracts and hence discourages customers from buying using long-term contracts. Various capacity mechanisms have therefore been proposed such as capacity payment which had been implemented under the old Electricity Pool of England and Wales and still exist in Spain and several Latin American countries, and capacity markets which have been adopted in the north east of the United States.

Some studies have been conducted to simulate dynamic investments in power generation under the market with capacity payment and capacity market as described previously in Chapter 2. However, few tools are available to study the combination effect of these mechanisms and the spot market on the investment strategy of the generating companies, which will be the focus of the analysis in this chapter. It is not the aim of this thesis to propose a new design of capacity mechanism but to use some designs that have been proposed in the literature or implemented in the real market. This is because the study intends to develop a generation expansion model that is able to represent the complex interactions of the participants in the market and to develop a tool that can be used to study the dynamic system behaviour of the generation expansion under various market designs.

3.8.1 Energy Only Market

In these markets, the generators submit their bid and all the bids below the market clearing price are dispatched and paid the market clearing price. The revenues of the generators come from selling energy and procuring spinning reserve. In the energy-only market the incentive for capacity investment is a natural process with no centralized administrative direction to drive the investment. The rationale behind this approach is that, according to economic theory, the equilibrium of energy-only markets in the long-term results in the optimal generation capacity, where scarcity payments to the marginal generators when demand exceeds supply covers exactly the cost of these generators [5].

The price hikes produced by the scarcity rents in the energy-only market are a signal for investment that should attract the right amount of generation capacity. Unfortunately, these price hikes are not only produced by the scarcity rent but also from some of the generating companies exerting market power. The price hikes can also be the result of anti-competitive bidding practices to raise the prices. In order to mitigate these prices hikes some regulators have placed caps on the market clearing prices. However this approach has discouraged generating companies from making investments. To overcome this issue, regulators have introduced some incentives to promote capacity investment by providing generators the opportunities to get extra revenue. Most of the electricity markets in the Organization for Economic Co-operation and Development (OECD) countries rely on the energy-only market for capacity expansion [7].

3.8.2 Capacity Payment

Capacity payment pays generators a per MW payment based on their availability whether they get dispatched or not. Through this incentive, a generating company has the opportunity to get extra revenue and is thus encouraged to invest in additional generation capacity. In the capacity payment, a regulator administratively sets the price of the capacity and lets the market determine the amount capacity available. The concept of capacity payment has its origins from the theory of peak load pricing. The theory describes that the amount of energy that can be produced at any given time period is dependent on the available capacity in the system. According to the theory, the energy is efficiently priced at marginal cost during the consumption period and the capacity payment that would recover the fixed cost of the units is imposed during the peak period.

The capacity payment is determined by the LOLP and charged to the consumers based on the time varying available capacity. The payment to the generators comes from the theory of optimal capacity planning, which suggests that the marginal cost of incremental capacity should be equal to the marginal cost of unserved load. This can be approximated by multiplying the marginal VOLL with the probability that the load must be curtailed because of the capacity shortage (LOLP). An alternative approach to the capacity payment is to pay the generators based on the cost of peaking technology. However this approach is not considered in designing the capacity payment in this thesis. Further reading on this approach can be found in [5].

In this chapter the capacity payment based on the LOLP is developed and tested using the proposed generation expansion model. The now defunct Electricity Pool of England and Wales used to make capacity payments at a rate proportional to the system's LOLP, which is a function of available generation capacity relative to the load in each segment of the LDC. The total capacity payment paid to a generator over a year is described by the following equation:

$$CP_j = \sum_{\forall j \in J} \sum_{s=1}^{S} VOLL X LOLP X FOR_j X P_j^{max} X d_s \tag{3.12}$$

where *VOLL* is the system's value of loss load, FOR_j is the forced outage rate of generating unit *j* and P_j^{max} is the capacity of generating unit *j*.

The VOLL which is the value that customers are willing to pay to avoid interruption should theoretically be measured based on customer surveys; however for simplicity, it is assumed deterministic in this analysis. On the other hand, the LOLP is calculated by first constructing a capacity on outage probability table (COPT) using recursive technique as shown in [80]. The COPT consists of an array of capacity on outage and probability associated with these outages. The LOLP is often defined as the likelihood that the system load level will exceed the generating capacity during a given period. The LOLP in each segment of the LDC is computed as follows:

$$LOLP_s = \sum_{z=1}^{Z} P_z((AC_s - CA_z) < pd_s) \tag{3.13}$$

where AC_s is the actual committed capacity at segment s, CA_z is the capacity on outage for element z in the COPT, pd_s is the system demand at segment s, $P_z((AC_s - CA_z) < pd_s)$ is the probability of loss of load for element z when the system demand exceeds the capacity in service, which can be directly obtained from the COPT.

3.8.3 Capacity Market

On the other hand, some regulators set the amount of capacity available to meet a target reserve and let the market determine its price. This version of capacity mechanism is known as capacity market. The evolution of capacity markets in the United States will be discussed in Chapter 5, where in that chapter a capacity market based on the New York Installed Capacity (ICAP) market is modelled for the analysis. Similar to the capacity payment, a capacity market also provides the generating company the opportunity to collect extra revenues; however the process is designed in a competitive way.

In this chapter the capacity market similar to the design presented in [26] is developed. The capacity market is assumed to be taking place on a yearly basis and the amount of capacity obligation is set deterministically by the system administrator at a specified amount above the peak load. The market is designed to provide generating units that are neither dispatching energy nor procuring spinning reserve the opportunity to collect extra revenue for their unutilized generation capacity. Similar to the pool market, participants in this capacity market submit their bid, and those with the bid price below the marginal clearing price are paid the market clearing price for the capacity that they will contract. It is assumed that each generating unit that can participate in the capacity market bid at the following price, which is at the minimum price so that they do not lose money.

$$CMb_m = \left(\frac{A_{revenue,m} - A_{prod\_cost,m} - A_{investment,m}}{P_m^{\max}} \right) \quad (3.14)$$

where $A_{revenue,m}$ is the projected annual revenue of generating unit m, $A_{prod\_cost,m}$ is the projected annual production cost and $A_{investment,m}$ is the present worth value of the initial investment which is uniformly annualized and amortized throughout the lifetime of the plant with the MARR. These are given as:

$$A_{revenue,m} = \sum_{s=1}^{S} P_m^{\max} \times uf_m \times \pi_{\exp,s}\ d_s \quad (3.15)$$

$$A_{prod\_cost,m} = P_m^{\max} \times MCb_m \times uf_m \times 8760 \quad (3.16)$$

$$A_{investment,m} = I_{PWV} \left(\sum_{n=1}^{lt} \frac{1}{(1+MARR)^n} \right)^{-1} \quad (3.17)$$

where uf_m is the utilization factor of generating unit m, $\pi_{exp,s}$ is the expected energy market clearing price at segment s, MCb_m is the bidding cost of generating unit m in the energy market, lt is the lifetime of generating unit m, 8760 is the number of hours in a year and I_{PWV} is the present worth value of the investment.

3.9 TEST RESULTS

The proposed model has been tested on the IEEE Reliability Test System [78] omitting the hydro generation, which consists of 26 generating units and a total of 3105MW of installed capacity. The existing technologies in the system are listed in Table 3-4. It is assumed that there are three generating companies in the system and the portfolios are as follows: Genco1 owns the set of generating units {1-10}, Genco2 owns the set {11-20} and Genco3 owns {21-26}. The units are classified so that Genco1 possesses the peaking units, Genco2 possesses the mid-size generating units and Genco3 possesses the base and some of the mid-size generators in the system. Figure 3-7 graphically shows the position of these units on the supply curve where each generating company's (Genco) portfolio has been ranked according to its bidding price.

Unit Group	Size, MW	Unit Name	Unit type	Heat rate offset, MBTU/h	Heat rate, MBTU/MWh	Remaining lifetime, years
U12	12x5	1 - 5	Oil/Steam	2.81	3.07	15
U20	20x4	6 - 9	Oil/Combus tion turbine (CT)	13.87	4.49	10
U76	76x4	10 - 13	Coal/Steam	44.38	8.82	17
U100	100x3	14 - 16	Oil/Steam	24.03	2.23	8
U155	155x4	17 - 20	Coal/Steam	64.88	7.28	14
U197	197x3	21 - 23	Oil/Steam	26.59	2.81	15
U350	350x1	24	Coal/Steam	12.12	1.37	25
U400	400x2	25 - 26	Nuclear	211.27	7.69	33

Table 3-4 Existing units' technology and costs

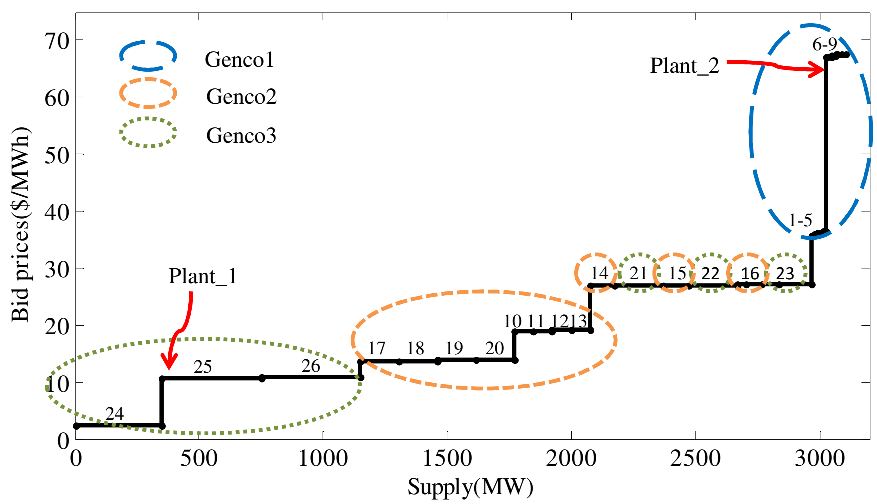


Figure 3-7 Generating companies' portfolios on the supply curve

Each generating company considers two plants for expansion every year: Plant_1, a 250MW coal base plant and Plant_2, a 25MW oil peaking plant as shown in Table 3-5. The position of these plants on the supply curve according to their bid price is also shown in Figure 3-7. Each generating company expects that its competitors will also choose to invest in one of these plants.

Plant Name	Size MW	Unit type	FOR	Util. Factor	Invest $/kW	Heat rate offset, MBTU/h	Heat rate, MBTU/ MWh	MARR, %	Build time, years	Lifetime, years
Plant_1	250	Coal	0.08	0.9	2700	22.124	5.879	12	4	20
Plant_2	25	Oil	0.02	0.1	900	3.011	4.821	12	2	20

Table 3-5 Technology and cost of the plants considered for investment

The LDC has been discretized into 5 segments as shown in Figure 3-2. The peak value is assumed to be 2173.5 MW at year 0 and the magnitude of each segment of the LDC increases by 25MW every year. The fuel costs are set at 2.31 $/MBTU for coal, 13.5 $/MBTU for oil and 5.54 $/MBTU for gas [81]. The system VOLL is assumed to be 2000 $/MWh. Since the demand is inelastic, the VOLL is also used as a cap in the energy-only markets. For the LOLP calculation, the COPTs were truncated considering probabilities down to $1x10^{-6}$. In the capacity market it is assumed that the installed capacity obligation passed to the load serving entities is 10% of the forecasted peak demand. The expected lifetime of the existing units and the new plants are provided as input data. All the existing generating units are considered sunk costs at year 0. The generation expansion planning is performed over a time horizon of 12 years. For the competitors' expectation, each investment option on the scenario tree has equal probability to be selected.

The system has been tested in different case studies which are described as follows: In Case I, a study to validate that the model is capable of reacting with different scenarios that could trigger different degrees of investment, in Case II a case study in which the generating companies' strategic investment and long-term generation expansion behavior in the energy-only market is analyzed, in Case III a study in which the generation expansion considering capacity payment and capacity market incentives are examined. Finally, Case IV presents a comparison of the total investment amount and investment pattern triggered by each incentive.

3.9.1 Case I: Various Scenarios to Trigger Investment

Four scenarios are considered over the 12 year planning horizon: 1) No load growth and no generator retirement, 2) No load growth but with generator retirement, 3) 25

MW load growth on each segment of the LDC each year with generator retirement and 4) 40 MW load growth with generator retirement. The simulations are performed for the energy-only market.

Figure 3-8 shows the total capacity investment for the 12 year planning horizon for each scenario. As one would expect, no generation is built when there is no load growth and no retirements. On the other hand, retirement only without load growth in the system triggers investments from the generating companies. As expected, larger investments arise when both load growth and retirement are taken into consideration in the simulation.

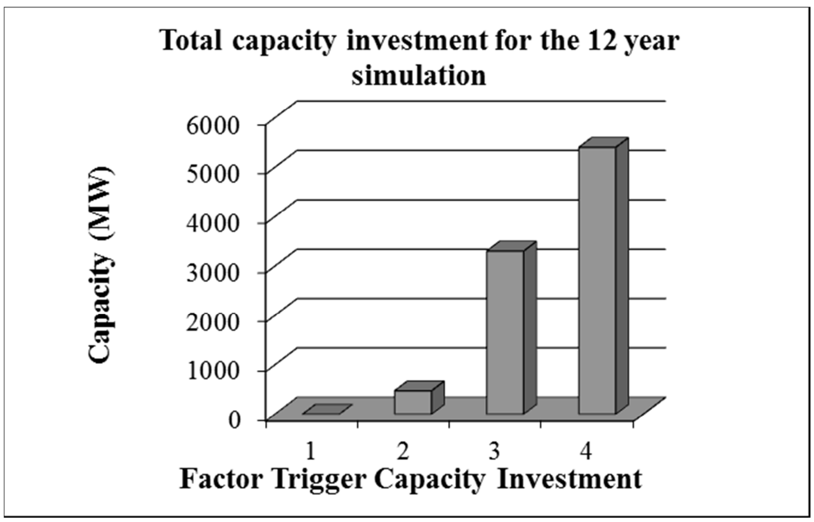


Figure 3-8 Total capacity investments for different scenarios

3.9.2 Case II: Dynamic Investment and Long-term System Behaviour in Energy-only Market

Table 3-6 shows the new plant selected by each Genco at each year over the 12 year planning horizon. The new plants are commissioned after the construction time has been completed as in Table 3-7. At the beginning of the simulation, none of the Gencos builds new generation; then as time goes by, since there is a demand increase, the Gencos start building smaller plants in the following years. As the demand increases, the reserve margin in the system starts to reduce and continues to fall until year 6 although the smaller plants decided earlier by the Gencos are commissioned in years 3 to 5. This happens because the capacity of these new plants is less than the growing demand. Figure 3-9 shows this effect. This results in an increase in the energy and spinning reserve prices until year 6 as shown in Figure 3-10. These larger prices are interpreted as a positive signal for investment by Genco3, which chooses to invest in a larger plant at year 4 followed by the remaining Gencos in year 5. Since the base plant has a longer building time, the reserve continues to fall to its lowest value in year 6, which is also the peak point of energy price. The largest capacity commission occurs in year 8 when all the base plants selected by the Gencos in year 5 come online and cause the energy price to fall at its lowest price. It can be seen that the boom and bust cycle of the capacity investment appears in the energy-only market and this cycle continues over the remaining years.

Year	1	2	3	4	5	6	7	8	9	10	11	12
Genco1	None	2	2	2	1	2	2	2	2	2	2	2
Genco2	None	2	2	2	1	2	2	2	2	2	2	2
Genco3	None	2	2	1	1	1	1	1	1	1	1	1

1-Plant_1, 2-Plant_2

Table 3-6 New plants selected by the Gencos each year over the 12 year planning horizon

Year	1	2	3	4	5	6	7	8	9	10	11	12
Genco1	None	None	2	2	2	None	2	1,2	2	2	2	2
Genco2	None	None	2	2	2	None	2	1,2	2	2	2	2
Genco3	None	None	2	2	None	None	1	1	1	1	1	1

1-Plant_1, 2-Plant_2

Table 3-7 New plants get into the system each year over the 12 year planning horizon

In this market, since there is no incentive to encourage the Gencos to make investments, Genco1 and Genco2 who own small and mid-size generators choose to build the smaller plants so that they are able to cover the costs of the investments. On the other hand, Genco3 who owns the biggest market share in the market continues to build the base plant to increase its profits. The results also prove that to leave the market as it is without regulator intervention will provide the correct incentives for capacity investment but that there will be significant variation in the capacity margin.

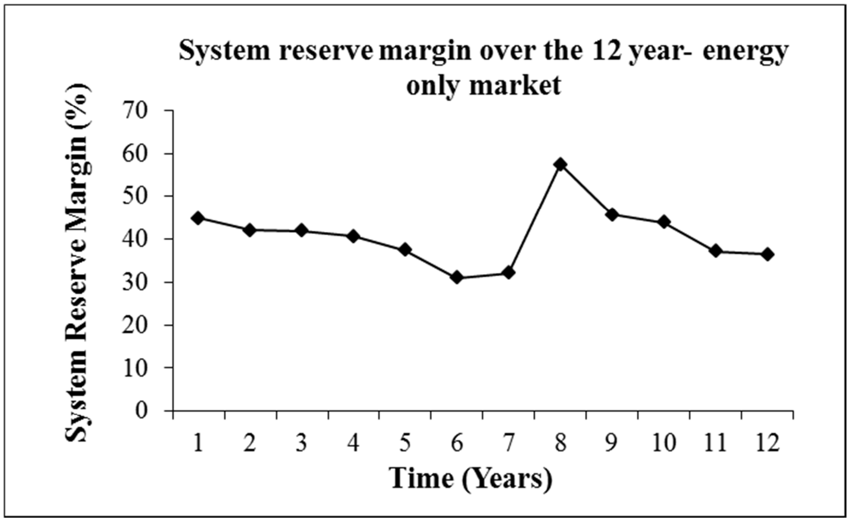


Figure 3-9 System reserve margin over the 12 years planning horizon

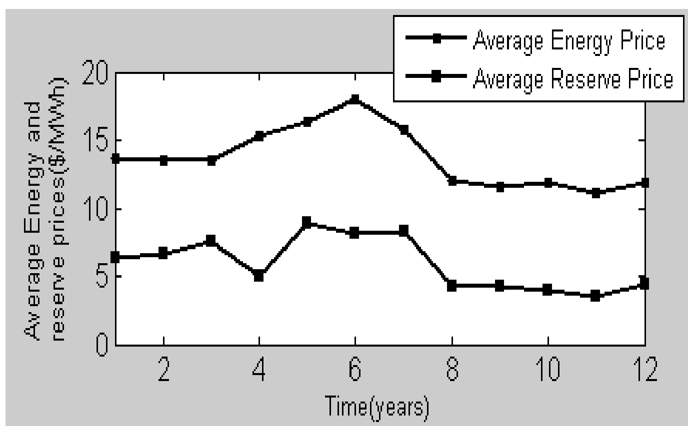


Figure 3-10 Average energy and spinning reserve price over the 12 year planning horizon

3.9.3 Case III: Generation Expansion with Capacity Payment

Table 3-8 shows the new plants selected by the generating companies when they receive capacity payments. With these capacity payments, all the generating companies choose to build more base plants because this type of plant receives the larger revenues, since these are proportional to its capacity (see equation (3.12)).

Year	1	2	3	4	5	6	7	8	9	10	11	12
GenCo1	None	2	2	1	1	1	None	None	None	1	1	1
GenCo2	None	2	2	1	1	1	None	None	None	1	1	1
GenCo3	None	2	2	1	1	2	None	None	None	None	1	1

1-Plant_1, 2-Plant_2

Table 3-8 New plant selected by the Gencos in capacity payment over the 12 year planning horizon

By giving a capacity payment as a means for promoting investment, the plants with larger capacities turn out to be more attractive options to the generating companies and the effect of the energy price has a smaller impact. This effect can be seen in Figure 3-11 when more new plants are added to the system during higher capacity payment and no plant is added between year 7 to year 9 when the payment is very low. The amount of the payment is also proportional to the system's LOLP. When there is a large amount of capacity available relative to the load; then the LOLP is low, reducing the capacity payment. The opposite holds when there is a small capacity margin in the system. The scatter plot in Figure 3-12 shows that the capacity payment is exponentially reduced as the reserve in the system increases.

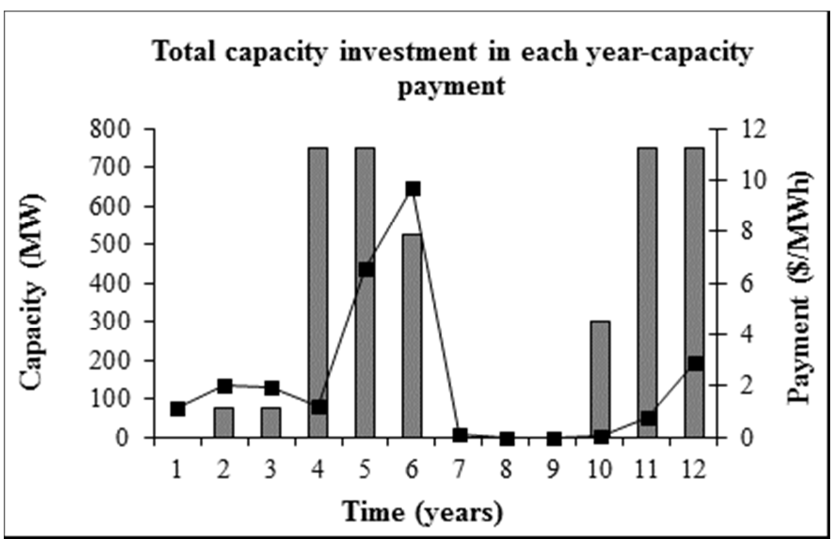


Figure 3-11 Total capacity investment and capacity payment over the 12 year planning horizon

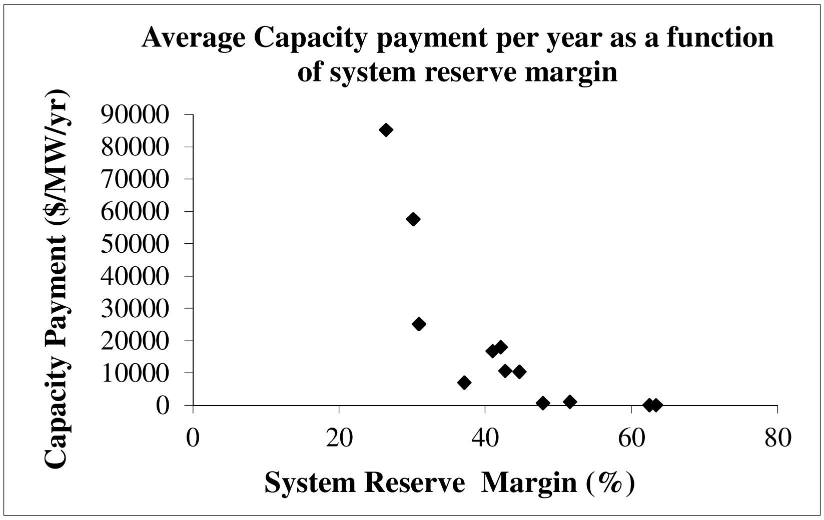


Figure 3-12 Capacity payments as a function of system reserve (%)

3.9.4 Case IV: Generation Expansion with Capacity Market

The capacity market incentive triggers investments to start from year 1 as shown in Table 3-9. In the capacity market developed in this model, not all the generators can participate in the market to serve the capacity obligation. This additional market gives to the peaking units that are not dispatched in the energy market, the opportunity to collect revenue for their unutilized generation. This market thus, influences the investment choices of the Gencos. Genco1 tends to build more base plants to collect revenue from the energy market; meanwhile its existing peaking unit can still collect revenue by participating in the capacity market. On the other hand, Genco2 that owns mid-size generating plants always gets dispatched in the energy market and building base plants would only displace its existing units in the supply curve. Because of this, Genco2 prefers to build peaking plants to collect extra revenue from the capacity market. Being the biggest base generation provider, Genco3 also decides to get extra revenue from the capacity market by building more peaking units. By doing this also at the periods in which the peaking generation is required, the market clearing price is higher and thus its base units collect larger revenues in the energy market.

In this market, the profits received by the generating units are based on the clearing price of the capacity market, which is carried out on a yearly basis. These prices are also dependent on the available system reserve. When the system reserve margin is low because of less capacity in the system as the load growth is assumed constant, most of the generators commit to provide energy and leave generators with higher marginal cost to participate in the capacity market. As a result the capacity market clearing price is higher during the shortage of reserve. On the other hand, during the period of excess capacity, fewer generators have the opportunity to dispatch energy; hence many of them participate in the capacity market. This causes the capacity market to be more competitive and hence reduce its prices during higher system reserve. The relative behavior between the system reserve margin and capacity market prices is shown in Figure 3-13.

Year	1	2	3	4	5	6	7	8	9	10	11	12
GenCo1	2	2	2	1	1	1	1	1	1	1	1	1
GenCo2	2	2	2	2	2	2	2	2	2	2	2	2
GenCo3	2	2	2	2	1	2	1	1	2	2	2	1

1-Plant_1, 2-Plant_2

Table 3-9 New plant selected by the Gencos in capacity market over the 12 year planning horizon

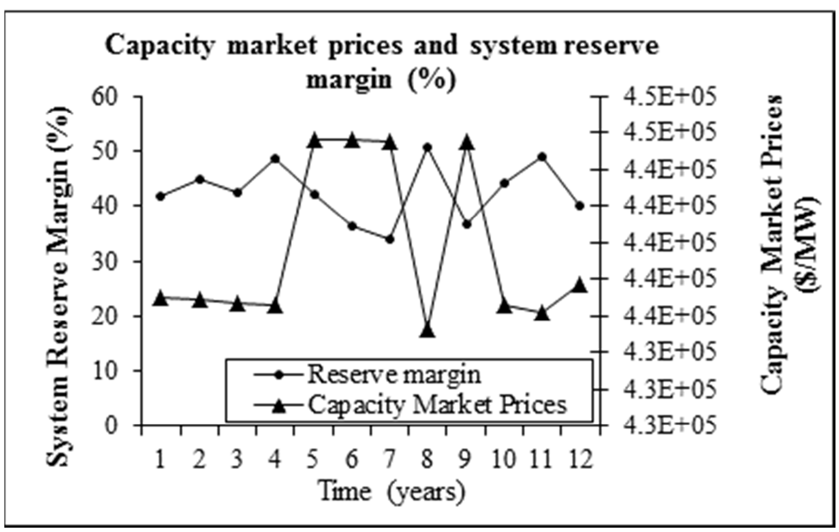
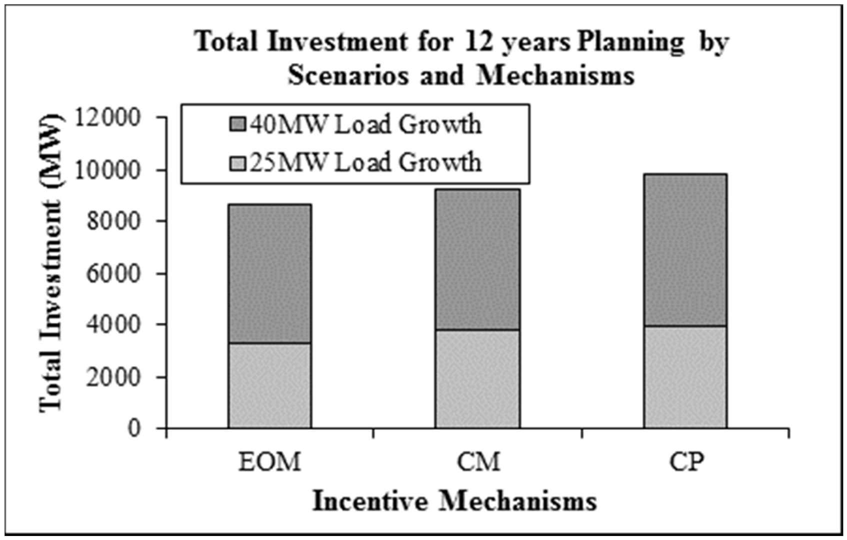


Figure 3-13 Annual capacity market prices and system reserve over the 12 year planning horizon

3.9.5 Case V: Comparison of the Different Mechanisms

Figure 3-14 shows the total investment from all the generating companies for the 12 years planning horizon by mechanisms at 25 MW and 40 MW load growth scenarios considered previously. Assuming that the market is competitive, the simulation shows that all the mechanisms succeed in promoting capacity investment in the system. Comparing the three incentive mechanisms, capacity payment is the one that results into the largest total investment for both scenarios. This is followed by the capacity market and the energy-only market.

The investment pattern of the generating companies under each mechanism is also simulated and it is seen that the competitive electricity market under all the mechanisms induce a similar pattern of boom and bust cycles. The amplitude of the cycles is a function of the capacity investments and the time between the booms and busts in each cycle vary between the mechanisms. Figure 3-15 shows the system reserve, which reflects the investment activity of the generating companies. It is seen that the capacity payment results in the largest swings of boom and bust as well as the biggest delay between the booms. This is because, the capacity payment attracts the generating companies to invest more in a bigger size of generation plant which cause the system reserve to shoot higher when these plants come online. These bigger plants are able to serve the load growth for a longer time hence delaying the price hikes that function as signals to the generating companies for the next investment boom. On the other hand, capacity market has the lowest amplitude and the most frequent of investment cycles. This is because the generating companies in this market tend to invest in the smaller units and cause the system reserve to drop faster in the next few years to cater for the load growth. The boom and bust cycle in the energy-only market is between the two capacity mechanisms.



EOM-Energy-only Markets, CM-Capacity Market, CP-Capacity Payment

Figure 3-14 Total investments for various scenarios and incentive mechanisms

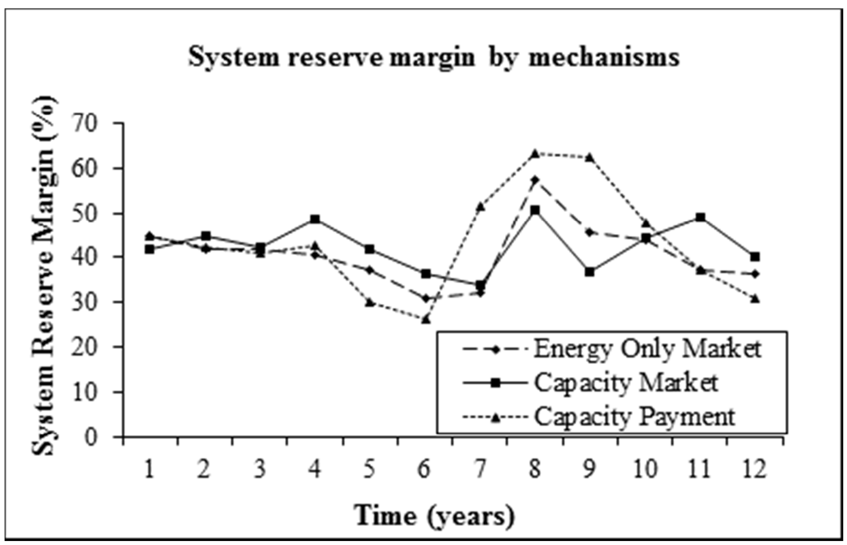


Figure 3-15 Investment cycles over the 12 year planning horizon for various incentive mechanisms

3.10 CONCLUSIONS

This chapter has presented a model to solve generation expansion planning in a restructured electricity supply industry using agent-based modeling. The model consists of multiple generating companies who make decisions on their generation expansion each year considering the possible investment strategies of their competitors. The overall framework can be divided into two parts. The first part is the forecasting period where each generating company estimates the profit of some potential investments and makes investment decision. The second part is the actual period where each of the generating company makes announcements on its expansion plans for that year, and then the market clearing is performed to calculate the actual energy and spinning reserve prices. Three types of capacity mechanisms have been presented in this model to complement the energy market in promoting capacity investment.

The case studies presented validate the model with different market scenarios and help study the complex interactions and investment strategies of the generating companies under different market mechanisms. Using the agent-based modeling technique, the imperfect foresight of the generating companies in making investment decisions and the construction delay can be incorporated in the generation expansion model. By doing this, the dynamic generation expansion in a liberalised electricity market can be simulated and studied. The analysis confirms that investment cycles could appear in the electricity market, mimicking the boom and bust cycles that have been observed in other commodities. In the analysis, assuming that the market is competitive, all the mechanisms succeed in promoting generation investment. It is seen that the 'boom' and 'bust' cycles also appear in the competitive market under all the capacity mechanisms. However the amplitude and the time delay of the cycles depend on how the market is designed. Since the design of capacity payment in the analysis attracts more investments in a bigger size generation plant with a longer lifetime, it results in the largest swings of cycle as well as the biggest delay between the booms. On the other hand, the capacity market presented by [26] which attracts more investments in a smaller size plant with a shorter lifetime has the lowest amplitude and the highest frequency of investment cycles.

This tool could be used by regulators to analyze generation expansion performance and to examine market designs. On the other hand, a generating company could use this tool to understand the complexity of the electricity market and to generate various system scenarios in formulating an investment plan.

The agent-based generation expansion planning model was not pursued much further in this thesis because there is not enough room for ‘learning’ activity between the market players in making investment decisions. An agent-based modeling concept that uses a ‘learning by doing’ paradigm is less suitable for modeling an investment decision of the generating companies who in reality use a ‘learning by thinking’ paradigm. The agent-based modeling approach is more suitable to model a decision that involves short-term operation such as a bidding strategy in the market. For that reason, a more comprehensive approach of assessing an investment for a single generating company is developed in the following chapters. In the model a framework to represent how the generating company should rationally make investment decisions in a liberalised electricity market is presented, rather than having a myopic view of its competitors’ investment strategy.

Chapter 4 Valuation Model for Generation Investment in Liberalised Electricity Market

Summary

This chapter presents a new explicit approach for a generating company to evaluate power generation investments in a liberalised electricity market. The basic investment framework consists of two levels of investment problems. The first problem is an optimization problem which models the expected future investments and retirements from all the companies in the market over the lifetime of the investment plant that the company is evaluating. The second problem corresponds to the net revenue calculation of the new investment plant for each year against the prototype schedule obtained in the first problem. Two different valuation models which extend the basic framework are presented. The first model (Model 1) is a probabilistic valuation model with risk analysis. The second model (Model 2) considers risk characteristics of different power generation technologies in an oligopoly electricity market. In the presented results, the effects of uncertainties on the profitability of the new investments are examined.

4.1 INTRODUCTION

Prior to the restructuring of the electricity supply industry, the utility companies which used to be operated as an integrated monopoly were able to pass all the costs of producing electricity to consumers in the form of a fixed tariff. Investments in power generation were less uncertain as there was no risk from the volatility of market prices. Any increase in the costs associated with the project, such as the fuel cost and the maintenance cost, could be covered by increasing the price to consumers. In such a situation there was little incentive for the companies to use a sophisticated analytical method to take into account the risks when assessing an investment.

The introduction of a liberalised electricity market exposes generating companies to various risks that might compromise their investment return. The generation investments are much riskier in this new market; where the generating companies are no longer guaranteed to cover their investment cost from the consumers. As a consequence, this more uncertain environment has led the generating companies to internalise various risks in their investment decision [6].

Specifically, there are two important factors that affect the investment decision and technology choice of the generating companies. The first factor is the different risk level posed by different power generation technologies. The issue of how to quantify and internalise the risks effectively into an investment evaluation and its effect on the technology choice has become a main concern of the generating companies. Moreover, the traditional leveli*s*ed cost methodology, which has been widely used as a costing assessment method for investment, is no longer suitable because it does not take risk into account in an effective way. The second factor is the structure of the electricity market; where most of the electricity markets are an oligopoly rather than perfect competition [7]. In an oligopolistic market, generators tend to increase their profits by raising their bid prices, increasing the market price and hence favouring the investment. Furthermore, since there are only a few companies in the market, interdependencies exist between the companies, in which the decisions of one company are influenced by and exert influence on the decisions of the other.

Therefore there is a need for new models that could consider the above factors in the investment evaluation, which is proposed by the models developed in this chapter. Unlike the model presented in Chapter 3 where the competitors' investment strategies are only considered in the current decision year but not into the future, in this model how the generating companies should rationally evaluate the investment considering the expected future changes in the system is presented. This study can be represented by the following objectives:

1. First to develop a new explicit valuation model for a generating company to assess power generation investments considering the risk characteristics of different generation technologies

2. Second to incorporate risk assessment techniques in the investment evaluation model in order to provide generating companies a systematic and comprehensive methodology to assess a new investment
3. Third to model the prices in the oligopolistic market; so that the value of a new investment is not underestimated
4. Finally to study the effect of uncertainty in the various parameters in the model on the profitability of different technologies.

4.2 INVESTMENT RISKS IN LIBERALISED ELECTRICITY MARKETS

The risks associated with the investment in power generation can be classified into two categories: 1) internal risk, which is associated with the factors under the control of the generating company such as the capacity and availability of the generating units, the technical characteristic of the units (heat rate, economic lifetime, construction time), the cost characteristic of the units (investment cost, operation and maintenance (O&M) cost) and the policy of the company. 2) External risk which refers to the external factors that influence the investment and which are outside the company's control such as the demand for the electricity, the electricity prices, the fuel prices, the regulatory policy, the environmental constraint, inflation and interest rate. In order to examine power generation options according to the different risks posed by different power technologies, the risks associated with the technologies are explicitly modelled in the investment valuation model proposed in this chapter.

4.3 HOW MARKET LIBERALISATION AFFECTS TECHNOLOGY CHOICES?

The uncertain future level of prices from the investments is the greatest risk for the technologies. Although this risk affects all the generating technologies, it does so in different ways. Technologies with higher investment costs but lower fuel costs such as nuclear and wind generation are more greatly affected by this risk, because there is less they can do to respond [6]. The technologies that have a long lead time are also affected by this risk. This is because the plants' economics are exposed to the unpredictable future prices for a longer time period.

The cost of fuel is another significant risk for generators, particularly the technologies where the fuel costs constitute a high relative amount of total generating cost, for example technologies that use natural gas as a fuel. Moreover, the price volatility in the natural gas market adds uncertainty to the investment in the natural gas technologies.

The action of the regulator in setting a new policy for the electricity market is also a risk to the investor. For example, the introduction of carbon tax on the carbon dioxide emissions from burning fossil fuels would affect the profitability of coal and natural gas technology. This scheme which has been implemented in the European countries, United Kingdom and New Zealand provides an incentive to reduce the use of high carbon fuels in generating electricity. On the other hand, the nuclear power plants are restricted in their emission of radioactive waste by the introduction of a nuclear waste fee. This fee is a charge imposed by the regulator to the power company for the disposal of radioactive waste, hence increasing the investment cost of the nuclear technology. Some regulators encourage development in wind generation by providing incentives such as tax credits in the United States, Canada and Germany. In the UK, the Renewable Obligations (RO) was introduced in 2002 to support generation of electricity from renewable sources. This scheme requires the electricity suppliers in the UK supply a specified percentage of the electricity that they produce from eligible renewable sources. A Renewable Obligation Certificates (ROC) is issued to these accredited generators which can be traded in a green certificate market. The profitability of other technologies would be affected by any increase in the renewable energy generated proportion in the market.

Table 4-1 shows qualitatively the investment risk characteristics of different power generation technologies based on a study presented by [6]. The gas fired technology which has relatively low investment costs, short lead time and flexibility in operation would be the favoured choice of the generating companies in this riskier environment. However the high level of uncertainty in natural gas prices poses a big challenge for the investor. The nuclear power plant in contrast with the gas fired technology has high investment costs, long lead and construction times and hence provides the largest investment risk. On the other hand, the profitability of coal technology is more affected by the environmental risks than the investment in natural gas technology and nuclear options.

Tech-nology	Unit Size	Construc-tion Time	Capital Cost /kW	Opera-ting Cost	Fuel Cost	CO2 Emission	Regula-tory Risk
CCGT	Medium	Short	Low	Low	High	Medium	Low
Coal	Large	Long	High	Medium	Medium	High	High
Nuclear	Very Large	Long	High	Medium	Low	Nil	High

Table 4-1 Qualitative comparisons of investment risk characteristics for different power generation technologies based on [6]

4.4 INVESTMENT EVALUATION MODEL

This model proposes an approach that a generating company could use to evaluate investments in a liberalised electricity market, taking into account the future investments that its competitors might make over the lifetime of the plant that it is considering. Instead of assuming the future electricity prices as a probability distribution [31], a trend extrapolation [82] or a stochastic process such as in real option theory [38], this model adopts an explicit approach which models the construction of new plants and the closure of old ones and calculates the electricity prices by clearing the market at several load levels for each year of the expected lifetime of the investment under consideration. Given the long-term nature of the investment in power generation, investment evaluations should be made on a long-term basis rather than looking at the short-term behaviour of the electricity prices [6]. The conventional discounted cash-flow method is therefore still an effective approach for power generation investment evaluations and is hence considered in this model. However the application is extended to take into account the various risks and to incorporate the risk assessment tools.

In the next section of this chapter, a basic structure of the proposed model is first described, including an overview of the investment evaluation framework, the prototype future system expansion schedule and the market model. Then two different investment models which extend the basic model are presented. The first model (Model 1) is a probabilistic investment evaluation model which is developed to consider uncertainties and to use the concept of Value at Risk (VaR) in measuring the risk of different investments. The second model (Model 2) is developed to take into account the risks posed by different technologies and to model the prices in an oligopolistic electricity market.

4.5 BASIC STRUCTURE OF THE PROPOSED INVESTMENT EVALUATION MODEL

4.5.1 Overview of Investment Evaluation Model Framework

Figure 4-1 illustrates the basic framework proposed in this thesis for investment evaluation by a generating company, which is referred to as Company A. At the initial stage of the process, it is assumed that Company A has access to the current system information such as load, fuel costs and spinning reserve requirements. The investment problem is divided into two stages: i.e. an upper and a lower problem. When evaluating each possible investment, the generating company needs to consider the fact that other plants will be built and retired in the system over the lifetime of the plant that the company is considering. A ‘prototype’ future system expansion for all the companies is then developed using Dynamic Programming (DP) in the upper problem. This prototype is based on the assumption that the market is sufficiently competitive in the long run to ensure that the overall system generation expansion will minimize the total cost of expansion and operation over the planning horizon. This prototype schedule is used as a base for Company A to evaluate the revenues that investment in a new plant will generate over its lifetime.

The lower problem calculates the profit that the new investment will produce each year, assuming that it operates in the context of the prototype system expansion obtained in the upper problem. On the other hand, electricity prices are a by-product of the yearly market clearing process. In this process, the generators in the system are stacked in merit order of bidding price to meet the demand and spinning reserve requirement. Based on the market clearing, the revenue produced by a new plant can be calculated for every year of its expected lifetime and used to determine the IRR and FWV of the investment.

In both the upper and lower problems, the generating company forecasts the LDC, the future load growth and the fuel cost. Finally, the generating company can use the model to evaluate and compare the profitability of different investment alternatives and decides which plant to build in maximising its profit.

4.5.2 Prototype Future System Expansion Using Dynamic Programming

In estimating the revenue of the investment plant over its lifetime, Company A needs to consider the generating plants that will be built by its competitors over the lifetime of the plant that it considers building. A potential new plant must therefore be evaluated against a "prototype future system investment schedule" for the entire sector because these future investments will affect the price of electricity and hence the profitability of the new plant. In this model, the prototype investment schedule for all the companies is determined using a DP-based optimization. An expected retirement schedule of the existing plants in the system is provided as input data to the DP. The generating company uses this expected system investment and retirement schedule as a base to calculate the revenue of the potential new plant for every year of its lifetime. Uncertainties on the prototype system investment schedule can be explored by varying the parameters used in its calculation. Changing the input parameters provided to the DP optimization gives different scenarios of future investment. This future prototype system schedule considers the influence of load growth, fuels escalation, regulatory policy and the new plant that the company is evaluating.

DP is applied over a time horizon to find a set of optimal decisions to minimize the objective function subjects to several constraints. It was one of the most widely used algorithms in generation expansion planning before the restructuring of the electricity supply industry [83, 84]. Some commercial packages like Wien Automatic System Planning (WASP) [85] use DP to find the "optimal" generation expansion planning strategy.

This model uses a similar technique for finding a prototype system investment schedule. In developing the prototype, it is assumed that generation expansion by Company A and its competitors will approximately minimize the total cost of generation expansion while meeting a minimum reserve capacity requirement for the system. In other words, it is assumed that the industry will behave in a rational manner in the long term and will not let the reserve capacity decrease below a level that might endanger the security of supply and hence trigger intervention by the regulator or the government. This assumption is supported by the IEA study [7] of seven reformed markets which concluded that substantial investments have been made since market liberalisation and the OECD electricity markets are generally reliable, with the exception of the California crisis. However, this minimum reserve capacity requirement constraint will be replaced by introducing capacity mechanisms in Chapter 5 of this thesis. The assumption of cost minimization made in DP-optimization is in line with the objective of electricity market liberalisation to improve the economic efficiency of electricity supply industry. There is evidence to suggest that the introduction of competition in the electricity industry has reduced the operating costs by improving labour productivity and fuel choice, and reducing maintenance costs [86]. As pointed out previously in Chapter 2, profit maximisation is usually used as an objective for an individual company in a liberalised market, however it is not suitable to represent the objective of future expansion from the whole system perspective.

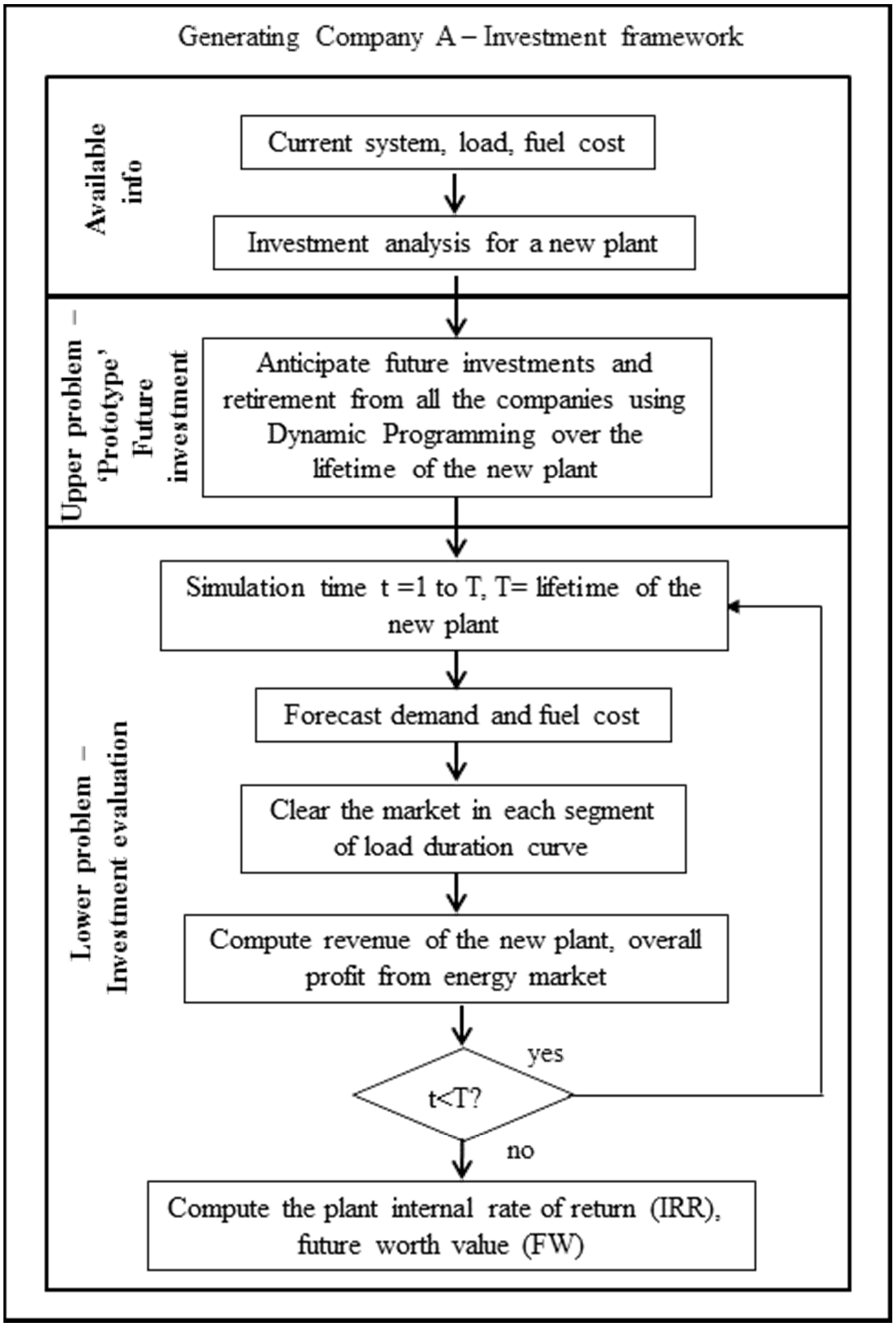


Figure 4-1 Basic framework of the investment evaluation model

The DP is an approach that transforms a complex problem into a simpler sub-problem. Its main characteristic lies in the way that the optimization is solved in multiple-stages. Using DP reduces the dimensionality of the problem. For example, suppose that there are *P* feasible states at interval *k-1* of a problem as shown in Figure 4-2. Each state has *S* paths from stage *k-1* to stage *k*. At interval *k*, the DP only selects and saves the cheapest path, for instance the yellow path in Figure 4-2. Each of the other states at stage *k* also has its cheapest path from stage *k-1* to stage *k* as depicted in green and pink. Thus, at most there are only *P* paths and states that need to be saved at each stage.

In this prototype investment schedule, a path is defined as the schedule of new investments that might be chosen by the generating companies and a state is defined as the existing units plus the new units. The DP-based optimization selects the investment options each year among the set of generation technologies until it reaches the optimization horizon. Since the initial state (the existing units and system information) of the problem is known and the cost of expansion is the functional equation in the following year (stage), therefore a forward DP approach has been chosen in developing the prototype system investment schedule.

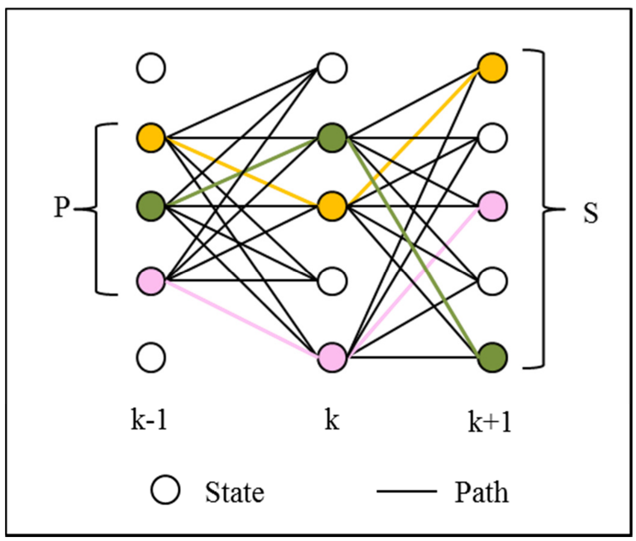


Figure 4-2 States and paths of DP-based optimization

The total system generation expansion cost is defined as follows:

$$TC = \min \sum_{t=1}^{T} \{ PC_{all}(X_t)_t + IC(U_t)_t \} \tag{4.1}$$

where *TC* is the total cost of expansion over the simulation horizon, PC_t is the total production cost of all the generating units in the system at year *t*, IC_t is the total investment cost of the new investments at year *t*, X_t is the cumulative capacity (MW) vector in year t, U_t is the capacity addition vector in year t and T is the lifetime of the new plant that the company considers building. Multiplying the marginal cost by the energy produced gives the production cost of each unit as shown in equation (3.9) in Chapter 3. The energy produced each year is computed by clearing the market for each segment of the LDC.

This optimization is subject to several constraints:

$$X_t = X_{t-1} + U_t - K_t \text{, } \forall t \in \mathrm{T} \tag{4.2}$$

$$R^{\min} \le R(X_t) \le R^{\max} \text{, } \forall t \in \mathrm{T} \tag{4.3}$$

where R is the reserve margin resulting from the generation capacity X_t, K_t is the capacity retirement and T is the optimization horizon. Equation (4.2) indicates that the cumulative capacity at year t is equal to the capacity at the previous year, plus the new capacity built at year t, minus the capacity retirement happening at year t. For each year, equation (4.3) constrains the installed capacity to be within the minimum and maximum reserve requirements allowed in the system. The minimum reserve constraint is enforced as it is assumed that the industry will not let the reserve capacity decrease below a level that might endanger the security of supply. On the other hand the maximum reserve constraint is set in the formulation to reduce the state space that the DP must search and hence reduce the computation time.

4.5.3 Market Representation

A similar electricity market design as presented in Chapter 3 is used in the investment evaluation model. The market clearing process is included both in the upper and lower problem of the investment framework as shown previously in Figure 4-1. In the upper problem, the market clearing is performed to calculate the energy production of the generating units, and then used to compute the production cost for the DP-optimization. In the lower problem, the energy price is obtained by clearing the market in each year over the lifetime of the new investment with respect to the expected future system's expansion from the DP. The prices are then used to calculate the expected revenue of the potential new plant.

4.6 MODEL 1: PROBABILISTIC MODEL FOR GENERATION INVESTMENT UNDER UNCERTAINTY

In this probabilistic investment evaluation model i.e. Model 1, the basic investment model presented in the previous section of this chapter is extended to consider uncertainty in the evaluation. The probabilistic valuation model is introduced to provide the generating company a wider analytical framework as well as to incorporate risk assessment in the evaluation. The new framework consists of: 1) defining a statistical distribution for future load and fuel costs which are the uncertainties considered, 2) anticipating future system generation expansion using DP, 3) generating future cash-flow for the new plant by clearing the market every year with respect to the anticipated system expansion, 4) computing the plant's net revenues and IRR over its lifetime, 5) performing a Monte Carlo simulation to capture the statistical fluctuations of the IRR and 6) analysing the IRR distribution using a risk assessment technique to make a decision. However the uncertainties in the future load and fuel costs are only considered in the lower problem of Figure 4-1 but not in the DP-optimization. This is because the objective of this model is to generate the profit distribution of the investment and to present a technique to measure the distribution using a risk analysis. In theory, uncertainty could be considered in the DP-optimization by using stochastic dynamic programming but this would require an unreasonable amount of computing time.

4.6.1 Uncertainty in Load and Fuel Costs

When assessing a generation expansion option, the future load and fuel costs must be predicted. Since these forecasts are subject to uncertainties, they are modelled as normal probability distributions function as shown in Figure 4-3. The load duration curve (LDC) is modelled with uncertainties not only on the amplitude but also on the duration of each segment. The magnitude of segment s is given as $A_s = N(\mu_s, \sigma_s^2)$ with duration $d_s = N(\mu_d, \sigma_d^2)$; where μ is the expected value and σ is the standard deviation. Since the LDC has a length of 1 year, the following equality must hold:

$$\sum_{s=1}^{S} d_s = 8760 \tag{4.4}$$

Similarly the uncertainty on the fuel cost is also modelled by a Gaussian distribution, $f_c = N(\mu_f, \sigma_f^2)$ where μ_f is the expected fuel cost and σ^2_f is its variance.

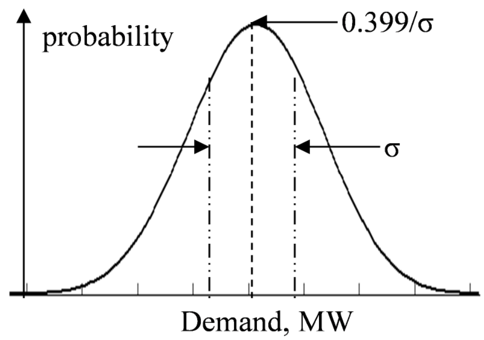


Figure 4-3 Demand distribution considering uncertainty

4.6.2 Investment Decision Considering Uncertainties

The yearly energy revenues, revenues derived from providing spinning reserve and production costs are obtained as described in Chapter 3. Once all these quantities have been computed over the life time of a given possible new plant, the IRR of the generated cash-flow is calculated. The IRR of the cash-flow for each scenario is calculated for randomly selected load demands and fuel costs using the specified probability distributions. This Monte Carlo simulation makes possible the characterization of the probability distribution of IRR. The resulting IRR probability distribution provides an investor with a much richer analytical framework to assess power generation investment. Figure 4-4 and Figure 4-5 show an illustrative example of IRR probability and cumulative distribution function for a power plant.

In order to quantify the risk in this model, the Value at Risk (VaR) which is a tool from financial risk theory for risk assessment is applied. The VaR is a technique used to measure the potential loss of a portfolio over a time period at a given confidence level. Instead of finding the VaR with a given probability as usually considered in financial analysis, the confidence level at VaR equal to the minimum acceptable rate of return (MARR) of the investment is calculated. From the distribution, for a given value of MARR, the probability of getting an IRR less or greater than MARR can be computed. In other words, this answers the following question: *"Considering all the risks involved, what is the confidence level associated with investing in a project with an IRR of x%?"* The example shows that the project provides a confidence level of 95% of getting IRR≥12%. The decision to accept or reject this project depends on the investor's perspective towards the risk. The risk-averse investor may accept a project with lower but more probable IRR, while a risk-taking investor may prefer a higher return despite a probability distribution with a high standard deviation. A different project may have a different risk distribution, which lead to different IRR distributions. With the aid of this IRR distribution, the management of the company may decide how much market risk the company is willing to take before any investment decision is made.

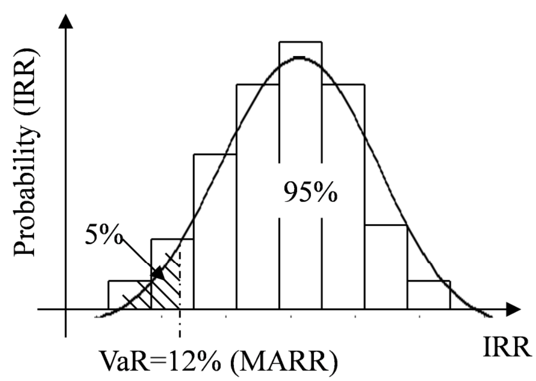


Figure 4-4 IRR probability distribution function with confidence level of 95% of getting IRR ≥12%

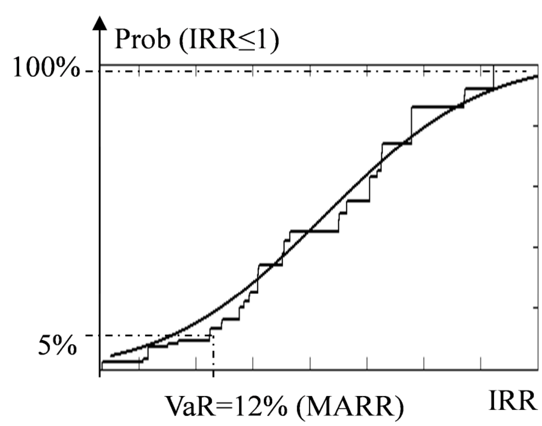


Figure 4-5 IRR cumulative distribution function with confidence level of 95% of getting IRR ≥12%

4.6.3 Test Results

A case study has been carried out using the proposed probabilistic investment evaluation model on the IEEE RTS presented in Chapter 3. Company A considers investing in one of two possible generating plants for the current year. Both are coal power plants with 155 MW (Plant_3) or 250 MW (Plant_4) capacities respectively. Table 4-2 shows the technical and cost characteristics of these two plants.

Plant name	Size MW	Unit type	Invest $/kW	Build time	Heat rate offset MBTU/h	Heat rate MBTU/ MWh	MARR %	Expected lifetime years
Plant_3	155	Coal	1000	3	64.881	7.2892	12	25
Plant_4	250	Coal	1000	3	70.124	6.679	12	25

Table 4-2 Investment plant's technology and cost

The characteristics of the investment technologies that can be selected by the DP for the prototype system expansion are given in Table 4-3.

Unit	Size MW	Unit type	Heat rate offset, MBTU/h	Heat rate, MBTU/MWh	Investment, $/kW	Lifetime, years
PGF_17	155	Coal/Steam	64.881	7.9044	1000	25
PGF_10	76	Coal/Steam	44.386	8.8288	1000	25
PGF_21	197	Oil/Steam	26.597	2.8134	500	25
PGF_01	12	Oil/Steam	2.8099	3.0774	500	25
PGF_24	350	Coal/Steam	70.124	6.679	1000	25
PGF_06	20	Oil/Steam	13.871	4.4939	500	25
PGF_14	100	Oil/Steam	24.029	2.2303	500	25

Table 4-3 Available investment technologies for DP

The LDC has been discretized into 5 non-optimised segments. The peak value is assumed to be 2577.2 MW at year 0 and it is assumed that the magnitude of each segment of the LDC increases by 2.3% per year. In this analysis the market is assumed to be perfectly competitive where the units bid at their marginal cost. The uncertainties in the LDC are modelled as Gaussian distributions with a mean value equal to the magnitude of the segment times the demand peak value and a standard deviation of 1% of the mean value. Similarly, the fuel costs are modelled with a Gaussian distribution with the following mean values: 2.31 $/MBTU for coal, 13.5 $/MBTU for oil and 5.54 $/MBTU for gas and a standard deviation of 1% of the mean value of the fuel. The LDC used for the prototype calculation using DP has the same values and increases at the same rate. The minimum and maximum reserve requirements in the DP are set at 18% and 30% respectively. It is assumed that all the existing generating units are sunk costs at year 0. At least 1000 trials of the Monte Carlo simulation are performed.

Figure 4-6 shows 12 of the 28 years of the prototype future system investment schedule resulting from the DP calculation. The new plant being evaluated by Company A (Plant_3) comes on line after construction is completed at year 4. The DP is carried out for the lifetime of Plant_3 i.e. 25 years. The upper block of Figure 4-6 shows the plants built by all the companies in the system over the simulation horizon, while the lower block shows the retirement of the units that have reached their expected lifetime. For example, it is expected that PGF_10 will be built in year 6 followed by PGF_14 in year 7 and so on. More plants will be built at years 9 and 11 to replace some of the existing units that are retired. When Plant_4 with a bigger capacity but similar build time and lifetime as Plant_3 is evaluated, the DP gives a different solution of prototype system expansion; where less capacity will be built to cater the same load growth and plants retirement considered in the case of Plant_3.

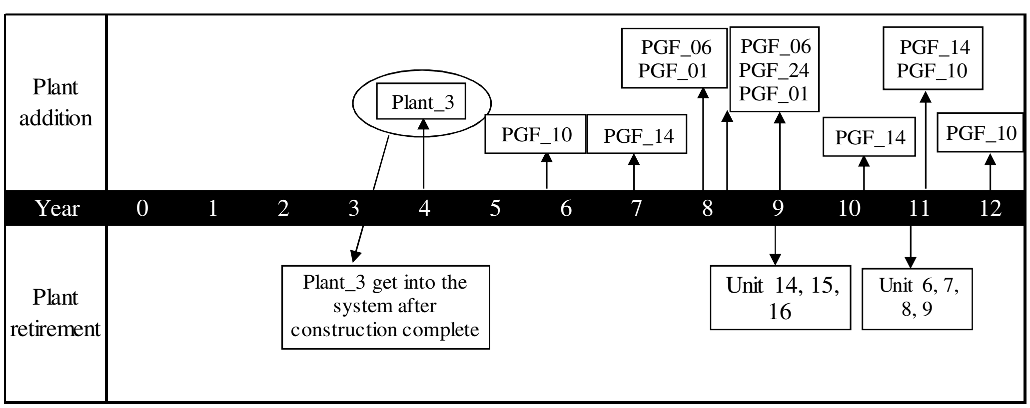


Figure 4-6 Prototype future system investment schedule using DP over the lifetime of Plant_3

The average energy price over 28 years resulting from the simulated market clearing process with respect to the expected changes in the system (Figure 4-6) is show in Figure 4-7.

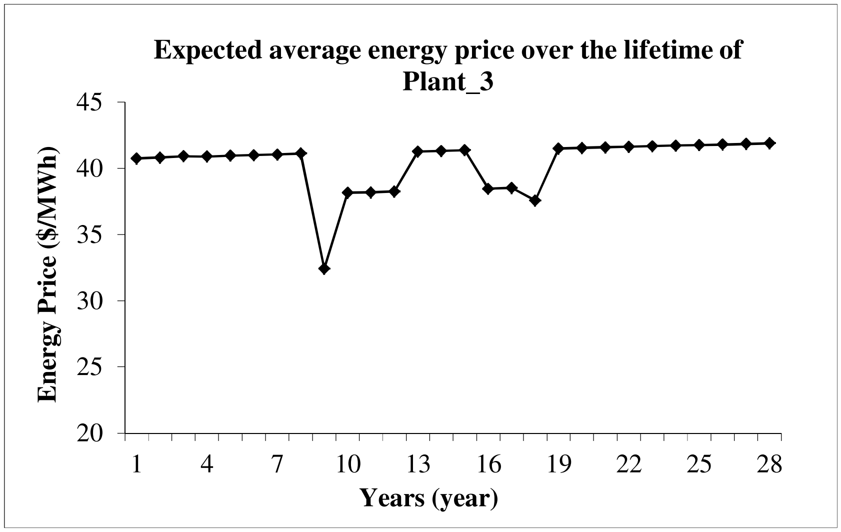


Figure 4-7 Expected average energy price over the lifetime of Plant_3

Figure 4-8 and Figure 4-9 show the IRR probability density and cumulative distributions function of Plant_3 and Plant_4 respectively with similar uncertainties applied to both investments. The IRR distribution of Plant_3 is skewed to the left compared to the distribution of Plant_4. This indicates that the probability of getting a smaller rate of return is greater with Plant_3. Assuming that the plants bid at their marginal cost, Plant_4 with a lower marginal cost has a better chance to be selected to dispatch energy in the market than Plant_3, hence in average shows a higher IRR. If the VaR of the investments is assumed to be equal to the MARR of both of the plants (i.e. 12%), then the plot of IRR cumulative distribution function of Plant_3 gives a confidence level of 63% to get a return greater than 12%. On the other hand Plant_4 provides a confidence level of 98.9%. The lower confidence level associated with Plant_3 indicates that investing in Plant_3 represents a higher risk than investing in Plant_4. Both of the IRR distributions are spread almost equally since they arise from uncertainty on the same fuel and demand.

By comparing the two plants, Company A may thus decide to invest in Plant_4 which is less risky and guarantees a higher return. However all decisions depend on the acceptable confidence level of Company A and the financial risk that the company is prepared to take. This probabilistic analysis combined with a risk assessment technique gives the generating company a wider analytical approach to assess an investment by providing the confidence level and riskiness of the investment under uncertainty.

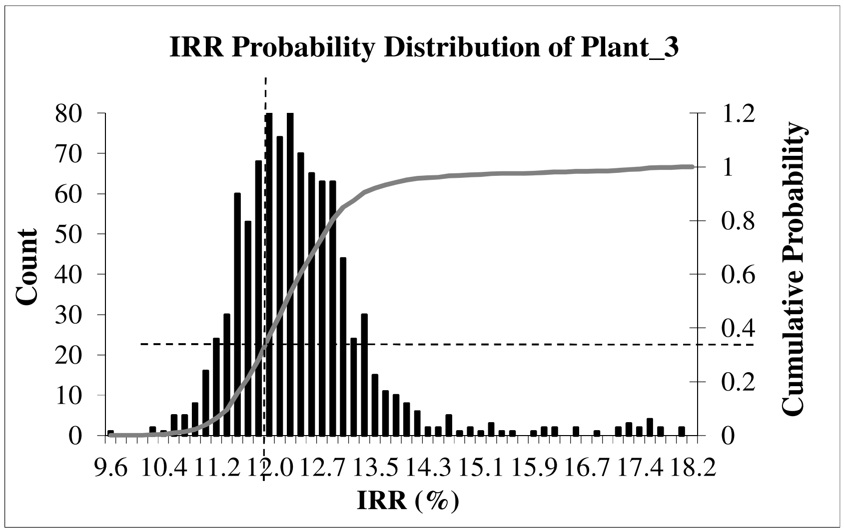


Figure 4-8 IRR probability distribution of Plant_3

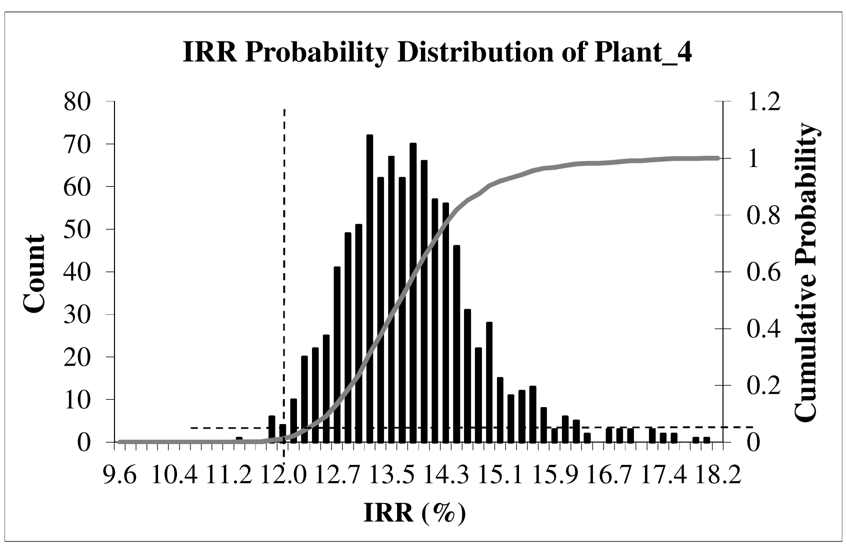


Figure 4-9 IRR probability distribution of Plant_4

4.7 MODEL 2: GENERATION INVESTMENT EVALUATION IN AN OLIGOPOLY ELECTRICITY MARKET CONSIDERING RISK CHARACTERISTICS OF DIFFERENT TECHNOLOGIES

In this section another model that also extends the basic investment evaluation model in Figure 4-1 to consider investment in an oligopoly electricity market is presented. In modelling the oligopolistic market, a price duration curve (PDC) from the PJM market is used to estimate the bid prices of the generators. This model also takes into account the different technologies' investment risk profile such as the investment cost, the fixed and variable O&M cost, the plant lifetime, the construction period, the fuel escalation rate, the carbon emission tax and the nuclear waste fee into the investment evaluation. Since the expected profitability of any investment plant is very dependent on the shape of the LDC, a technique to discretize the LDC based on the minimization of a penalty function [87] is introduced prior to the investment evaluation.

4.7.1 Optimal Step-Function Approximation of LDC

When considering generation investments, the LDC is usually approximated using a step function. This approximation is usually produced by sketching or in some other ad hoc manner. However, because the expected profitability of any investment plant is very dependent on the shape of this discretized LDC (as will be shown later in the analysis), it is necessary to use a more rigorous technique. Some techniques have been developed to find a step function that optimally fits the LDC. The first attempt was proposed by Loney [88] who used Dynamic Programming with a six step approximation. The authors of [87, 89] extended Loney's algorithm to widen the application. In this model, the algorithm proposed in [87] to discretize the LDC based on the minimization of a penalty function is used prior to the investment evaluation. In this section, a brief explanation about the concept and formulation of the algorithm is presented. A more detailed description of this algorithm can be found in Appendix B.

Figure 4-10 shows the three-step approximation of a typical LDC that is used to illustrate the methodology.

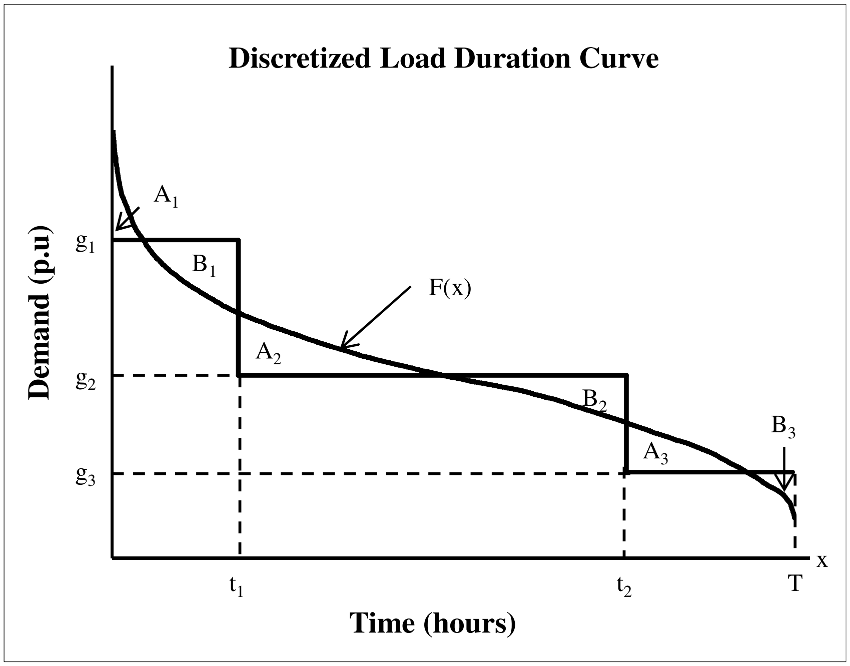


Figure 4-10 Typical LDC with a three step approximations (source:[87]

The LDC is denoted by F and T is the number of hours being considered. The three segments are defined by the break points t_1 and t_2 and the corresponding heights g_1, g_2 and g_3. Since the area under the LDC is equal to the total electrical generation in the period, the area under the step-function approximation should be equal to the area under the LDC for each step. Each g_i can be expressed mathematically as a function of t_1 and t_2 as follows;

$$g_1 = \frac{1}{t_1}\int_0^{t_1} F(x)dx \tag{4.5}$$

$$g_2 = \frac{1}{t_2 - t_1}\int_{t_1}^{t_2} F(x)dx \tag{4.6}$$

$$g_3 = \frac{1}{T - t_2}\int_{t_2}^{T} F(x)dx \tag{4.7}$$

In Figure 4-10, area A_1 above the first segment and under the LDC can be interpreted as representing a deficit of electrical generation and the area B_1 above the LDC but below the first segment as representing an excess of generation. Areas A_2, B_2, $A3$ and B_3 can be interpreted in the same way.

The authors of [87] also introduce a penalty function, $p(e(x))$, to solve the optimization problem where $p(e(x))$ is the penalty to be paid per unit of mismatch at x and $e(x)$ is the amount of mismatch at x. From Figure 4-10, $e(x)$ can be expressed as $|F(x)–g(x)|$. The total penalty for the step-function approximation is given by:

$$P = \sum_{0}^{H} p(e(x))e(x)dx \tag{4.8}$$

The goal of this optimization problem is to find the value of t_1 and t_2 in such a way that the total penalty of the mismatch is minimized. This problem can be solved using backward Dynamic Programming where the solution is searched recursively for each interval $[x,y]$ defined for the LDC until the total penalty of all the segments is minimized. The functional equation for the minimal penalty, $f_n(x)$ from an n-stage process given that the starting point for the process is at the point x is shown below:

$$f_n(x) = \min_{x \le y \le T}\left(\sum_x^y p\big(e(x)\big)e(x) + f_{n-1}(y)\right) \quad n = 1,\ldots, S-1 \tag{4.9}$$

where S is the number of segments of the LDC and $[x,y]$ is the interval where the solution of the n-stage process lies.

The simulations were carried out for a six steps approximation of the LDC using a penalty function, $p(e(x))=1$. The hourly load data is from the PJM RTO regions [90] for the load from 1st January 2008 to 31st December 2008 with 8784 hours. Figure 4-11 shows the six steps approximation of the LDC from the PJM market at a given starting point for each interval $[x,y]$ where the break point lies. These intervals are first defined by the user according to the desired shape of the discretized LDC, for example to have more segments at the peak load. These intervals are shown by the top arrows in Figure 4.11. The break points and the total error are tabulated in Table 4-4.

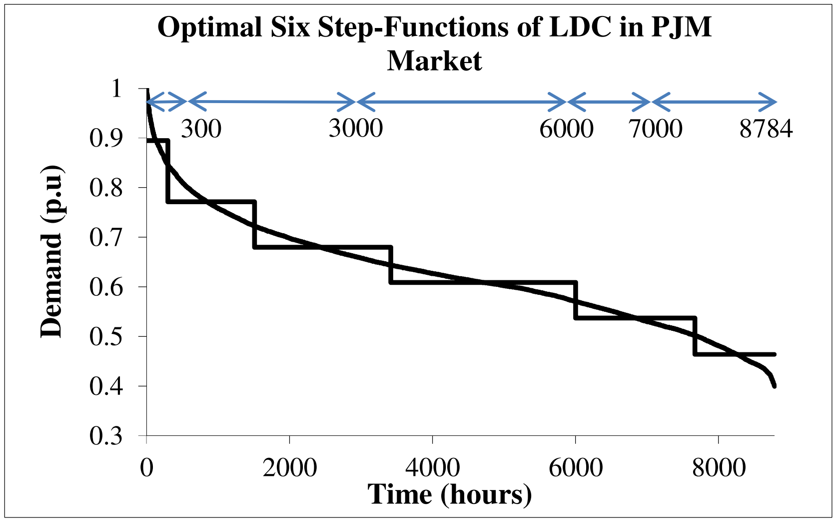


Figure 4-11 Optimal six step-functions approximation of LDC in PJM market at a given interval

Steps	Break Points	Total Error
6 step-function of LDC	300 1511 3416 6001 7672	0.03218222

Table 4-4 Break points and total error of six step-functions approximation of LDC in PJM market

4.7.2 Modelling an Oligopoly Electricity Market

As mentioned previously in this thesis, the existing electricity markets behave more like oligopoly than perfect competition. This is because the electricity supply industry has some special features such as a small number of firms competing in the market, a long construction period and a huge capital investment of power plants that introduce barriers to the new entrants in the market, and transmission constraints which isolate consumers from generators. In such a situation, generating companies can increase their profits by exercising market power through the use of various bidding strategies that raise the market price.

The word oligopoly is derived from the Greek words “oligos”, which means “few”, and “politi”, which means “seller”. There are three characteristics of an oligopoly market. First, an oligopoly market is dominated by a few large companies, resulting in a high degree of market concentration, i.e. the leading companies dominate a large share of the market. The second characteristic is that it has a high barrier to entry due to the large capital investments required. Finally, since there are only few companies in the market, interdependencies exist between the companies in the sense that each company is very much aware of the actions of the other companies. Some studies show that generators in an oligopoly market tend to adjust their bidding strategies and learn to reach tacit collusion in order to profitably increase the market prices [91-93].

The strategic bidding of the generating companies in the electricity market is usually modelled using game theory. The method can be classified into two: 1) the matrix game based in [94, 95] and 2) oligopoly games based such as Cournot model, Stackelberg model and Supply Function equilibrium model in [96-98]. However the game theory in the works presented above only considers a single-shot game which does not take into account the repeated nature of the interactions between the generating companies. The authors of [99] combine the concept of game theory with a genetic algorithm to include “learning” in searching for an optimal bidding strategy of a generating company. On the other hand, [100] combines game theory with conjectural variations to model the dynamic bidding behaviour of the companies over time. Another approach is to develop a bidding strategy of the generating company based on the estimation of the bidding behaviours of its competitors using possibility theory [101] and probability theory [102].

Lucas and Taylor [103] in their “strategy curve” found that generating units with lower running costs are bid at their marginal cost, while the more expensive ones are bid higher than their marginal cost. Generators that are technically flexible can start and shut down quickly when needed. However they tend to be more expensive. These generators command a premium for their flexibility, therefore owners of these plants can afford to bid high and still expect the plants to be run. Furthermore, these generators have less competition in setting the price at the higher loads since most of the generators with lower marginal cost have been committed to supply energy at lower loads. This provides them an opportunity to bid high but still expect the plants to be committed.

In this thesis, an empirical approach has been adopted to model the prices in the oligopoly market considering the oligopolistic behaviour of the generating companies. This approach assumes that generators bid at their marginal cost when the load is light (i.e. the lowest segment of the LDC) but submit bids higher than their marginal cost at higher load segments. This assumption has also been used by [104] in modelling a price duration curve (PDC) using probability theory. It is not the aim of this thesis to model the interaction of the generating companies in setting the prices in the oligopoly market as usually developed using game theory. However the model proposed in this chapter uses the findings presented in the literature that the prices in the oligopoly market are usually higher than what would arise from perfect competition as a result of oligopolistic behaviour of the generating companies in modelling the prices. The objective of modelling the bid prices of the generating units as in the oligopoly market is to have a realistic price in calculating the revenues from a new investment, so that the new investment is not underestimated. It is also beyond the scope of this thesis to analyse other issues related to oligopolistic markets such as tacit collusion.

In modelling the bidding behaviour of the generating units in an oligopoly market, it is assumed that the bid price of the units will imitate the bidding behaviour in a real market such as PJM. Since the shape of PDC is resulted from the bid prices that clear the market, the PDC from the PJM market is used to extrapolate the bid price of the generating units.

An ideal PDC (from market clearing simulation) where the generators bid at their marginal cost is first built. A bid factor is then introduced to scale up the marginal cost to actual bids. The bid factor is determined by comparing a PDC obtained from weighted average real time locational marginal price data of the PJM market with the PDC that would result from perfect competition. The PDC from the PJM market is discretized using the optimal break points obtained for the LDC in Figure 4-11 and shown in Figure 4-12. The bid factor at each of the higher load segments is computed in such a way that the shape of the PDC with the marginal cost follows the trend of the PDC in the PJM market, but the price at the lowest load segment is unchanged. In order to calculate the bid factor, since it is assumed that the generators submit bids higher than their marginal cost at higher loads, the ratio of the prices at the higher load segments (segment 1 to 5) to the lowest load segment (segment 6) of PJM market i.e. R_{PJM} as shown in Table 4-5 is first calculated. Similar to the PDC in PJM market, these price ratios are also computed for the PDC with the marginal cost i.e. R_{MC} as shown in Table 4-6. The bid factor at each of the load segments is then calculated by dividing R_{PJM} with R_{PC} as in Table 4-7.

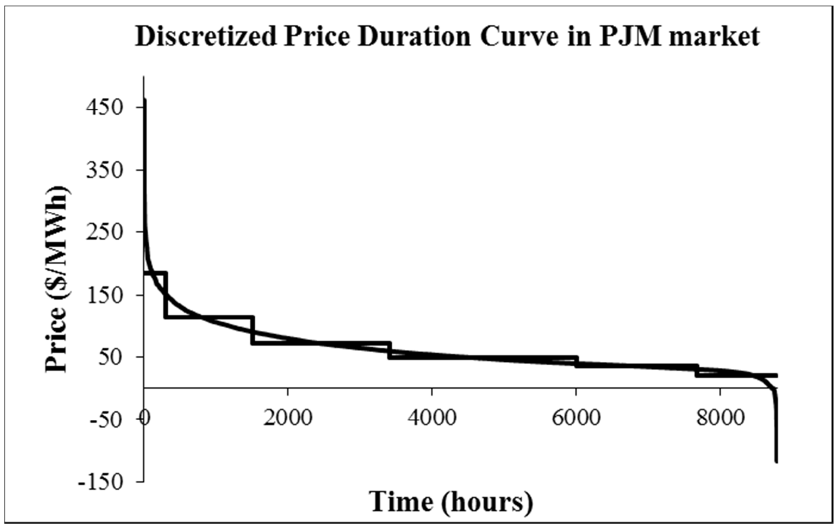


Figure 4-12 Optimal six step-functions of PDC from PJM market

Segment (Hours)	1 0-300	2 301-1511	3 1512-3416	4 3417-6001	5 6002-7672	6 7673-8784
Price in PJM market	184.13	112.64	72.76	48.38	35.36	21.18
Price to the lowest price ratio, R_{PJM}	8.69	5.32	3.43	2.28	1.67	1

Table 4-5 Prices in each segment of PDC in PJM market

Segment (Hours)	1 0-300	2 301-1511	3 1512-3416	4 3417-6001	5 6002-7672	6 7673-8784
Price with marginal cost	108.14	43.27	24.36	24.2	17.6	17.52
Price to the lowest price ratio, R_{MC}	6.17	2.47	1.39	1.38	1	1

Table 4-6 Prices in each segment of PDC with marginal cost

Segment (Hours)	1 0-300	2 301-1511	3 1512-3416	4 3417-6001	5 6002-7672	6 7673-8784
Bid factor (R_{PJM}/P_{MC})	1.41	2.15	2.47	1.65	1.66	1

Table 4-7 Bid factor at each of the load segments

The new PDC in the oligopoly market is obtained by multiplying the marginal cost of the generating unit that clears the market at each segment of the LDC with the bid factors. Figure 4-13 shows the PDC under an oligopoly market at year 0, which has higher prices at higher load segments than the PDC with the marginal cost.

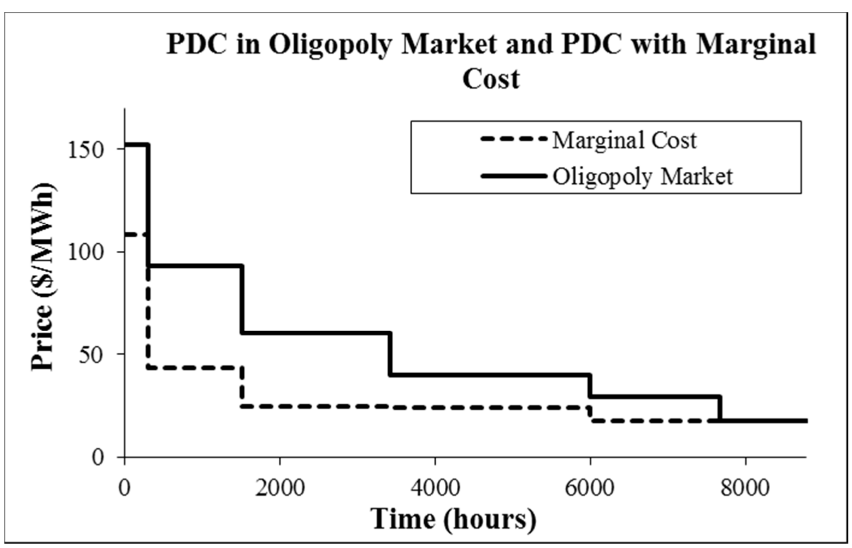


Figure 4-13 PDC in oligopoly market and PDC with marginal cost

4.7.3 Prototype Future System Expansion Considering Technologies' Risk Characteristics

In order to consider the investment risk profiles of different power plant technologies, some factors that contribute to the investment risks of the technologies are included in the investment evaluation model. These include the investment cost, the construction time, the plant life time, the fixed and variable O&M costs, the fuel cost, the fuels escalation rate, the carbon emission tax and the nuclear waste fee. The risk profiles of the technologies affect not only the profitability of the technologies that the company is evaluating but also the future technology choices of all the generating companies and hence the future technology mixes in the system. In such a situation, the risk profiles of different technologies need to be considered while developing the prototype future system expansion schedule using DP as previously presented in the basic structure of the investment evaluation model. To see the effects of the risk characteristics of the plant technologies on the future system expansion, the fixed and variable O&M costs, the cost of carbon emission and the nuclear waste fee are included in the formulation of the prototype future system expansion. These risks are added in the formulation as they contribute to the overall cost of generating electricity. The total cost of future system expansion considering the risk profiles of different technologies is given by the following equation:

$$TC = min \sum_{t=1}^{T} \{PC_{all}(X_t)_t + IC(U_t)_t + FOM_{all}(X_t)_t + VOM_{all}(X_t)_t + NWC_t + CC_t\} \tag{4.10}$$

where TC is the total cost of expansion over the simulation horizon, $PC_{all,t}$ is the total production cost of all the generating units in the system at year t, IC_t is the total investment cost of the new investments at year t, $FOM_{all,t}$ is the total fixed O&M cost of all the generating units at year t, $VOM_{all,t}$ is the total variable O&M cost of all the generating units at year t, NWC_t is the total nuclear waste cost of nuclear technologies at year t and CC_t is the total carbon emission cost of coal and combined cycle technologies at year t. The mathematical description of *FOM*, *VOM*, *NWC* and *CC* of the individual generating units in the system are similar to the formulations shown in equation (4.12) to equation (4.15) in the next section of this chapter.

4.7.4 Net Revenue Considering Technologies' Risk Characteristics

To see the effects of the risk characteristics on the profitability of the investment technologies under consideration, the risk profiles of different technologies are also included in the net revenue calculation. The annual revenue of the new power plant as shown in equation (3.6) of Chapter 3 is refined in this model to include the fixed and variable O&M costs, cost of a carbon emission tax and the cost of a nuclear waste fee as shown in the following formula;

$$P_{new,t} = ER_t + SR_t - PC_t - FOM_t - VOM_t - NWF_t - CC_t \tag{4.11}$$

The yearly fixed and variable O&M cost, nuclear waste fee and carbon emission cost are given by:

$$FOM = F_{O\&M} P^{max} \tag{4.12}$$

$$VOM = \sum_{s=1}^{S} V_{O\&M} p_s d_s \tag{4.13}$$

$$NWF = \sum_{s=1}^{S} WF\, X p_s d_s \tag{4.14}$$

$$CC = \sum_{s=1}^{S} CO_2 CT\, X p_j d_s \tag{4.15}$$

where $F_{O\&M,}$ is the annual fixed O&M cost per MW capacity of the new generating unit, $V_{O\&M,}$ is the variable O&M cost per MWh of energy produced by the new generating unit at segment *s* of the LDC, *WF* is the nuclear waste fee per MWh of energy produced using nuclear technology at segment *s* of the LDC, CO_2 is the amount of carbon dioxide emission per MWh of energy produced by coal and combined cycle gas turbine (CCGT) technologies at segment *s* of the LDC and *CT* is the carbon tax set by government for every tonne of carbon.

Once the revenues have been computed over the lifetime of the plant under consideration, the IRR, the NPV and the FWV of the generated cash-flow are calculated. If the generating company is comparing several investment alternatives, with the intent of building only one, the alternatives are called mutually exclusive [105]. In some cases inconsistent ranking problems can occur when IRRs of unequal lifetime among the alternatives are used as a basis for comparison. This is because when using the IRR method, the best alternative produces satisfactory functional results and requires the minimum capital investment. This is true unless the incremental investment of a larger investment can be justified [105]. Therefore, the IRR should be used when evaluating a unique investment project and can only be compared with the MARR of the investment.

If the lifetimes of various investment alternatives are not equal, all the monies must be projected to the largest lifetime (lf_{max}), since it is assumed that the cash-flow generated by the unit with shorter lifetime will be reinvested by the company up to the lf_{max} at MARR as shown in Figure 4-14. By doing this, the alternatives are compared over the same evaluation period. In such a situation, the FWV method which calculates the value of the cash-flows at the end of the investment's lifetime in the future is more suitable for comparing the alternatives.

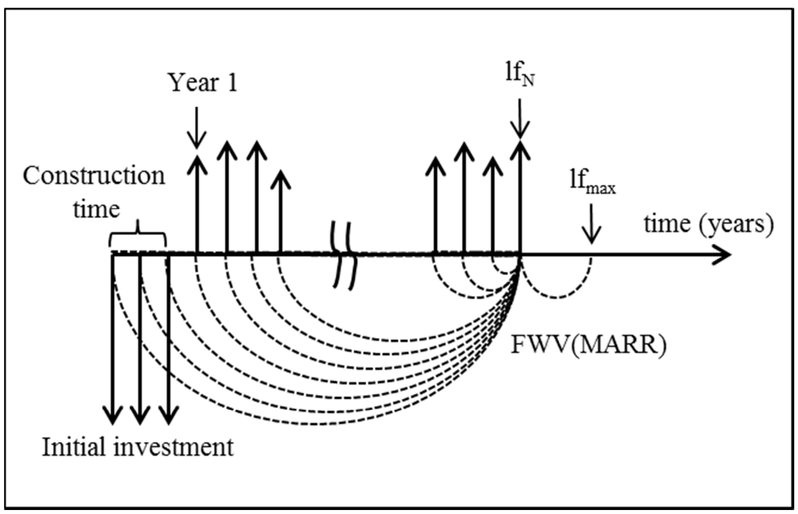


Figure 4-14 Net cash-flow of an alternative reinvested at MARR (source: Ortega-Vazquez [26])

4.7.5 Comparing Investment in Different Power Plant Technologies

The analysis has been carried out on the IEEE RTS omitting the hydro generation, which consists of 26 generating units and a total of 3105MW of installed capacity. The existing technologies in the system are listed in Table 4-8.

Size MW	Unit Name	Unit type	Heat rate offset MBTU/h	Heat rate, MBTU/ MWh	Remaining lifetime year	Invest Cost $/kW	Fix O&M $/MW/ yr	Variable O&M, $/ MWh
12x5	1-5	Oil	2.81	3.07	15	800	21500	3.17
20x4	6-9	Oil	13.87	4.49	10	800	21500	3.17
76x4	10-13	Coal	44.38	8.82	17	1175	20630	3.063
100x3	14-16	Oil	24.03	2.23	8	800	21500	3.17
155x4	17-20	Coal	64.88	7.28	14	1175	20630	3.063
197x3	21-23	Oil	26.59	2.81	15	800	21500	3.17
350x1	24	Coal	12.12	1.37	25	1175	20630	3.063
400x2	25-26	Nuc	211.27	7.69	33	1810	57140	0.365

Table 4-8 Existing units' technology and costs

Company A assumes that nine generation technologies can be selected by the DP each year for the prototype system expansion schedule. The characteristics of these technologies are given in Table 4-9.

Unit	Size MW	Unit type	Heat rate offset MBTU/h	Heat rate MBTU/ MWh	Invest Cost $/kW	Life time years	Fix O&M $/MW/ yr	Variable O&M $/MWh
PGF_17	155x2	Coal	64.881	7.9044	1175	25	20630	3.063
PGF_10	76x2	Coal	44.386	8.8288	1175	25	20630	3.063
PGF_21	197	Oil	26.597	2.8134	800	25	21500	3.17
PGF_01	12	Oil	2.8099	3.0774	800	25	21500	3.17
PGF_24	350	Coal	70.124	6.679	1175	25	20630	3.063
PGF_06	20	Oil	13.871	4.4939	800	25	21500	3.17
PGF_14	100	Oil	24.029	2.2303	800	25	21500	3.17

Table 4-9 Available investment technologies for DP

The three possible investment technologies that are considered by Company A are shown in Table 4-10. The technical and cost characteristic of these candidates are given in [31]. The position of these possible investments on the supply curve according to their marginal cost is shown in Figure 4-15 which indicates that the nuclear plant is a base load plant, the coal plant produces energy at the medium load level and the CCGT plant serves as a peaking unit. The optimal six step-functions of LDC as obtained and previously shown in Figure 4-11 is used in the investment evaluation. It is assumed that the magnitude of each segment of the LDC increases by 2.3% every year. The NPV of each investment is calculated at 10% of discount rate and the MARR is set to 12%. In this analysis, the prototype future system expansion schedule from the DP is obtained considering the installed capacity is within the 18% minimum and 30% maximum of reserve requirements. The spinning reserve requirement in the market is set at 4% every year.

Parameters	Units	Nuclear	Coal	CCGT
Technical Parameters				
Net capacity	MW	300		
Heat rate	MBTU/MWh	10.4	8.6	7
Construction period	years	5	4	2
Plant life time	years	40	30	20
Carbon intensity	tC/MBTU	0	0.0258	0.0145
Cost Parameters				
Overnight cost	$/kW	1810	1175	452
Fixed O&M	$/kW/yr	57.14	20.63	14.29
Variable O&M	$/MWh	0.365	3.063	0.476
Fuel cost	$/MBTU	0.55	2.06	5.24
Fuel escalation rate	%	0.5	0.5	1.2
Nuclear waste fee	$/MWh	0.95	0	0
Financing Parameters				
Discount rate	%	10		
Regulatory Action				
Carbon tax	$/tC	63.5		

Table 4-10 Technical and cost characteristic of investment plants

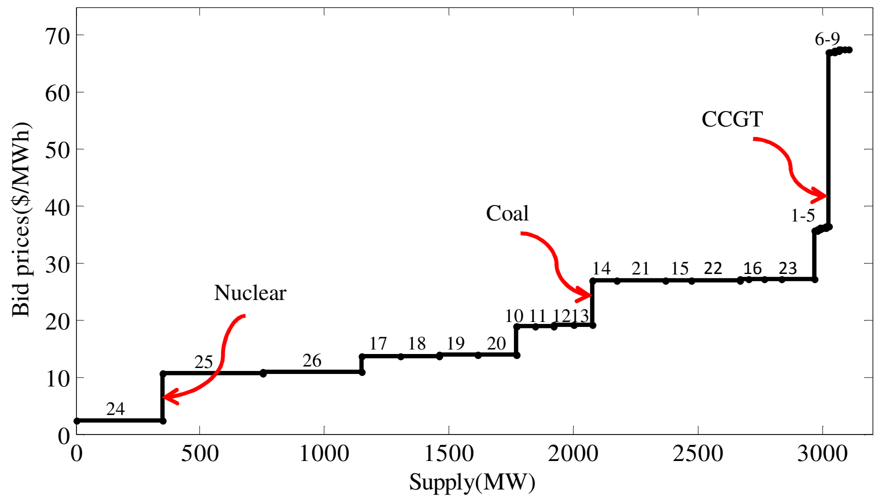


Figure 4-15 Position of the investment technologies according to their marginal cost on the supply curve

Figure 4-16 shows the first 15 years of the 44 years of the prototype future system expansion resulting from the DP calculation. The nuclear plant being evaluated by Company A comes on line at year 5 after its construction is completed. The DP is carried out for the lifetime of nuclear investment plant, i.e. 40 years. It is expected that PGF_01, PGF_10 and two units of PGF_17 will come on line in year 1. No new plant will be added to the system at years 6 and 7 as the nuclear plant considered by Company A would enter the market at year 5 and would be enough to cater for the load growth for the following years. As mentioned in the previous section, since each investment technology enters the system at a different year, the DP gives a different optimal solution for the prototype system expansion and hence different expected energy prices for each plant under evaluation.

Figure 4-17 shows the expected cash flow for the nuclear investment over its expected lifetime. In this system, the plants collect revenue from selling energy and by providing spinning reserve. The revenues collected by the plants each year are based on the energy and spinning reserve prices resulting from the market clearing process with respect to the expected changes in the system from the DP calculation. Being a base unit in the system, the revenue of the nuclear plant depends mostly on the price of energy. This is shown in Figure 4-17 and Figure 4-18 where the expected revenue of the nuclear plant follows the trend of the energy prices over its lifetime. On the other hand, the revenues of the coal and CCGT plants, which are intermediate and peaking units respectively, depend on both the energy and spinning reserve prices.

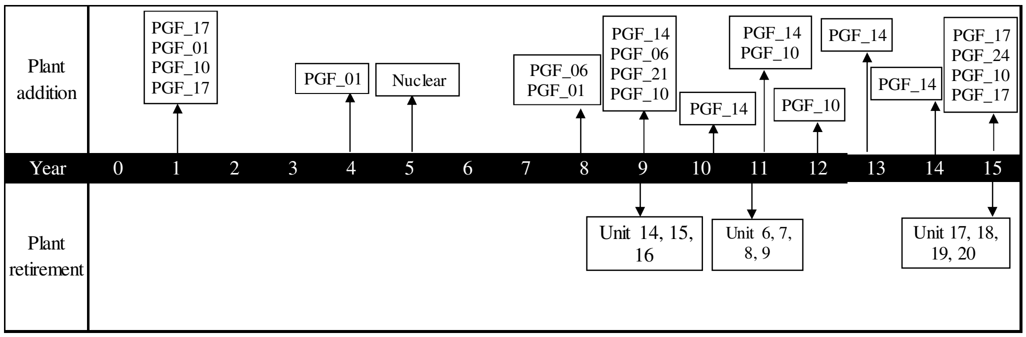


Figure 4-16 Prototype future investment schedule using DP for nuclear investment plant

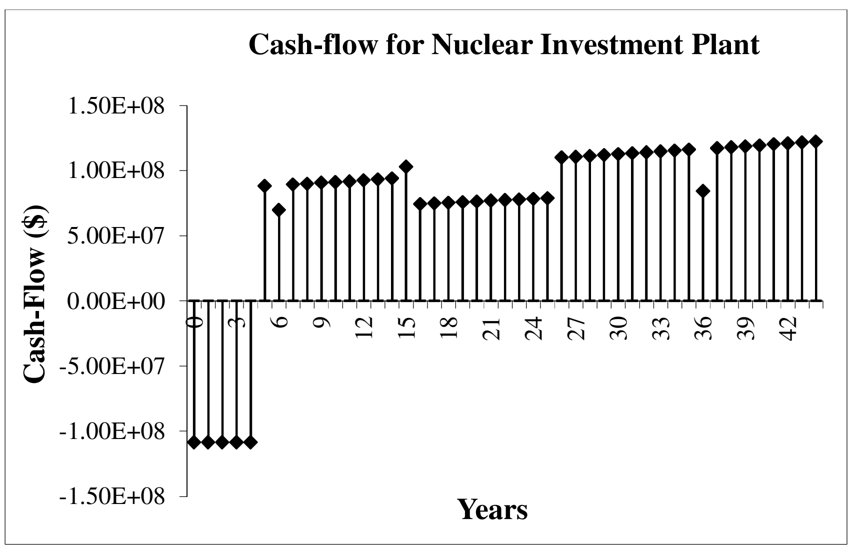


Figure 4-17 Expected cash-flows of nuclear investment plant

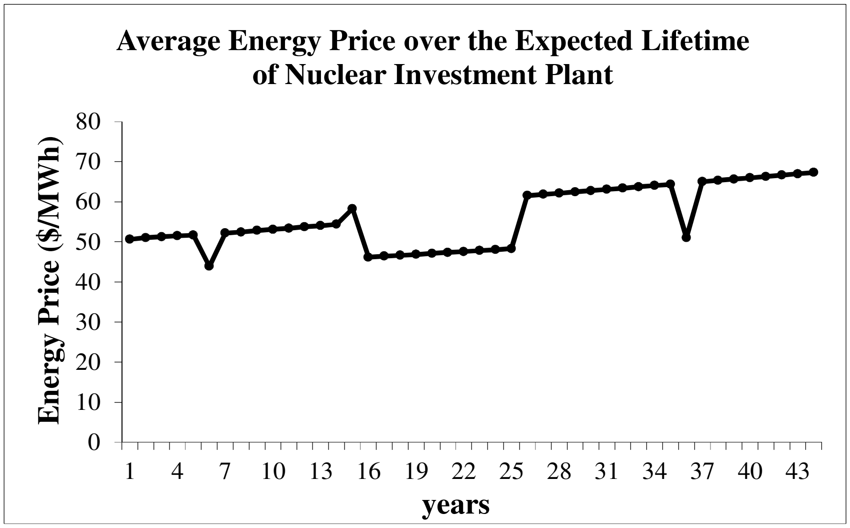


Figure 4-18 Average energy prices over the expected life time of nuclear investment plant

Since the investment alternatives have different economic lives, it is more appropriate to compare the alternatives using the FWV. The FWV of the coal and CCGT are calculated considering that the plants are reinvested up to the lifetime of the nuclear plant. Comparing the three technologies, the CCGT plant which has lower investment and O&M costs and a shorter lifetime, provides higher FWV than nuclear and coal technologies. On the other hand, the coal plant which has a high investment and O&M cost as well as high cost for carbon emissions, is a less desirable investment. Although the nuclear plant has a high investment cost, being a base unit in the system and providing clean energy makes it the second most profitable investment after the CCGT plant. Table 4-11 shows the IRR, the NPV and the reinvested FWV of all the investments. In this example, the inconsistent ranking problem does not arise because the ranking of the alternatives using the IRR method is similar to the NPV and FWV methods. It is seen that the oligopolistic market structure which has higher prices favours investment in the nuclear and CCGT; where the IRRs of the investments are greater than the MARR, and the NPVs and the FWVs are greater than zero, therefore the investments should be accepted. Although the investment in the nuclear and CCGT plant would be profitable, Company A may expect a higher level of return from the nuclear since investing in that plant is much riskier. In such a situation, if Company A only decides to build one plant, Company A may choose to invest in the CCGT which has shorter lifetime and is more profitable, and hence is a less risky investment.

	IRR (%)	NPV ($)	FWV ($)
Nuclear	12.41	1.39E+08	3.25E+09
Coal	8.4767	-3.21E+07	*-1.10E+10
CCGT	32.705	2.66E+08	*3.33E+10

*Reinvested up to the lifetime of nuclear investment plant

Table 4-11 IRR, NPV and projected FWV of the investment plants in the base case

The analysis is extended to see the effect of different scenarios of forecasted load growth on the future system expansion from the DP. Figure 4-19 shows how the installed capacity, as calculated by the DP, varies over time with 2.7%, 2.3% and 1.5% load growth.

The expected average energy price fluctuates but increases as the demand increases over the planning horizon. A higher load growth in the system provides expensive generators the opportunity to dispatch energy and hence leads to higher market clearing prices. This is shown in Figure 4-20 where the 2.7% load growth in general results in higher energy prices than the smaller load growths and hence provides a higher rate of return for the nuclear plant (Table 4-12).

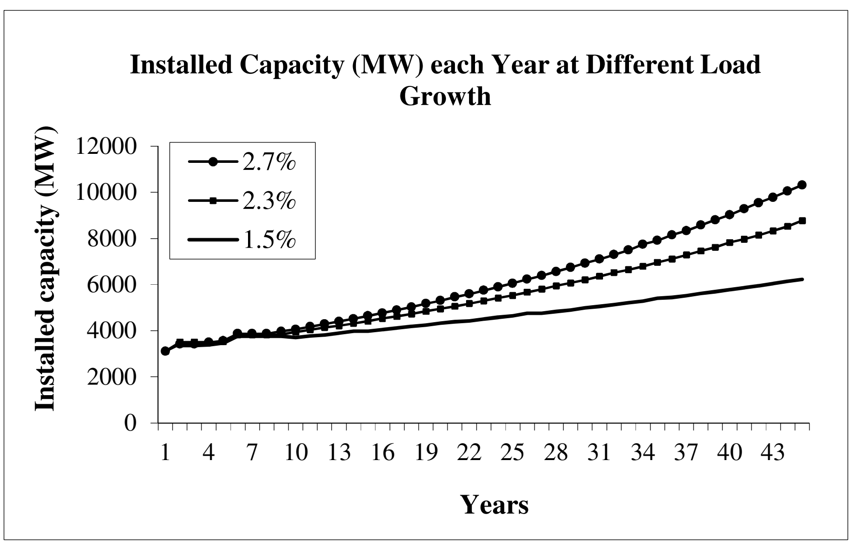


Figure 4-19 Installed capacities in the system at various load growth scenarios

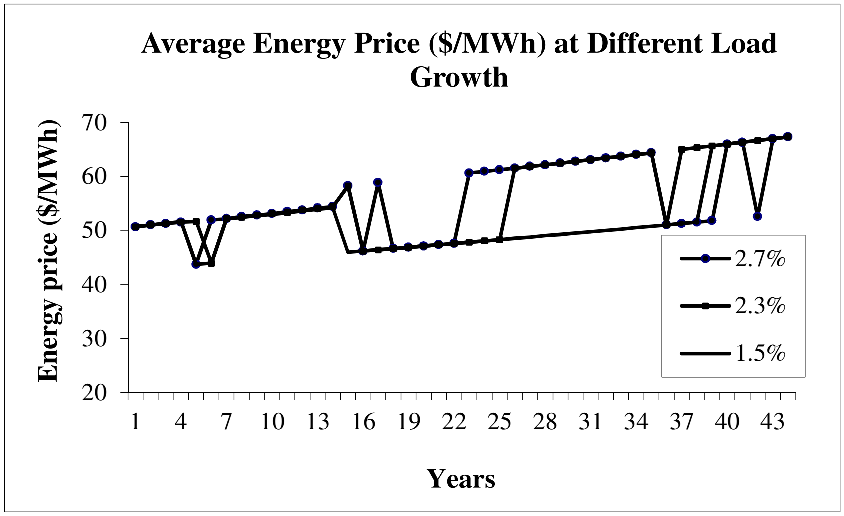


Figure 4-20 Expected average energy prices at various load growth scenarios

Load Growth	IRR (%)
2.70%	12.58
2.30%	12.41
1.50%	11.58

Table 4-12 IRR of nuclear investment plant at various load growth scenarios

4.7.6 Sensitivity to the Shape of Load Duration Curve

As mentioned previously in this chapter, the expected profitability of an investment is dependent on the shape of the discretized LDC i.e. the height of each segment (which indicates the average load for that period) and the width of the segment (which indicates the duration for which this load occurs). In this analysis, three different shapes of LDC obtained from the optimal step-function simulation by varying the interval where the optimal breaking points lie are tested using the proposed investment evaluation model. Then, their effects on the profitability of different investment alternatives are compared.

The first LDC denoted as Case 1 in Figure 4-21 is simulated with a smaller period in segments 2 and 3 and a bigger period in segments 4, 5 and 6 than the LDC denoted as base case as shown previously in Figure 4-11. The breaking points of all these LDC cases are shown in Table 4-13. Reducing the duration of segments 2 and 3 in

Case 1 increases the load in those segments. Similarly, increasing the duration of segments 4, 5 and 6 also increases the load. These are shown in Table 4-14. Although reducing the duration of segments 2 and 3 increased the load, and hence the prices in those segments, the generating companies are only able to make profit from these higher prices for a shorter period of time. This causes the NPV of all the investments to be lower in Case 1 (Table 4-15) compared to the base case (Table 4-11) particularly for the coal and the CCGT plants which are the medium and peaking units. In this analysis, the NPV of the investments are used, as the analysis does not intend to select the best alternative but only to study the impact of the shape of the LDC on the investment plants.

Break Points	Case 1	Case 2	Case 3
T1	300	100	100
T2	1000	1000	808
T3	2500	2500	2153
T4	5315	5315	4158
T5	7255	7255	7001

Table 4-13 Break points of the optimal discretized LDC for all the LDC cases

	Base Case		Case 1		Case 2		Case 3	
Segment	Load (p.u)	Duration (h)	Load (p.u)	Duration (h)	Load (p.u)	Duration (h)	Load (p.u)	Duration (h)
1	0.895	300	0.895	300	0.936	100	0.936	100
2	0.772	1211	0.795	700	0.813	900	0.825	708
3	0.680	1905	0.713	1500	0.713	1500	0.728	1345
4	0.609	2585	0.632	2815	0.632	2815	0.654	2005
5	0.537	1671	0.559	1940	0.559	1940	0.582	2843
6	0.464	1112	0.477	1529	0.477	1529	0.484	1783

Table 4-14 Height and duration of each segment of the optimal discretized LDC for all the LDC cases

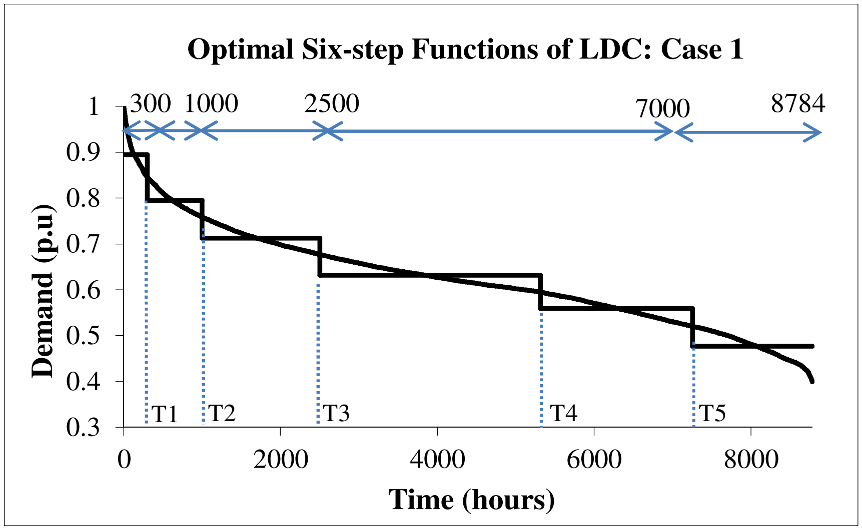


Figure 4-21 Optimal six-step functions approximation of PJM LDC in Case 1

In case 2, the duration of segments 3, 4, 5 and 6 are similar as in the Case 1. On the other hand, segment 1 (peak load) is made shorter than in Case 1 (Figure 4-22). This situation impacts the profitability of the CCGT which is operating at the peak load. It has a lesser impact on the NPV of the coal and nuclear plants. These are also shown in Table 4-15.

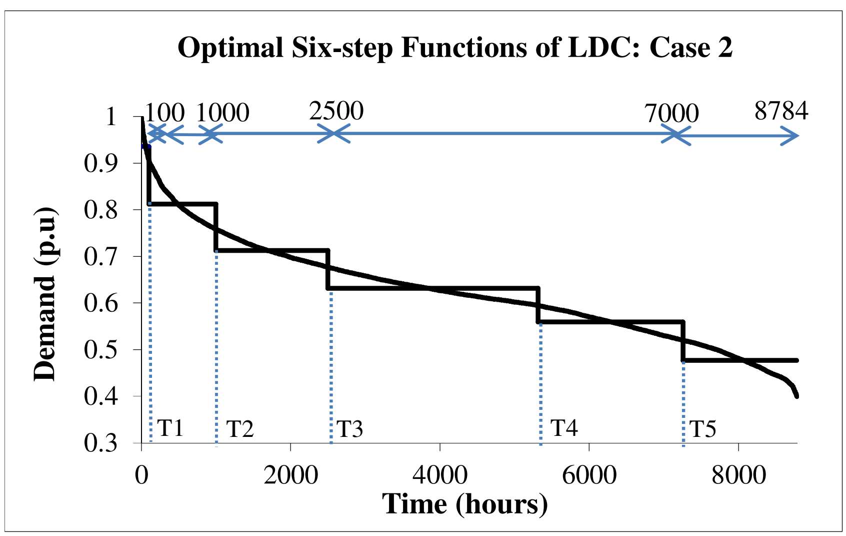


Figure 4-22 Optimal six-step functions approximation of PJM LDC in Case 2

Finally, in Case 3, the break points are obtained by first optimally discretizing the PJM PDC (Figure 4-23) using the same interval defined for the Case 2. These break points are then used to discretize the LDC in Case 3 as shown in Figure 4-24. By doing this, the duration in segment 1 is kept similar as in Case 2 and bigger durations of segment 5 and 6 (base load) are obtained (Table 4-14). Since the duration of segment 1 remains the same as in Case 2 the impact on the NPV of the CGGT plant as a peaking unit is smaller. On the other hand, a bigger duration of segment 5 and 6 in the Case 3 than in Case 2 gives a greater impact to the NPV of the coal (medium unit) and particularly for the nuclear plant which is the base unit in the system.

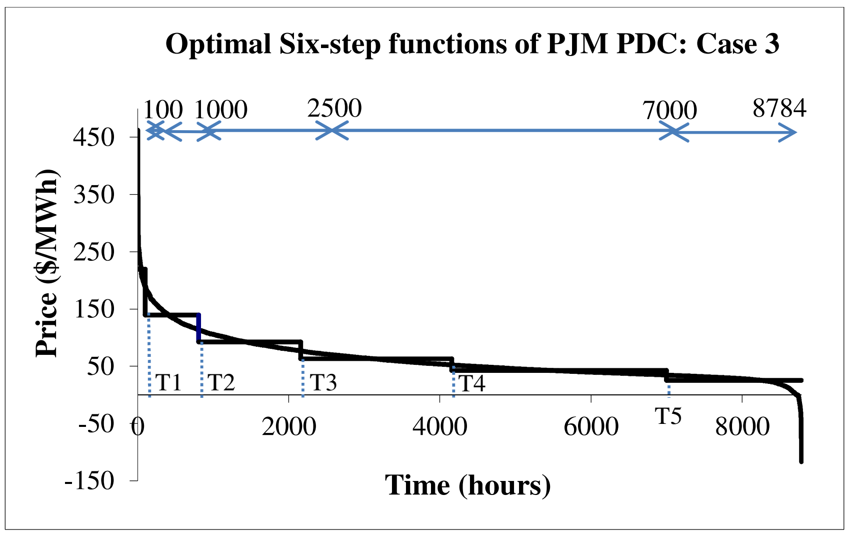


Figure 4-23 Optimal six-step functions approximation of PJM PDC in Case 3

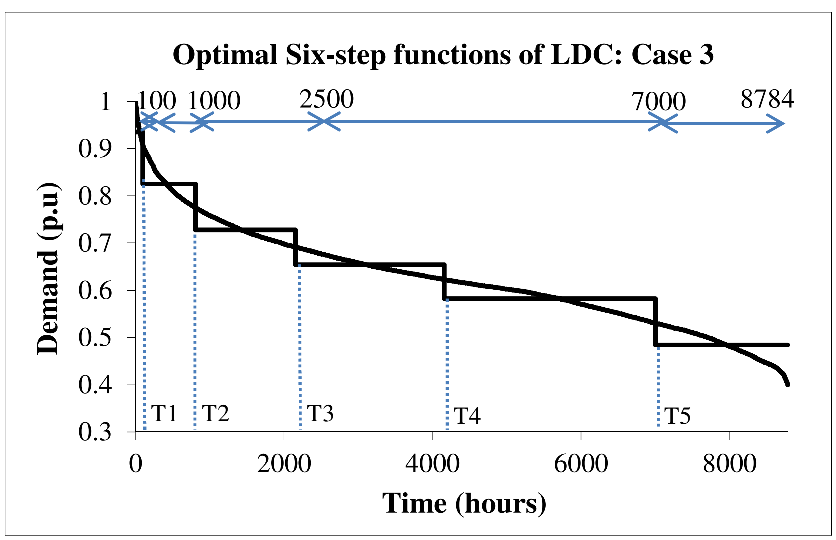


Figure 4-24 Optimal six-step functions approximation of PJM LDC in Case 3

	NPV		
	Case 1	Case 2	Case 3
Nuclear	4.41E+07	4.50E+07	1.53E+07
Coal	-1.31E+08	-1.33E+08	-1.73E+08
CCGT	1.86E+08	1.60E+08	1.46E+08

Table 4-15 NPV of the investment technologies for all the LDC cases

4.8 SENSITIVITY ANALYSIS WITH A TEST SYSTEM BASED ON GREAT BRITAIN'S 2010 SEVEN YEAR STATEMENT

In this analysis, the proposed investment evaluation model in an oligopoly electricity market (Model 2) is tested and verified with a bigger test system based on Great Britain's 2010 Seven Year Statement [106]. The system consists of 75 generating units (the wind and hydro generations are aggregated) and a total of 74212 MW of installed capacity. It is assumed that some of the large generating units will be closed over the next 15 years to meet more stringent air quality standards introduced by the European Union's Large Combustion Plant Directive (LCPD) scheme. The technical and cost data of these units are provided in Appendix A of this thesis. Company A assumes that six generation technologies can be selected by the DP each year for the prototype system expansion schedule. The three possible technologies shown in Table 4-10 are considered in the analysis. However the capacity of each plant is modified to suit the bigger test system. More realistic technical and cost data for the existing units and the potential investment as presented in [30] are also used. The characteristics of the plants for the DP and the possible investment technologies are also provided in Appendix A.

A thorough sensitivity analysis of the profitability of the three investment technologies to the uncertainties of the various parameters in the model has been performed. Two types of sensitivity analyses are: 1) to the system uncertainties such as the carbon emission tax, the nuclear waste fee, the development of wind power plant and the system reserve margin, 2) to the technical and cost uncertainties of the investment technologies such as the heat rate, the overnight cost, the O&M cost, the construction time and the discount rate which is used to calculate the NPV.

The LDC is also optimally discretized into six segments. The hourly load data is from the National Grid [National Grid 2010] for the load from 1st January 2008 to 31st December 2008. Figure 4-25 shows the six-step approximations of the LDC used in this analysis.

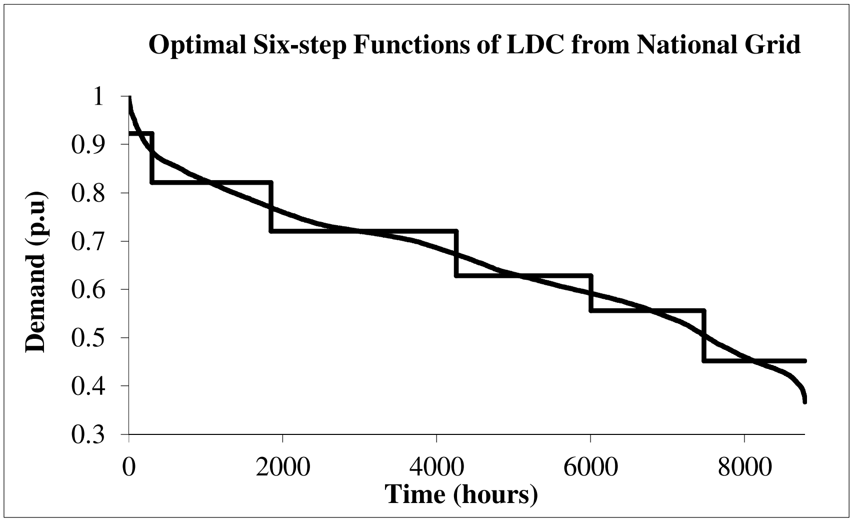


Figure 4-25 Optimal six-step functions of LDC from National Grid

4.8.1 The Base Case

The sensitivity analysis is performed by first creating a base case as a benchmark for the other case studies. The base case assumes that no carbon emission tax or nuclear waste fee is imposed by the government to control the emission of carbon and nuclear waste from the power plant to the environment. The load growth, the fuel cost and the discount rate are similar to the analysis presented in section 4.7.5. On the other hand, the minimum system reserve margin for the prototype system investment schedule from DP is set higher i.e. 30% to consider the interruptible energy from the wind and hydro generation.

In the base case, the coal plant which has a capacity, cost parameters (i.e. the overnight cost, the fixed O&M cost and the fuel cost) as well as lifetime and construction time in between the nuclear and the CCGT plants is the most profitable option followed by the nuclear plant and the CCGT plant. This is shown in Table 4-16 where the NPV per megawatt capacity and the reinvested FWV per megawatt capacity of the coal plant are the highest among the other plants. It is seen that the 'inconsistency ranking problem' exists when the alternatives are compared using the IRR, where the CCGT plant turns out to be the most profitable investment. Therefore, it is more appropriate to compare the alternatives using the FWV. The FWV of the coal and CCGT are calculated considering that the plants are reinvested up to the lifetime of the nuclear investment plant as previously illustrated in Figure 4-14. In this simulation, it is expected that all the investment alternatives under the higher prices of an oligopoly market would be profitable investments. However the acceptance of the investment is also dependent on the level of risk posed by the technology i.e. how sensitive it is to the various changes in the system, which is the focus of the analysis in the following section.

	IRR	NPV/MW	FWV/MW
Nuclear	15.498	1.03E+06	7.98E+07
Coal	19.892	1.25E+06	*1.23E+08
CCGT	22.621	6.70E+05	*7.18E+07

*Reinvested up to the lifetime of nuclear investment plant

Table 4-16 Expected NPV and FWV of the investment technologies in the base case

Figure 4-26 shows the expected future technology mix over the lifetime of the nuclear investment plant under consideration as determined by the prototype future system expansion. The technology mix indicates that more CCGTs are expected to be built in the earlier years to replace some existing coal and oil-fired generating plants that will be closed under the Large Combustion Plants Directive (LCPD) scheme. However, since the gas prices are expected to increase quicker than the coal and uranium prices, the operating cost of CCGTs will therefore increase faster, fewer CCGTs and more nuclear and coal power plants will be built towards the end of the period considered. The expected energy prices resulting from this expected future technology mix are shown in Figure 4-27.

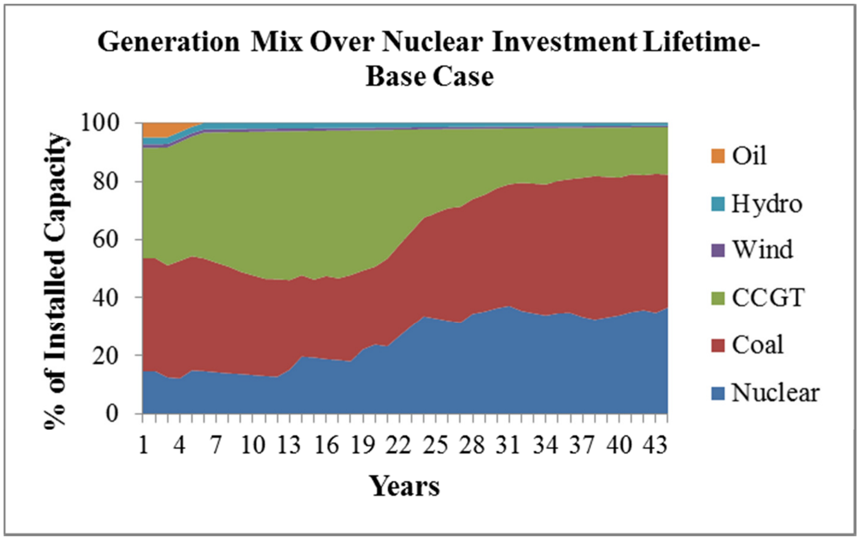


Figure 4-26 Expected technology mix over the lifetime of an investment in a nuclear plant for the base case

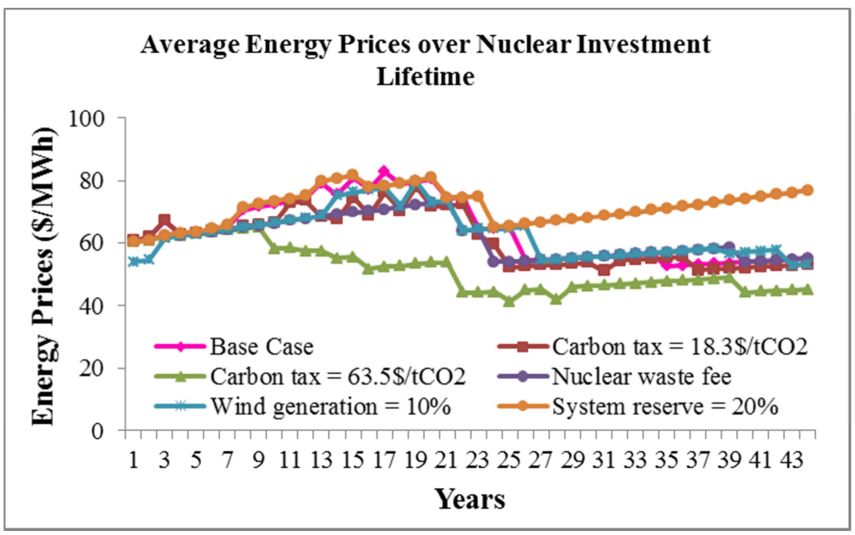


Figure 4-27 Expected average energy price over the lifetime of an investment in a nuclear plant for all cases

4.8.2 Sensitivity to the Carbon Emission Tax

Two scenarios of carbon tax have been tested to see how the system reacts. The coal power plant, which has the highest carbon intensity, is the most affected technology followed by the CCGT and the nuclear plant. The profitability of the coal and the CCGT plant are severely affected under the extreme case i.e. when the carbon tax is set at 63.5$/tCO2 as shown in Table 4-17. Although the nuclear power plant has zero carbon emission, the revenue of this plant is also affected by the implementation of the carbon emission tax. This is because when the carbon tax is imposed in the system, the generating companies tend to build more nuclear power plants, which are less affected by the carbon emission tax. This is shown in Figure 4-28 and Figure 4-29. The installed capacity of coal and CCGT shrink more under the extreme case, with the coal-fired capacity shrinking faster than the CCGT capacity.

When nuclear dominates the system, the energy price drops below the base case because the nuclear plants have a lower operating cost. This is shown in Figure 4-27. This answers why the profitability of the nuclear plant is also reduced when the carbon emission tax is introduced in the system. Figure 4-30 shows the difference in the FWV between the base case and the other cases for all the investment alternatives. This also illustrates how sensitive the technologies are to these uncertain exogenous factors.

	Carbon tax = 18.3	Carbon tax = 63.5
	FWV*/MW	FWV*/MW
Nuclear	5.81E+07	7.40E+06
Coal	8.26E+07	-4.79E+07
CCGT	4.96E+07	-1.99E+07

*Reinvested up to the lifetime of nuclear investment plant

Table 4-17 Expected FWV of the investment technologies under evaluation in the case of carbon emission tax

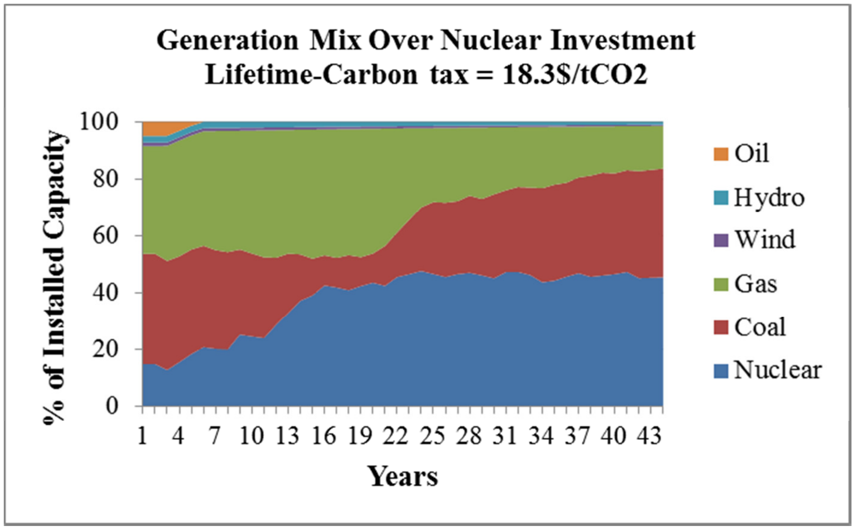


Figure 4-28 Expected technology mix over the lifetime of an investment in a nuclear for the case of carbon emission tax = 18.3$/tCO2

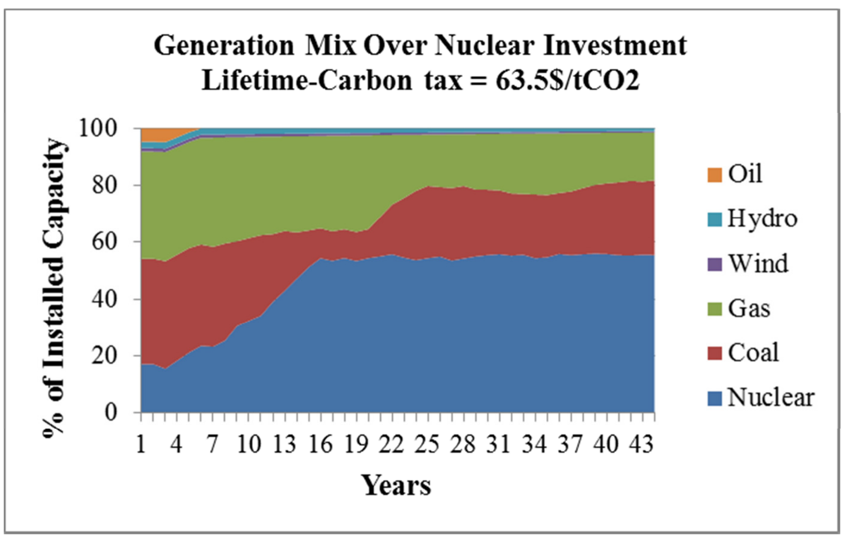


Figure 4-29 Expected technology mix over the lifetime of an investment in a nuclear for the case of carbon emission tax = 63.5$/tCO2

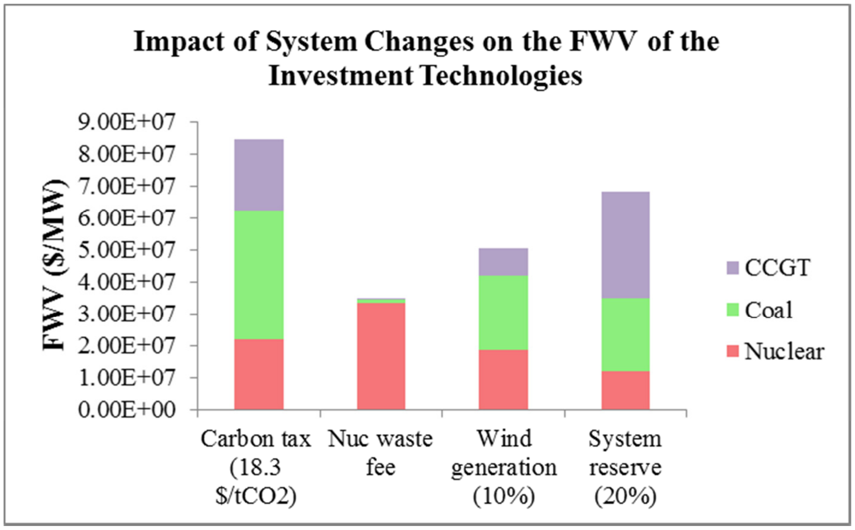


Figure 4-30 Impact of system changes on the FWV of the investment technologies

4.8.3 Sensitivity to the Nuclear Waste Fee

The third analysis is performed to study the effect of a nuclear waste fee on the profitability of the various technologies. In this analysis the generating companies that owned nuclear power plants are assumed to be charged for their radioactive waste. In order to see the effects clearly, the carbon emission tax is not considered in this analysis.

Figure 4-31 shows the expected system technology mix over the lifetime of an investment in a nuclear plant when a nuclear waste fee is imposed. This nuclear waste fee discourages generating companies in the system from building more nuclear plants. The coal power plant is expected to be the favoured investment followed by the CCGT plants. This scenario is in line with the results in Table 4-18 where under this situation, the nuclear investment plant that is being evaluated by Company A has the smallest FWV followed by the CCGT and the coal plants.

In this case, the energy price is slightly higher on average than the base case because the coal plants that dominate the system have a higher operating cost than the nuclear plants. This results in a very small rise in the profit of the coal and the CCGT plants. It is also seen that the nuclear waste fee has a large impact on the nuclear plant and very little impact on the coal and the CCGT plants (Figure 4-30), which indicates that investing in nuclear plants is much riskier under this scenario.

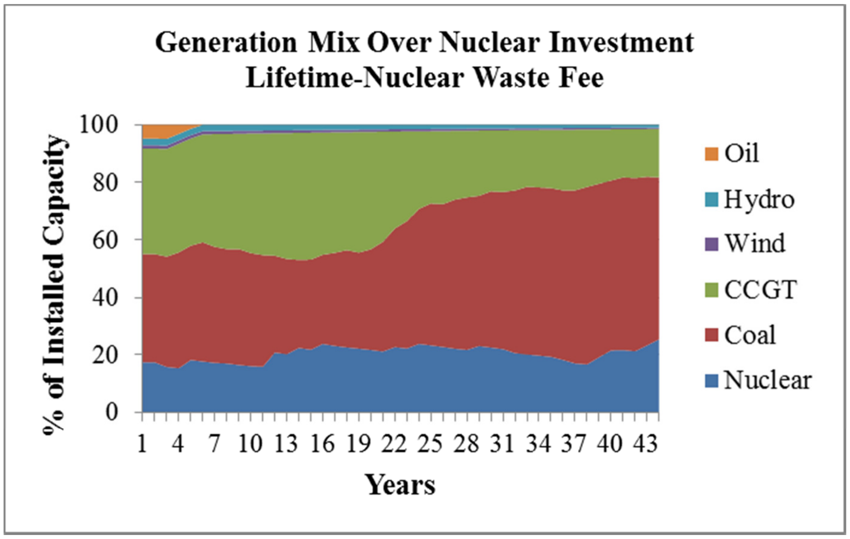


Figure 4-31 Expected technology mix over the lifetime of an investment in a nuclear for the case of nuclear waste fee

	FWV/MW
Nuclear	4.65E+07
Coal	*1.24E+08
CCGT	*7.19E+07

*Reinvested up to the lifetime of nuclear investment plant

Table 4-18 Expected NPV and FWV of the investment technologies under evaluation in the case of nuclear waste fee

4.8.4 Sensitivity to the Development of Wind Generation

Wind generation has been increasing rapidly in the United State and several countries in Europe. The increase in wind generation will affect the system's generation mix, then the price of electricity and hence the profitability of the investment technologies under consideration. In order to see the effect of the development of wind generation on the system and the new investments, in this analysis it is assumed that wind generation increases 10% each year as in Figure

4-32. As the energy from the wind is essentially free, it is assumed that the wind generator bids at zero price. In this situation, the wind power plants will displace the position of nuclear plants in the supply curve and shift the plants in the supply curve to the right. As a consequence some of the expensive plants that were previously scheduled to produce energy during the peak hours in the base case are not be able to do so under this scenario. As a result the market clearing price is lower than in the base case. This is seen in Figure 4-27 where the average energy price in the case of increasing wind generation is slightly lower than the base case and hence reduces the profitability of all the technologies being evaluated (Table 4-19). The nuclear and the coal plants which are the base and intermediate units in the system are the most affected technologies under this scenario (Figure 4-30).

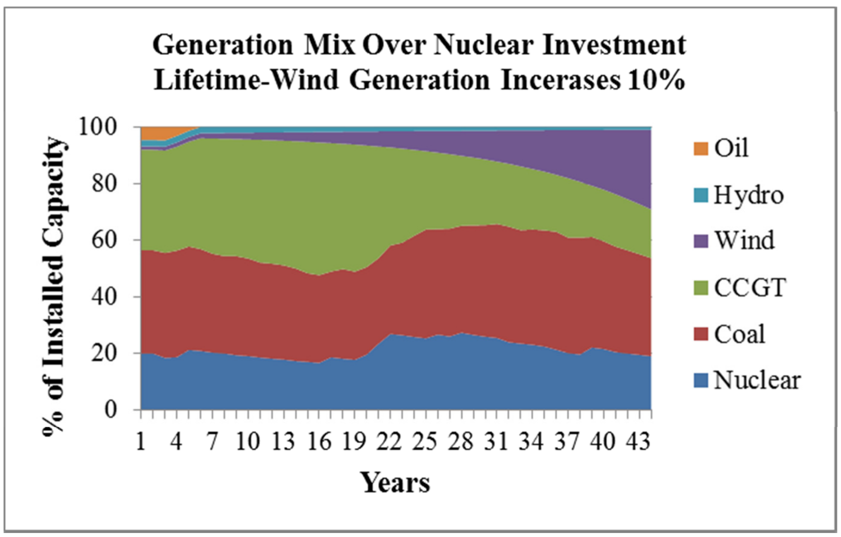


Figure 4-32 Expected technology mix over the lifetime of an investment in a nuclear for the case of increasing wind generation

	NPV/MW	FWV/MW
Nuclear	8.78E+05	6.13E+07
Coal	1.05E+06	*9.98E+07
CCGT	5.95E+05	*6.33E+07

*Reinvested up to the lifetime of nuclear investment plant

Table 4-19 Expected NPV and FWV of the investment technologies under evaluation in the case of increasing wind generation

4.8.5 Sensitivity to the System Reserve Margin

In this analysis, the sensitivity of the new investments to the system reserve margin is tested. The minimum system reserve margin for the prototype future system expansion using DP which was previously set at 30% in the previous analyses is lowered to 20% in this analysis. Figure 4-27 shows that a 20% minimum reserve margin results in higher energy prices than the base case. As a result, the profitability of all the investment technologies increases as shown in Table 4-20. Being a peak unit in the system, the CCGT plant benefits the most from the decrease in the system reserve margin, followed by the coal and the nuclear plants. This is shown in Figure 4-33 where the expected installed capacity of CCGT plants over the nuclear investment plant being evaluated is slightly higher than in the base case.

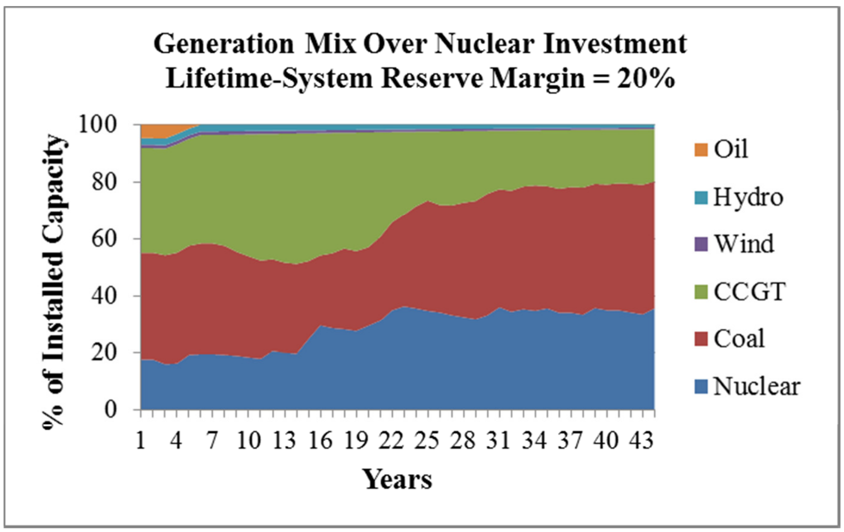


Figure 4-33 Expected technology mix over the lifetime of an investment in a nuclear for the case of 20% expected minimum reserve margin

	NPV/MW	FWV/MW
Nuclear	1.16E+06	9.19E+07
Coal	1.45E+06	*1.46E+08
CCGT	9.28E+05	*1.05E+08

*Reinvested up to the lifetime of nuclear investment plant

Table 4-20 Expected NPV and FWV of the investment technologies under evaluation in the case of 20% expected minimum reserve margin

4.8.6 Sensitivity to Technical and Cost Characteristic of the Technologies

The sensitivity analysis presented in this chapter is not limited only to the uncertainty on exogenous factors (external risk) but extends also to the effect of internal risk i.e. technical parameters such as the heat rate and the construction time, and cost parameters such as the overnight cost and the O&M cost of each technology on its own profitability. As previously explained in this chapter, the changes in the various parameters in the model result in a different forecasted prototype system expansion from the DP. Therefore, in this analysis in order to see the effect of the technology's characteristic effectively, the prototype system expansion obtained for each investment technology in the base case of the previous analysis is used to calculate the NPV of the technology considering a 10% change in the parameters.

The economics of a nuclear investment depend greatly on the overnight cost and the construction time. As an intensive capital investment with a medium operating cost, the nuclear plant is also sensitive to the discount rate but less sensitive to the heat rate. Figure 4-34 shows the impact of a 10% change in the various costs and technical characteristics on the NPV of the nuclear investment.

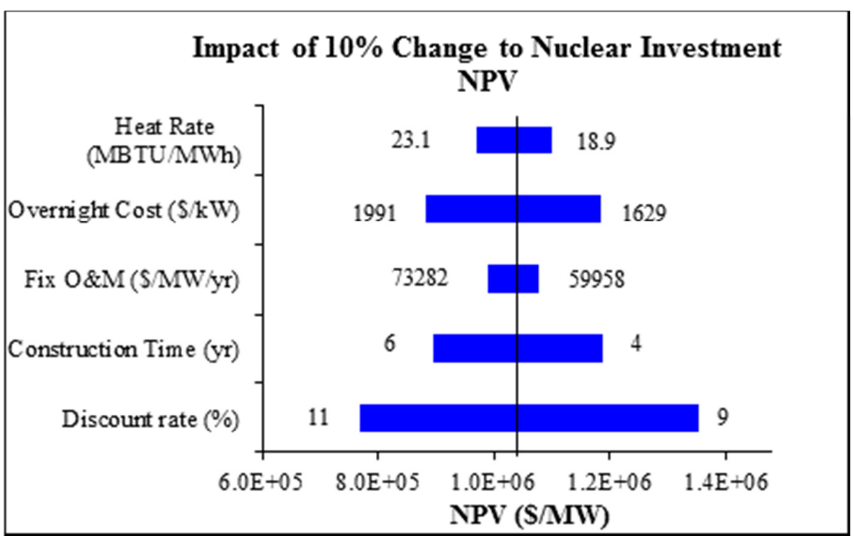


Figure 4-34 Impact of 10% change on the various parameters to the NPV of nuclear plant

The sensitivity analysis of the CCGT plant shows a different pattern than the nuclear case as shown in Figure 4-35. The CCGT plant is very sensitive to changes in the heat rate. It is however much less sensitive than nuclear to the overnight cost, the construction time, the discount rate and the fixed O&M cost. This is because the CCGT is a less capital intensive than an investment in nuclear, but has higher fuel cost and operating cost.

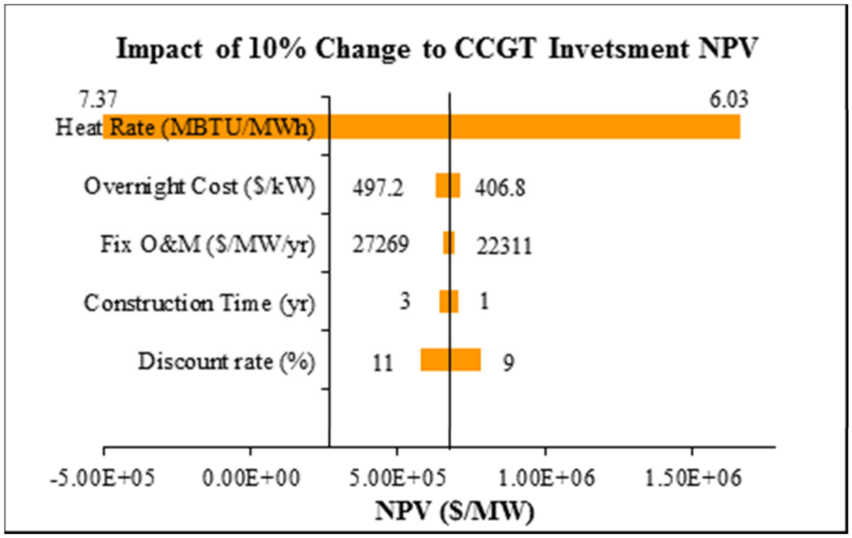


Figure 4-35 Impact of 10% change on the various parameters to the NPV of CCGT plant

On the other hand, the sensitivity of a coal investment is in between the nuclear and the CCGT. Having a large investment cost, long building time as well as quite high operating cost, the economics of the coal plant depends on all the parameters i.e. the heat rate, the overnight cost, the construction time and the discount rate. These are shown in Figure 4-36. Figure 4-34, Figure 4-35 and Figure 4-36 also show that smaller heat rate, overnight cost, fixed O&M cost, construction time and discount rate increase the profitability of the technologies.

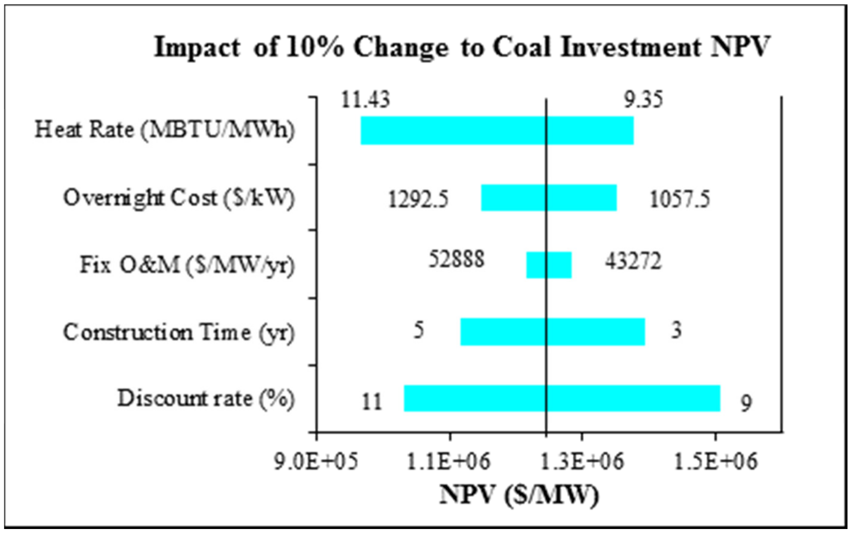


Figure 4-36 Impact of 10% change on the various parameters to the NPV of coal plant

4.9 CONCLUSIONS

This chapter has presented a new explicit approach for a generating company to evaluate an investment in a power plant under a restructured electricity supply industry. In the beginning of the chapter, the basic framework for investment evaluation which consists of two stages of investment problems is first introduced. The first stage is an optimization problem which models the expected future investments and retirements from all the companies in the system (the prototype system investment and retirement schedule) using dynamic programming (DP) over the lifetime of the investment that the main generating company is evaluating. The second stage calculates the revenue of the new investment in each year of its lifetime against the prototype system investment schedule obtained in the first stage. The basic investment evaluation model is then extended into two different models. The first model (Model 1) is developed to consider uncertainty using a probabilistic valuation technique. A Monte Carlo simulation is introduced in the second stage of the problem in order to get the rate of return distribution of the investment. The uncertainty in the load and the fuel cost are modelled as normal probability distribution functions. The risk analysis is also incorporated in the model to measure and compare the risks associated with different investments. The second evaluation model (Model 2) takes into account the risk profiles of different power plant technologies (nuclear, coal and CCGT) in the investment model. An oligopoly electricity market is modelled using an empirical approach so that the investment is evaluated under a realistic environment. Since the profitability of the investment is very dependent on the shape of the discretized LDC, an optimal step-function approximation of the LDC is also presented prior to the investment evaluation.

Sensitivity analyses show that, being a base unit in the system, the profitability of the nuclear plant is mostly affected by the changes in the shape of the LDC at the base segments. It is also sensitive to the uncertainties in the nuclear waste fee and the development of wind generation in the system. As a capital intensive investment, the economics of the nuclear plant are also very dependent on the investment cost, the construction time and the discount rate. On the other hand, as a peaking unit, the change in the shape of the LDC at the high load segment and in the system reserve has a great impact on the profitability of a CCGT plant. It is also very sensitive to the heat rate. However, having a low capital cost and a short construction time, it is much less sensitive than the nuclear to the uncertainty in the overnight cost, the construction time, the discount rate and the fixed O&M cost. On the other hand, having lower carbon intensity, it is less affected by the carbon emission tax compared to a coal power plant. The sensitivity analysis of the coal plant shows result somewhere in between the nuclear and the CCGT. It is, however much more affected by changes in the carbon emission tax than the nuclear and the CCGT. Meanwhile, the heat rate, the overnight cost, the construction time and the discount rate are also important parameters to the economics of the coal plant.

The probabilistic evaluation model (Model 1) proposed in this chapter provides generating company a wider analytical framework and a systematic way to compare the risks of different investments under uncertainties. The profit distribution which is graphically presented is useful for a project manager to demonstrate the riskiness of an investment to non-economical people in the company as it gives a better picture and the confidence level of investing in the power plant. On the other hand, the second model (Model 2) proposed in this chapter helps a generating company to assess investments in an oligopoly electricity market and quantify the risks of different investment technologies. It also can be used to perform sensitivity analysis to study the effect of different system scenarios and various uncertainties on the profitability of the technologies.

Chapter 5 Generation Investment Evaluation Model in Oligopoly Market with Capacity Mechanisms

Summary

This chapter extends the investment evaluation model (Model 2) presented in Chapter 4 to consider investment in an oligopoly electricity market with a capacity mechanism. The capacity mechanism is included both in the formulation of prototype future system expansion and revenue calculation of the investment under consideration. In the prototype system expansion, the capacity mechanism is considered as an additional cost to the total cost of system expansion, but is extra revenue for the new plant that the company is evaluating. Two types of capacity mechanisms have been modelled: 1) capacity payment with linear representation and with payment proportional to the loss of load probability (LOLP), and 2) capacity market with various slopes of a demand curve. In the analysis, the effects of capacity mechanisms on the future system expansion and on the profitability of different technologies are presented.

5.1 INTRODUCTION

There are on-going debates among economists about whether energy prices in competitive electricity markets are high enough to stimulate sufficient investments from the generating companies to meet the required capacity in the system. This is especially true in the aftermath of the California crisis of 2000. This has become a main concern of regulators in some of the countries that have restructured their electricity industries since the availability of electricity is essential to the well-being of the economy.

As previously discussed in Chapter 3, a perfectly competitive power market should, in theory and in the long run, provide the correct signals to attract investments from generating companies, but this might not happen in the real world. This has led to the emergence of various capacity incentives such as capacity payments and capacity markets to provide the generating companies with additional income to cover their fixed cost and hence encourage them to invest in power generation.

Modelling generation investment decisions in a market with a capacity mechanism are even more complex because the potential investor has to forecast the expected revenue that the new investment will generate not only from the energy market but also from the capacity mechanism. Moreover interplay exists between the market and the mechanism. The exact form of the capacity mechanism has an effect on the investment decision and technology choices made by the generating companies. It is also important to know whether the capacity mechanism gives a right signal to invest and serves its objective to help generators to cover their investments and fixed costs.

In this chapter, a technique that a generating company could use to evaluate its investment options in an oligopoly electricity market with capacity mechanism is presented. The proposed model extends the investment model in an oligopoly market (Model 2) presented in Chapter 4 to consider capacity mechanisms both in the upper problem i.e. the prototype system expansion schedule and the lower problem i.e. the revenue calculation of the new plant under consideration. It is important to understand that the effects of capacity mechanisms on the upper and lower problem are considered from different perspectives. The capacity mechanism in the prototype future system expansion is looked at from the overall system perspective in which its implementation is seen as an extra cost of system expansion. On the other hand, from the perspective of the generating companies, the capacity mechanism is additional revenue to cover their investment costs.

Two types of capacity mechanisms are included in the model: 1) capacity payment either as a linear capacity payment or as a payment based on the LOLP, and 2) a capacity market similar to the ICAP market organised by the New York Independent System Operator (NYISO). The objectives of this study are:

1. First, to develop a model that can be used by a generating company to calculate the expected revenues that a new investment it is considering would earn from both the energy market and the capacity mechanism

2. Second is to analyse the interrelated dynamics of the spot prices and the capacity mechanism

3. Third is to study the effects of capacity mechanism on the system and profitability of the plants under evaluation.

This type of analysis is important not only for the investors, but also for the regulators who are trying to design a robust electricity market. It is not the aim of this thesis to propose a new capacity mechanism but instead to investigate how some of the designs that have been proposed and applied in actual markets could affect investment decisions. However the architecture of the proposed model is made flexible so that it can be applied to any design of capacity mechanisms in the future.

5.2 PROTOTYPE FUTURE SYSTEM EXPANSION UNDER THE MARKET WITH CAPACITY MECHANISM

Since the payment from the capacity mechanism is priced based on the available system capacity relative to the load, the implementation of the mechanism in the market will affect the investment strategy of the generating companies, the expected future energy prices and hence the expected profitability of the new investment that is being evaluated. In order to take into account these effects in the investment evaluation, the formulation of the prototype future system expansion using DP-based optimization has to be redefined.

As [5] argues, there is a price to pay by the consumers for the generation adequacy assurance that a capacity mechanism provides. In a market with capacity payments, the amount paid to the generators for the available capacity that they provide is shared among the consumers. On the other hand, in the capacity market, it is the responsibility of the Load Serving Entities (LSEs) to contract with the generators to meet the prescribed level of reserve capacity. As a result, having the generation adequacy assurance in the system adds an uplift to the overall cost of generating electricity. This is reflected in the objective function of the prototype future system expansion using DP by adding a capacity mechanism term in the equation (4.1) in Chapter 4. The new objective function is shown in equation (5.1) below. As previously pointed out, the payment from the capacity mechanism is a function of the system reserve capacity (i.e. installed capacity relative to the load). A lower reserve capacity means a higher payment is required for the mechanism. Since the objective of the prototype system expansion is to minimize the total cost, the DP will choose to build more plants to reduce the cost of the capacity mechanism and hence keep the reserve capacity at an optimal level. By doing this, the minimum reserve requirement constraint no longer needs to be included in the formulation of the prototype optimization.

The total system generation expansion cost under the capacity mechanism over the lifetime, T, of the investment plant that the company is evaluating is redefined as follows:

$$TC = \min \sum_{t=1}^{T} \left\{ PC_{all}(X_t)_t + IC(U_t)_t + FOM_{all}(X_t)_t + VOM_{all}(X_t)_t + CM_{all}(X_t, l_{\max,t})_t \right\} \tag{5.1}$$

where $CM_{all,t}$ is the total payment from the capacity mechanism as a function of the system available capacity, X_t, and the peak load, $l_{max,t}$, at year t to all generating units in the system.

Similar to the investment evaluation model that is presented in Chapter 4, the prototype future system expansion schedule under the capacity mechanism is developed to provide generating companies a possible scenario of what may happen in the system regarding the future investments and the retirements of other generating units over the life time of the new plant that the company is evaluating. This scenario is used as a base for the generating company to calculate the future energy prices and capacity prices and hence the expected revenue of the new investment.

5.3 NET REVENUE FROM ELECTRICITY MARKET WITH CAPACITY MECHANISM

As pointed out in the introduction, a capacity mechanism is a scheme that provides generating companies the opportunity to collect extra money. When considering investment decisions, all the revenues streams generated by the new plant must be considered such as the revenues from the sale of energy, provision of reserve and also the capacity mechanism. The net operating revenue made by the new plant under the electricity market with this mechanism is computed as follows:

$$P_{new,t} = (ER_t + SR_t + CM_t - PC_t - FOM_t - VOM_t) \tag{5.2}$$

where CM_t is the revenue collected by the new plant from the capacity mechanism in year t.

Since the model developed in this chapter focuses on the effects of the capacity mechanism on the system and the profitability of a new investment, other regulatory interventions such as the carbon emission tax and the nuclear waste fee are not considered in the analysis.

5.4 CAPACITY PAYMENT

5.4.1 Design of Capacity Payment

Two types of capacity payments have been modelled and included in the investment evaluation model. The first model is a linear capacity payment where the payment to the generators is inversely proportional to the system reserve capacity. The second model is a capacity payment that is based on the LOLP and is thus similar to the one that had been used under the old Electricity Pool of England and Wales.

5.4.1.1 Linear Capacity Payment

In this model, the linear capacity payment is a function of the reserve capacity in the system and is paid to the generators on a yearly basis. Figure 5-1 illustrates this form of capacity payment. The capacity payment is paid to the generators when the system reserve capacity, CF_t which is the ratio of the available generation capacity X_t, to the peak load $l_{max,t}$, only in the years when it drops below a preset margin threshold, R_{lim}. The amount paid per MW of available capacity increases linearly when the system reserve capacity decreases. The revenue of the new plant from the capacity payment, CPr_{new} over the year equals the capacity of the plant, P^{max}, times the capacity payment prices in that year, CP. This type of capacity payment is similar to the one presented in [40]. The system reserve capacity and the revenue made by the new plant at year *t* from the linear capacity payment are described mathematically by equation (5.3) and equation (5.4):

$$CF_t = \frac{X_t}{l_{max,t}} \tag{5.3}$$

$$CPr_{new,t} = CP(X_t, l_{max,t})_t x P^{max} x 8760 \tag{5.4}$$

The total cost of capacity payments to all generating units in the system at year *t* for the prototype future system expansion formulation is shown in the following formula:

$$CP_{all,linear,t} = \sum_{z=1}^{Z} CP(X_t, l_{max,t})_t x P_z^{max} x 8760 \tag{5.5}$$

where Z is the number of generating units in the system.

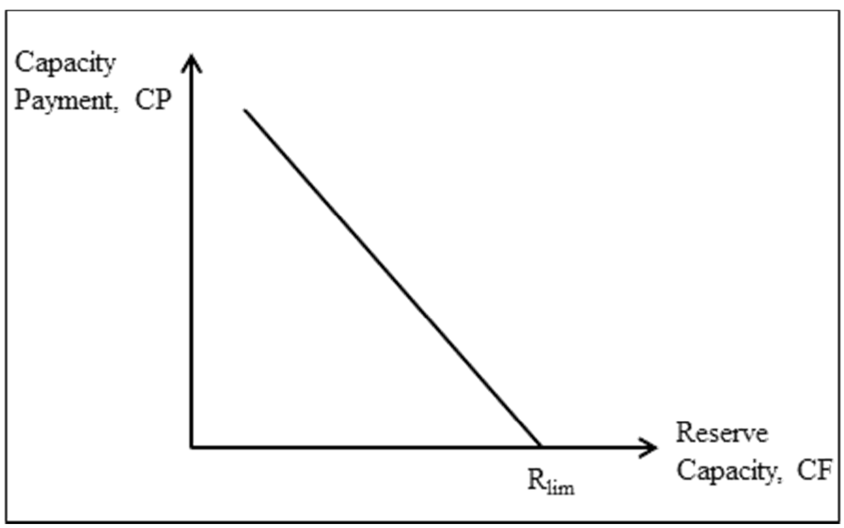


Figure 5-1 Linear capacity payment

5.4.1.2 Capacity Payment Based on the Load of Loss Probability (LOLP)

Similar to the linear capacity payment above, the capacity payment based on the LOLP is also a function of available capacity in the system relative to the load. However, in this model the capacity payment price is calculated in a more sophisticated way based on the expected probability that the system load level will exceed the generation availability in a given period, and is paid to the generators in each segment of the LDC. The capacity payment based on the LOLP in this chapter is modelled like the capacity payment presented in Chapter 3 of this thesis. The total cost of capacity payments paid to all generators in the system each year for the prototype system expansion formulation is described by the equation below:

$$CP_{all,LOLP,t} = \sum_{z=1}^{Z} \sum_{s=1}^{S} VOLL X LOLP X FOR_z X P_z^{max} X d_s \tag{5.6}$$

5.4.2 Test Result

The proposed investment model with capacity payment has been tested on the test system based on the Great Britain's 2010 Seven Year Statement presented in Chapter 4. The list of generation technologies that can be selected by the DP for the prototype future system expansion and the three possible investment technologies (i.e. nuclear, coal and CCGT) are shown in Appendix A. The system parameters such as the LDC, the load growth, the initial system reserve margin, the spinning reserve requirement and the plants' retirement are similar to those used in section 4.8.1.

Four analyses have been performed using the proposed model. In the first analysis it is assumed that Company A is comparing the investment alternatives when a linear capacity payment mechanism is in place. The second analysis is performed considering that the capacity payment based on the LOLP is used in the system. The third analysis is carried out to see the effect of VOLL on the system and on the profitability of the investment alternatives. Finally, the global effect of having the capacity payment proportional to the LOLP on the total cost of generating electricity is studied.

5.4.2.1 Scenario 1: Investment with Linear Capacity Payments

In the first scenario, it is assumed that the payments are made only when the reserve capacity drops below 20% (i.e. R_{lim}). The steepness of the curve is such that when the reserve capacity is equal to zero, the capacity payment price is 34900$/MW/yr. This curve is shown in Figure 5-2 as a base case. Figure 5-3 shows the expected revenue that would be collected each year from the energy market and the capacity payment if a nuclear plant were built. Such a plant makes much more money from the energy market than from the capacity payments. The expected annual capacity payment paid to the generators and the system reserve capacity resulting from the prototype future investment schedule over the lifetime of this nuclear plant are shown in Figure 5-4. This figure also shows that the lower the system reserve margin, the higher the capacity payment paid to the generators.

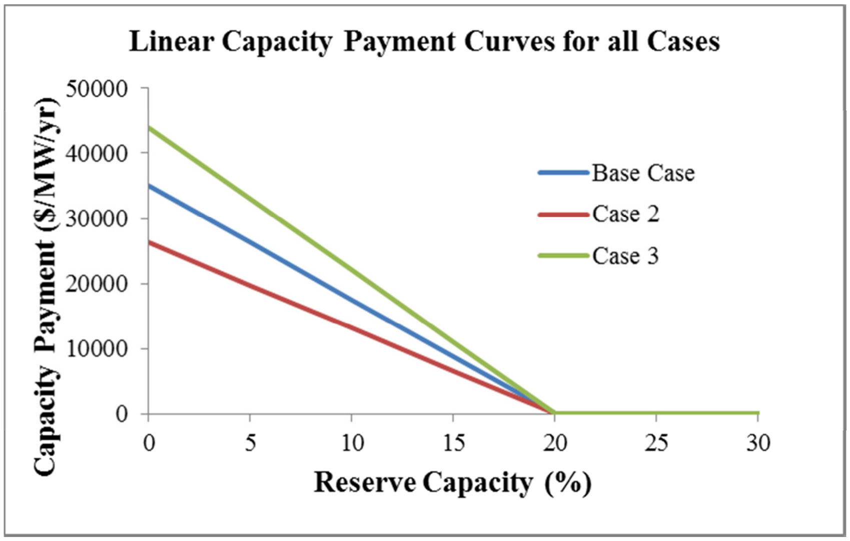


Figure 5-2 Linear capacity payment curves for all the cases

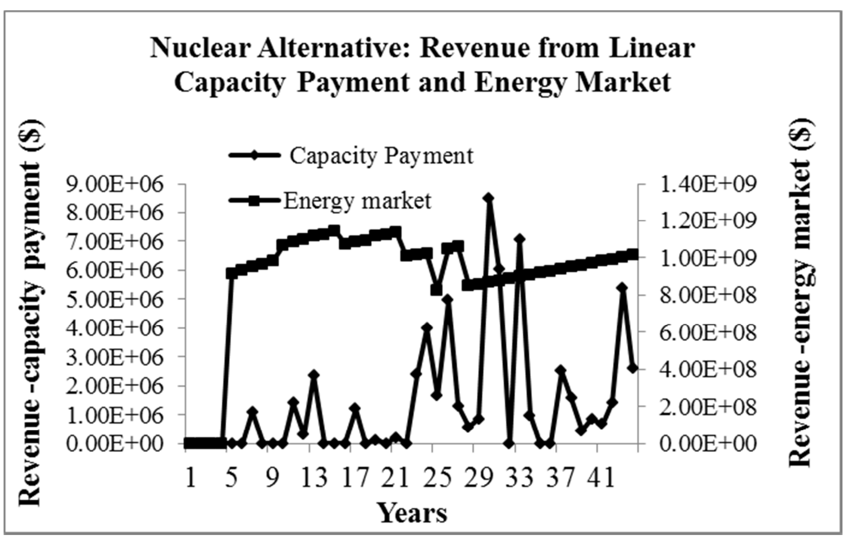


Figure 5-3 Expected revenues from energy market and linear capacity payment scheme for an investment in a nuclear plant (Base case)

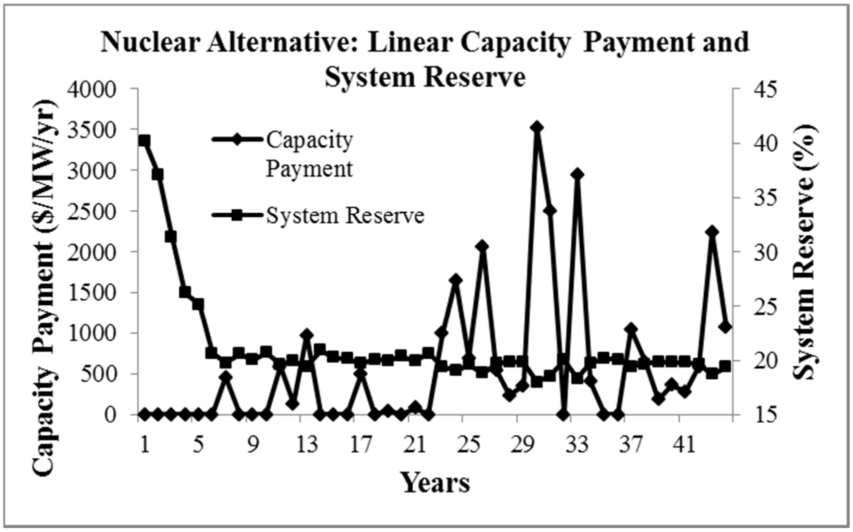


Figure 5-4 Expected average system reserve and linear capacity payment over the lifetime of an investment in a nuclear plant (Base case)

Under this scenario, which is denoted as the base case in Table 5-1, coal power plants are the most profitable investment followed by nuclear then CCGT. In this revenue evaluation the effects of carbon emissions are not included. It is seen that the 'inconsistency ranking problem' exists if the alternatives are compared using the IRR. Therefore, it is more appropriate to compare the alternatives using the FWV. The FWV of the coal and CCGT plants are calculated considering that the plants are reinvested up to the lifetime of the nuclear plant. It is also shown that under the implementation of linear capacity payment, all the alternatives are profitable and the investment should be accepted.

A less steep capacity payment curve (Figure 5-2) as in case 2 results in fewer investments in the prototype plan (this is shown by the system reserve margin in Figure 5-5), and hence an increase in energy prices (Figure 5-6) and capacity payments (Figure 5-5). When this happens, all the investment alternatives considered by Company A collect more revenue than in the base case. However, in such a situation Company A may decide not to invest although the investment alternatives that the company are evaluating are expected to be profitable. This is because by doing this, the system will lack capacity, and its existing portfolios of generating plants will collect more money from higher energy prices and capacity payments. This behaviour can lead to gaming and manipulation of the capacity payments in an oligopoly market. On the other hand, when a steeper capacity payment curve is considered such as in case 3 (Figure 5-2), the DP predicts more investments, bringing down the energy and capacity payment prices, and hence less expected net revenue for the alternatives (Table 5-1). This scenario gives more impact to the nuclear plant which has a longer economic lifetime and a riskier investment. In this situation, the CCGT plant becomes more profitable than the nuclear after the coal power plant.

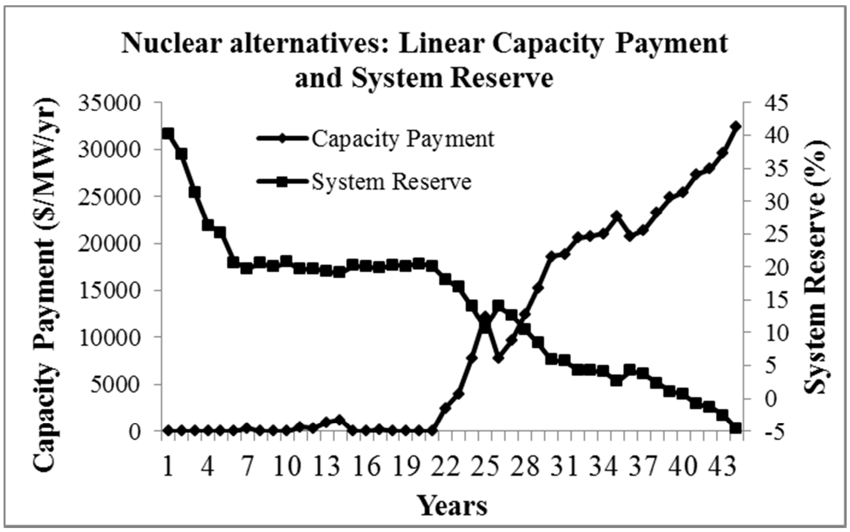


Figure 5-5 Expected average system reserve and linear capacity payments over the lifetime of an investment in a nuclear plant (Case 2)

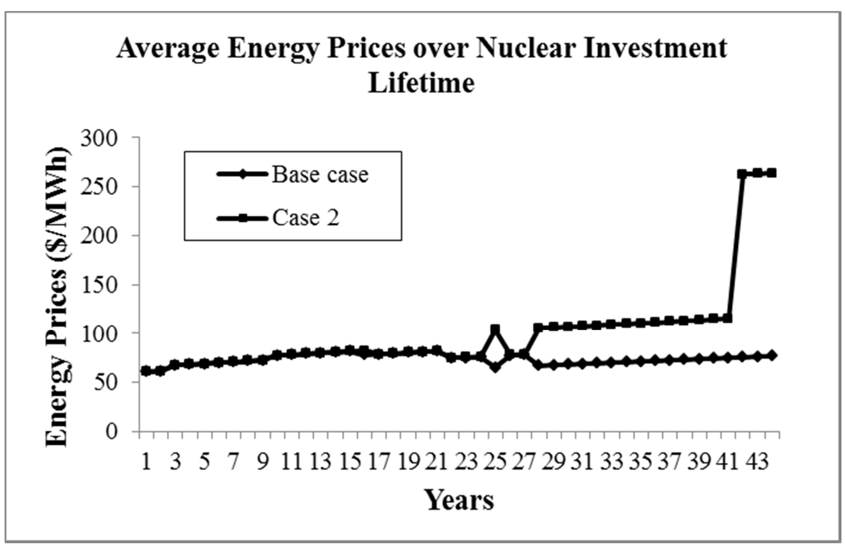


Figure 5-6 Expected average energy prices over the lifetime of an investment in a nuclear plant in the base case and case 2

	Case 1-Base Case		Case 2		Case 3	
	IRR	FWV/MW	IRR	FWV/MW	IRR	FWV/MW
Nuclear	16.56	1.09E+08	16.89	1.33E+08	15.90	9.46E+07
Coal	20.96	1.43E+08	21.15	1.60E+08	20.03	1.31E+08
CCGT	28.18	1.05E+08	28.18	1.05E+08	28.16	1.05E+08

Table 5-1 IRR and FWV of the investment alternatives under various cases of linear capacity payments

5.4.2.2 Scenario 2: Investment under Capacity Payment Proportional to LOLP

Figure 5-7 shows the expected revenue from the energy market and capacity payments when these capacity payments are proportional to LOLP for an investment in a nuclear power plant with a VOLL of 6000$/MWh. Similar to the linear capacity payment, more payment will be made to the generators under the LOLP scheme when the reserve capacity is lower. This relationship is shown in the scatter plot of Figure 5-8. Comparing the three investment alternatives, at VOLL equal to 6000$/MWh, the coal power plant turns out to be the most profitable investment followed by the nuclear and CCGT plants (Table 5-2), which is similar to the trend in the linear capacity payment. Under this type of capacity payment, all the alternatives are also expected to be profitable and the investments should be accepted.

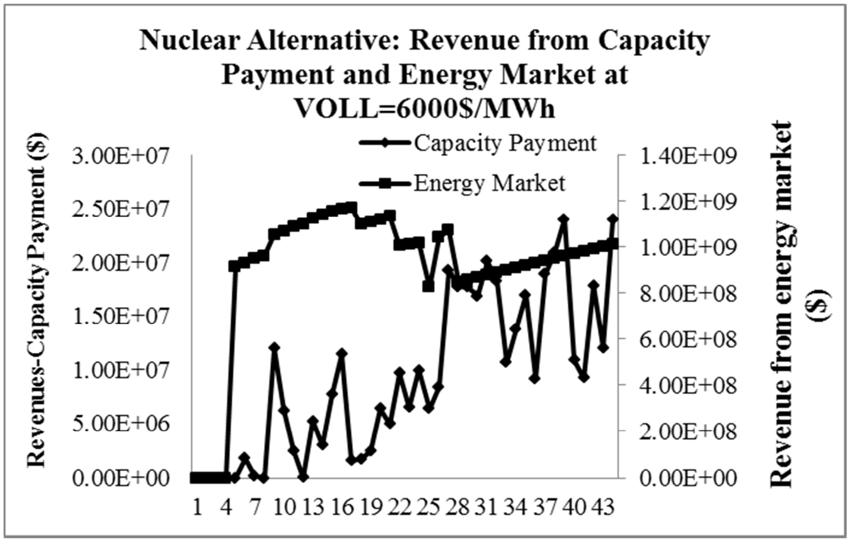


Figure 5-7 Expected revenue for a nuclear investment from energy market and capacity payment proportional to LOLP

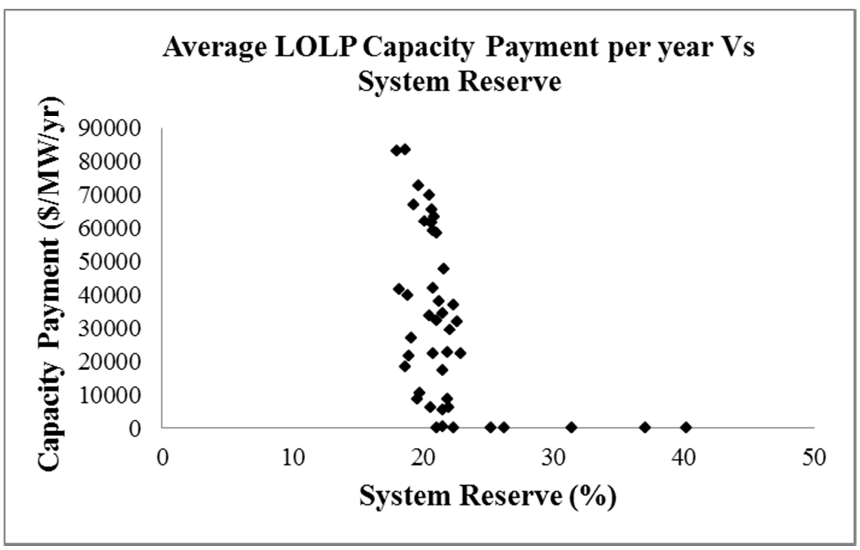


Figure 5-8 Scatter plot showing the relationship between the annual average capacity payment price and system reserve at VOLL=6000$/MWh

	VOLL		
FWV/MW($/MW)	1000	6000	12700
Nuclear	1.08E+08	1.14E+08	9.68E+07
Coal	1.43E+08	1.51E+08	1.34E+08
CCGT	1.07E+08	1.04E+08	1.09E+08

Table 5-2 FWV of the investment alternatives under various VOLL for the LOLP capacity payment scheme

5.4.2.3 Sensitivity to Value of Loss Load (VOLL)

The value of VOLL and LOLP are important in determining the capacity payment prices. The VOLL should theoretically be measured using customer surveys; however it is difficult to define because it varies among consumer categories. On the other hand, the LOLP which is usually calculated using simple models of probabilistic failure might overestimate the chances of power failure [107]. In this study the value of VOLL is varied to see how this parameter affects the expected system reserve margin, the energy prices, the capacity payments and the expected profitability of the investment alternatives.

Figure 5-9 shows the expected system reserve margin under the various VOLL over the lifetime of an investment in nuclear capacity. The prototype future investments from the DP increases as the system VOLL increases. However this capacity payment is also a function of LOLP. When there is a large amount of capacity available relative to the load, the LOLP is low and the capacity payment prices are lower (Figure 5-10). Hence the capacity payment prices do not exhibit wide variations as a function of VOLL.

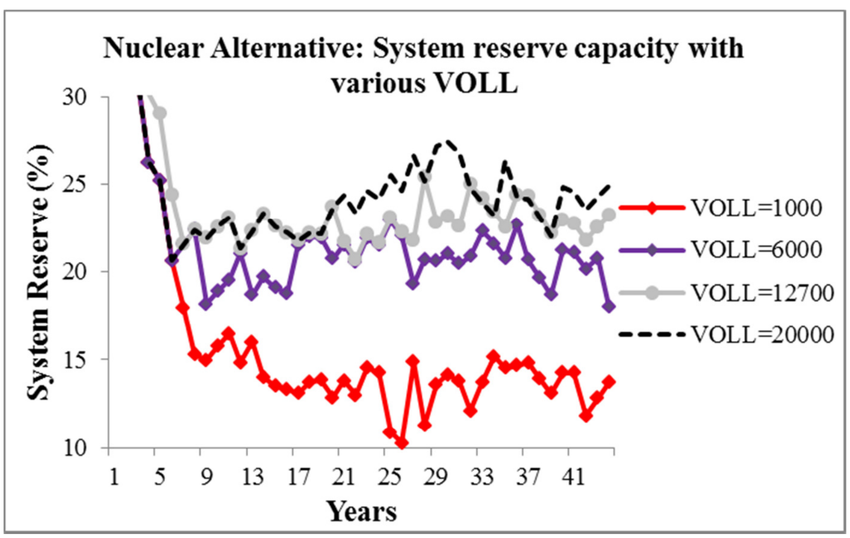


Figure 5-9 Expected system reserve capacity under LOLP capacity payment scheme for various VOLL over the lifetime of investment in a nuclear power plant

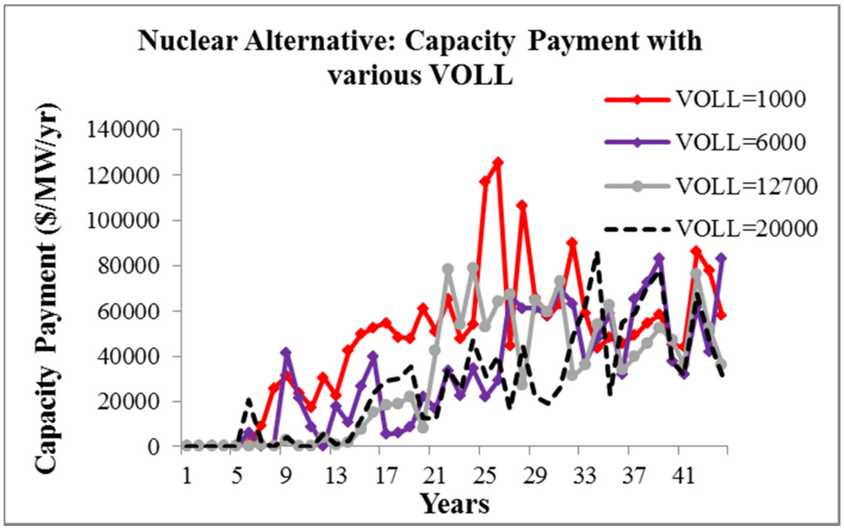


Figure 5-10 Expected annual average capacity payment prices under LOLP capacity payment scheme for various VOLL over the lifetime of investment in a nuclear power plant

If VOLL is given a low value (e.g. 1000 $/MWh), not enough capacity is built and load shedding is necessary for peak loads during years 25 and 26. Since the Energy Not Served (ENS) is assumed to have a value equal to VOLL, this significantly increases the average energy prices in those years (Figure 5-11). Figure 5-9, Figure 5-10 and Figure 5-11 also demonstrate that, as one would expect, a lower system reserve capacity results in higher capacity payment prices and higher average energy prices.

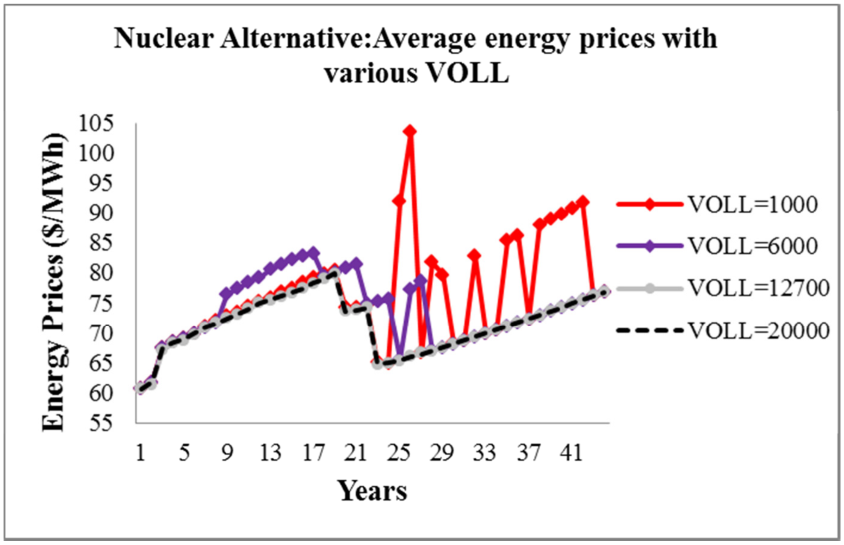


Figure 5-11 Expected average energy prices under LOLP capacity payment scheme for various VOLL over the lifetime of investment in a nuclear power plant

The profitability of the investment alternatives for different VOLL was shown in Table 5-2. Since the energy and capacity payment prices are interrelated with the available system capacity relative to the load and the technology mix, it is difficult to clearly see the effect of VOLL on the profitability of the investment alternatives. However, comparing the three alternatives, the nuclear power plant, which has a bigger capacity and longer lifetime, is more sensitive to the various changes in both capacity payment schemes followed by the coal. On the other hand, unlike the nuclear and the coal, the profitability of CCGT is more sensitive to the uncertainty of the LOLP capacity payment mechanism than to linear capacity payment scheme because it operates more often as a peaking unit. The simulation also shows that under optimal conditions, both the capacity payment schemes succeed in promoting investments from the DP for the prototype future system expansion without enforcing a minimum reserve requirement constraint in the formulation.

5.4.2.4 Global Effect of Having Capacity Payments Based on LOLP

Figure 5-12 shows the total payment to all generators in the system over the planning horizon (i.e. from both the energy market and the capacity payments) as a function of VOLL. This total payment decreases when VOLL increases from 1000$/MWh to

9000$/MWh because this results in more investments, hence an increase in the system reserve margin and a reduction in the energy and capacity payment prices. However, for a further increase in VOLL, the total payment to the generators saturates and VOLL has a smaller impact on the investments and the capacity margin. This is because the capacity payment is determined by the product of VOLL and LOLP. At some points, a further increase in system VOLL is compensated by a decrease in system LOLP and thus has no more influence on the capacity payments.

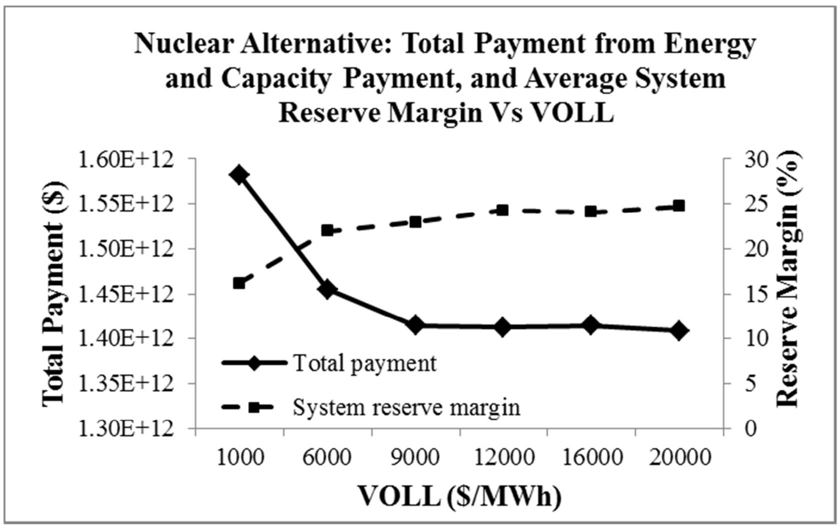


Figure 5-12 Total payment from energy and capacity payment and system reserve margin as a function of VOLL

5.5 CAPACITY MARKET

5.5.1 Evolution of Capacity Markets in the United States

In a capacity market, the Load Serving Entities (LSEs) are obligated to buy a specified amount of capacity above their peak load from resource providers to meet some minimum reserve capacity requirement. The 'missing money' phenomenon, which arises when the prices from the energy market is not high enough to provide sufficient revenue to cover the total cost of existing or new units, has been observed in several electricity markets in the United States [108]. As a consequence, some Independent System Operators (ISO) in the North-eastern United States electricity markets, for example New York ISO (NYISO), PJM and ISO New England (ISO-

NE) have introduced additional incentives to promote generation availability and investments through Installed Capacity (ICAP) markets.

Initially, the ICAP market was designed to deal with the availability of generating units in the short term. However, generating companies were seeking an incentive such as forward contracts that guarantee them the sale of energy in the long run to cover the cost of building new plants. Several issues arise when the functions of the ICAP market are revised to consider new investments for long term generation adequacy. [109] discusses three issues of contention about the effectiveness of ICAP market in providing incentives for new investment: 1) the difficulty to set the time horizon that is far enough for the ICAP to remunerate the new investment, 2) whether it is appropriate to put the responsibility of ensuring generation adequacy on the LSEs, and 3) how to design an attractive ICAP market that ensures enough revenue for the new investments. The initial ICAP markets were characterized by a vertical demand curve that fixed the planning reserve margin target and a near vertical supply curve to set the prices. This arrangement was criticised for its vulnerability to exercised market power [54]. This is because any capacity withholding in the market will shift the supply curve to the left from A to B (Figure 5-13) and cause a large increase in the capacity price.

The drawbacks of the early ICAP designs led to the first attempt by the NYISO to refine its ICAP market by proposing a downward sloping demand curve. This is particularly to solve the third issue discussed above and to reduce the use of market power by the generating companies in setting the capacity prices. Using the sloping demand curve, the capacity price becomes less sensitive to the changes in the supply curve that might result from capacity withholding. A similar concepts to the NYISO ICAP market was then proposed by ISO-NE, but with two downward sloping segments and by the PJM market with a ‘kinked’ demand curve known as Variable Resource Requirement (VRR) [110]. Another solution to the issue of market power is to conduct ICAP auction in advance to allow new entry to occur. This will extend the supply curve in Figure 5-13 to the right and make it less steep and thus reduce the effect of market power. This concept has been proposed by the PJM market in its Reliability Pricing Model (RPM) where the ICAP auction is made three years in advance prior to the delivery year i.e. the year where the units that clear the ICAP auction must make their capacity available.

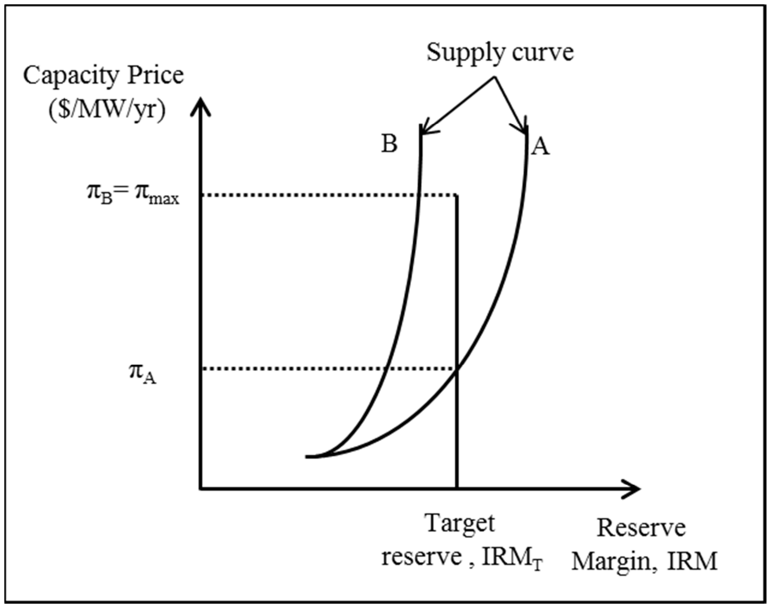


Figure 5-13 Vertical demand curve in ICAP market, source: Chandley 2003 [54]

The reformed ICAP markets in those regions combine the concepts of capacity payments and capacity markets. In this approach, the ISO defines a sloping demand curve as a function of installed reserve margin (IRM), which describes the payment to be paid to the generating units for their unforced capacity (i.e. capacity derated for expected force outages). On the other hand, the supply curve is constructed from the bid prices that the generating units submit in the ICAP market for the available capacity that they are willing to commit. The ICAP prices and the quantity of the capacity obligation are determined by the intersection of these two curves. The objective of the downward sloping demand curve is also to align the capacity pricing with the system reliability requirement in the system. Similar to the initial ICAP market, there is a target reserve, when there is an excessive capacity in the system, the price is zero; otherwise a higher capacity price is paid to the generators.

A more detailed description of the reform of the ICAP market in the North-eastern United States can be found in [54, 55, 109].

In this study, a general ICAP market model has been developed and included in the investment evaluation framework shown in Figure 4-1 of Chapter 4. In order to see the effects of the ICAP market on the prototype future system expansion using DP, the ICAP market is incorporated in the upper level of the investment framework. The ICAP model is also considered in the lower level of the investment model to calculate the expected revenue that the investment will derive from the ICAP market. A demand curve based on the NYISO ICAP market is modelled and used in the analysis. A sensitivity analysis has been performed to see the impacts of changing the parameters of the demand curve on the system as well as on the revenue of the investments.

5.5.2 Design of Capacity Market

5.5.2.1 Overview of the ICAP Market Model

The ICAP market is modelled as a general auction process. The participants in the market are from both the demand and supply sides. Unlike the ICAP model presented in Chapter 3 of this thesis where participation was limited to units that did not provide energy or reserve, it is assumed that all the generating units in the energy market can participate and are willing to join the ICAP market. On the other hand, the LSEs are aggregated to buy capacity from the energy resources to meet their installed capacity obligation. The capacity payments are determined by the crossing point of the supply curve and the demand curve administratively defined by the ISO. It is assumed that the ICAP payments received each year by the generating units result from an ICAP auction that has been performed earlier. The plants whose capacity clears the auction receive the ICAP market clearing price for their unforced capacity.

5.5.2.2 Plotting Downward Sloping Demand Curve

The demand curve that is used in the analysis is similar to the NYISO demand curve which has one downward sloping segment as shown in Figure 5-14. Three points with several key parameters are required to construct this curve. The first point is the intersection of the net Cost of New Entry (CONE) and the target IRM. The net CONE is the levelised capital and fixed O&M cost of a benchmark unit minus the gross margin that it would receive from the energy and ancillary service market. This benchmark unit is assumed to be the lowest cost way to add capacity. It is usually a simple combustion turbine. This point is the break-even point for the investment. If the capacity is at this target reserve, the payments to the generating units would exactly equal to the cost of building a simple combustion turbine. The second point is the zero crossing point where the capacity price is equal to zero. Beyond this capacity level no payments are made to the generators as the system is deemed to have excess capacity. On the other hand if the reserve level is to the left of this point, some payment is made to the generators. The curve is drawn by connecting these two points. The final point is the price cap for the capacity and is defined differently in each ISO's region. For example in the original NYISO demand curve, the price cap is equal to 1.5 times the net CONE; on the other hand in the ISO-NE the value is set at 2.0 times the CONE [54].

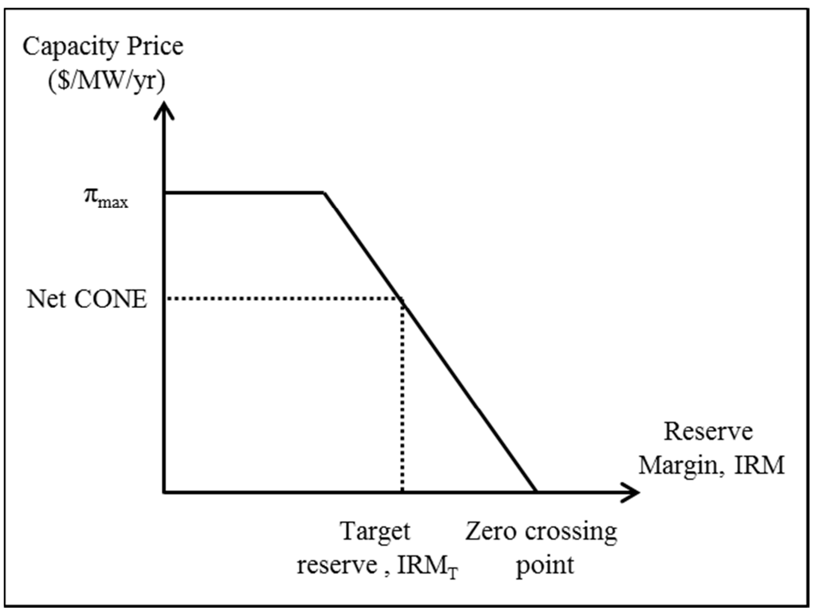


Figure 5-14 NYISO downward sloping demand curve

The slope of the curve affects the incentive to invest in the new capacity. Moving the zero crossing point to the left while keeping the point where the target reserve and the net CONE intersect results in a steeper demand curve. A steeper demand curve gives more incentive to the generating companies to invest when the reserve margin is below the target reserve as the price increases rapidly when the system shortage increases. On the other hand, a steeper curve adds more incentive to retire the plants as the price drops faster when the system reserve is above the target. The steeper demand curve increases the risk to investors because the price for capacity fluctuates more and a small overbuilding above the target reserve results in the generating companies receiving only a small revenue (or none at all) from the ICAP market. On the other hand, moving the zero crossing point to the right makes the demand curve flatter. Although a flatter demand curve reduces the incentive to invest as the capacity price increases slowly when the reserve decreases, the price fluctuates less and thus provides generating companies more constant revenues and thus a less risky investment environment. Moreover a zero crossing point further to the right would increase investments because the generating companies would still have a chance to receive some payments although the capacity is far beyond the target reserve.

5.5.2.3 Supply Curve in ICAP Market

The supply curve is constructed from the bid prices submitted by the participants in the ICAP market. Similar to the energy market, these bids are ranked in merit order. In this ICAP model, it is assumed that the existing units in the energy market bid at a lower prices, while the new units that are willing to make their capacity available in the future might bid higher [60]. These new capacities are assumed to be the plants that are chosen by the DP each year for the prototype future system expansion. Since there is no article available in the open literature regarding the offer price strategies versus technologies in the ICAP market, it is assumed that the nuclear power plants, which have a lower marginal cost, bid at a lower price followed by the coal and the CCGT plant. The formulation of the bid prices of the units in the ICAP market are simple, with the bid prices ranging from zero for the existing nuclear units to about two thirds of the CONE for the new peaking units [60]. Figure 5-15 shows the supply curve resulting from the prices and capacities bid into the auction.

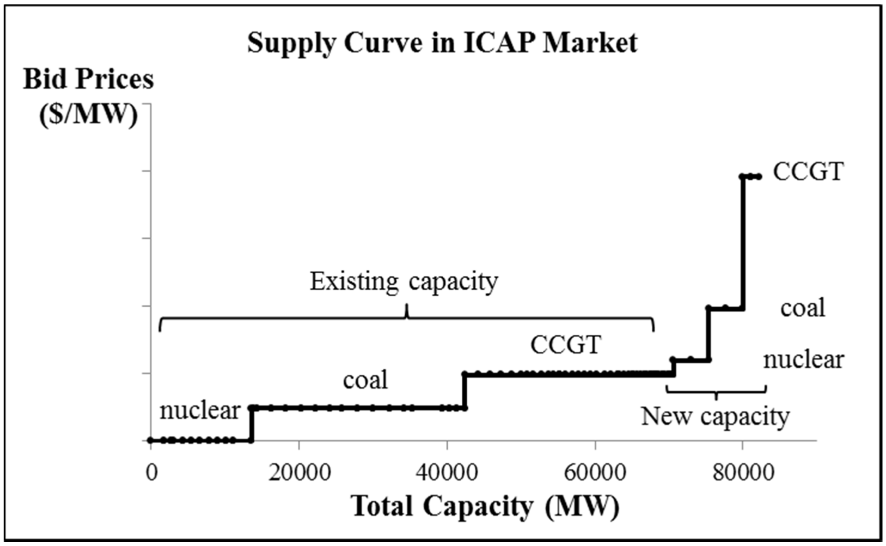


Figure 5-15 Bid prices of existing units and new units in ICAP market

5.5.2.4 ICAP Clearing Mechanism

The capacity and the ICAP clearing price is determined from the intersection of the capacity payment demand curve and the supply curve. In the event where the supply curve does not intersect with the demand curve, the clearing will be set along the demand curve by extending the supply curve vertically upward until it intersects with the demand curve [110]. This is shown in Figure 5-16.

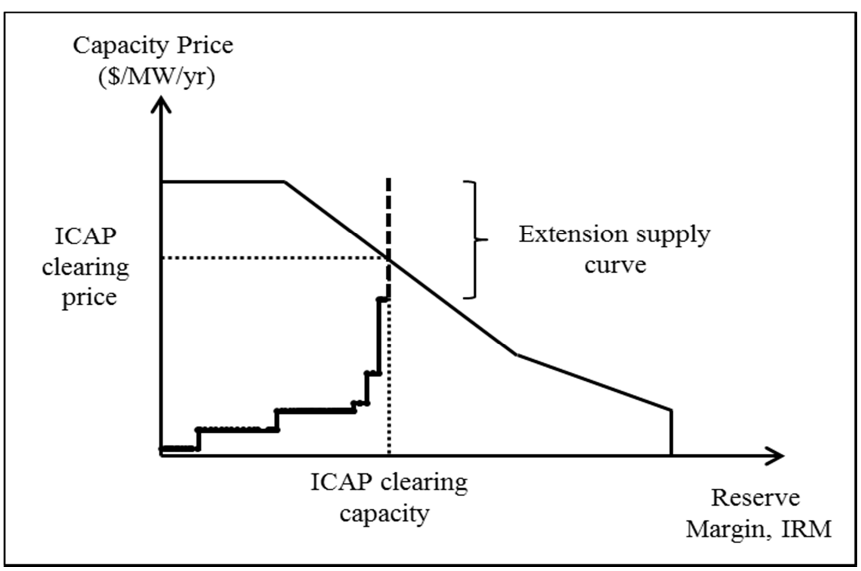


Figure 5-16 ICAP clearing process

All the units with the bids below the ICAP clearing price are paid the clearing price for their unforced capacity (i.e. capacity derated for expected force outages). The total cost of having the ICAP market in the system (i.e. the payment to all the generating units) each year for the prototype system expansion formulation is described by the equation below:

$$CM_{all,t} = \sum_{z=1}^{Z} CM_{price} X 0.9 X P_z^{max} \tag{5.7}$$

where CM_{price} is the ICAP clearing price and it is assumed that the capacity of each unit is derated 10% from their installed capacity (unforced capacity) to take into account the expected forced outages.

5.5.3 Test Results

The analysis has been carried out on a test system based on the Great Britain 2010 Seven Year Statement. The system parameters such as the LDC, the load growth, the system retirement and the spinning reserve requirement are similar to the analysis presented in section 4.8.1 of Chapter 4. The CONE and the ICAP price cap are set to 49000$/MW and 120000$/MW respectively. The bid prices of the existing units in the ICAP market are set to zero for nuclear, wind and hydro generations, 0.05 x CONE for the coal, 0.10 x CONE for the CCGT and 0.15 x CONE for the oil-fired generation. Meanwhile, the new installed capacity in that year is assumed to submit higher bids in the last auction, i.e. 0.12 x CONE for the nuclear, 0.20 x CONE for the coal and 0.40 x CONE for the CCGT. The target system reserve margin for the demand curve is set at 20% and the zero crossing point is at 25% of the reserve margin.

5.5.3.1 Investment in ICAP Market with Various Sloping Demand Curves

Figure 5-17 shows the expected revenue that the nuclear power plant would collect each year from the energy and ICAP market over its lifetime. As one would expect, such a plant makes more revenue from ICAP market when the reserve capacity in the system is low but receives no remuneration when there is excess system reserve. This is shown in Figure 5-18 where at a lower system reserve, the ICAP price is higher. This ICAP price is also dependent on the existing technology mix in the system that participates in the auction. On the other hand when the reserve exceeds the zero crossing point of the ICAP demand curve which is set at 25% in the base case (Figure 5-19), the prices drop to zero. The simulation also shows that under the optimal condition, adopting the ICAP market would encourage investments from the DP for the prototype future system expansion without enforcing a minimum reserve requirement constraint in the formulation.

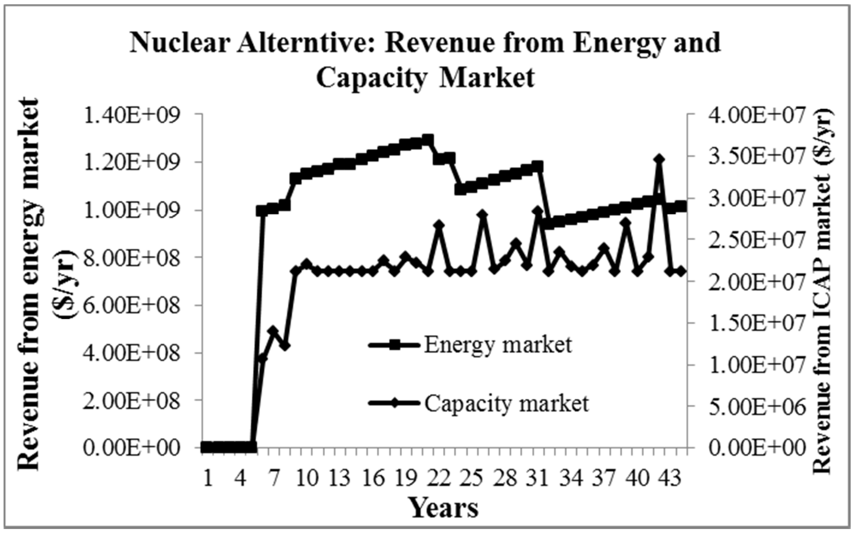


Figure 5-17 Expected revenue for a nuclear investment from the energy and ICAP markets

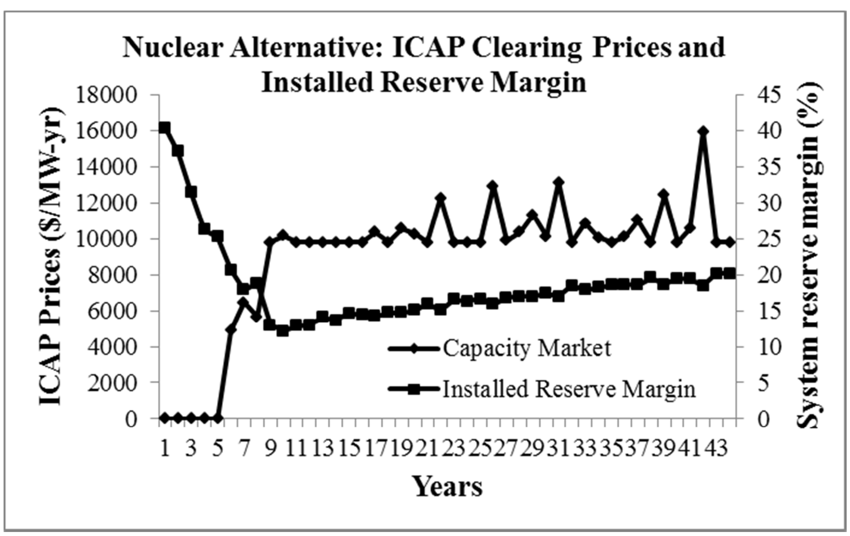


Figure 5-18 ICAP clearing prices and system reserve margin over the lifetime of an investment in a nuclear power plant

The analysis is extended by moving the zero crossing point from 25% reserve margin in the base case to 24% in case 2 while keeping the breakeven point (i.e. the point where the target reserve and the net CONE intersect). This results in a steeper demand curve as shown in Figure 5-19. A steeper demand curve on average increases the investments from all the companies in the prototype future system expansion, where more power plants will be built over the lifetime of the nuclear power plant under evaluation. This is shown in Table 5-3 where the average system reserve margin is higher in case 2 than in the base case. A higher average reserve in the system results in a lower average energy price and a lower average ICAP price. As a consequence, a steeper demand curve provides a generating company with lower total revenues for the nuclear plant that it considers building. It is also shown that investing under the steeper demand curve is a riskier investment because the ICAP prices and the energy prices fluctuate more than with the flatter demand curve. This is shown in Table 5-3 where the standard deviation of the prices from the energy market and the ICAP market over the lifetime of the nuclear plant under evaluation are higher under the steeper demand curve. As a result, the total revenue that would be received by the nuclear plant from the energy and ICAP market is uncertain under this environment.

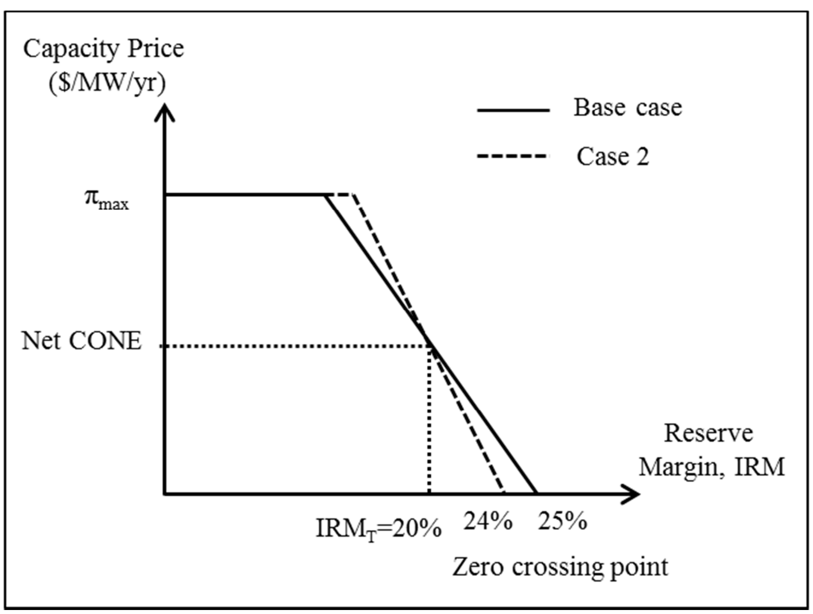


Figure 5-19 Demand curves with zero crossing points at 25% and 24% reserve margin

	Base Case		Case 2	
	Average	Standard deviation	Average	Standard deviation
Average System reserve margin (%)	18.45	5.67	18.97	6.36
Average Energy prices ($/MWh)	76.34	6.27	75.78	6.65
Average ICAP prices ($/MW)	8994	3640	7881	3904
Average Total revenue ($)	1.02E+09	3.390E+08	1.01E+09	3.393E+08

Table 5-3 Average reserve margin, energy prices, ICAP prices and total revenue of the investment in a nuclear power plant

All the investment alternatives being considered have positive FWV in both cases which indicate that the investments should be accepted. Comparing the three alternatives, with no carbon tax imposed in the system, the coal power plants are the most profitable investment followed by the nuclear and then the CCGT. This is shown in Table 5-4. Having a longer economic lifetime, the profitability of the nuclear investment plant is more sensitive to the uncertainty in the slope of the demand curve followed by the coal and the CCGT plants.

	Demand Curve	
FWV/MW ($/MW)	Base case	Case 2
Nuclear	3.42E+11	3.27E+11
Coal	3.70E+11	3.66E+11
CCGT	1.48E+11	1.47E+11

Table 5-4 FWV of the investment alternatives under various slope of demand curve in ICAP market

5.6 CONCLUSIONS

The model described in this chapter extends the previous investment evaluation model in oligopoly electricity market presented in Chapter 4 to consider capacity mechanism used to promote generation investments. The capacity mechanism is included both in the prototype future system expansion formulation as well as in the net revenue calculation of the plant that the company is evaluating. In the prototype formulation, the implementation of a capacity mechanism is considered as an additional cost to the total cost of system expansion. Since a lower reserve in the system increases the payment from the mechanism, the DP will choose to build more plants in order to minimize the total cost, hence keeping the reserve at the optimum. Modelling this incentive thus removes the need to include the minimum reserve requirement constraint that was enforced in the previous DP-prototype formulation. On the other hand, the capacity mechanism is the extra revenue for the plant that the company is evaluating. Two types of capacity mechanisms have been modelled: 1) the capacity payments with linear payments and with payments based on the LOLP; 2) capacity markets with various slopes of the NYISO demand curve.

The analysis shows that a less steep curve for the linear capacity payment induced fewer investments in the prototype plan than a steeper curve. On the other hand, in the capacity payment proportional to the LOLP, a higher VOLL on average increases the investments from all the companies in the prototype system expansion. However, when the VOLL increases further, the effects of VOLL on the system reserve, energy and capacity payment prices become less significant. This is because the capacity payment paid to the generators is determined by the combination of system VOLL and LOLP. An increase in the VOLL is compensated by a decrease in the LOLP hence reducing the impact to the capacity payment price. The analysis also shows that a lack of reserve in the system would increase the expected future energy prices and the capacity payment prices; hence a higher profitability for the investment that the company is evaluating would be expected. Although such situation would attract investments, for a better profit the company might decide not to accept the project. This is because by keeping the system with a lower reserve, its existing portfolio would receive greater revenue from higher energy and capacity payment prices. Such behaviour may lead to the manipulation of capacity payment to raise the price.

Similar to the linear capacity payment, a steeper demand curve for the ICAP market results in more investments in the prototype expansion schedule. The energy and ICAP prices for the steeper demand curve are more volatile than a flatter curve, hence increase the risk to the investors as the revenue that they will receive is uncertain.

Comparing the three investment alternatives, a nuclear power plant which has a longer lifetime is the most exposed to the risks and the most affected by the uncertainty in capacity payment and capacity market mechanisms. It is followed by the coal and the CCGT plants. On the other hand, as a peaking unit, the CCGT plant is more sensitive to the changes in the capacity payment based on the LOLP calculation than the linear capacity payment.

The investment evaluation model with a capacity mechanism proposed in this chapter is useful for the generating companies to evaluate an investment in a market with a capacity mechanism. It also provides generating companies a framework to calculate the expected revenues that they will receive from the energy market and the capacity mechanisms with regards to the various designs of the incentive schemes. Using this explicit investment model, it is also possible to analyse the interrelated dynamics of the energy prices and the capacity prices, and their effects on the profitability of the investment under evaluation. Such analyses are important for investors to plan an expansion and for regulators to design a reliable electricity market.

Chapter 6 Conclusions and Suggestions for Further Research

Summary

This chapter summarizes the main achievement of this research. It also identifies the main contributions of the models developed in this thesis. Finally it suggests some improvements that could be made to the existing models and research topics that might be interesting to carry out in the future.

6.1 INTRODUCTION

The introduction of competitive electricity markets exposes generating companies to various uncertainties in making investment decisions. Since there is no centralized decision-making authority in this new environment, each generating company has to formulate its own generation expansion plans based on its own judgement. This creates the need for a new model that is able to take into account market risks and uncertainties in assessing investments. Since investing in this new environment is much riskier, generating companies might be tempted to invest conservatively. This has raised concerns from regulators. As a result various market designs and incentives have been implemented to try to ensure the security of supply. However, due to the long-term nature of generation investments, it is impossible to wait for several investment cycles to be completed in the actual market before the performance of a market design can be evaluated. Therefore, these market designs need to be appraised using a simulation model. This thesis in general proposes three techniques in the scope of modelling generation expansion planning from the system perspective and developing an investment assessment model from individual company's perspective.

The first model is generation expansion planning using agent-based modelling which consist of multiple generating companies in the market. In order to represent the dynamic investment cycles, the construction delays of the new investment and the imperfect foresight of the generating company in making decisions have been modelled. Various capacity mechanisms have been tested using the proposed model to study their effects on the investment decision of the generating companies and the dynamic cycles of investments. The model was first validated with different scenarios that could trigger investment. The analysis shows that 'boom and bust' cycles could appear in the electricity market. Assuming that the market is competitive, it was shown that all the capacity mechanisms succeed in promoting investments. The investment cycles also appeared under the market with capacity mechanisms. However the amplitude and the time delay of the cycles vary depending on the design of the capacity mechanism.

The investment model in Chapter 4 is built for a generating company to calculate the expected revenue that a new investment would collect over its lifetime considering risk and uncertainty. The revenue of the new investment is determined each year assuming a "prototype" future investment and retirement schedule from all the companies in the system. This prototype plan is capable of representing future generation mixes in the system resulting from investment strategies of generating companies under different scenarios. Two different models have been developed within this framework to take into account risk and uncertainty in the evaluation. The first model is a probabilistic analysis using Monte Carlo simulation. The Value at Risk (VaR) has been set equal to MARR of an investment in the distributions to determine the confidence level for an investment in a specific project. The second model takes into account the different risk characteristics posed by different power generation technologies i.e. nuclear, coal and CCGT in the evaluation. The expected revenues of the new investment are calculated based on the prices in an oligopoly market, which are higher than those that would be obtained from a model that assumed perfect competition. The results show that all the technologies considered would be profitable under the oligopolistic prices. A sensitivity analysis shows that the profitability of a nuclear plant is mostly affected by the uncertainty on the shape of the LDC at the base segments, the nuclear waste fee, the development of wind generation in the system, the investment cost, the construction time and the discount rate. On the other hand the CCGT is sensitive to changes in the shape of the LDC at the high segments, the system reserve and the heat rate. The sensitivity analysis of the coal plant shows a result somewhere between the nuclear and the CCGT.

However, coal is much more affected by the uncertainty in the carbon emission tax than the CCGT and nuclear.

The investment model in Chapter 5 is built considering that the investment to be evaluated takes place in a market with a capacity mechanism. The effect of this incentive in the prototype schedule has been modelled in such a way that a lower reserve capacity in the system increases the capacity mechanism payment to the generators hence more plants (more investments) will be chosen in the prototype plan by the dynamic programming to reduce the total cost of system expansion. On the other hand, a capacity mechanism would provide additional revenues to the new plant. Two types of investment incentives have been modelled: 1) a capacity payment (either linear or based on the LOLP), 2) a capacity market with various demand curves. The results show that all the capacity mechanisms succeed in promoting investments in the prototype system expansion plan without enforcing a minimum reserve requirement constraint in the formulation. The analysis shows that a steeper curve for the linear capacity payment results in more investments in the prototype plan because larger payments would be made to the generators. This reduces the energy and capacity payment prices, hence a lower profit for the investment plant under evaluation. On the other hand, a higher VOLL for the LOLP capacity payment increases the investments in the prototype plan. However further increases in VOLL have less impact on the capacity payments and hence on the system reserve margin. A steeper demand curve in the capacity market exhibits a similar impact as in the linear capacity payment scheme. But this steeper demand curve creates bigger variations in the energy and capacity prices and thus provides uncertain profits to the companies. In comparing the investment alternatives, the result shows that the nuclear investment alternative which has a longer lifetime is the most affected by the uncertainty of all the mechanisms.

6.2 MAIN CONTRIBUTIONS OF THE THESIS

In general the main contribution of this thesis lies on its explicit representation of the elements in the models and the process involved in power investment activities which provide system regulators and generating companies a realistic framework for studying investments in a liberalised electricity market. In the models, rather than assuming the future electricity price as an exogenous variable, the models calculate the price based on the expected system expansion and retirement resulting from investment strategy of the companies in the market. By modelling this, the electricity price can be simulated under various system scenarios. These explicit models are also useful to study the effects of various uncertainties in the market on the profitability of an investment and on the reliability of the power system.

Furthermore, this thesis uses a multi-disciplinary approach in developing the models. Economic theory, agent-based modelling, dynamic programming, probabilistic analysis, and financial risk analysis have been combined to deliver an original contribution to the state of the art.

Specific contributions of the model presented in each chapter of this thesis are described in the following sections.

6.2.1 Agent-based Generation Expansion Planning Model

The contributions of the agent-based generation expansion model presented in Chapter 3 are described as follows:

1. Agent-based modelling that uses a bottom-up approach where the individual decisions of the generating companies are first specified and then linked together to form a larger system provides a framework that is able to study the complex interaction between the generating companies in the market and its effect on the overall system expansion.

2. The investment signal is modelled based on the mix information of the simulated spot prices and the capacity mechanism prices. This provides a model that can be used to study the combined effects of the spot market and capacity mechanism on the investment strategy of the generating companies and the dynamics of investments in power generation.

3. The incorporation of delay in the construction and the generating companies' lack of perfect foresight on the future market prices enable the model to simulate the dynamic of generation expansion and provide a decision framework that is actually being practised by the companies in the real

market. Such models could be used by the regulator to study the dynamic investments behaviour in the system and to make assessments on a new market design.

4. The step by step approach of the generation expansion is useful for the generating company to understand the complex processes involved in the market and to generate various system scenarios in formulating an investment plan.

6.2.2 Valuation Model for Generation Investment in a Liberalised Electricity Market

The contributions of the valuation model for generation investment in a liberalised electricity market presented in Chapter 4 are described as follows:

1. In this model, in evaluating revenue of an investment, a prototype of future investment and retirement schedule from all the companies are first defined. This prototype plan is a function of the future demand, the fuel cost, the investment under evaluation and the various regulatory uncertainties in the market. The market prices and the revenue of the investment considered by the company are calculated based on this prototype plan. By modelling such explicit framework allows the simulation of future electricity price scenarios under different technology mixes, and can thus be used to study the effect of various uncertainties on the profitability of the investment.

2. The probabilistic assessment model in Chapter 4 provides a generating company with a probabilistic approach in assessing investments considering risks. A risk assessment technique which is incorporated in the model enables a generating company to determine the confidence level of investing in a power plant. The profit distribution which is graphically presented gives a better picture and is useful for a project manager to demonstrate the riskiness of the investment to non-economical people in the company.

3. The investment evaluation model in an oligopoly electricity market helps investors to determine a realistic price in an oligopoly market which is

usually higher than the perfect competition. By doing this the value of the new investment that the company is evaluating is not under estimated. The model also considers risk characteristics of different technologies in the financial model. This is useful for the investors to quantify the risks and to compare investment alternatives with different technologies.

4. A similar sensitivity analysis presented in Chapter 4 could be performed by a generating company using this model to study how sensitive the profitability of the new power plant in which the company is considering investing is to the various uncertainties in the system. By performing such analysis a generating company could gain more information before investment decision could be made and could thus reduce the investment risk.

6.2.3 Generation Investment Evaluation Model in Oligopoly Market with Capacity Mechanisms

The contributions of the generation investment evaluation model in an oligopoly electricity market with a capacity mechanism as presented in Chapter 5 are described as follows:

1. The explicit representation of the capacity mechanisms in the model is useful for the generating company to study the effects of uncertainty in the mechanisms on the profitability of the investment.
2. The effect of capacity mechanisms is also modelled in the prototype future system expansion. By doing this, the prototype plan is generated from the combined effect of the spot prices and the capacity mechanism prices. Hence, this provides a generating company a more realistic future energy and capacity mechanism prices in calculating the expected revenue of the new investment.
3. This model could also be used by the system regulator to study and design a capacity mechanism that is fair enough to give an incentive to the generators while providing a lower price to the consumers.

6.3 SUGGESTIONS FOR FURTHER RESEARCH

The suggestions for further research are divided into two groups: 1) suggestions that focus on some possible refinements to the models proposed in this thesis, 2) suggestions of new directions for research related to generation investments in a liberalised electricity market.

Some improvements that could be made to the models and analyses presented in this thesis are:

1. The business strategy of a generating company involves not only investments in new plants but also the retirement, mothballing, sale or purchase of existing plants. In this thesis the retirement of generating units is modelled as an exogenous input. It would be interesting to consider these other strategies as decision variables that a company could use in maximizing its profit.

2. In the agent-based generation expansion model, it was assumed that all the generating companies have access to sufficient capital for all the investment options. However, the financial structure of the company might influence its investment decisions.

3. In the probabilistic investment model of Chapter 4, the uncertainty in the load and fuel costs are only considered in the revenues calculation of the new plant but not in determining the prototype system expansion. Future work could use stochastic dynamic programing to consider the uncertainty in the prototype plan. Other uncertainties such as investment costs, construction times and regulatory actions that might differentiate the profitability distributions of different technologies could be modelled. Furthermore, other coherent risk measures such as Conditional Value at Risk (CVaR) could be used.

4. The sensitivity analyses performed in Chapter 4 examine the effects of various uncertainties in the model on the profitability of different technologies. However, a technique that could summarize all these impacts on the technologies for investment choice is not presented. Therefore, it is suggested for future work to conclude the sensitivity analysis by adopting Utility Theory which is a technique that can be used for decision making.

This technique calculates an expected monetary value for each technology under all the uncertainties and suggests the alternative with the highest expected utility. Using this approach the risk preference of the generating company can also be considered in the investment decision.

5. The optimal prototype future investment schedule is made under the assumption that the system expansion will minimize the total costs. Other objective functions such as maximizing social welfare could be used and compared with the cost minimization.

Some other research topics that might be interesting to carry out in the future in the context of generation investment are described as follows:

1. **Development of a new capacity mechanism to promote investments in a liberalised electricity market**

   A key problem of concern to the regulator in a restructured electricity industry is how to ensure sufficient generation to meet the demand and system reliability in the long-term. Incentives such as capacity payments and capacity markets have been implemented in some markets. However these capacity mechanisms have been criticised for their prices that are much too dependent on engineering calculations, either using VOLL in the capacity payment or by capacity obligation in the capacity market [64]. The English capacity payment that was based on the system LOLP was manipulated by the generating companies to raise the capacity prices. On the other hand, the operation of capacity markets is disconnected from the energy market. The drawback of these mechanisms is also due to no real product received by customers for the price that they have to pay. Therefore, a new capacity mechanism that could solve the problems needs to be proposed. The effectiveness of such a new mechanism in promoting system expansion and in incentivizing new investments could be examined using the models proposed in this thesis.

2. **Valuation model for investment in a liberalised electricity market using real options theory**

   A new trend to appraise investments is the use of real options theory. This approach adds two important aspects in the evaluation: 1) optimal timing to make the investment, 2) representation of uncertainties using a stochastic process. Some researchers argue that the profitability of peaking plants which operate for a few hours at the peak load should be valued using this technique to account for the volatility of the fuel and electricity prices. Thus, it is suggested that future work adopt real option theory within the investment model framework proposed in this thesis.

Appendix A System Data

The sensitivity analysis in section 4.8 of Chapter 4 and the analysis in Chapter 5 were performed using a test system based on Great Britain's 2010 Seven Year Statement. The system consists of 75 generating units (the wind and hydro generations are aggregated) and a total of 74212 MW of installed capacity. It is assumed that some of the large generating units will be closed over the next 15 years to meet more stringent air quality standards introduced by the European Union's Large Combustion Plant Directive (LCPD) scheme.

The technical and cost data of these units are presented in Table A-1 as follows:

Unit	Fuel	P_{min}	P_{max}	Yoff, MBTU/h	Slope, MBTU /MWh	Life-time, years	History, years	FOR	Invest Cost, $	Utilization Factor
01	gas	5	23.2	2.75	6.68	25	3	0.08	1.05E+07	0.85
02	gas	10	50	2.83	6.95	25	1	0.08	2.26E+07	0.85
03	gas	10	60	2.82	6.95	25	9	0.08	2.71E+07	0.85
04	gas	30	229	2.81	7.07	25	5	0.08	1.04E+08	0.85
05	gas	50	245	2.81	7.07	25	4	0.08	1.11E+08	0.85
06	gas	50	260	2.83	7.06	25	3	0.08	1.18E+08	0.85
07	gas	50	340	2.86	7.06	25	3	0.08	1.54E+08	0.85
08	gas	50	395	2.84	7.06	25	5	0.08	1.79E+08	0.85
09	gas	50	401	2.86	7.06	25	9	0.08	1.81E+08	0.85
10	gas	50	405	2.81	7.05	25	5	0.08	1.83E+08	0.85
11	gas	50	408	2.81	7.04	25	2	0.08	1.84E+08	0.85
12	gas	50	420	2.80	7.03	25	2	0.08	1.90E+08	0.85
13	gas	50	420	2.80	7.02	25	6	0.08	1.90E+08	0.85
14	gas	50	425	2.84	7.02	25	7	0.08	1.92E+08	0.85
15	gas	50	425	2.84	7.02	25	8	0.08	1.92E+08	0.85
16	gas	50	505	2.81	7.01	25	5	0.08	2.28E+08	0.85
17	gas	50	552	2.81	7.00	25	1	0.08	2.50E+08	0.85
18	gas	70	665	2.85	7.00	25	3	0.08	3.01E+08	0.85
19	gas	70	665	2.81	6.97	25	4	0.08	3.01E+08	0.85
20	gas	70	700	26.6	6.63	25	4	0.08	3.16E+08	0.85

Unit	Fuel	P_{min}	P_{max}	Yoff, MBTU /h	Slope, MBTU /MWh	Life-time, years	History, years	FOR	Invest Cost, $	Utilization Factor
21	gas	70	715	26.56	6.62	25	1	0.08	3.23E+08	0.85
22	gas	70	735	26.49	6.61	25	2	0.08	3.32E+08	0.85
23	gas	100	800	26.45	6.70	25	10	0.08	3.62E+08	0.85
24	gas	100	800	26.45	6.69	25	8	0.08	3.62E+08	0.85
25	gas	100	805	26.44	6.69	25	5	0.08	3.64E+08	0.85
26	gas	100	810	26.44	6.68	25	2	0.08	3.66E+08	0.85
27	gas	100	850	26.40	6.68	25	8	0.08	3.84E+08	0.85
28	gas	100	880	26.36	6.68	25	6	0.08	3.98E+08	0.85
29	gas	120	900	26.64	6.68	25	3	0.08	4.07E+08	0.85
30	gas	120	900	26.64	6.62	25	4	0.08	4.07E+08	0.85
31	gas	120	905	26.60	6.61	25	4	0.08	4.09E+08	0.85
32	gas	150	1000	0.00	6.73	30	8	0.08	4.52E+08	0.85
33	gas	150	1100	0.00	6.70	30	7	0.08	4.97E+08	0.85
34	gas	150	1234	0.00	6.62	30	7	0.08	5.58E+08	0.85
35	gas	150	1285	0.00	6.61	30	6	0.08	5.81E+08	0.85
36	gas	150	1380	0.00	6.56	30	1	0.08	6.24E+08	0.85
37	gas	200	1500	0.00	6.52	30	3	0.08	6.78E+08	0.85
38	gas	200	1524	0.00	6.51	30	10	0.08	6.89E+08	0.85
39	gas	200	1875	0.00	6.50	30	9	0.08	8.48E+08	0.85
40	coal	40	363	44.29	10.01	30	6	0.02	4.27E+08	0.8
41	coal	50	420	44.35	10.18	30	5	0.02	4.94E+08	0.8
42	coal	100	964	44.35	10.65	30	16	0.02	1.13E+09	0.8
43	coal	150	1018	44.57	10.72	30	17	0.02	1.20E+09	0.8
44	coal	150	1102	44.32	10.64	30	17	0.02	1.29E+09	0.8
45	coal	150	1131	44.21	10.55	30	22	0.02	1.33E+09	0.8
46	coal	150	1692	64.88	10.39	30	3	0.02	1.99E+09	0.8
47	coal	150	1940	64.30	10.34	40	12	0.02	2.28E+09	0.8
48	coal	150	1966	64.00	10.31	40	28	0.02	2.31E+09	0.8
49	coal	150	1986	63.00	10.31	40	25	0.02	2.33E+09	0.8
50	coal	150	1987	63.11	10.30	40	32	0.02	2.33E+09	0.8
51	coal	150	1987	63.12	10.30	40	21	0.02	2.33E+09	0.8
52	coal	250	2000	70.98	10.42	40	27	0.02	2.35E+09	0.8
53	coal	250	2021	70.88	10.40	40	22	0.02	2.37E+09	0.8
54	coal	250	2109	69.13	10.41	40	26	0.02	2.48E+09	0.8
55	coal	250	2284	69.15	10.42	40	10	0.02	2.68E+09	0.8
56	coal	300	3906	68.11	10.59	40	29	0.02	4.59E+09	0.8
57	nuc	50	470.4	250.65	17.30	45	43	0.12	8.51E+08	0.9
58	nuc	100	980	255.65	19.99	45	43	0.12	1.77E+09	0.9
59	nuc	100	1074	245.65	19.78	45	10	0.12	1.94E+09	0.9
60	nuc	100	1081	241.23	19.71	45	12	0.12	1.96E+09	0.9

Unit	Fuel	P_{min}	P_{max}	Yoff, MBTU /h	Slope, MBTU /MWh	Life-time, years	History, years	FOR	Invest Cost, $	Utilization Factor
61	nuc	100	1200	240.55	19.70	45	9	0.12	2.17E+09	0.9
62	nuc	100	1207	239.45	19.50	45	12	0.12	2.18E+09	0.9
63	nuc	100	1215	211.09	19.74	45	5	0.12	2.20E+09	0.9
64	nuc	100	1261	211.00	19.73	45	14	0.12	2.28E+09	0.9
65	nuc	250	2406	211.00	21.00	45	4	0.12	4.35E+09	0.9
66	gas	10	49.9	15.88	7.05	40	1	0.08	2.26E+07	0.85
67	gas	10	100	15.88	7.04	40	4	0.08	4.52E+07	0.85
68	gas	10	140	15.86	7.04	40	3	0.08	6.33E+07	0.85
69	gas	10	144	15.87	7.03	40	5	0.08	6.51E+07	0.85
70	gas	10	145	15.87	7.00	40	5	0.08	6.55E+07	0.85
71	oil	100	1036	13.97	4.95	25	20	0.1	1.39E+09	0.1
72	oil	100	1245	13.94	4.95	25	22	0.1	1.67E+09	0.1
73	oil	100	1355	13.91	4.95	25	21	0.1	1.82E+09	0.1
74	wind	100	893	37.20	12.00	50	2	0.04	1.25E+09	0.32
75	hyd	100	1743	150.00	4.59	50	2	0.02	6.97E+09	0.45

Table A-1 Technical and cost characteristics of the existing system

The six generation technologies that can be selected by the DP each year for the prototype system expansion schedule are presented in Table A-2 as follows:

Unit	Fuel	Pmin	Pmax	Yoff, MBTU/h	Slope, MBTU/MWh	Lifetime, years
P17	nuclear	250	2406	211.00	21.00	40
P10	coal	250	2284	64.88	10.39	30
P21	gas	150	1100	0.00	6.70	20
P13	nuclear	250	2406	211.00	21.00	40
P24	coal	250	2284	64.88	10.39	30
P03	Gas	150	1100	0.00	6.70	20

Build time	Invest Cost, $	MARR	FOR	Utilization Factor
5	4.35E+09	0.12	0.08	0.85
4	2.68E+09	0.12	0.08	0.85
2	4.97E+08	0.12	0.08	0.85
5	4.35E+09	0.12	0.08	0.85
4	2.68E+09	0.12	0.08	0.85
2	4.97E+08	0.12	0.08	0.85

Table A-2 Technical and cost characteristics of the technologies for prototype system expansion using DP

The three possible investment technologies that are considered in the analysis are shown in Table A-3.

Unit	Fuel	Pmin	Pmax	Yoff, MBTU/h	Slope, MBTU/MWh	Lifetime, years
I01	Nuclear	250	2406	211.00	21.00	40
I02	coal	250	2284	64.88	10.39	30
I03	gas	120	1100	0.00	6.70	20

Build time	Invest Cost, $	MARR	FOR	Utilization Factor
5	4.35E+09	0.12	0.08	0.85
4	2.68E+09	0.12	0.08	0.85
2	4.97E+08	0.12	0.08	0.85

Table A-3 Technical and cost characteristics of the investment technologies

The carbon intensity for the coal and the CCGT technologies are 0.0258tC/MBTU and 0.0145tC/MBTU respectively. The nuclear waste fee for the nuclear technology is 0.95 $/MWh. The fixed O&M cost for the nuclear, coal and CCGT technologies are 57.14$/kW/yr, 20.63$/kW/yr and 14.29$/kW/yr respectively. The variable O&M costs for the nuclear, coal and CCGT technologies are 0.365$/MWh, 3.063$/MWh and 0.476$/MWh respectively.

Appendix B Optimal Step-Function Approximation of Load Duration Curve

The optimal step-function approximation of LDC is developed using the steps presented as follows:

Step 1: LDC from hourly load data is constructed

Example 13 hours of 8784 hourly load data from PJM market from 1st January 2008 to 31st December 2008 is shown in Table B-1 below:

Original Hourly Data Set		Duration Curve Data		
Time	Value	Count	Sorted Value (Y Axis)	per-unit (X Axis
01/01/2008	73,126	1	130,100	1.00
01/01/2008	71,001	2	129,845	1.00
01/01/2008	68,954	3	129,481	1.00
01/01/2008	67,977	4	129,394	0.99
01/01/2008	67,842	5	129,097	0.99
01/01/2008	68,925	6	128,912	0.99
01/01/2008	70,402	7	128,681	0.99
01/01/2008	71,302	8	128,624	0.99
01/01/2008	72,514	9	128,407	0.99
01/01/2008	74,604	10	128,390	0.99
01/01/2008	76,861	11	128,387	0.99
01/01/2008	77,862	12	127,954	0.98
01/01/2008	78,147	13	127,938	0.98

Table B-1 Sample of hourly load data

The hourly load data is sorted from maximum to minimum value and the per-unit value of each sorted load data is obtained. Figure B-1 shows the per-unit of LDC from the PJM market.

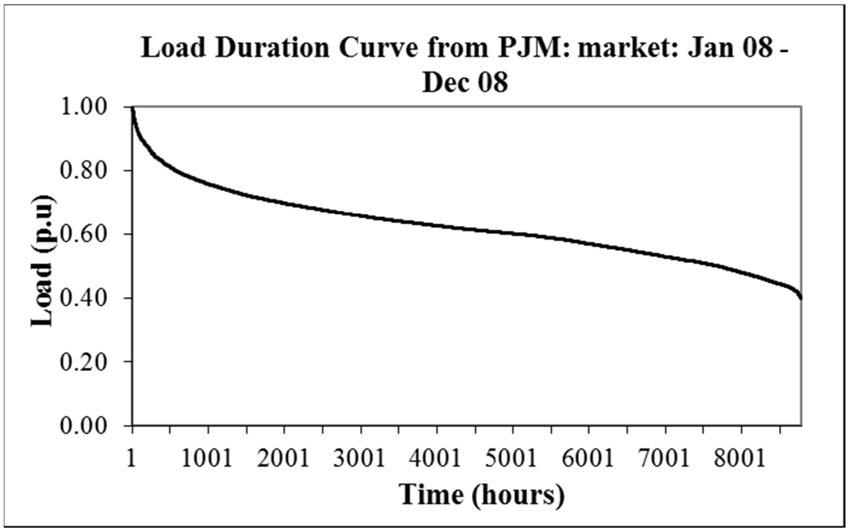


Figure B-1 LDC from PJM market

Step 2: The load data is normalized

The normalization is carried out so that the area under the curve equal to one. This is performed by dividing the per-unit load data by the total area under the curve. This total area is calculated using the trapezoidal rule.

Step 3: The interval where the optimal break points of the LDC are defined

For example, a six-step function of LDC has five break points. The five intervals (Int 1 to Int 5) where these break points lie are first defined as shown in Figure B-2.

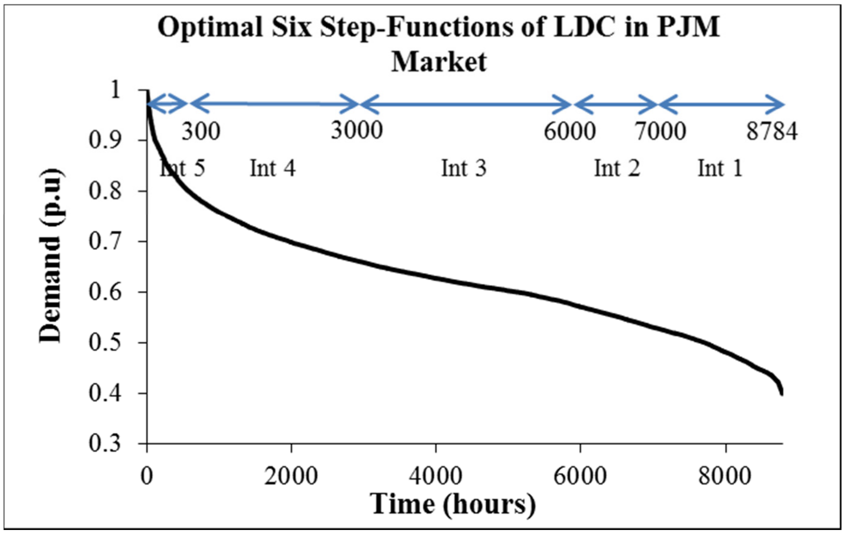


Figure B-2 Five intervals where the break points of a six-step function of LDC lie

Step 4: The optimal break points is computed using Backward Recursion Dynamic Programming

The optimal break points can be solved using backward Dynamic Programming where the solution is searched recursively for each interval [x,y] defined for the LDC until the total penalty of all the segments (from 1 – T) is minimized. The functional equation for the minimal penalty, $f_n(x)$ from an n-stage process given that the starting point for the process is at the point x is shown below;

$$f_n(x) = \min_{x \le y \le T}\left(\sum_x^y p\big(e(x)\big)e(x) + f_{n-1}(y)\right) \quad n = 1, \ldots, S\text{-}1 \qquad \text{(B.1)}$$

where S is the number of segments of the LDC and [x,y] is the interval where the solution of the n-stage process lies. The normalized area obtained above is used as a function of LDC denoted by $F(x)$.

The procedure begins with $x = T$ - 1 in interval Int 1 shown in Figure B-2. The value of g_N as in Figure B-3 is calculated using:

$$g_N = \frac{1}{(T-(T-1))} xF(T) \qquad \text{(B.2)}$$

The total penalty, $f(T - 1)$ which is stored is equal to:

$$f_1(T-1) = \sum_{x=T-1}^{T} P(e(T-1))e(T-1) \tag{B.3}$$

Where *p(e(x))* is the penalty to be paid per unit of mismatch at *x* and *e(x)* is the amount of mismatch at *x*.

If $P(e(T\text{-}1)) = 1.0$,

$$f_1(T-1) = \sum_{x=T-1}^{T} (F(T-1) - g_N) \tag{B.4}$$

Next a value of $x = T - 2$ is used to find a value of g_{N-1}:

$$g_{N-1} = \frac{1}{(T-(T-2))} x(F(T) + F(T-1)) \tag{B.5}$$

from which the penalty, $f(T - 2)$ is calculated and stored.

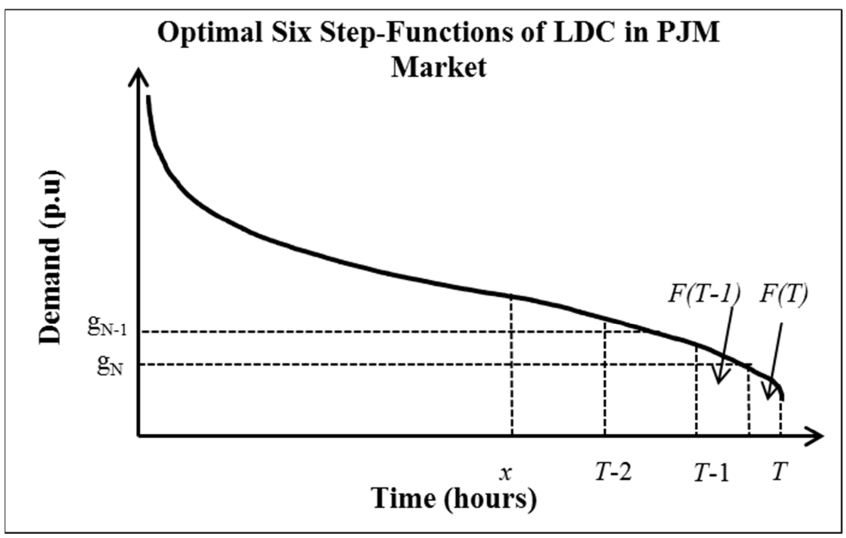


Figure B-3 Optimal break point in interval Int 1 are computed using Backward Recursion Dynamic Programming

This is continued for $x = T$ - 3,. . ., 2, 1 and the corresponding values of *f(x)* are stored for the next stage (Int 2) of the dynamic programming calculation until the total penalty of all the stages are minimized.

The optimal six-step functions of LDC are shown in Figure B-4.

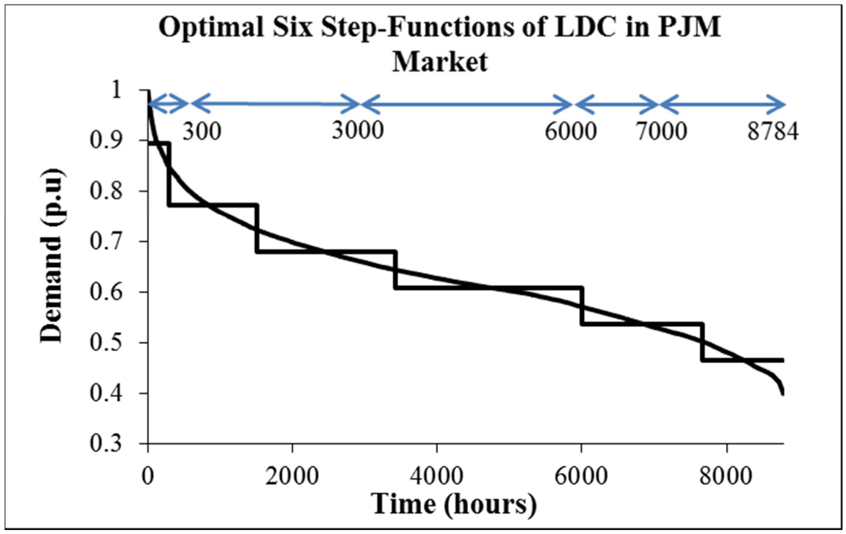


Figure B-4 Optimal six-step functions of LDC from PJM market

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