ECONOMIC IMPACT OF NON-UTILITY GENERATION ON ELECTRIC POWER SYSTEMS

A Thesis Submitted to the College of
Graduate Studies and Research
in Partial Fulfillment of the Requirements
for the Degree of Doctor of Philosophy
in the Department of Electrical Engineering
University of Saskatchewan
Saskatoon

by

Rajnish Gupta
Fall 1997

0-612-23935-7

UNIVERSITY OF SASKATCHEWAN

College of Graduate Studies and Research

SUMMARY OF DISSERTATION

Submitted in Partial Fulfillment
of the Requirements for the

DEGREE OF DOCTOR OF PHILOSOPHY

by

RAJNISH GUPTA
Department of Electrical Engineering
University of Saskatchewan

1997

Examining Committee:

Dr. W. Bishopp, Dean's Designate, College of Graduate Studies & Research
Dr. T.S. Sidhu: Department of Electrical Engineering
Dr. N.A. Chowdhury: Supervisor, Department of Electrical Engineering
Dr. R. Billinton: Supervisor, Associate Dean of Engineering
Dr. S.P. Verma: Department of Electrical Engineering
Dr. H. Wood: Department of Electrical Engineering
Dr. S. Sokhansanj: Department of Agricultural and Bioresources Engineering

External Examiner:
Dr. V. Quintana
Department of Electrical and Computer Engineering
University of Waterloo
Waterloo, Ontario, Canada

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Non-Utility Generation (NUG) has become increasingly important mainly due to environmental concerns, possible depletion of oil supplies and government regulations. When a power utility buys electrical energy from a NUG at short notice, such as a few hours, one of the difficult issues encountered by the utility is the evaluation of the rate (buyback rate) it should pay the NUG such that the utility maximizes its economic benefit. Short-term buyback rates should be based on the operating cost that a utility avoids by utilizing energy from a NUG. This cost is termed in this thesis as the avoided operating cost (AOC).

Suitable techniques for thermal and hydrothermal systems have been developed to assess the short term AOC that can be utilized to evaluate the buyback rate in a just and reasonable manner. In the case a of thermal system, both deterministic and probabilistic techniques were utilized to evaluate the AOC at HL I. At HL II, AOC was evaluated deterministically on the thermal system. In the case of a hydrothermal system, fixed head and variable head hydro systems are considered for the evaluation of AOC utilizing a deterministic technique. The studies described in this thesis focus specifically on the economic assessment of the incorporation of NUG in the short term operational planning of power systems at HL I and HL II. In another study, it was assumed that NUG generates energy from its cogeneration and wind facilities.

It is shown in the thesis that the AOC can be evaluated for different types of system and at different hierarchical levels. It is also shown that the AOC is not fixed but varies with the type of the utility, the operating practice of the utility, the duration of time for which a NUG sells energy to the utility, the system load level and the location of a NUG in the network. The studies and examples presented in the thesis suggest that the proposed techniques for the evaluation of the AOC will treat both parties involved in a NUG energy transaction fairly and can include the standard operating practices used by the respective utilities. The techniques can be used to assess the AOC in a consistent manner, and are flexible enough to include other system operating criteria. They can also be used by the utility as a basic framework upon which relevant system operating criteria, and cost parameters can be added to assess an appropriate generic buyback rate.

BIOGRAPHY

Rajnish Gupta received the B.E. and M.Sc. degrees in Electrical Engineering from M.M.M. Engineering College, India, in 1988 and University of Saskatchewan, Canada in 1991 respectively. He worked in an engineering consulting company for one year in India between 1988 and 1989. He started his Ph.D. Degree (Electrical Engineering) in 1992 at the University of Saskatchewan. Presently he is a lecturer in the Department of Electrical Engineering, Singapore Polytechnic, Singapore.

PUBLICATIONS

[1] R. Gupta, N. Chowdhury and R. Billinton, "A Probabilistic Technique for the Evaluation of the Avoided Operating Cost" IEEE Canadian Conference on Electrical and Computer Engineering, St. John's, 1997

[2] R. Gupta, N. Chowdhury and R. Billinton, "Economic Impact of Cogenerated Energy on a Power System", International Power Energy Conference, Singapore, 1997

[3] R. Gupta, N. Chowdhury and R. Billinton, "Economic Impact of NUG on Hydrothermal Systems" IEEE Canadian Conference on Electrical and Computer Engineering, Calgary, 1996

[4] R. Gupta, N. Chowdhury and R. Billinton, "Economic Implications of Non-Utility Generation on Power System Short Term Planning", IEEE North Saskatchewan Section Annual Symposium, Saskatoon, Canada, 1995

[5] R. Gupta, N. Chowdhury and R. Billinton, "Economic Implications to Electric Power Utilities of Wind Energy Produced by Non-Utility Generation, IEEE Canadian Conference on Electrical and Computer Engineering, Montreal, 1995

[6] N. Chowdhury, R. Gupta and R. Billinton, "Avoided Operating Cost in Thermal Generating System". Canadian Electrical Association, Vancouver, 1995

[7] N. Chowdhury, R. Gupta and R. Billinton, "Deterministic and Probabilistic Techniques for the Evaluation of Appropriate Avoided Operating Cost", Sent for publication review for the Utilities Policy Journal.

[8] R. Gupta, N. Chowdhury and R. Billinton, "Economic Impact of Non-Utility Generated Wind Energy on a Power Utility", ", Sent for publication review for the Electric Power Systems Journal

[9] R. Gupta, N. Chowdhury and R. Billinton, "Impact of Non-Utility Generation on Composite System Economics", sent for review in IEE.

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ABSTRACT

Non-Utility Generation is a major force in the way electrical energy is now being produced and marketed, and electric utilities are reacting to the growth of this new industry. When a utility buys electric energy from a non-utility generation at short notice, such as a few hours, one of the difficult issues encountered by the utility is the evaluation of the rate (buyback rate) it should pay the non-utility generation such that the utility maximizes its economic benefit. Utilities calculate their purchase rates based on a number of different formulae. Short term buyback rates should be based on the operating cost that a utility avoids by utilizing energy from a non-utility generation. This cost is termed as the avoided operating cost in this thesis. Suitable techniques for thermal and hydrothermal systems are developed to assess the short term avoided operating cost under different operating conditions.

The studies described in this thesis focus specifically on the economic assessment of the incorporation of non-utility generation in the short term planning of power systems at the generation level and the composite generation and transmission level. In another study, it was assumed that non-utility generation produces energy from its cogeneration and wind facilities. These sources of energy have some typical characteristics that make them different from other sources of electricity. These characteristics were taken into account in modeling the non-utility generation and studies were performed to show their effect on a thermal power system. Composite generation and transmission assessment involves a composite appraisal of both the generation and transmission facilities and their ability to supply adequate, dependable and suitable electrical energy to the major load point. Studies were performed to show the impact of non-utility generation on a thermal power system at this level.

The studies and examples presented in the thesis suggest that the proposed techniques for the evaluation of the avoided operating cost will treat both parties involved in energy transaction consistent and include the standard operating practices used by utilities. They can also be used by the utility as a basic framework upon which relevant systems operating criteria and cost parameters can be added to assess a generic buyback rate appropriate for a utility.

ACKNOWLEDGMENTS

The author would like to express his heartfelt gratitude and a deep feeling of indebtedness to his supervisors, Dr. Nurul Chowdhury and Dr. Roy Billinton, for their consistent encouragement, support and guidance. Their advise and assistance throughout the course of this work is thankfully acknowledged. It has been a wonderful opportunity and pleasant experience working under their supervision.

Secondly, the author wishes to express his gratitude and appreciation to his advisory committee members, Dr. S. Sokhansanj, Dr. H. C. Wood, Dr. S. P. Verma and Dr. T. S. Sidhu, for their advise and assistance in the preparation of this thesis.

Thirdly, the author wishes to express his acknowledgment and thanks to his family members for their patience and tolerance during his long absence from India while working on this thesis.

Finally, the financial assistance in the form of Graduate Scholarship from the College of Graduate Studies and Research is thankfully acknowledged.

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LIST OF ABBREVIATIONS

NUG	Non-Utility Generation
AOC	Avoided Operating Cost
RBTS	Roy Billinton Test System
IEEE-RTS	Institute of Electrical and Electronics Engineer-Reliability Test System
IPP	Independent Power Producer
PURPA	Public Utility Regulatory Policy Act
QF	Qualifying Facility
FERC	Federal Energy Regulatory Commission
NERC	North American Electric Reliability Council
LFC	Load Frequency Control
HL	Hierarchical Level
POF	Probability of Failure
UC	Unit Commitment
ORR	Outage Replacement Rate
ELD	Economic Load Dispatch
$R(t)$	system risk at time t
$P_i(t)$	probability that the system is in state i at time t
$Q_i(t)$	probability that the system, in state i at time t, will fail to meet the quality, continuity or other performance criteria
m	total number of system states
CU_{si}	capacity of ith unit
N	number of committed units

P_D^j	system load during hour j
P_{si}^j	output of ith unit during jth hour
$R(load, cap)$	deterministically evaluated spinning reserve
C_j	running cost during hour j
F_i^j	running cost of unit i during hour j
a_i	quadratic coefficient of cost function of unit i
b_i	linear coefficient of cost function of unit i
c_i	constant term of cost function of unit i
λ^j	incremental running cost of the system during hour j
ΔF_i^j	savings in running cost of unit i during hour j
$\Delta\xi$	discrete amount of NUG energy utilized in one hour
ΔS_k^j	discrete savings during jth hour from kth iteration
E_n^i	NUG energy output during hour i
ψ	AOC
l	number of iterations required to utilize ξ MWh of NUG energy
UR^j	calculated unit committed risk during hour j
UR^{spec}	pre-specified unit committed risk
$R(risk)$	probabilistically evaluated spinning reserve
$Prob(m,t)$	probability of meeting a regulating margin of m MW within a specified margin time of t minutes
$Prob^{spec}$	specified response risk
P_h^j	active hydro power at hour j
q^j	rate of water discharge at hour j
h^j	effective head at hour j
$\eta(q,h)$	efficiency of hydro unit
$P_{h(\max)}$	maximum power output of the hydro plant.
$P_{h(\min)}$	minimum power output of the hydro plant

ΔF_{hi}^{j}	savings in the running cost of unit i due to a discrete amount of hydro energy during hour j
ΔP_{h}^{j}	discrete amount of hydro energy utilized in hour j.
ΔS_{hk}^{L}	discrete savings in 24 hours due to the incorporation of ΔP_{h}^{j} MWh of hydro power.
$h_{\max}$	maximum permissible reservoir head
$h_{\min}$	minimum permissible reservoir head
C_{eq}	equivalent capacity of the cogenerating unit
C_r	rated capacity of the cogenerating unit
E_a	energy available to the cogenerating unit
T	study period in hours
Ψ_i	AOC at state i of the composite system containing both utility generation sources and cogeneration source.
Φ_{i1}	AOC at state i of the composite system when the cogeneration unit is in service.
Φ_{i2}	AOC at state i of the composite system when the cogeneration unit is not in service.
A_i	probability of cogeneration unit at state i to be in up state in 24 hours
U_i	probability of cogeneration unit at state i to be in down state in 24 hours
P_r	rated power output
V_{ci}	cut-in wind speed
V_r	rated wind speed
V_{co}	cut-out wind speed.
TL_k	transmission losses
ΔTL	difference in transmission losses
ε	tolerance level in two successive iterations
Q	reactive power at each bus

1. INTRODUCTION

1.1. Power System Reliability

The basic function of an electric power system is to supply electrical energy to the consumer as economically as possible and with an acceptable degree of reliability and quality. While satisfying this function, the power system must remain within a set of operational constraints, some of which relate directly to the quality of supply such as busbar voltage violations and frequency variations. The reliability associated with a power system is a measure of the ability of the system to provide an adequate supply of electrical energy. The concept of power system reliability is extremely broad and covers all aspects of the ability of the system to satisfy consumer demands. For the sake of simplicity and convenience, power system reliability can be divided into the two basic aspects of system adequacy and system security, as shown in Figure 1.1 [1].

Adequacy relates to the existence of sufficient facilities within the system to satisfy consumer load demand. These include the facilities necessary to generate sufficient energy and the associated transmission and distribution facilities required to transport the energy to actual consumer load points. Adequacy is, therefore, associated with static conditions which do not include system disturbances. Security relates to the ability of the system to respond to disturbances arising within the system. Security is, therefore, associated with the response of the system to whatever perturbation it is subjected. These include the conditions associated with both local and widespread disturbances and the loss of major generation and transmission facilities. It can be realized that adequacy and security deal with quite different reliability issues in a power system.

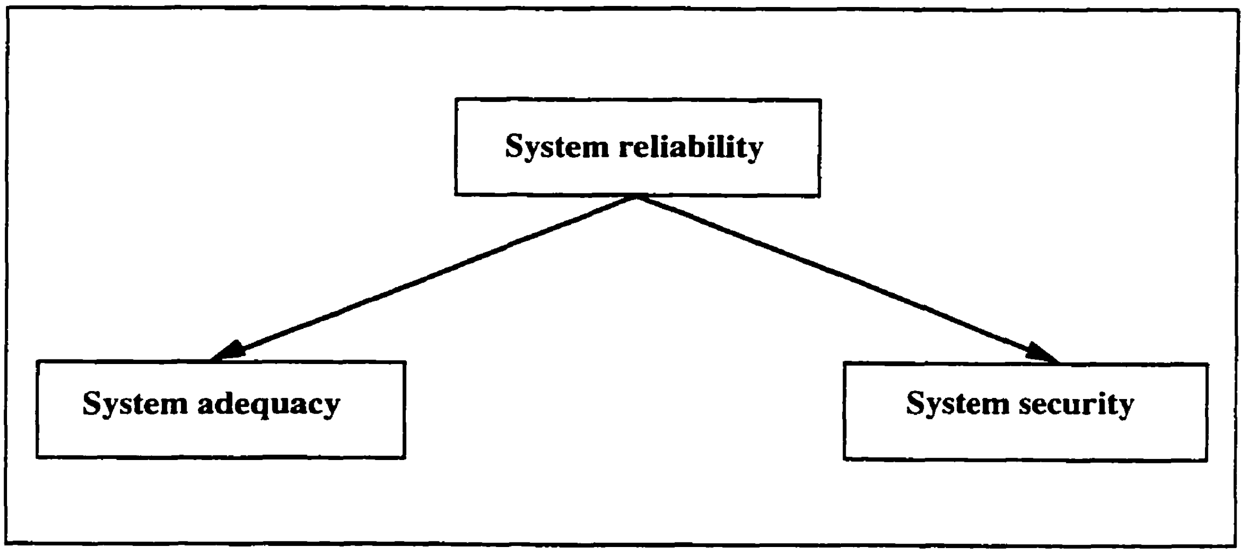


Figure 1.1 Subdivision of system reliability

A complete power system is a very complex entity. For the sake of convenience, it can be classified into three functional zones, as shown in Figure 1.2 [1]. These functional zones are generation, where electrical energy is generated; transmission, which connects the generation to the major load points; and distribution, which connects individual load points to the transmission zone. Each functional zone can be considered as a separate entity which operates in conjunction with the others. This classification is appropriate as most utilities are divided into these zones for purposes of organization, planning, operation and analysis. Adequacy and security studies can be conducted individually in these three functional zones. Functional zones can be combined to form the three hierarchical levels (HL) shown in Figure 1.2 [1]. Hierarchical level I (HL I) is concerned only with the generation facilities. The focus at this level is on the ability of the total generation to satisfy the demand.

Hierarchical level II (HL II) includes both generation and transmission facilities. An HL II configuration is usually termed a composite system or a bulk transmission system.

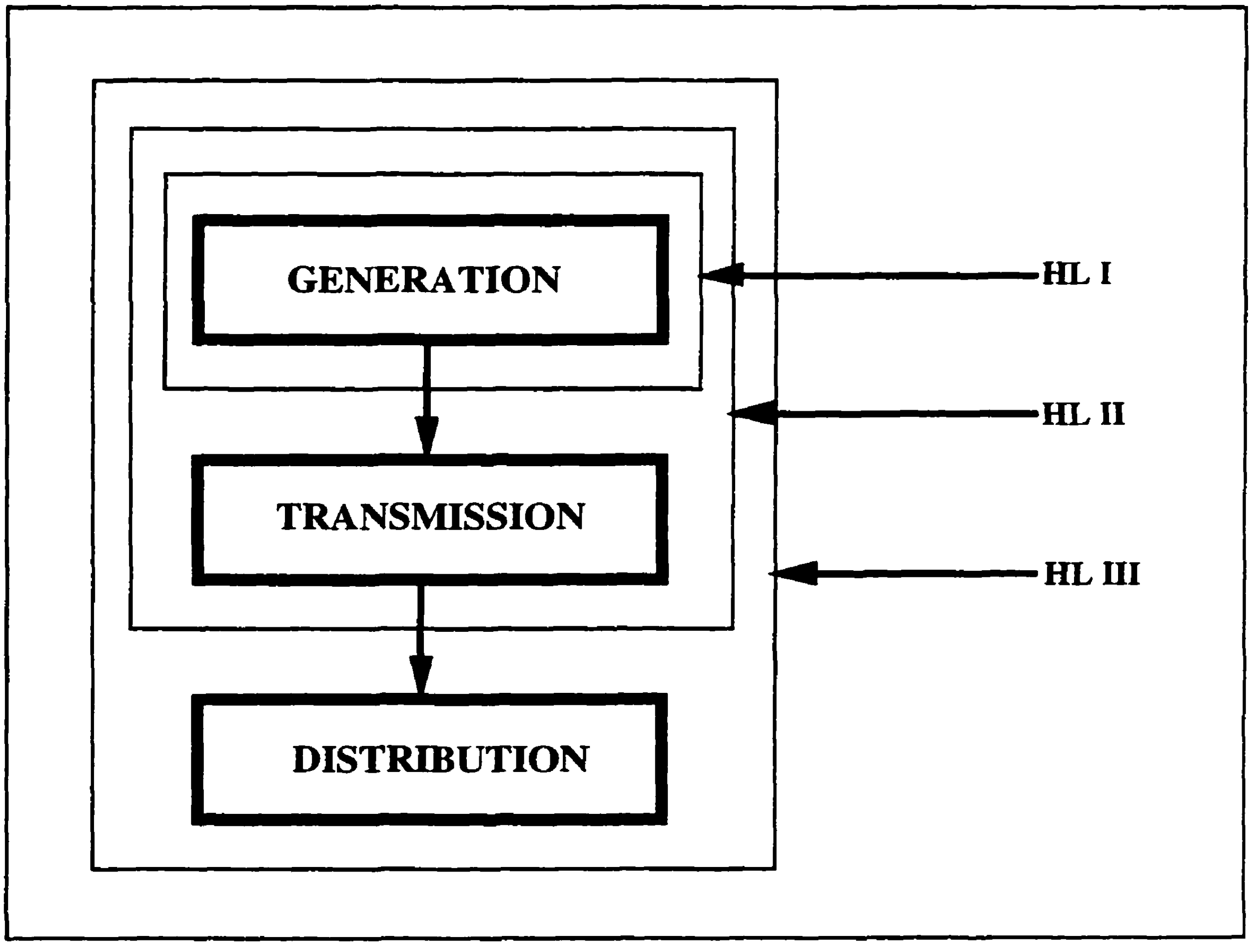


Figure 1.2 Functional zones and hierarchical levels

Reliability evaluation at this level extends the HL I indices by including the ability to move the generated energy through the bulk transmission system. Hierarchical level III (HL III) includes all three functional zones starting with the generation facilities and terminating at the individual customer load points. The HL III indices can be evaluated by utilizing the HL II load point indices as input to the distribution functional zone.

This thesis is primarily concerned with reliability constrained economic assessment at HL I and HL II. The problem at HL I is the determination of the required amount of system generation to ensure an adequate supply in an economical manner. The system model at this level is shown in Figure 1.3 [1]. The basic concern in HL I studies is to estimate the necessary generating capacity to satisfy the system load and to have sufficient capacity to perform corrective and preventive maintenance on the generating facilities. The simplified generation-load model shown in Figure 1.3 is extended to include bulk transmission in HL II studies. An HL II model is shown in Figure 1.4 [1]. Economic assessment at HL II includes the generation facilities covered in HL I together with the transmission required to move the generated energy to the major load points. Transmission losses, which are a part of the operating cost of an electric system, are considered in economic assessment.

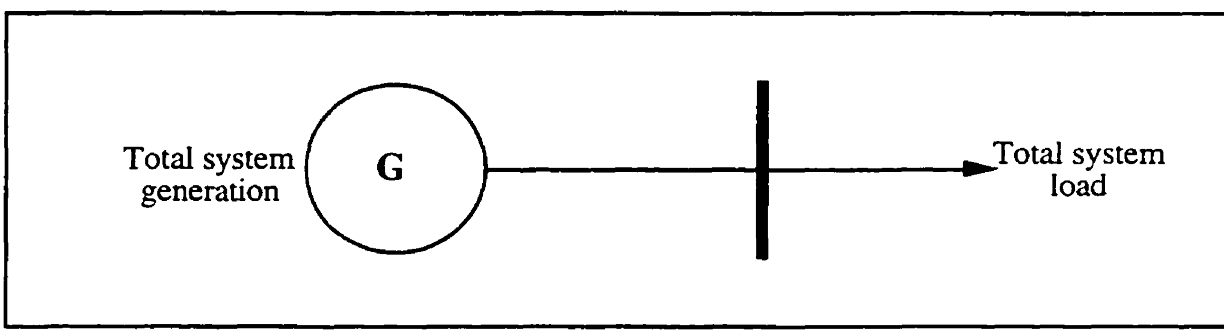


Figure 1.3 Model for hierarchical level I

1.2 Power Systems Planning

Power system planning can be divided into two conceptually different areas dealing with static and operating capacity requirements [2]. The static capacity area relates to the long-term evaluation of the over-all system requirement. It normally has a time horizon of ten to thirty years. The tasks involved include both generation and transmission expansion planning as well as fuel procurement in the cases of HL I and HL II. Predictions beyond a thirty year horizon are generally meaningless and some argue that even this time span is too ambitious. The time horizon length is a management decision but should recognize the lead-time requirements for implementing system expansion plans. Generation and transmission

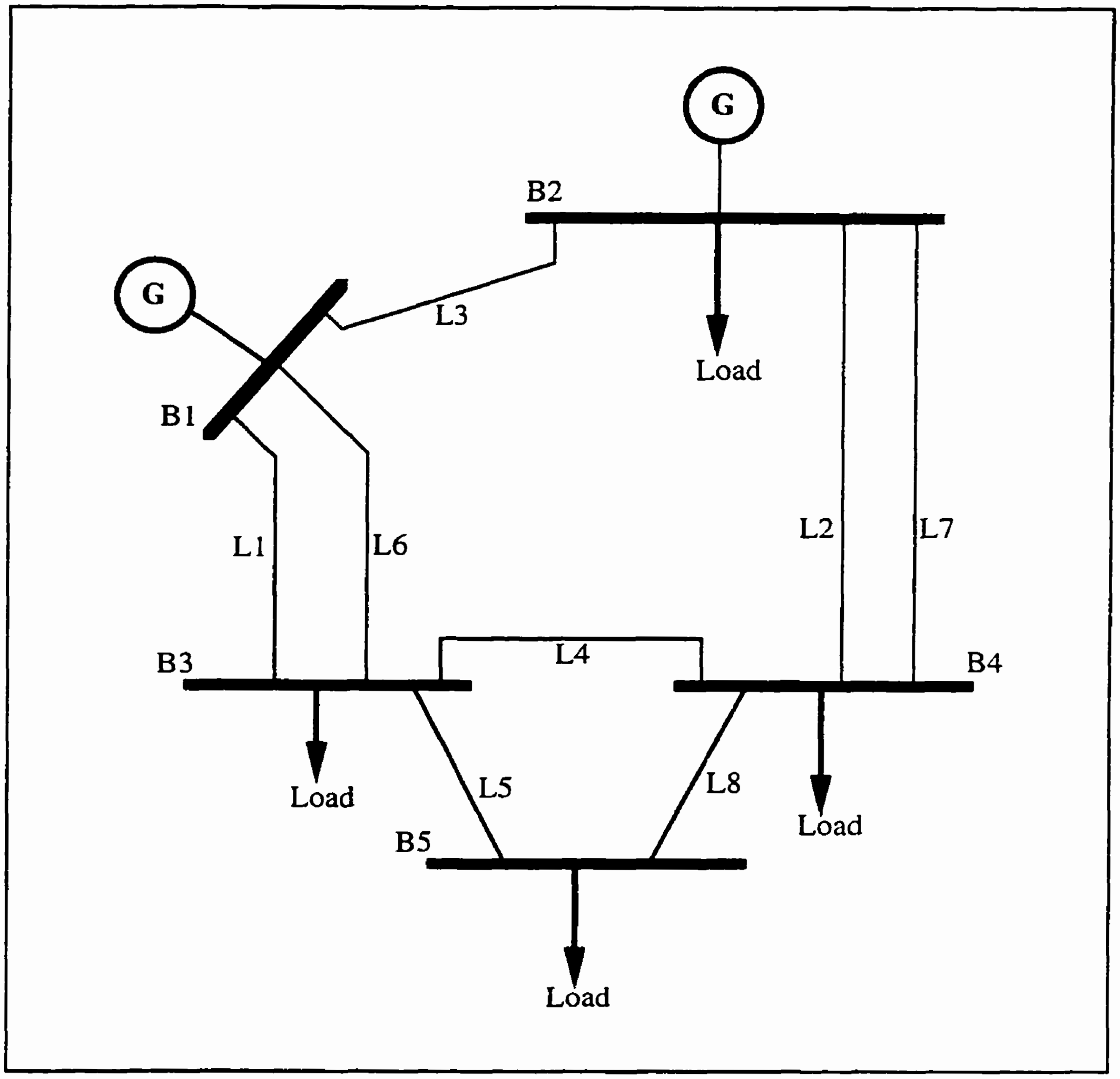


Figure 1.4 Model for hierarchical level II

expansion is probably the oldest and most extensively studied planning area. Operating capacity assessment relates to the short term evaluation of the actual capacity required to meet a given load level. System operation planning normally has a time horizon of up to one year. There are relatively few papers that deal with operating capacity requirements [4-7] compared with those on static capacity evaluation [8-14]. Both the static and operating areas must be examined at the planning level in evaluating alternative facilities. Once the decision has been made, however, the short term requirement becomes an operating problem. The impact of non utility generation (NUG) on utility operational planning is examined in this thesis. Certain general characteristics which directly affect the scheduling of system generation are considered in detail.

In power system operation, the expected load must be predicted and sufficient generation must be scheduled accordingly. Reserve generation must also be scheduled in order to account for load forecast uncertainties and possible outages of generating units. Once this capacity is scheduled and spinning, the operator is committed for the period of time it takes to achieve output from other generating units. This time may be several hours in the case of thermal units but only a few minutes in the case of gas turbines and hydroelectric units. Historically, operating reserves have been determined deterministically, the most frequently used method being a reserve equal to the largest unit in the system [2]. Deterministic methods cannot account for the probabilistic or stochastic nature of system behavior, of customer demands or of component failures. In the operational phase, deterministic rules can lead to over scheduling which, although more reliable, is uneconomical, or to under scheduling which, although less costly to operate, can be very unreliable. A more consistent and realistic method is one based on probabilistic methods. The need for probabilistic evaluation of system behavior has been recognized since at least the 1930's [2], and it may be questioned why such methods have not been widely used in the past. The main reasons were lack of data, limitations of computational resources, lack of realistic reliability techniques, aversion to the use of probabilistic techniques and a misunderstanding of the significance and meaning of probabilistic criteria and risk indices. None of these reasons are valid today. Consequently, there is no need to artificially constrain the inherent probabilistic or stochastic nature of a power system into a deterministic one. However, most Canadian utilities still utilize deterministic approaches to operate their generating capacity. A survey conducted by the Power System Reliability Subsection of the Canadian Electrical Association in 1983 [15] indicates that most Canadian utilities determine operating reserve requirements based on a "largest contingency" criterion and some utilities complement this reserve assessment technique with a megawatt margin of some form. This method has generally been tailored to suit each system's particular needs. No immediate changes in operating reserve assessment practices were foreseen by any of the utilities which responded to the survey. In this thesis, both deterministic and probabilistic criteria have been utilized to determine the economic impact of NUG on utility short term scheduling with regard to HL I and HL II.

The total scheduling problem can be decomposed into different time horizons. This is done to make each sub problem solvable with known methods and feasible computer resources. The sub problems are hierarchical where the weekly schedules impose constraints on the hourly schedules which in turn constrain the real time control. The information flows between the above functions are illustrated in Figure 1.5 [3]. The decomposition of the system operation function in terms of the time horizon is as follows.

1.2.1. Long Term Scheduling

The scheduling functions are carried out for a time horizon of up to one year in order to determine weekly strategies and it requires a weekly load forecast for a future year. A long term load forecast is a pre-requisite for this function. Due to the uncertainties associated with forecast, probabilistic techniques have been proved to be more meaningful than deterministic techniques in the long term domain. The following long term scheduling functions are identified in Figure 1.5.

a) Fuel Scheduling: The weekly fuel constraints are determined on the basis of negotiated fuel contracts.

b) Maintenance Scheduling: The unit maintenance schedules are determined in an optimal manner using forced outage data.

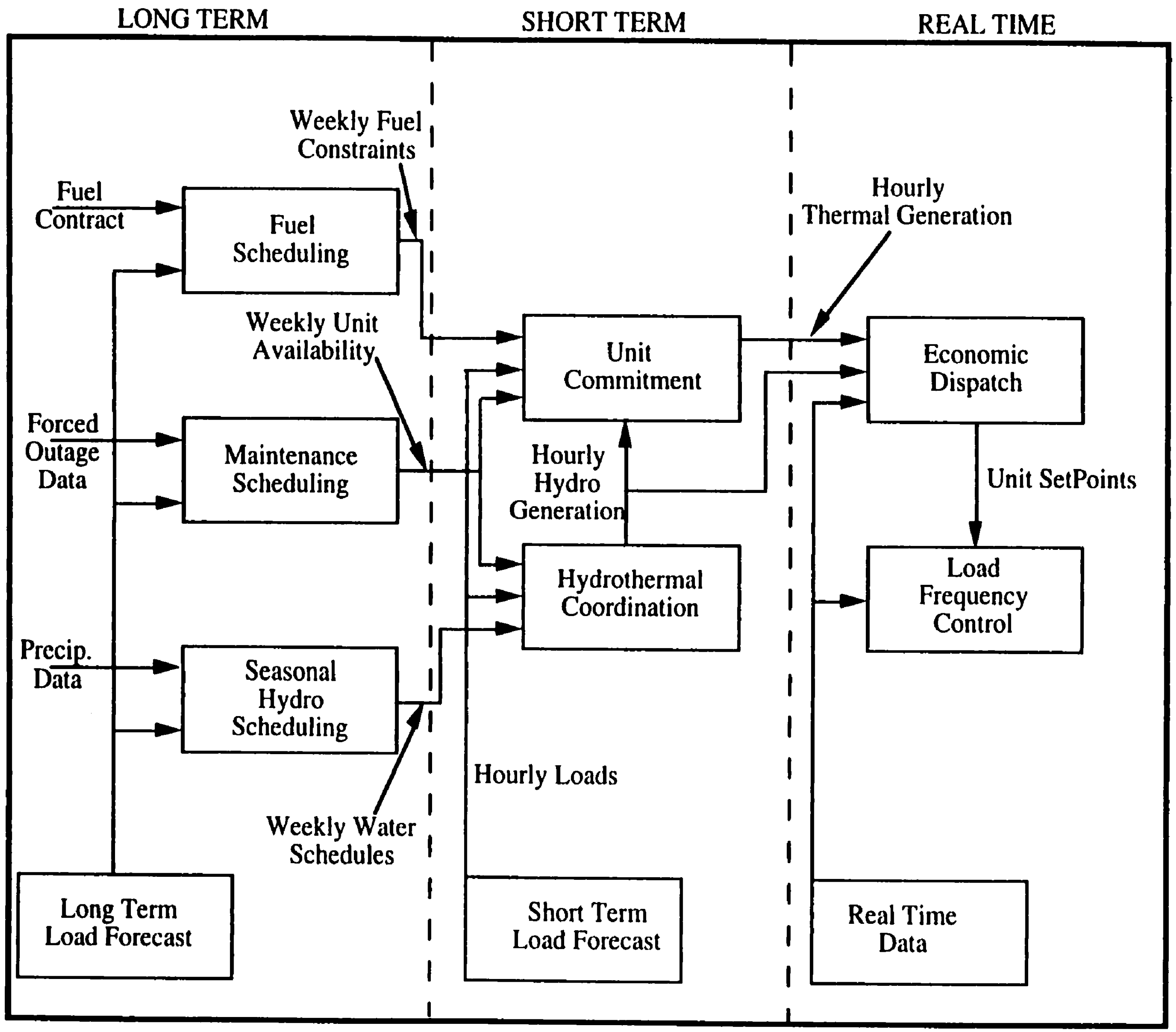


Figure 1.5. Operational planning hierarchical diagram

c) Seasonal Hydro Scheduling: Weekly water draw-down volumes are determined on the basis of precipitation and snow coverage data and weather predictions.

1.2.2. Short Term Scheduling

The usual time horizon in short term scheduling is considered to be one week, which is discretized on an hourly basis. The short term scheduling functions are utilized to commit and decommit all generation sources to minimize the total production cost. The scheduling is done for a load profile obtained by load forecasting. There are two major functions within this time frame.

a) Unit commitment (UC): Unit commitment is defined as the process of determining the most economical start up and shut down times for each generating unit such that the system load and the operating requirements are satisfied during the optimization period [16-21]. The output of a unit commitment program is an hourly scheduling of thermal units available for production. The strategy is based on the outcome of the fuel scheduling program providing the weekly fuel constraints as well as the weekly unit availability as determined by the maintenance scheduling program.

b) Hydrothermal coordination: Given the weekly water scheduling program, the function of hydrothermal coordination is to provide input to the economic dispatch function.

1.2.3. Real Time Control

The time horizon in real time control is very small. For economic load dispatch, it is two to ten minutes and for load frequency control it is few seconds.

a) Economic load dispatch: Load dispatch is the problem of determining the power outputs of the committed generating units such that the fuel cost is minimized while satisfying certain operating constraints [21-24]. Given a power system load and the on-line generation resources, the object is to determine the optimal generation level.

b) Load frequency control: The object here is to change generation levels to track the load. This function is not treated in practice as an optimal control problem.

The classification indicated above represents a view shared by many but not all utilities. A given decomposition should be based on an operating system's particular environment and constraints.

1.3. Economics of System Operation

Operation of a power system involves forecasting the daily load demand, utilization of available resources under certain constraints, understanding the electro-mechanical behavior of various system components including generating units and most importantly, economics of operation. The economic aspects of generating system operation deal with the unit commitment and load dispatch of a selected set of available generating units under certain operating constraints in order to minimize the overall production cost. The unit commitment and load dispatch in a system should be such that economic considerations as well as pre-defined reliability criteria are satisfied under normal system conditions. Under these conditions, the generating capacity in operation is greater than the actual load demand. Additional generating capacity necessary to meet the load demand is required to make the system capable of handling unforeseen load changes and possible outages of generation or other facilities. This extra generating capacity or spinning capacity held in reserve must be capable of responding within an allowable margin time to ensure reliable system operation. Two types of margin time are important [2,25];

a) time to satisfy system frequency and dynamic stability and

b) time to satisfy loss of generation or other facilities

These margin times are normally of the order of one minute and five minutes respectively. The actual magnitude of these time periods can, however, vary from system to system.

The rotating capacity in excess of the system load, available at all times to satisfy the probable loss of some generating capacity without impairing system frequency and tie line regulation, is called spinning reserve. A number of different methods are presently used to assess the spinning reserve requirements in a power system. Deterministic assessment of the spinning reserve requirement can be done using:

a) percentage of system load or operating capacity,

b) fixed capacity margin,

c) largest contingency, or

d) any combination of the above methods.

Different utilities have their own rationale for selecting a particular method. As mentioned earlier, deterministic approaches do not specifically take into account the likelihood of component failure, i.e. the probability of failure of generating units, transmission lines, etc., in the assessment of spinning reserve. A probabilistic approach can be used to recognize the stochastic nature of system components and to incorporate them in a consistent evaluation of the spinning reserve requirement. The actual magnitude and even the type of spinning reserve is, therefore, determined on the basis of system risk. This risk can be defined as the probability that the system fails to meet the load or just be able to meet the load for a specified time period [2,26]. A time dependent risk can be expressed mathematically as [26]:

$$R(t) = \sum_{i=1}^{m} P_i(t) Q_i(t) \quad , \tag{1.1}$$

where

$R(t)$ = system risk at time t

$P_i(t)$ = probability that the system is in state i at time t

$Q_i(t)$ = probability that the system, in state i at time t, will fail to meet the quality, continuity or other performance criteria

m = total number of system states.

The selection of a suitable risk level is somewhat arbitrary, as there is no simple direct relationship between risk and corresponding worth and both experience and judgment are required in selecting a particular risk level. The operating risk, however, can be decreased by providing more spinning reserve, i.e. scheduling more generating units. Decreasing the risk level will result in increased operational costs. The selection of an allowable risk level is, therefore, a management decision.

Generally two values of system risk can be evaluated with respect to system operation; unit commitment risk and response risk [2,26]. Unit commitment risk is the probability of the committed generation just satisfying or failing to satisfy the expected demand during the lead time. Lead time is the time required to start, synchronize and start load sharing for a particular generating unit. This time is of the order of 4 to 24 hours for a thermal unit depending upon the size of the unit and the length of time since it last operated. This time may be from one to five minutes for hydro units. Gas turbine units require about five minutes to be fully loaded from a cold condition. Response risk is defined as the probability of achieving a certain response or regulating margin within the required response time or margin time. The ability to respond to system changes and to pick-up load on demand depends very much on the type of unit used as spinning reserve. Typically, the response rate may vary from about 30% of full capacity per minute for hydro-electric plant to only 1% of full capacity per minute for some types of thermal plant. Rapid start units such as gas turbines can usually reach full output within 5 minutes from standstill.

It is normally assumed in operating reserve studies that there is sufficient generating capacity available within the system to meet the load demand and that it is only a matter of time before additional capacity can be brought into service. The basic statistics used in spinning reserve studies is called the outage replacement rate (ORR) [2] and is defined as the probability of the operating units failing and not being replaced by other capacity within the lead time. A table with various capacity states and their corresponding probabilities called a capacity outage probability table can be developed using ORR for all the operating units for a given generating schedule.

1.4. Current Operational Planning Problems

Operational planning includes those tasks that are performed by operating personnel to influence operating decisions beyond the current hour. Greater emphasis is being placed on operational planning to get the most, at the least cost, from existing equipment. This is due to the fact that new capacity plans are being postponed or canceled because of slow load growth, tight cashflows, political pressure, possible depletion of oil supplies, etc.. Most North American utilities have acquired sophisticated operational planning tools, such as unit commitment, maintenance planning or production costing software to optimize the use of existing generation resources.

Beside investing in more advanced hardware and software, utilities are also assigning more manpower to operational planning tasks. In the last 5-10 years, there has been a steady transfer of engineers from planning departments to control centers to support system operators in operational planning tasks.

System operators face a large number of system problems in operational planning. A survey of current operational problems faced by power system operators was conducted in 1989. Some of the current issues in operational planning with regards to generation are listed below [27,28]:

a) Environmental constraints: Due to restrictions imposed by some governments on the annual reduction of SO_2 emissions and NO_2 emissions from thermal power stations, environmental constraints top the list of management concerns. Emission constrained software for unit dispatch have already been described in the literature.

b) Transmission constraints: In the past, a common practice used in generation scheduling was to ignore transmission constraints. In recent years, the amount of power transfer for some utilities has increased to the point where transmission bottlenecks seriously influence generation commitment and loading decisions.

c) Operator's acceptance: Some of the mid-range planning tasks, previously performed by the planning department, such as maintenance scheduling or transaction pricing, are now being transferred to the system operation groups.

d) Impact of uncertainty: An important issue, often raised by skeptics, is: "Since some of the key input data, used in operational planning programs, such as fuel costs and load forecasts, are just "guesstimates", with some amount of built-in uncertainty, why do we bother using sophisticated optimization software to fine-tune system costs by 1 or 2 percent?

e) Post analysis: A number of utilities have recently used post analysis techniques to close the planning loop and provide feedback to their management as to how well the system was actually operated on the previous day or week.

f) Resource scheduling: Advanced modeling programs are needed to permit the evaluation of complex operating strategies involving such things as load management, cogeneration, pumped storage, environmental constraints, etc.

g) Non-utility generation: Energy management system software with feedback loops and appropriate models are needed for the dispatch and control of non-utility generation (NUG) and load management. Different types of contracts are needed to assure the response of NUG in the system operation planning process.

1.5. The Scope and the Objective of the Thesis

NUG is a major force in the way electrical energy is now being produced and marketed, and electric utilities are reacting to the growth of this new industry. When a utility buys electric energy from a NUG at short notice, such as a few hours, one of the difficult issues encountered by the utility is the evaluation of the price it should pay the NUG such that the utility maximizes its economic benefit.

This research project deals with the economic implications associated with incorporating NUG in the short term operational planning of a utility. The thrust of the project was to evaluate the monetary transactions resulting from energy purchases by a utility from a NUG. These facilities may include non-conventional generation sources such as solar, wind, geothermal, etc. and cogenerators. The non-conventional sources of generation can be attractive alternatives to fossil fuel plants. Many utilities strongly feel that these non-conventional sources of energy, or NUG, can ease critical future problems of fuel cost and availability. Much of this optimism is limited by the fact that such generation sources are known to produce extraneous operating problems in the power system as a whole. Some papers have been published in the area of integration of non-conventional electricity generators in the planning process of a utility [30-35]. Most of the work reported is in the adequacy area. Very little work has been performed to investigate the integration of NUG in utility short term operational planning. In this thesis, the incorporation of NUG energy in utility short term operational planning is done in such a way that the most optimal generation configuration is obtained.

Many public service commissions are currently examining the issues involved in establishing purchase rates for energy bought by a utility from cogenerators and small power producers. Several state public utility commissions have issued final orders regarding the methods to be used in estimating a reasonable avoided cost rate to be paid to cogenerators. Most state commissions have issued interim orders permitting experimental purchase rates to be offered while reserving final judgment on the best methods to be used in estimating the avoided costs associated with utility purchases from cogenerators. In Canada, purchase rates for energy bought by a utility from cogenerators and small power producers (buyback rates) are not determined according to any single governing principle such as the avoided cost rule used in the United States of America under the Public Utility Regulatory Policy Act (PURPA) [36,37]. Utilities calculate their purchase rates based on a number of different formulae. Short term buyback rates should be based on the operating cost that a utility avoids by utilizing energy from a NUG. This cost is termed the avoided operating cost (AOC) in this thesis. In this project, a standard method for evaluating the AOC is developed. Buyback rates are based on AOC. Suitable techniques for thermal and hydrothermal systems have been developed to assess the short term AOC under different operating conditions. A time-differentiated price system is used to reflect the different value placed on purchase price by a utility at different times of the day in short term scheduling. The effect of dispatchable and non-dispatchable NUG have also been considered in the techniques.

Intermittent sources of energy such as wind and cogeneration, are receiving increasing interest, both in the short and long terms. These intermittent sources of energy differ from conventional power sources by having quite variable outputs. Questions regarding their integration in power systems and their effect on short term planning are likely to attract growing attention and some of these concerns were examined in this research.

AOC of a utility depends on the time, and duration of energy transfer from a NUG and also on the location of the NUG in the network. Different locations of the same NUG in the network will have different economic impact on the utility due to the associated transmission losses. Transmission losses are a part of the cost of supplying energy and, therefore, taken into account in the evaluation of the AOC. A utility will derive maximum benefit when the NUG is connected at a load bus. At other locations, the economic benefit is decreased by the cost associated with the transmission loss. This decrease, however, is a complex function of network configuration, load profile, unit loading, etc. An algorithm is developed to determine short term rescheduling of the utility generation, at HL II as a result of NUG energy purchase by the utility. Transmission losses are evaluated in order to assess incremental costs of the generating units. A deterministic criterion is utilized to maintain the reliability of the utility generation system at a desired level. AOC with and without transmission losses are presented for the sake of comparison.

In summary, the objectives of this research are:

a) To develop a technique to evaluate the AOC in a consistent manner for all thermal and hydrothermal systems.

b) To include deterministic and probabilistic criteria in the evaluation of the AOC.

c) To develop a technique to evaluate the AOC in systems buying energy from cogenerating and wind NUGs.

d) To develop a technique to evaluate AOC at HL II.

1.6. Thesis Outline

The thesis is divided into seven chapters. Chapter 2 provides an overview of NUG. The term NUG is defined and factors associated with NUG development are discussed including its contributions in the electricity generation of some countries. A new algorithm utilized to incorporate NUG energy into utility short term generation planning in the most optimal manner is presented in this chapter. The Institution of Electrical and Electronics Engineer-Reliability Test System (IEEE-RTS) [38] is utilized to illustrate the application of the proposed algorithms. The details of this system are given in Chapter 2.

Thermal plant is a common form of electricity generation. The economic implication of NUG in a all thermal power system is discussed in Chapter 3. Two algorithms which are based on the deterministic and the probabilistic techniques are presented in this chapter. These algorithms can be utilized to analyze economic issues related to the inclusion of NUG in the short term planning of a thermal power system. Based on these algorithms, sensitivity studies were performed utilizing the IEEE-RTS and the results are discussed in this chapter.

Hydrothermal system is defined as having both hydro and thermal generation sources. Fixed head and variable head hydrothermal systems are discussed in Chapter 4 which deals with the economic impact of NUG on hydrothermal systems. Deterministically based algorithms are illustrated which can be utilized to include NUG energy into fixed head and variable head hydrothermal systems in an optimal manner. The algorithms are based on the optimal operation of the hydrothermal systems both before and after the utilization of NUG energy. Sensitivity studies have been performed and the results are presented in this chapter.

Chapters 3 and 4 consider the inclusion of NUG energy in thermal and hydrothermal systems respectively. In Chapter 5, it is assumed that NUG provides electrical energy from non-conventional sources. Industrial cogeneration and wind are the two non-conventional sources considered in this chapter. The economic impact of wind and cogenerated energies, produced by NUG, on a utility is examined. Some important characteristics of these non-conventional sources are discussed. Sensitivity studies that reflect the inherent characteristics of the two non-conventional sources were performed on the IEEE-RTS and the results are discussed in this chapter.

The economic implications of NUG on utilities at HL I are discussed in Chapters 3, 4 and 5. Chapter 6 deals with the economic implications of the inclusion of NUG energy in thermal power utility short term operational planning at HL II. The location of NUG in a utility network becomes an important aspect when determining the monetary transaction between a utility and a NUG. An algorithm is illustrated in this chapter that can be utilized for short term optimal scheduling of the utility generation, considering transmission loss, as NUG energy is included in the utility system. The IEEE-RTS is a relatively large test system with a complex network structure. The Roy Billinton Test System (RBTS) [39] is utilized as a test system to illustrate the usefulness of the algorithm in this chapter. The RBTS is sufficiently small to permit the conduct of a large number of system studies with reasonable time but sufficiently detailed to reflect the actual complexities involved in a practical system. Sensitivity studies were performed on the RBTS and the results are presented in this chapter. The conclusions and summary of the thesis are presented in Chapter 7.

2. INTRODUCTION OF NON-UTILITY GENERATION

2.1 Introduction

Most North American power utilities have either delayed or put a temporary hold on building large conventional base load generating units due to the environmental concerns, lowering of demand growth, the possible depletion of conventional energy sources and increasing cost of construction [40-43]. Utilities are looking at more flexible options for meeting some of their forecasted load growth, other than the construction of conventional base load units. Unstated but implicit in the utilities decision to avoid new conventional base-load units is the presence of desirable alternatives that were either not present or less attractive when decisions on prior capacity were made. Figure 2.1 shows the wide range of alternatives available to management today [44,45]. Some of the utilities are rehabilitating older units while others have chosen to depend upon non-utility generation (NUG) in order to satisfy a portion of customer demand. NUG are defined as those facilities owned and operated by electric producers other than regulated utilities and include cogeneration plants and independent power producers [46]. This group provides a measure of flexibility and diversity in electric energy supply and facilitates the orderly, economic and efficient use of natural resources. In some countries, federal laws and regulations are encouraging non-utility generation in the form of independent power producers (IPPs) and cogenerators. It has become a major consideration in the capacity and energy planning of most utilities around the world.

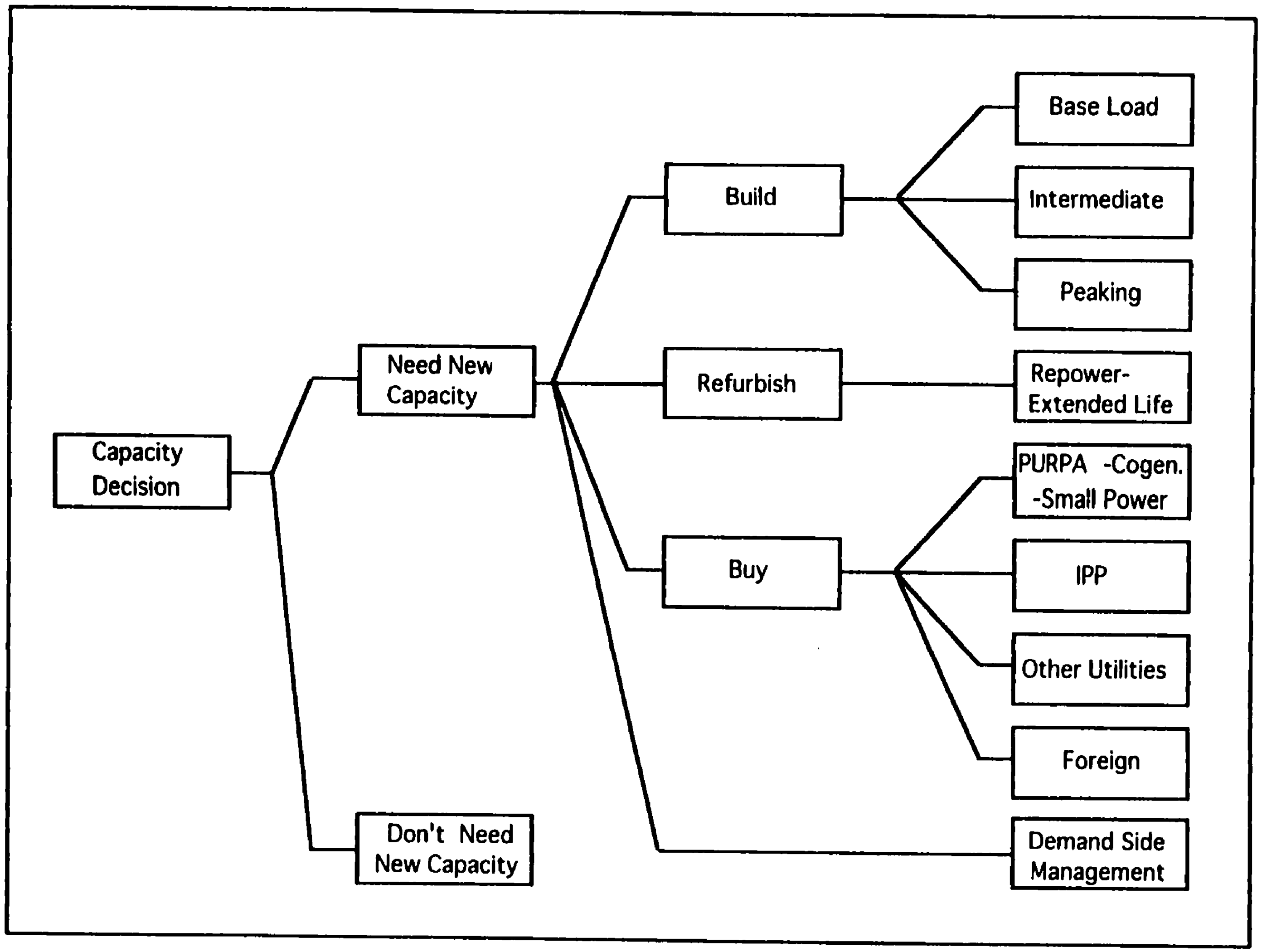


Figure 2.1 Capacity decision tree

2.2. Contribution of Electrical Energy from NUG

The legal and regulatory changes in some countries, the recent success of competitive procurement as a means of acquiring NUG, and the response of the NUG developers to competitive procurement solicitations make NUG growth in the 1990s inevitable. In the United States, Federal laws and regulations under the PURPA [37,47] clearly established the existence of qualifying facilities (QFs) [37,47], and the Federal Energy Regulatory Commission (FERC) [37,47] has shown a willingness to encourage further NUG in the form of IPPs and cogenerators. The 1989 North American Electric Reliability Council (NERC) forecast includes the addition of 93,600 MW of new capacity for the U.S.A. between 1989 and 1998 [40]. Figure 2.2 illustrates the contribution made by different

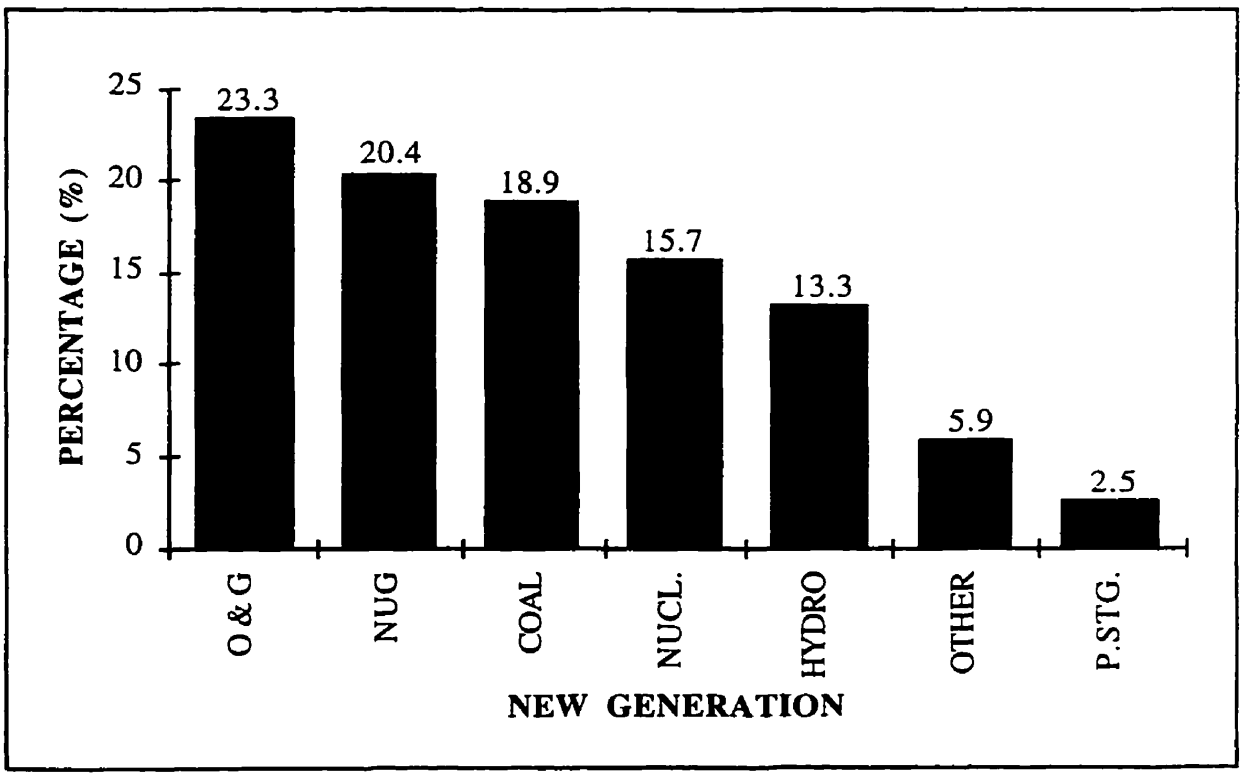


Figure 2.2 NERC forecast of new generation capacity for the USA.

different sources from which electric energy will be generated in the U.S.A.. It can be observed from the figure that the contribution made by NUG is significant.

In Italy, the total NUG production (26.6 TWh gross) in 1991 was about 9.6 percent of the country's total production [48]. Two laws on Institutional Aspects and on Energy Savings of January 1991 removed many of the shackles to independent producers giving additional administrative and financial incentives. The NUG production can be sold to ENEL or to any company. A rapid increase in IPP proposals has been observed. Approximately 9000 MW of new capacity has been proposed [48]. Forecast sales by NUG included in the ENEL plan are in the range of 3000-4500 MW of capacity with a projected supply of 18-27 TWh. Figure 2.3 shows the percentage production for load in Italy.

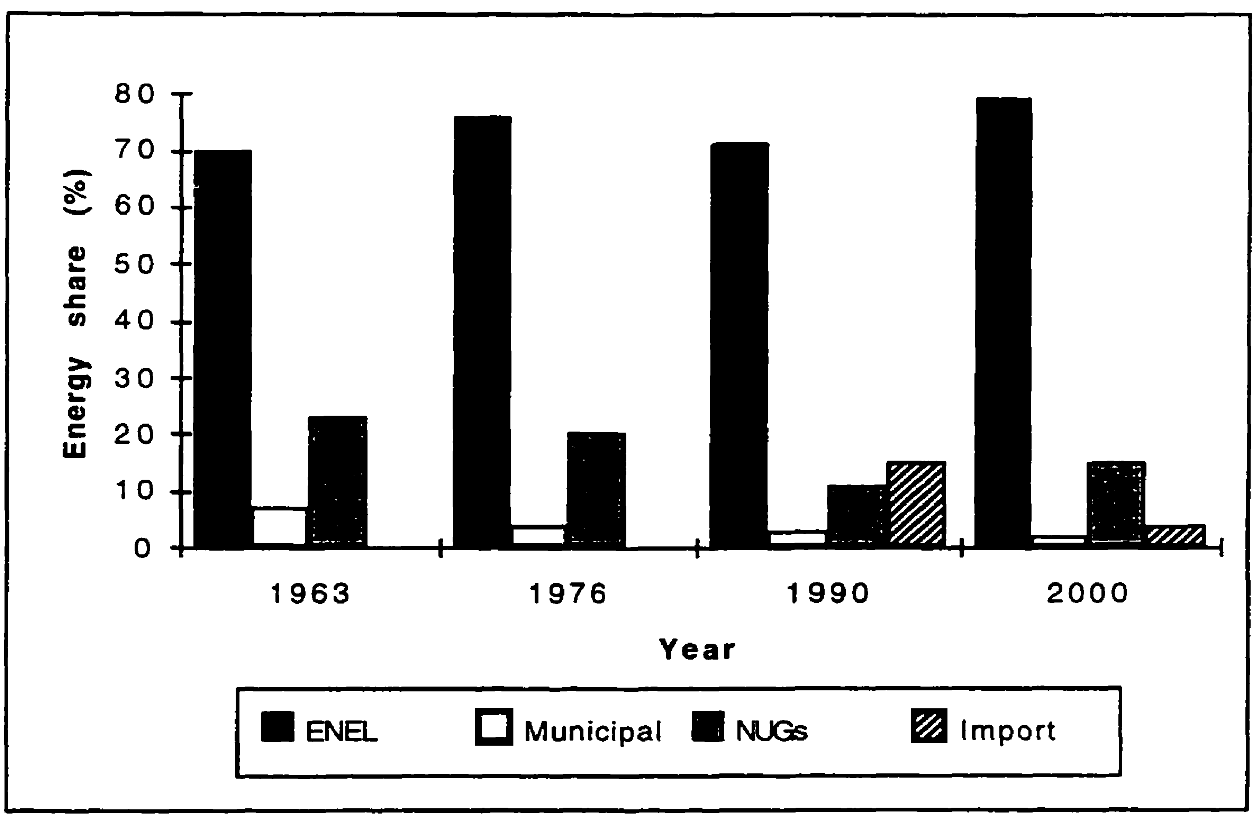


Figure 2.3. Percentage electrical energy production in Italy

Use of cogeneration systems in Japan, is expected to expand from now on as their role and effectiveness is becoming well recognized. According to a recent study, potential demand of cogeneration systems in the commercial field, in 1990, was about 4.2 GW and is expected to be 5.2 GW by 2000 [48].

In Denmark, the independent generating capacity totaled 503 MW, or 5.5 percent of the installed capacity in the public generating system in 1992 [48]. The major portion of NUG comes from wind energy.

According to a report published by Frost and Sullivan's London office [48], there is a potential market for 40,000 MW of cogeneration in Europe. In West Germany, the installed capacity of cogeneration was 14,000 MW in 1988. An additional 3000 MW of new cogeneration capacity is anticipated by 1993.

In Scandinavia, about 2000 MW of new cogeneration is expected to be installed. With the additional capacity, the Scandinavian countries will have a total cogeneration capacity of 13,000 MW.

New cogeneration capacity of 2300 MW will be added in the three Benelux countries. By the end of 1993, the total installed capacity of the Benelux countries will amount to 5300 MW. In the Mediterranean areas, Iberia and Greece will add 840 MW of new cogeneration capacity by the end of 1993.

With the privatization of the Central Electricity Generating Board in the UK, it is anticipated that by the end of 1993, an additional 2100 MW of new cogeneration capacity will be added. This will increase the area's cogeneration capacity by 53%.

About 500 MW and 200 MW of new cogeneration capacities will be added in France and Austria respectively. They also have the potential for developing additional hydropower in the Alps.

Canada does not have a national policy with regard to the development of NUG, nor is there any comprehensive legislation similar to PURPA in the United States. The federal and some provincial governments, however, have indicated their interest in, and support for, NUG development. It is predicted that regulations will eventually be created to increase the amount of electrical energy from NUG.

2.3. Operational Problems with Regards to NUG

A significant portion of the power plant investment in the next decade is predicted to be made by the NUG industries [49]. Inclusion of NUG in utility operational planning has, however, associated problems. Of all the ways NUG affect the utility operations, the planning process is affected the most. NUG cause operational problems since they are characteristically owned by unregulated industries [50,51]. The overall impact of NUG on utility operation can best be viewed in the context of the various types of agreements that can be contracted between the two parties. These contracts are as follows [52,53]:

A) Firm capacity: When a utility contracts with a NUG facility for a given amount of capacity, that capacity becomes a usable resource similar to a utility's own unit. For a given amount of NUG capacity, a utility can fulfill a need for generation resources in a manner similar to a planned power purchase from another utility. The utility dispatcher needs to receive hourly schedule availability information from the NUG so as to make the necessary operational plans for items such as unit commitment, spinning reserve, control reserves, fuel schedules, maintenance, etc. The contract, therefore, must have scheduling provisions commensurate with the generation that the firm capacity contract replaced.

   Utilities believe that they should have dispatch rights over NUG very similar to those that they exercise over equivalent units in their own systems and they must be able to modify the schedule in varying amounts in accordance with system requirements. For instance, a firm cogeneration contract signed to replace a base load coal unit may require a utility dispatcher to change the schedule only a few times a year, whereas a contract replacing a peaking gas turbine may involve many changes in scheduled output. Often, a source of disagreement between the utility and a NUG is what constitutes a reasonable time to commit a unit or change a schedule. Another source of contention is how many such changes may be initiated by the utility. The contract should address these requirements in detail.

Many firm contracts require the NUG to carry from 3-6% of their contracted capacity as spinning reserve. Firm capacity contracts usually result in little fuel or capacity planning problems for the utility if proper scheduling, dispatch and capacity factor incentive clauses are included in the contract. Failure to include these items could add considerable uncertainty in the utility operational planning process.

B) Non-firm energy sales: This contract permits the NUG to sell energy whenever it desires. The NUG makes no commitment to provide capacity on a guaranteed basis. Sales to a utility that are non-firm are either governed by a contract or an enforceable tariff. The NUG provides energy on an 'as available' basis. Non-firm energy sales are usually unpredictable and can have significant planning and operational repercussions. Since the delivery to the utility is non-firm, the utility must be able to replace the energy from the NUG immediately. The utility must commit sufficient spinning reserve to be able to replace the energy from the NUG. Contract provisions should address the utility requirement for a daily schedule by hour and an annual schedule by month of the planned or forecast sales. Some utilities require both a daily schedule by hour and annual schedule by month of forecasted energy deliveries, although no commitment is made by the NUG on accuracy. Daily schedules are usually reasonable if the NUG has a good estimate of the buyback rates. Annual schedules are not usually accurate and can result in the utility having to adjust fuel purchases substantially month to month.

C) Wheeling: Wheeling contracts, where a utility wheels NUG energy from its control area in which the NUG is located to another control area, can result in a different set of utility operating problems. When the utility transfers NUG generated power from its own service area to that of another utility, it can have a significant impact on interchange scheduling, security analysis, instantaneous standby, and inadvertent energy accounting.

D) Combination: Mixtures of different types of agreements sometimes occur to address specific requirements of a NUG. The following are four possible combinations of NUG contracts:

   a) Firm, non-firm combined

   b) Wheeling, firm combined

   c) Wheeling, non-firm combined

   d) Wheeling, firm, non-firm combined

   The problems and constraints associated with these arrangements are different and depend upon the combination selected.

In addition to the problems discussed above, a question that arises in the consideration of NUG is whether it will be under the control of the utility. Almost all generating units today are controlled from a dispatch control center, but, it is not clear that this will be the case for NUG. If a NUG is not controlled, the load frequency control (LFC) will see its effect as negative load. The effective load, that is made up of the actual load minus this new generation, must be matched by controlling the conventional generating units. The response rate of conventional generation is usually adequate to follow the actual load but may not be able to follow the effective load. If a NUG is under utility dispatch control, the basic problem is one of availability. If the NUG sources are solar and wind, for example, it is not possible to depend on them for effective regulation, and sufficient response capability must be available from other sources during night, cloudy or calm periods.

Communication between a utility and NUG regarding NUG energy sales can also create some difficulties. If there are a large number of NUG dispersed across the system, the present communication system of microwave or lease lines between NUG generators and the control centre may become expensive. Alternative systems using radio, power line carrier and other communication channels such as those considered for load management are probably more appropriate for highly dispersed NUG generation. The communication time delay for such systems may be much higher than those in the LFC cycle.

The responsibility for the cost of transmission facilities is a critical problem when NUG is included in the utility grid. A further problem is who pays for system losses associated with the addition of NUG energy. The monetary impact of NUG will vary according to who (utility or NUG) is responsible for the cost of the losses.

One of the difficulties that arises when including NUG in a conventional utility is the economic dispatch where the cost curves of all the units should be known. For wind and solar NUG, the production cost is virtually zero and they should be dispatched completely. Other generators like biomass, etc. have finite cost characteristics. The cost curves of these kinds of sources are often not well known and, therefore, it is difficult to include them in conventional economic dispatch.

In a large bulk power system, integration of NUG energy into the planning and operating process does not necessarily have to be difficult if properly planned and managed. Most technical problems are foreseeable and have a technical solution. The more difficult problems associated with NUG are those which are rooted in economics and financial issues.

2.4. Evaluation of the Avoided Operating Cost

The most contentious economic issue related to NUG is the price paid by utilities for the electrical energy supplied by the NUG to the utilities (buyback rate) [54-56]. The price a utility typically selects to pay to a NUG, in exchange for the electrical energy, should be based on their avoided operating cost (AOC). By purchasing electrical energy from a NUG, a utility reduces the generation cost associated with its committed units. The purchase rate from a NUG is based on the energy cost that a utility can thereby avoid by virtue of making the purchase. AOC can be defined as the difference between the cost that an electric utility will incur, if it did not buy energy from the NUG and the cost that the utility will incur if it buys energy from the NUG.

A generalized algorithm based on a deterministic approach is developed in this research and presented in this chapter. The algorithm can be utilized to examine the economic impact of NUG energy on the short-term operational planning of a utility. The algorithm is divided into three sections. The first section covers the unit commitment or selection of units to be operated to meet the forecast load. The second section determines the economic dispatch which dictates the loading of each utility unit and the NUG. The final section provides the evaluation of the AOC. The unit commitment and load dispatch are performed utilizing deterministic criteria.

A complete priority order method is utilized for unit commitment. Units are committed according to a priority order based on the average full load costs of the unit. Unit commitment is done in such a way that the spinning reserve is equal to the sum of the largest contingency plus 10% of the peak load. Unit commitment is, therefore, based on the load and the spinning reserve at each hour. Number of units committed can be obtained by putting the units on-line until Equations (2.1) and (2.2) are satisfied.

$$\sum_{i=1}^{N} CU_{si} \geq P_D^j + R(load, cap) \tag{2.1}$$

$$\sum_{i=1}^{N} P_{si}^j = P_D^j \tag{2.2}$$

where,

CU_{si} = capacity of ith unit,

N = number of committed units,

P_D^j = system load during hour j,

P_{si}^j = output of ith unit during jth hour and

$R(load, cap)$ = deterministically evaluated spinning reserve.

The information provided to the utility operator by a NUG regarding its energy is very often at the last minute due to the uncertainty associated with the host process. It has, therefore, been considered in the algorithm that the utility, in general, is not able to include NUG energy in its unit commitment but includes NUG energy in the load dispatch. Economic load dispatch methods consider allocation of load to different operating units in order to achieve minimum running cost. The objective of load dispatch is to minimize the operating cost.

Running cost over a 24 hour period can be expressed as [57,58]:

$$\sum_{j=1}^{24} C_j = \sum_{j=1}^{24} \left(\sum_{i=1}^{N} F_i^j (P_{si}^j) \right) \tag{2.3}$$

where

C_j = total running cost during hour j

F_i^j = running cost of unit i during hour j

The objective of the economic load dispatch is to minimize the 24 hour running cost. Minimize $\sum_{j=1}^{24} C_j$ such that the constraints of Equations (2.1) and (2.2) are satisfied for $j=1,2,3....,24$.

The running cost of a unit can be represented by a quadratic function of active power output [26]:

$$F_i^j = a_i(P_{si}^j)^2 + b_i P_{si}^j + c_i \tag{2.4}$$

where

a_i = quadratic coefficient of cost function of unit i

b_i = linear coefficient of cost function of unit i

c_i = constant term of cost function of unit i

If minimum power output, $P_{\min}$, and maximum power output, $P_{\max}$, are given then optimal generation is obtained as:

$$P_{si}^j = \frac{\lambda^j - b_i}{2a_i} \tag{2.5}$$

where

$P_{\min} \le P_{si}^j \le P_{\max}$

λ^j = incremental running cost of the system during hour j

The AOC is evaluated after the unit commitment and economic load dispatch is obtained. The technique for evaluating the AOC is based on the maximum savings approach. In this technique, a utility tries to maximize its economic savings by utilizing NUG energy in its short term operational planning. Assume that NUG has a total energy of ξ MWh for a 24 hour period. The NUG energy should be utilized to replace high cost generation and the replacement should be done in a way that the resulting saving is maximized. In order to determine the loading schedule modified by the NUG energy, a small discrete amount of NUG energy is considered in each iteration and the corresponding saving evaluated. The iterative process continues until all the NUG energy is exhausted. Savings in running cost can be expressed as

$$\Delta F_i^j = a_i\{2P_{si}^j(\Delta\xi) - (\Delta\xi)^2\} + b_i\Delta\xi \qquad (2.6)$$

where

ΔF_i^j = savings in running cost of unit i during hour j

$\Delta\xi$ = discrete amount of NUG energy utilized in one hour

All loaded units are searched except the ones that reached their minimum output limits. The unit giving maximum saving (kth unit) during hour j can be found by selecting k th unit such that the following equation is satisfied.

$$\Delta S_k^j = Max\{\Delta F_1^j, \Delta F_2^j, \Delta F_3^j, \ldots\ldots\ldots, \Delta F_N^j\} \qquad (2.7)$$

where

ΔS_k^j = discrete savings during jth hour from kth unit

The iteration continues for hour $j+1$ and ΔS_k^{j+1} is evaluated. After evaluating ΔS_k^j, j=1, 2, 3, ...24, the hour with the largest ΔS_k^j is selected for the incorporation of $\Delta\xi$

MWh of NUG energy. In the next iteration, the evaluation starts with a NUG energy of $\xi = \xi - \Delta\xi$. The process continues until all the NUG energy is exhausted.

The algorithm makes a distinction between a dispatchable and a non-dispatchable NUG. When a utility has dispatch rights over NUG then the energy provided by the NUG is dispatchable energy. When NUG provides energy to the utility, whenever it desires, then that energy is called non-dispatchable energy.

A system may include NUG energy at different hours during the day. The selection of these hours depends on anticipated overall savings from the daily operation. The most appropriate hours are selected in a way that maximizes the utility savings. The problem is to identify the hours in each 24 hour segment and the corresponding NUG output such that the running cost expressed in Equation (2.3) is minimized.

The appropriate hours can be identified whenever the NUG energy output is non zero, i.e.,

$$E_n^i > 0$$

where,

E_n^i = NUG energy output during hour i

The unknown E_n^i for i = 1, 2, ...,24 is solved such that $\sum_{i=1}^{24} C_i$ is minimized subject to the equality constraint of:

$$\sum_{i=1}^{24} E_n^i = \xi \tag{2.8}$$

For the sake of simplicity, it has been assumed that the NUG output remains unchanged within each hourly segment. Variable NUG output can be considered by subdividing each hourly duration into multiple segments. A utility may find it more convenient to utilize the NUG energy over a period of continuous hours rather than following a variable on and off schedule. In this scheme, a utility will continue to utilize the available NUG energy until it is exhausted. The problem is to find E_n^i such that the 24 hour running cost of the utility plant, $\sum_{i=1}^{24} C_i$ is minimized subject to the following conditions.

$$\sum_{i=k}^{p} E_n^i = \xi \tag{2.9}$$

$$E_n^i \neq 0, \qquad i = k,\ k+1,\ k+2, \ldots\ldots p-1,\ p$$

$$E_n^i = 0, \qquad i = 1,\ 2,\ 3,\ \ldots\ldots,\ k-1$$

$$\text{and } i = p+1,\ p+2,\ \ldots,\ 24$$

For a sufficiently large amount of NUG energy, k could be as low as 1 and p could be as high as 24. An iterative technique is utilized to find k and p such that the optimality conditions are satisfied.

Once the rescheduling of the utility units and NUG units is obtained, the AOC is evaluated by determining the difference between the total cost that would be incurred by a utility to meet a specified demand at a particular hour and the cost that the utility would incur if it purchased energy from a NUG to meet a part of its demand and supplied its remaining needs from its own facilities. Mathematically, the AOC can be represented as

$$\psi = \sum_{k=1}^{l} Max\{\Delta S_k^1, \Delta S_k^2, \Delta S_k^3, \ldots\ldots\ldots\ldots, \Delta S_k^{24}\} \tag{2.10}$$

where,

ψ = AOC

l = number of iterations required to utilize ξ MWh of NUG energy

Ψ is the cost that a utility avoids when it buys a specific amount of energy from a NUG.

A larger value of $\Delta\xi$ will require a fewer number of iterations, but the calculated AOC may move from the optimal value. A smaller value of $\Delta\xi$, on the other hand, will require more iterations in general. Different values of $\Delta\xi$ should be tried before settling on a specific value. A large system with a lot of NUG energy may have to utilize a larger value of $\Delta\xi$ than that of a smaller system.

Modifications can easily be incorporated in the generalized algorithm in order to evaluate the AOC in systems which contain thermal, fixed head hydrothermal and variable head hydrothermal generation. These modifications are shown in the following chapters.

The proposed algorithm will treat both parties involved in NUG energy transactions fairly and recognizes the standard utility operating practices. The technique can be used to assess AOC in a consistent manner, and it is flexible to include other system operating criteria. The technique can be utilized by a utility as a basic framework upon which relevant system operating criteria and cost parameters can be added. The approach includes a time differentiated price system to reflect the different value placed on purchase price by a utility at different times of the day. Computer programs have been developed in this research to evaluate and examine the economic implications of NUG. The IEEE-Reliability Test System (RTS) has been utilized to test the algorithm and is presented in the next section.

2.5. The IEEE-Reliability Test System

The IEEE-Reliability Test System (IEEE-RTS) [39,59] is utilized as an example system in this thesis. The IEEE-RTS represents a reasonably large power system and has been extensively used to study and compare techniques used in reliability studies. It does not contain complete data for conducting unit commitment and load dispatch studies for a power utility with NUG energy included in its short term planning. The missing data have been assumed wherever required. The IEEE-RTS has 32 generating units ranging from 12 MW to 400 MW. The generating unit data for the IEEE-RTS are shown in Table 2.1. All hydro and nuclear units are considered to be thermal equivalent units in the studies described in the thesis. The priority loading order, failure rate and running cost of each generating unit of the IEEE-RTS are also shown in Table 2.1. For the sake of simplicity, it has been assumed that similar generating units have identical running costs.

Two identical rapid start units, of 10 MW each, have been added and incorporated in the probabilistic analysis described in Chapter 3. Rapid start units are represented by the four state model shown in Figure 2.4 [2].

In Figure 2.4, λ is the transition rate from state i to state j. The transition rates used for the two rapid start units are: $\lambda_{12} = 0.005$, $\lambda_{21} = 0.0033$, $\lambda_{14} = 0.03$, $\lambda_{41} = 0.015$, $\lambda_{23} = 0.0008$, $\lambda_{32} = 0.0$, $\lambda_{34} = 0.025$, $\lambda_{42} = 0.025$.

The hourly peak load variations in the IEEE-RTS during the specified 24 hour scheduling period are shown in Table 2.2. NUG data consist of the running cost parameters, maximum power output and minimum power output of the NUG. They are changed for each program run in order to obtain the sensitivity curves discussed in the following chapters.

2.6. Summary

NUG is becoming an important aspect of electrical power generation in North America and in many other parts of the world. NUG includes a wide variety of generating approaches utilizing many different energy conversion techniques. More and more utilities are now depending upon the purchased energy from NUG to satisfy their customer

Table 2.1. Generation data for the IEEE-RTS.

Size (MW)	Unit Type	No. of Units	Priority Loading Order	Failure Rate (f/)	Min. Output (MW)	Max. Output (MW)	Response Rate (MW/min)	Running Cost Parameter		
								c	b	a
50	Hydro	6	1-4,31-32	4.42	0	50	10	0.0	0.500	0.0000
400	Thermal	2	5-6	7.96	200	400	~0	216.5	5.345	0.0002
350	Thermal	1	7	7.62	150	350	9	388.2	8.920	0.0039
155	Thermal	4	8-11	9.13	60	155	5	206.7	9.271	0.0667
76	Thermal	4	12-15	4.47	25	76	2	100.4	12.145	0.0113
100	Thermal	3	16-18	7.30	40	100	3	286.2	17.924	0.0220
197	Thermal	3	19-21	9.22	80	197	6	301.2	20.023	0.0030
12	Thermal	5	22-26	2.98	5	12	1	30.4	23.277	0.1373
20	Thermal	4	27-30	19.47	6	20	4	40.0	37.554	0.1256

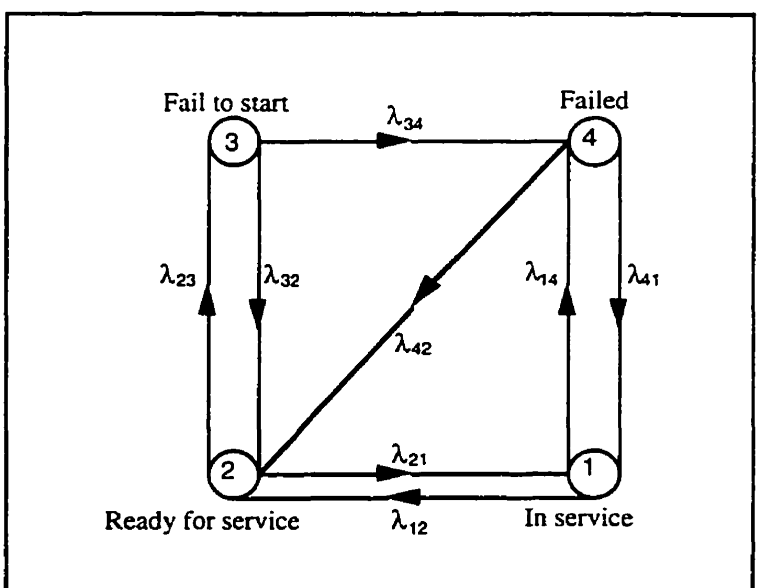


Figure 2.4. Four state model for rapid start units

Table 2.2. Load data for the IEEE-RTS.

Hour	Load (MW)	Hour	Load (MW)	Hour	Load (MW)
1	1667	9	1710	17	1945
2	1539	10	1881	18	2137
3	1453	11	1923	19	2116
4	1410	12	1945	20	2073
5	1368	13	1923	21	2009
6	1389	14	1881	22	1966
7	1410	15	1859	23	1859
8	1496	16	1859	24	1731

demands. Increasing penetration of NUG energy affects many aspects of utility planning and operation. Among these is the economic optimization of utility generation scheduling at a specified reliability. In this chapter, the contributions of NUG energy to the utility systems of different countries has been illustrated. Integration of NUG in the utility grid is not without problems, some of which have been discussed in this chapter. The problem of determining the fee paid to the NUG by the utility due to the exchange of NUG energy has been examined in this chapter. A generalized algorithm, based on a deterministic approach, is developed and discussed. This algorithm can be utilized to accommodate the NUG energy into the utility generation schedule in the optimal manner and can also be utilized to evaluate the AOC. The fee charged by the NUG to the utility is based on the AOC. The application of this algorithm is considered using the IEEE-RTS in the following chapters which also present a range of sensitivity studies.

3. ECONOMIC IMPACT OF NON-UTILITY GENERATION IN A THERMAL POWER SYSTEM

3.1. Introduction

Many regulators and utilities have expressed interest in NUG in order to reduce the overall cost of energy production. Inclusion of NUG energy into a thermal power system gives rise to reliability and economic issues that affect the short term operation planning of the system. The principal difficulty is the process of selecting a suitable technique to assess payments to a NUG which are viewed by both parties as fair and consistent. Financial transactions between NUG and utilities, in the short-term, should be based upon thermal power utility's AOC originating from the energy purchase from NUG. In this chapter, algorithms based on deterministic and probabilistic techniques that can be utilized to evaluate the AOC are developed and results are presented. The AOC will change significantly if its evaluation technique is changed provided all other factors remain the same. Computer programs have been developed to examine the economic implications of NUG on a thermal power system and to evaluate the AOC.

Economic operation of thermal power systems is discussed in the next section in order to make the reader familiar with the thermal power system economic concepts. A distinction between the variable cost and the fixed cost of the thermal power system is made and LaGrange's method to obtain the minimum production cost of the thermal units is illustrated. Evaluation of the AOC is shown in the next section. Both deterministic and probabilistic techniques are illustrated in the evaluation of the AOC. The IEEE-RTS is considered to be a thermal power utility in this chapter, which is utilized to demonstrate the algorithms. Results obtained from the IEEE-RTS studies utilizing the deterministic and the probabilistic techniques are analyzed in this chapter. A comparison of sensitivity studies based on the two techniques is also made.

3.2. Economic Operation of Thermal Power Systems

It is important to understand the economic operation of a thermal power system before dealing with the inclusion of NUG energy into the system. A typical boiler-turbine-generator unit is shown in Figure 3.1.

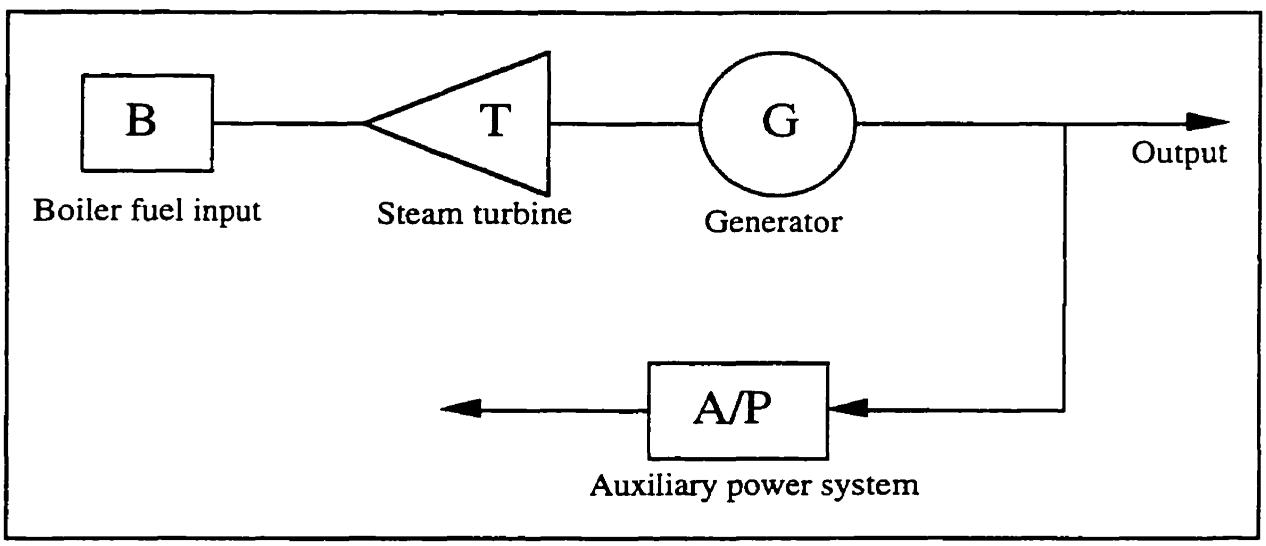


Figure 3.1. Boiler-turbine-generator unit

The problem of providing low cost electrical energy by a thermal utility is affected by efficiencies of power generating equipment, cost of installation and fuel costs. Factors involved in the cost of producing energy can be divided into fixed and variable types [60]. Fixed costs include capital investment, interest charges on borrowed money, labor, taxes and other expenses that continue irrespective of the load on the power system.

Power system operators have little control over these fixed costs. Variable costs are those costs which are affected by loading of different generating units and the control of losses caused by line flows. These costs are controlled by power system operators who try to ensure that power generated to carry the power system load is always produced in such a way that minimum costs will result. The savings that can be achieved by prudent operation can be very significant and may amount to several thousand dollars a day on large power systems. Many thermal power systems have a range of energy sources such as natural gas, oil, coal or nuclear sources with varying costs for each. The load on a power system is also continually changing and, therefore, the economic supply problem must be reviewed frequently and load allocations on the various power sources readjusted so that deviations from the most economic operation will be held to a minimum.

The overall efficiency of thermal units is determined by measuring the heat input and the electrical energy output. The results are expressed as ratios at various loads. The fuel input to the plant is measured in terms of dollar per hour and the output is the electrical power output available to the electric utility system. As the fuel input increases, electrical output also increases but not necessarily linearly [21]. The thermal generating unit outputs, corresponding to minimum production cost, are usually evaluated with the help of incremental cost curves as shown in Figure 3.2. The incremental cost characteristic is the derivative of the input-output characteristic. This characteristic is approximated by a sequence of straight line segments and is utilized in economic load dispatch. The LaGrange multiplier [21, 61-64] method is utilized in this chapter, to find the minimum production cost of the committed thermal units. The minimum production cost occurs when the incremental costs of all the committed units are equal.

An objective function, F_T, is equal to the total cost to satisfy the load. The problem is to minimize F_T subject to the constraint that the sum of the power generated must equal the load. Any transmission losses are neglected and any operating limits are not explicitly stated when formulating this problem.

$$F_T = F_1 + F_2 + F_3 + \ldots\ldots + F_N \tag{3.1}$$

$$F_T = \sum_{i=1}^{N} F_i(P_i) \tag{3.2}$$

where

$F_i =$ running cost of unit i

$P_i =$ output of unit i

$$\phi = 0 = P_R - \sum_{i=1}^{N} P_i \tag{3.3}$$

LaGrange function, $1 = F_T + \lambda\phi$, can be utilized to establish the necessary conditions for a minimum value of the objective function. Taking the partial derivative of the LaGrange function with respect to the power output values one at a time and equating to zero as shown in Equations (3.4) and (3.5).

$$\frac{\partial 1}{\partial P_i} = \frac{dF_i(P_i)}{dP_i} - \lambda = 0 \tag{3.4}$$

$$\frac{dF_i}{dP_i} - \lambda = 0 \tag{3.5}$$

That is, the necessary condition for the existence of a minimum cost-operating condition for the thermal power system is that the incremental cost rates of all the units be equal to some undetermined value, λ, i.e.,

$$\frac{dF_i}{dP_i} = \lambda \tag{3.6}$$

To this equation, a constraint equation that the sum of the power outputs of all committed units must be equal to the load, P_D, has to be added. In addition, two inequalities must be satisfied for each of the units. That is, the power output of each unit, P_i, must be greater than or equal to the minimum power , $P_{i,\min}$, permitted and must also be less than or equal to the maximum power, $P_{i,\max}$, permitted on that particular unit. The equality equation and inequality constraints are shown below.

$$\sum_{i=1}^{N} P_i = P_D \tag{3.7}$$

$$P_{i,\min} \le P_i \le P_{i,\max} \tag{3.8}$$

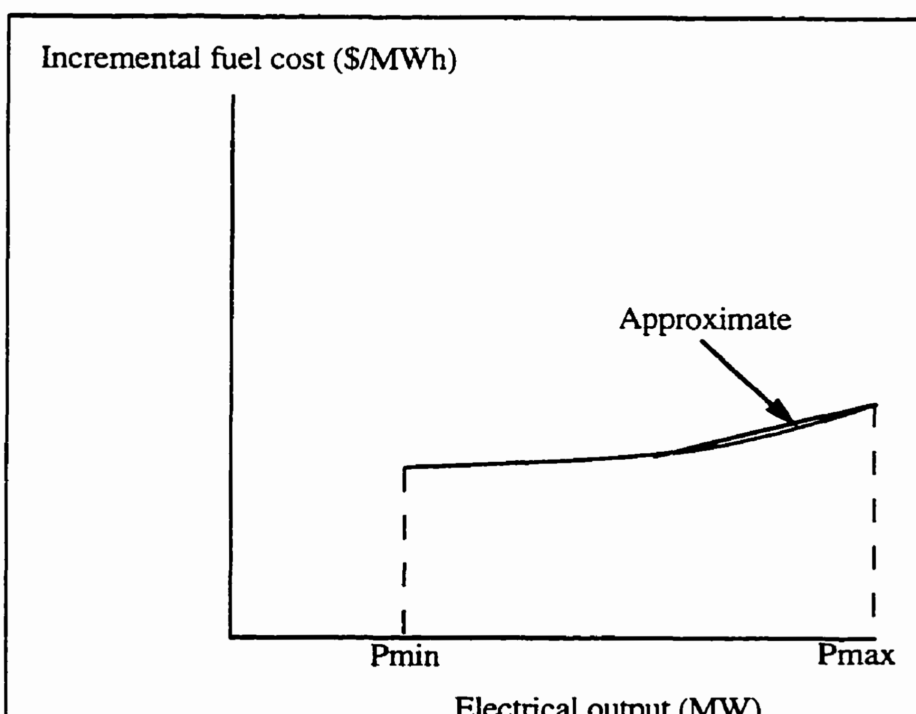


Figure 3.2. Incremental cost characteristics

When we recognize the inequality constraints, then the necessary conditions may be expanded slightly as shown below [26].

$$\frac{dF_i}{dP_i} = \lambda \qquad \text{for } P_{i,\min} < P_i < P_{i,\max} \tag{3.9}$$

$$\frac{dF_i}{dP_i} \le \lambda \qquad \text{for } P_i = P_{i,\max} \tag{3.10}$$

$$\frac{dF_i}{dP_i} \ge \lambda \qquad \text{for } P_i = P_{i,\min} \tag{3.11}$$

3.3. Evaluation of the Avoided Operating Cost

The impact of NUG energy on a thermal power utility can be measured in terms of the AOC. The fee paid by the utility to a NUG in exchange for the electrical energy is based on the AOC. There is, therefore, a need for a suitable algorithm that can be utilized to accommodate the NUG energy into the thermal system in an optimal manner and can also be used to evaluate the AOC. In order to be clear and acceptable to both parties, i.e., utility and NUG, such an algorithm should be simple and straightforward.

Most Canadian utilities utilize deterministic approaches to operate their generating capacity. A survey conducted by the Power System Reliability Subsection of the Canadian Electrical Association in 1983 [15] indicates that most Canadian utilities determine operating reserve requirements based on a "largest contingency" criterion and some utilities complement this reserve assessment technique with a megawatt margin of some form. This method has generally been tailored to suit each system's particular needs. No immediate changes in operating reserve assessment practices were foreseen by any of the utilities which replied to the survey. A deterministically based algorithm is, therefore, developed to evaluate the monetary transactions resulting from energy purchases by a thermal power utility from a NUG. The generalized algorithm discussed in

Section 2.4, can be used to evaluate AOC in a thermal power utility without any modifications.

Chapter 1 notes, that a probabilistic method is more consistent and realistic than a deterministic method. The stochastic nature of a power system can be recognized using probabilistic concepts and, therefore, a probabilistic method has also been developed to assess the AOC in a thermal power system.

The probabilistic algorithm is divided into three sections as in the case of the deterministic algorithm. The first two sections, unit commitment and economic load dispatch, are different and the third section, evaluation of the AOC, is the same for both types of algorithms. In the case of the probabilistic technique, generation units are committed such that a pre-specified unit commitment risk is satisfied. Unit commitment risk is the probability of the committed generation just satisfying or failing to satisfy the expected demand during the lead time. Lead time is the time required to start, synchronize and start load sharing for a particular generating unit and is of the order of 4 to 24 hours for a thermal unit depending upon the size of the unit and the length of time since it last operated. The calculated unit commitment risk must satisfy the pre-specified risk, i.e.,

$$UR^{j} \leq UR^{spec} \tag{3.12}$$

where

UR^{j} = calculated unit commitment risk during hour j

UR^{spec} = pre-specified unit commitment risk

Reliability of a generation system can be improved by increasing the spinning reserve with a corresponding increase in the operating cost. The increased operating cost should be judged against the cost of unserved energy. The selection of a pre-specified unit commitment risk is a managerial decision. A specified unit commitment risk of 0.001 is considered in the thesis. The number of units committed to satisfy a pre-specified risk level should be such that the following expression is satisfied:

$$\sum_{i=1}^{N} CU_{si} \geq P_D^j + R(risk) \tag{3.13}$$

$$\sum_{i=1}^{N} P_{si}^j = P_D^j \tag{3.14}$$

where

$R(risk)$ = probabilistically evaluated spinning reserve

It is assumed in this thesis that due to the non-firm nature of NUG, these sources are not included in the unit commitment process.

Unit commitment does not indicate how the committed units should be dispatched. Economic load dispatch method considers allocation of load to different operating units in order to achieve minimum running cost subject to physical and operational constraints. In the case of a probabilistic approach, both economic and reliability aspects are considered and the type of the spinning reserve is determined on the basis of system response risk. System response risk is defined as the probability of achieving a certain response or regulating margin within the required response time or margin time [2]. The ability to respond to system load changes and to pick-up load on demand depends very much on the type of unit used as spinning reserve. Part of the spinning reserve must be available within a certain margin time to protect system frequency and tie line regulation. These margin times are normally of the order of one minute and five minutes. The actual magnitude of these time periods can, however, vary from system to system. A system may have a large amount of spinning reserve at a particular generation/load condition but the actual responding capability may be quite inadequate for reliable system operation.

The units held as spinning reserve should be capable of picking up load within the specified margin time in the case of a sudden generation loss or an increase in the load. A response risk of 0.001 and a regulating margin requirement of 20 MW in 5 minutes is considered in this chapter.

The objective of the economic load dispatch is to minimize the 24 hour running cost. Minimize $\sum_{j=1}^{24} C_j$ such that the constraints expressed by Equations (3.13) and (3.14) are satisfied for j=1,2,3....,24.

$$P_D^j = \sum_{i=1}^{N} P_{si}^j \qquad (3.15)$$

where

P_D^j = system load during hour j.

The load dispatch should be such that the system has adequate responding capability. The response risk should be equal to or less than a specified level, i.e.,

$$Prob(m,t) \leq Prob^{spec}$$

where

$Prob(m,t)$ = probability of meeting a regulating margin of m MW within a specified margin time of t minutes

$Prob^{spec}$ = specified response risk

Once the unit commitment and economic load dispatch are obtained, the AOC is evaluated. The technique for evaluating the AOC, in the case of probabilistic method, is the same as that in the case of deterministic method, and is illustrated in Chapter 2.

In this chapter, the IEEE-RTS is considered as the utility that buys electrical energy from the NUG. Sensitivity studies were performed on the IEEE-RTS utilizing the deterministic and probabilistic algorithms and results are discussed in the next section.

3.4. System Studies

In order to illustrate the usefulness of the algorithm and provide quantitative analysis, some sensitivity studies have been performed on the test system, IEEE-RTS. The studies, as discussed, should give system planners an insight in the utilization of NUG in short term operational planning. Sensitivity studies based on the deterministic technique are illustrated first followed by studies based on the probabilistic technique. A comparison of sensitivity studies based on both deterministic and probabilistic techniques is also made.

3.4.1. Deterministic Applications

3.4.1.1 Economic benefit to the utility

The economic benefit incurred by a utility due to a purchase of energy from the NUG is illustrated in Figure 3.3. The variation in the cost per unit energy incurred by the utility as a function of the energy supplied by a dispatchable and a non-dispatchable NUG in one day is illustrated in the figure.

Utility original cost is the cost incurred by the utility in 8 hours of the day if it did not buy energy from the NUG to satisfy its load. It is assumed in this study that the NUG sells energy to the utility during 8 hours of the day. Dispatchable and non-dispatchable energies bought from the NUG are accommodated in the utility schedule at different times of the day. Utility original costs for dispatchable and non-dispatchable NUG are, therefore, different. These costs depend upon the load that is served during those hours.

The utility original costs for dispatchable and non-dispatchable NUG energies are $9.55 and $7.46 per unit of energy respectively. It can be observed from Figure 3.3 that costs per unit energy incurred by the utility due to the purchase of dispatchable and non-dispatchable NUG energies are lower than the corresponding original costs and they decrease with an increase in the NUG energy purchased by the utility. This is due to the fact that the expensive utility units are generating less energy due to the purchase of energy from the NUG. The marginal cost of the utility is, therefore, reduced. Utilities

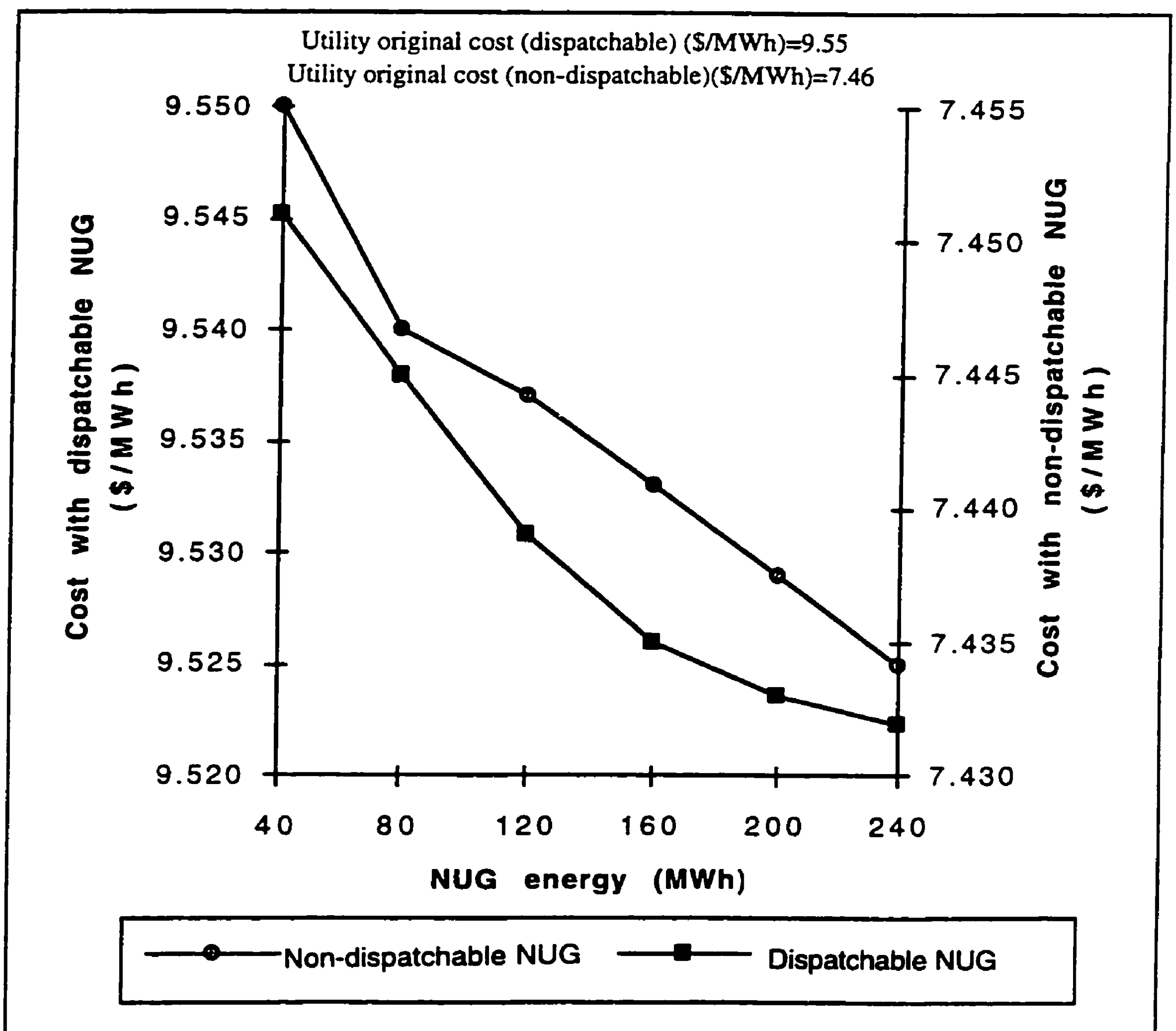


Figure 3.3 Thermal utility economic benefit in $/MWh due to the inclusion of NUG

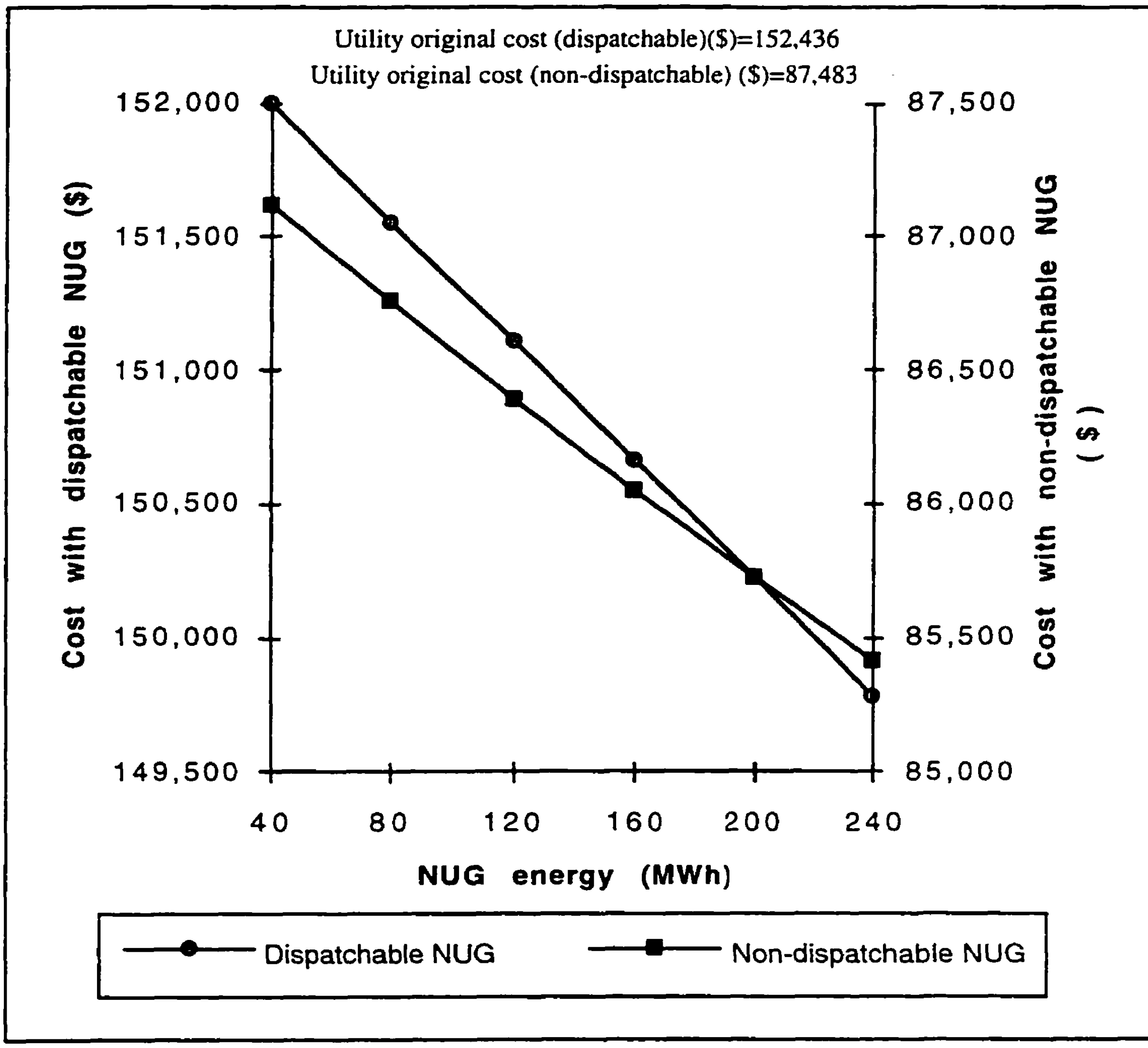


Figure 3.4 Thermal utility economic benefit in $ due to the inclusion of NUG

may incur higher savings in the case of dispatchable NUG than that in the case of non-dispatchable NUG.This is because the utility has a greater flexibility in utilizing the energy purchased from a dispatchable NUG than from a non-dispatchable NUG. Figure 3.4 illustrates the variation in the actual cost incurred by the utility due to a purchase of electrical energy from a NUG in 8 hours of the day. The original costs to the utility are \$152,436.81 and \$87,483.31. It can be observed from Figure 3.4 that the costs incurred by the utility due to a purchase of dispatchable and non-dispatchable energy from the

NUG decrease with an increase in the purchase of the NUG energy. The utility, therefore, achieves greater economic benefits with the purchase of more NUG energy. The slope of the curve for dispatchable NUG is greater than that for non-dispatchable NUG.

3.4.1.2. Economic benefit to the NUG

Economic benefit of dispatchable NUG, β_b^n , can be defined as the difference between the avoided operating costs of the utility when it buys energy from a dispatchable NUG, ψ_d, and when it buys energy from non-dispatchable NUG, ψ_{nd}. Mathematically, it can be defined as

$$\beta_b^n = \psi_d - \psi_{nd} \tag{3.16}$$

The variation in the AOC per unit energy as a function of the energy purchased by the utility in one day from dispatchable and non-dispatchable NUG is illustrated in Figure 3.5. The AOC can be embedded in a complex rate structure for energy exchange between utilities and NUG. It can be observed from Figure 3.5 that the AOC per unit energy decreases with an increase in the energy purchased from dispatchable and a non-dispatchable NUG. This is due to the fact that the utility replaces the NUG energy with energy that has higher marginal cost. As the NUG energy purchased by the utility increases, the marginal cost decreases. The AOC is dependent upon the marginal cost and, therefore, decreases with an increase in the NUG energy. The AOC for dispatchable NUG energy is higher than that for non-dispatchable NUG energy. Figure 3.6 shows the variation in the AOC with a variation in the energy purchased by the utility from the NUG in 8 hours of the day. Both dispatchable and non-dispatchable NUG energies are considered. It can be observed from Figure 3.6 that an increase in the NUG energy causes an increase in AOC. The rate of change in the AOC with an increase in the NUG energy in the case of dispatchable NUG is greater than that in the case of non-dispatchable NUG,

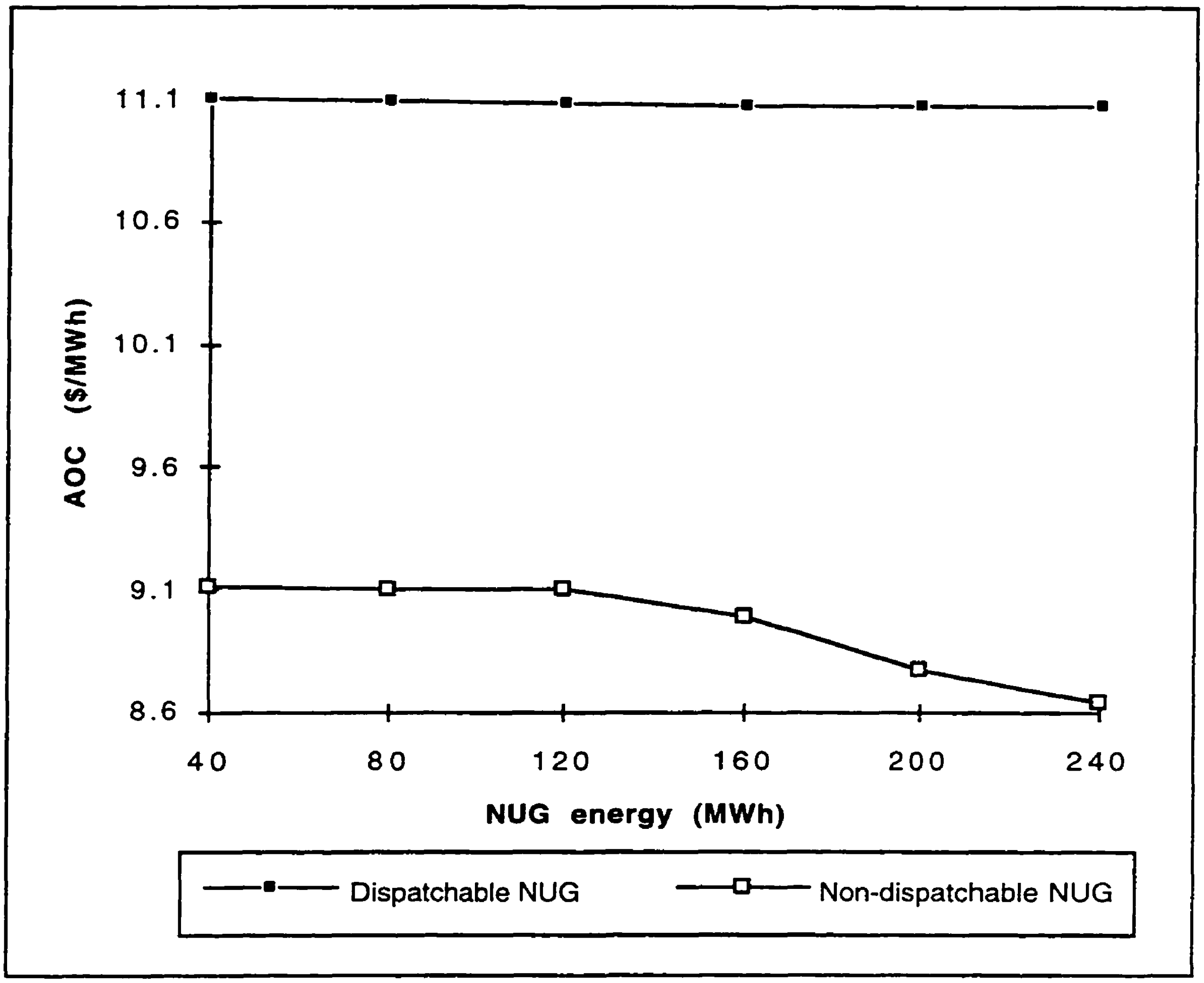


Figure 3.5 AOC per unit of energy comparison for dispatchable and non-dispatchable NUG

which means that the NUG providing dispatchable energy to the utility achieves greater economic benefit than the one providing non-dispatchable energy. It can, thus, be inferred that, in order to achieve higher economic benefits, a NUG should sell dispatchable energy. This may not be possible due to constraints in the NUG host process.

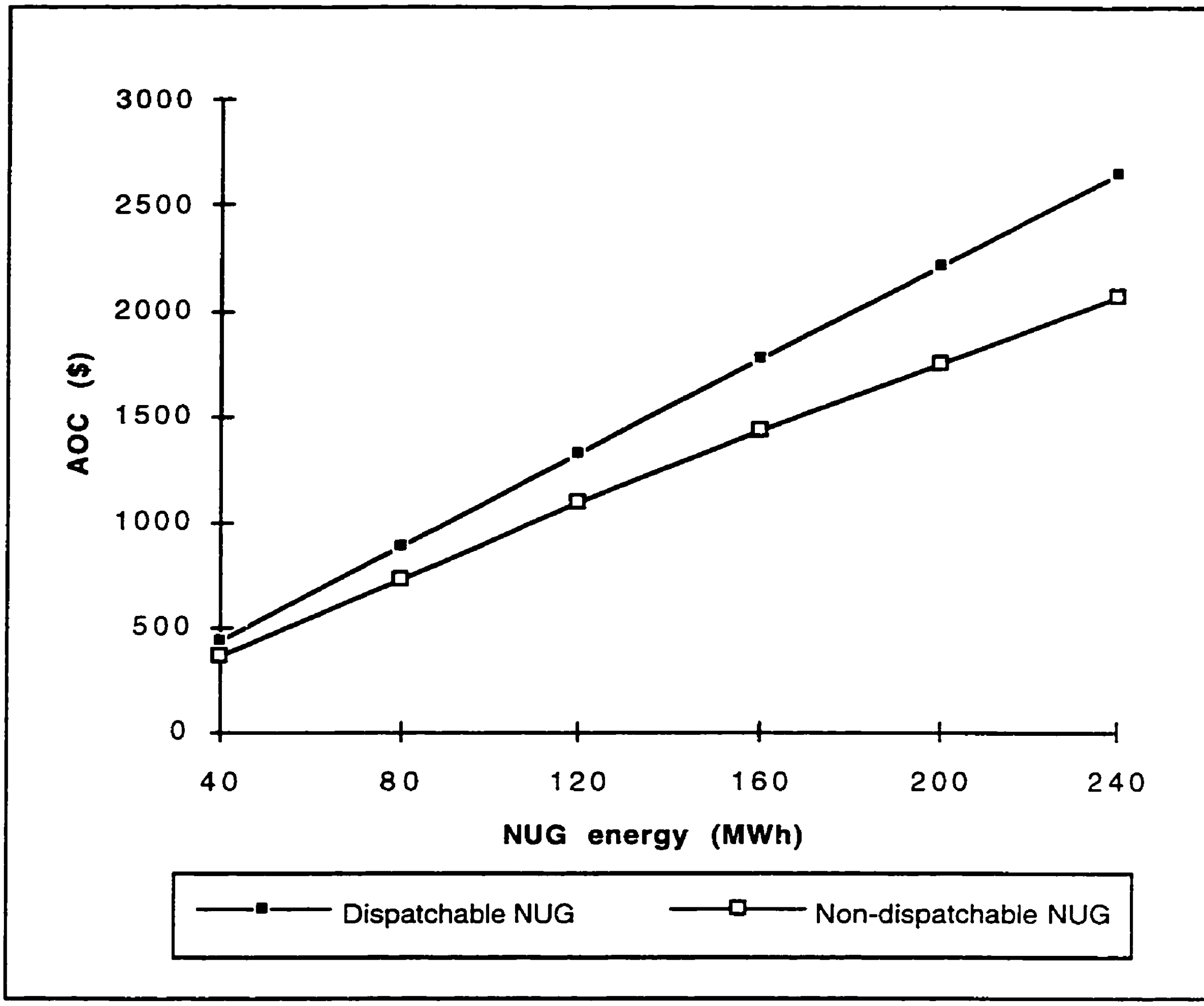


Figure 3.6 AOC comparison for dispatchable and non-dispatchable NUG

3.4.1.3. Time of use of NUG energy by using deterministic technique

The variation in the AOC when a utility buys dispatchable energy from a NUG at the most appropriate 8 hours of the day and the most appropriate hourly period of the day, as a function of the average NUG energy is illustrated in Figure 3.7. The most appropriate hours are those hours in a day (24 hours) for which the inclusion of NUG energy results in the maximum cost savings in utility short term operation. The most appropriate

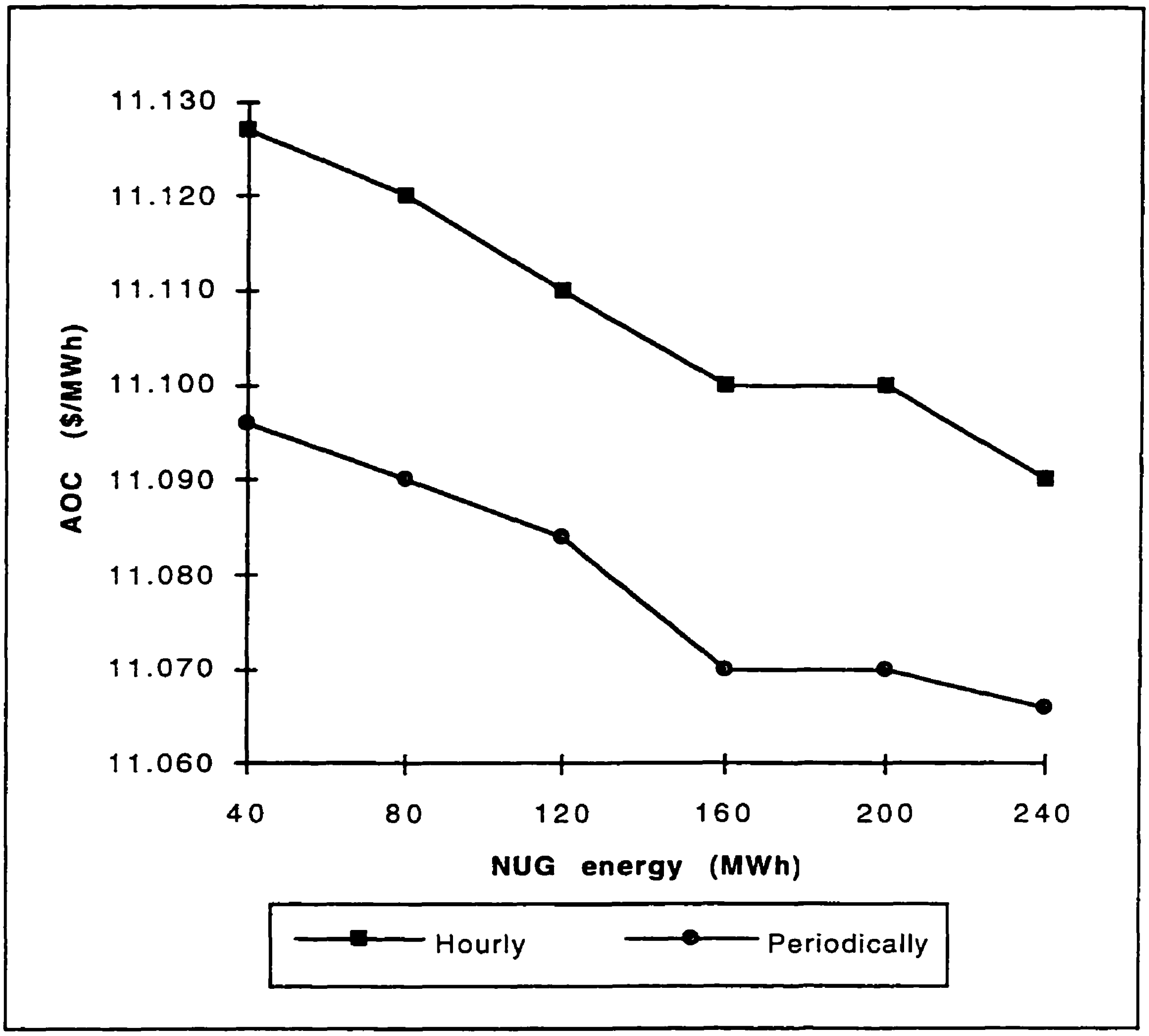


Figure 3.7 Time of use of NUG energy by a thermal utility

period is the contiguous hours in a day (24 hours) during which the inclusion of NUG results in maximum cost savings in the utility short term operation. In this case, a period consists of 8 consecutive hours. It can be observed from Figure 3.7 that the AOC calculated on an hourly basis is higher than the AOC calculated on a contiguous periodic basis. This is due to the fact that when the AOC is calculated periodically the additional constraint that all 8 hours should be consecutive is introduced. The NUG will have higher economic benefit if its energy is dispatched by the utility at the most appropriate hour of the day than at the most appropriate period of the day.

3.4.1.4. Economic impact of NUG energy at different loads

The economic impact of energy generated by NUG at different system load levels is illustrated in Figure 3.8. An increase in the energy sold by NUG to the utility results in an increase in the AOC. The rate of increase in the AOC depends on the number of units committed at each hour and also the loading of each committed unit.

It can be observed from Figure 3.8 that though the AOC increases for all load levels with an increase in the NUG energy, the rate of increase is different for each load level. For loads of 1667 MW and 2137 MW, 16 and 19 units are committed respectively as observed from Table 3.1. The last 5 units, i.e. units 12 to 16 and the last 8 units, i.e. units 12 to 19 are loaded at their minimum permissible outputs for loads of 1667 MW and 2137 MW respectively. Units 1 to 6 are inexpensive compared to other units, therefore, units 7 to 11 are considered for reduction in load in order to accommodate the NUG energy. In the first case, the load is 1667 MW. Units 7 to 11 are carrying less load than in the case where the load is 2137 MW and the marginal energy cost is lower in the first case. The AOC is, therefore, lower in the first case than in the second case. The same units, i.e. units 7 to 11, are considered for reduction in load to adjust the NUG energies from 5 MW to 30 MW. The slopes of the curves (AOC) in Figure 3.8 are, therefore, constant in the two cases provided the NUG energy is small. It can be further observed from Table 3.1 that 12 units are committed for a load of 1368 MW. In this case the last 6 units are loaded at their minimum outputs. The first 4 units are inexpensive compared to other units. Units 5 and 6 are, therefore, available for NUG energy adjustments. The marginal energy costs of these units are less than those in the case of the 2137 MW and 1667 MW loads. The AOCs and the corresponding slopes of the curves are, therefore, lower in this case than in previous cases. Since units 5 and 6 are the only ones that are chosen for NUG energy accommodation for all NUG energy levels, the slope of the curve for 1368 MW load is constant. It can be concluded from the study that AOC depends not only on the amount of NUG energy and time of use of energy but also on the loading of each unit.

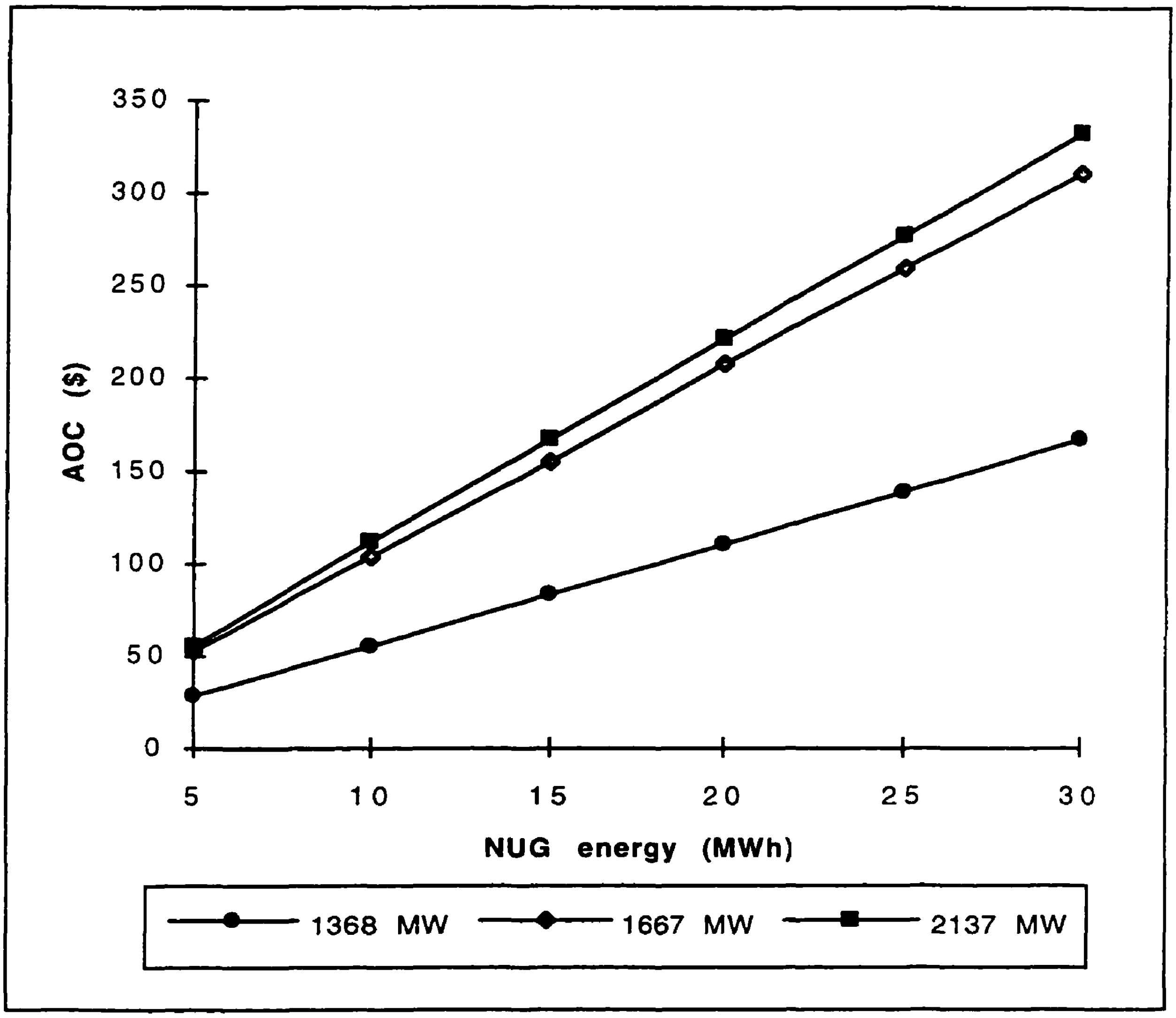


Figure 3.8. Variation of AOC with a variation of NUG energy at different load levels

Table 3.1: Hourly load dispatch (deterministic technique)

	Output of Each Unit in MW							
Unit Numbers (Min.out-Max.out)	1-4 (0-50)	5-6 (200-400)	7 (150-350)	8-11 (60-155)	12-15 (25-76)	16 (40-100)	17-18 (40-100)	19 (80-197)
Load=1368 MW Without NUG	50.00	376.49	150.00	60.00	25.00			
Load=1667 MW Without NUG	50.00	400.00	188.74	84.56	25.00	40.00		
Load=2137 MW Without NUG	50.00	400.00	281.25	138.94	25.00	40.00	40.00	80.00

3.4.1.5. Operating reserve criteria

The economic impact of a NUG depends upon the operating reserve criteria utilized by a utility. Figure 3.9 shows the variation in the AOC per unit of energy and the production cost of the utility as a function of the utility spinning reserve. The spinning reserve is shown as a percentage of the peak load in Figure 3.9. The utility production cost utility is the cost incurred by the utility to satisfy its load without taking any energy from the NUG. It is assumed in this study that the utility purchases 160 MWh of energy from the NUG in one day. It can be observed from Figure 3.9 that the production cost of the utility increases and the AOC decreases with an increase in the required spinning reserve. As the spinning reserve is increased, expensive generating units are put on-line to satisfy the load. The production cost of the utility is, therefore, higher at higher spinning reserve. The expensive units that are committed due to an increase in the spinning reserve, run at their minimum permissible output levels. The NUG energy purchased by the utility is, therefore, accommodated not in these expensive units but in the less expensive units that are not at their minimum permissible output. The marginal costs of these units are lower than the ones that are running at their minimum permissible output.

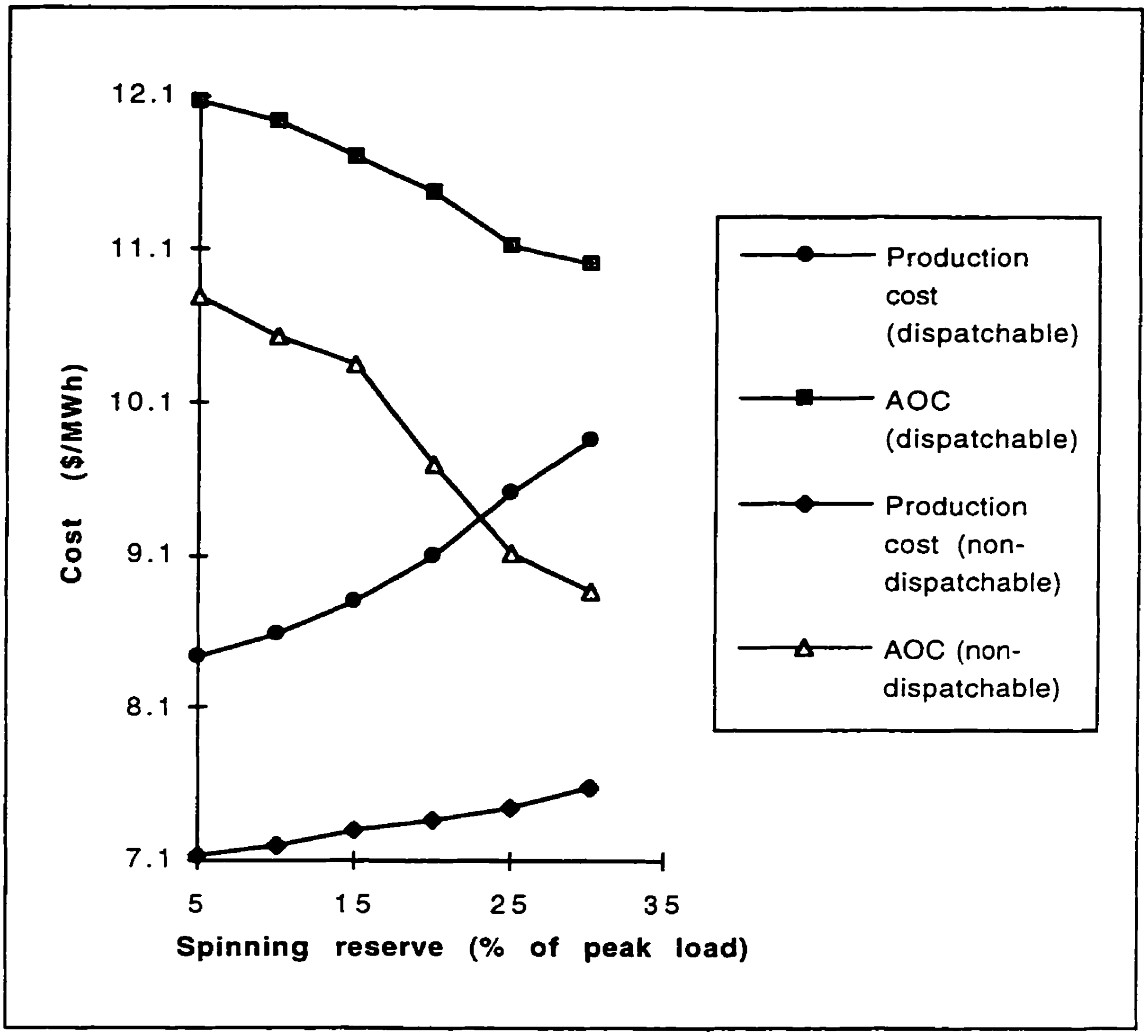


Figure 3.9 Economic impact due to variation in the reserve criteria.

The AOC, which is dependent upon the marginal cost, therefore, decreases with an increase in the spinning reserve.

3.4.1.6. Priority loading order

The economic impact of NUG depends upon the priority loading order of the available generating units. Figure 3.10 shows variations in the AOC and the production cost of a utility as a function of the priority loading order of the utility units. The loading order of the six 50 MW (inexpensive) units are changed in order to illustrate the effect of priority loading order. Priority loading order 1 as shown in the figure represents all six inexpensive units placed at the beginning of the loading order. Priority loading order 2 represents two units at the beginning, two in the middle and two at the end of the loading order. Priority loading order 3 represents four units at the beginning and two at the end of the loading order. Priority loading order 4 represents two units at the beginning and four at the end of the loading order.

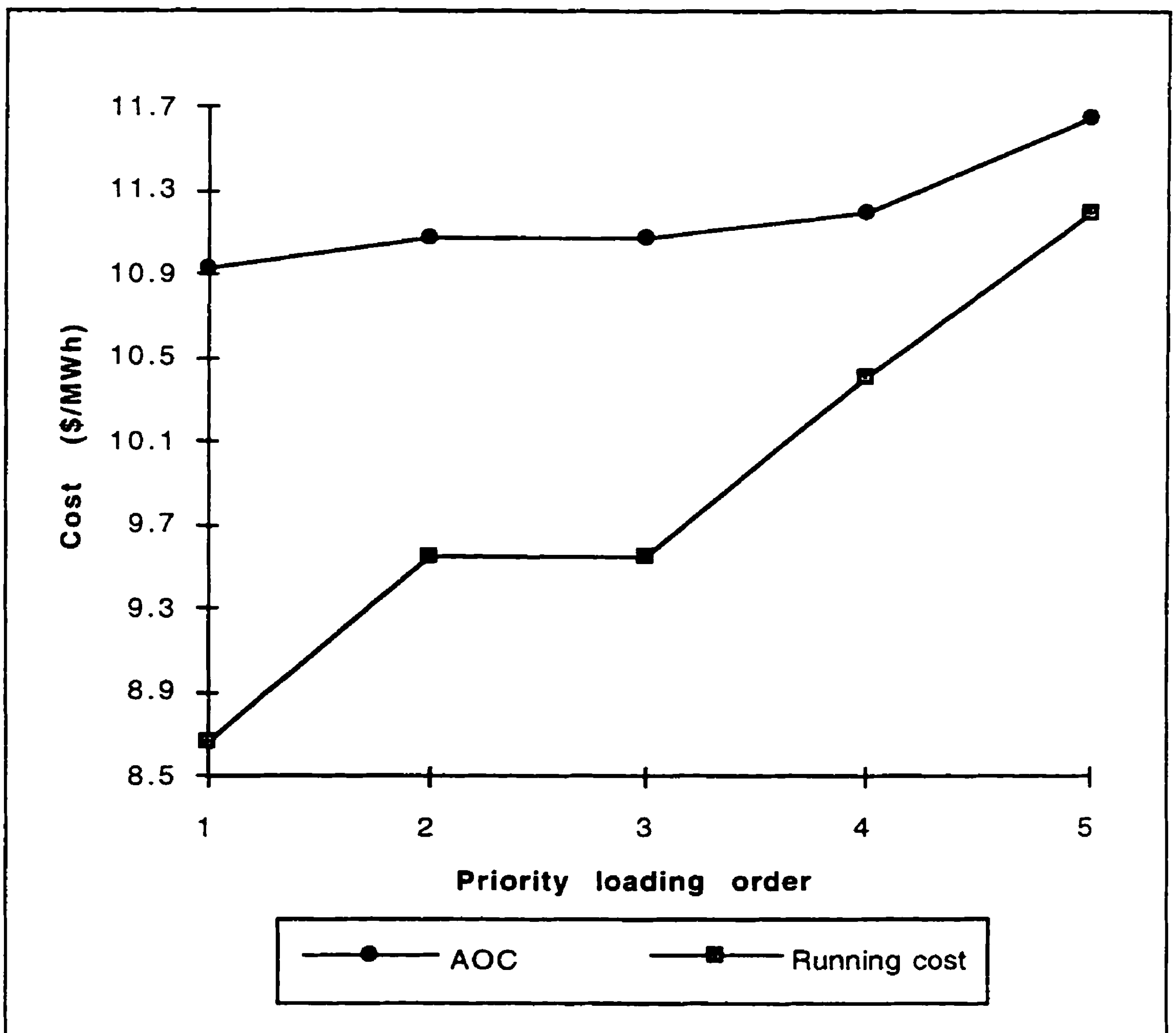


Figure 3.10 Economic impact due to variation in the priority loading order.

All six units are placed at the end of the loading order in priority loading order 5. It can be observed from Figure 3.10 that the AOC and the utility production cost is different for each unit priority loading order. The proper selection of the priority loading order is, therefore, very important for the efficient utilization of the generating units and the correct evaluation of the AOC. The selection of priority loading order is different for different systems. In some systems, the priority loading order selected is usually the one that gives minimum production cost. In this case, the utility production cost is minimum at priority loading order 1. The AOC is also minimum at this loading order. Some utilities maintain minimum response capability while keeping the cost low. The loading order in this case will be different from that used in the minimum production case.

3.4.1.7. Cost of NUG energy

It is assumed in this study that the costs incurred to produce 1 MWh of energy by some NUGs varies from \$ 8.5 to \$ 11.5. If the IEEE-RTS purchases energy from these NUG, only a few NUG will achieve economic benefit by selling energy to the IEEE-RTS. Figure 3.11 shows the variation in the AOC and the running cost of the NUG as a function of the NUG energy cost per unit of energy. The maximum costs at which a NUG achieves economic benefit are \$ 11.1 per MWh for a dispatchable NUG and \$ 8.98 per MWh for a non-dispatchable NUG. If the costs at which a NUG produces electrical energy are higher than these values then they have less return from the utility. The figure also shows the difference between the NUG costs of producing dispatchable energy and non-dispatchable energy. The NUG has a higher flexibility, regarding cost, in the case of dispatchable energy than in the case of non-dispatchable energy.

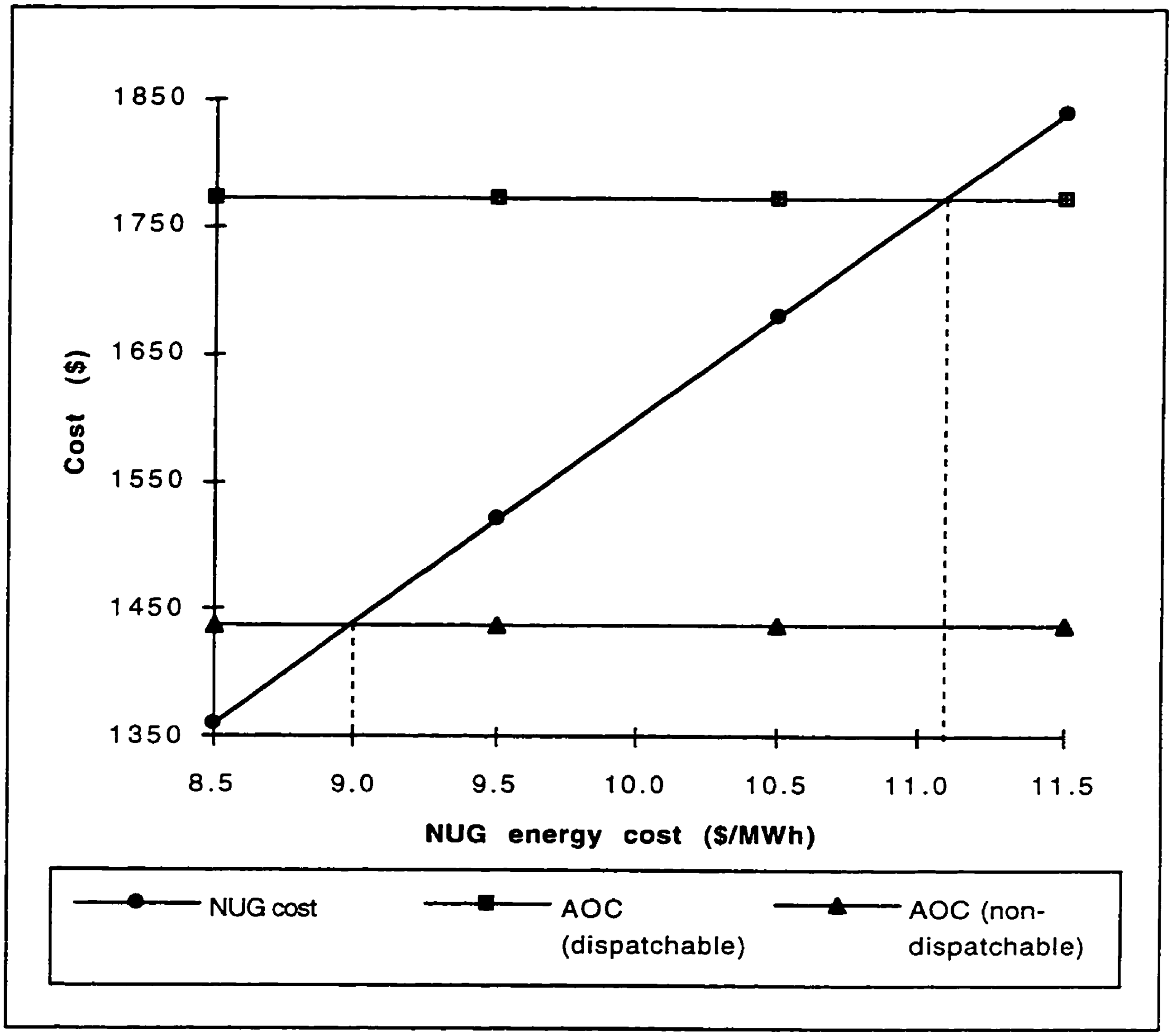


Figure 3.11 Energy cost of dispatchable and non-dispatchable NUGs.

3.4.2. Probabilistic Applications

3.4.2.1 Energy cost of NUG

A study was performed to show that the minimum cost at which NUG should produce energy to sell to the utility can be easily found. Figure 3.12 shows the variation in the AOC for dispatchable and non-dispatchable NUG energies and an assumed cost curve as a function of the NUG cost per unit of energy. It can be observed from Figure 3.12 that the maximum costs at which a NUG should generate electrical energy should be $12.02 for a dispatchable energy and $ 11.1 for a non-dispatchable energy. These values can be designated as threshold values. In order to achieve savings, the production cost of NUG should be lower than the threshold value. The AOC is higher than the NUG production cost for NUG energy costs lower than the threshold value.

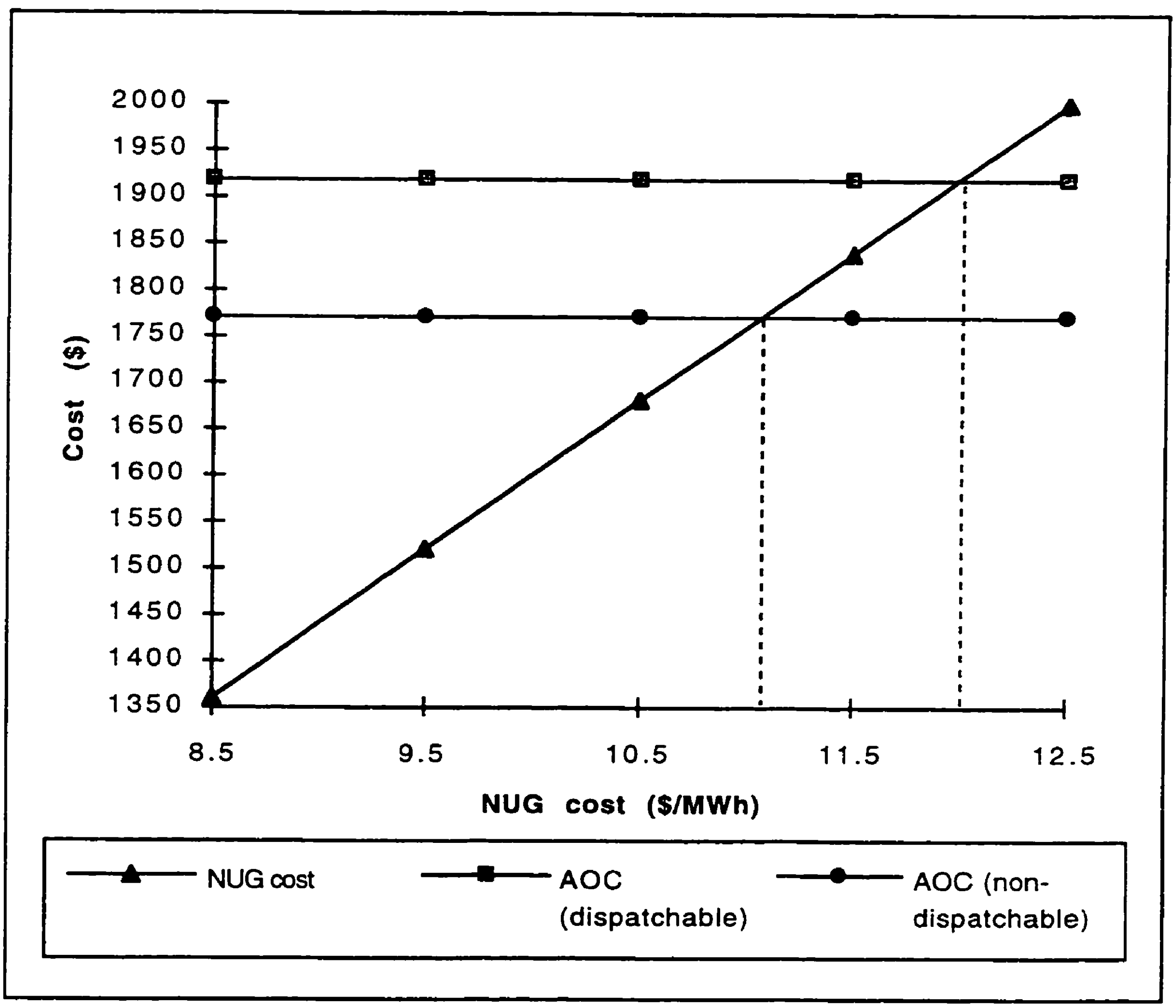


Figure 3.12. Cost estimates for NUG energy.

3.4.2.2. Utility running cost and NUG energy

The economic benefit achieved by the utility due to purchases of electrical energy from dispatchable and non-dispatchable NUG is illustrated in Figure 3.13. The variation in cost incurred by the utility due to purchases made by the utility from dispatchable and non-dispatchable NUG as a function of the NUG energy are shown. It can be observed that an increase in the NUG energy causes a decrease in the utility running cost.

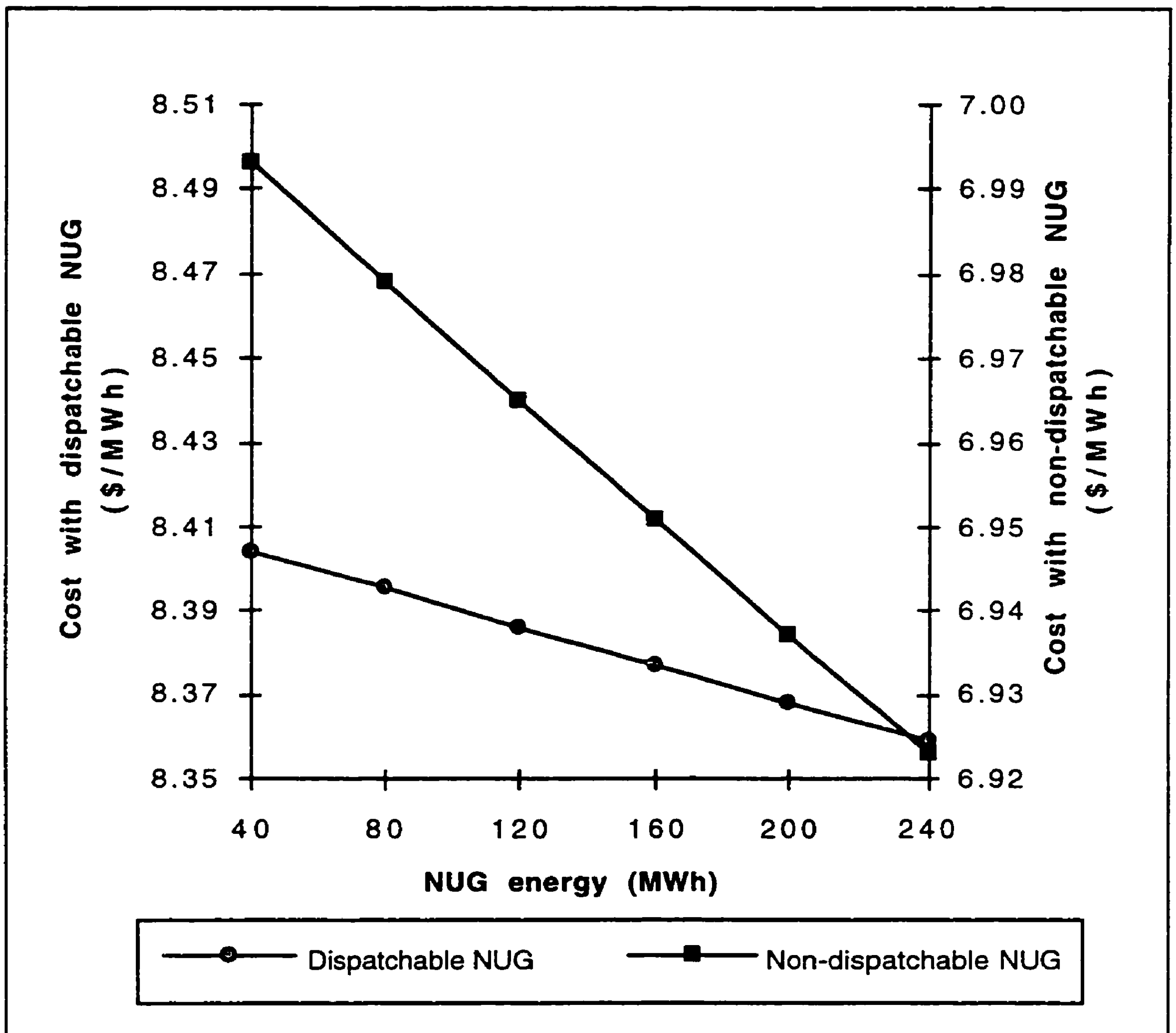


Figure 3.13. Utility running cost per unit of energy comparison.

This is due to the fact that the utility accommodates the NUG energy by replacement of the most expensive units. It can be further observed that the utility incurs a higher running cost when it buys energy from the dispatchable NUG. Figure 3.14 illustrates a decrease in the utility cost due to dispatchable and non-dispatchable NUGs with an increase in the NUG energy. It is, therefore, economically beneficial for the utility to purchase energy from a dispatchable NUG than from a non-dispatchable NUG.

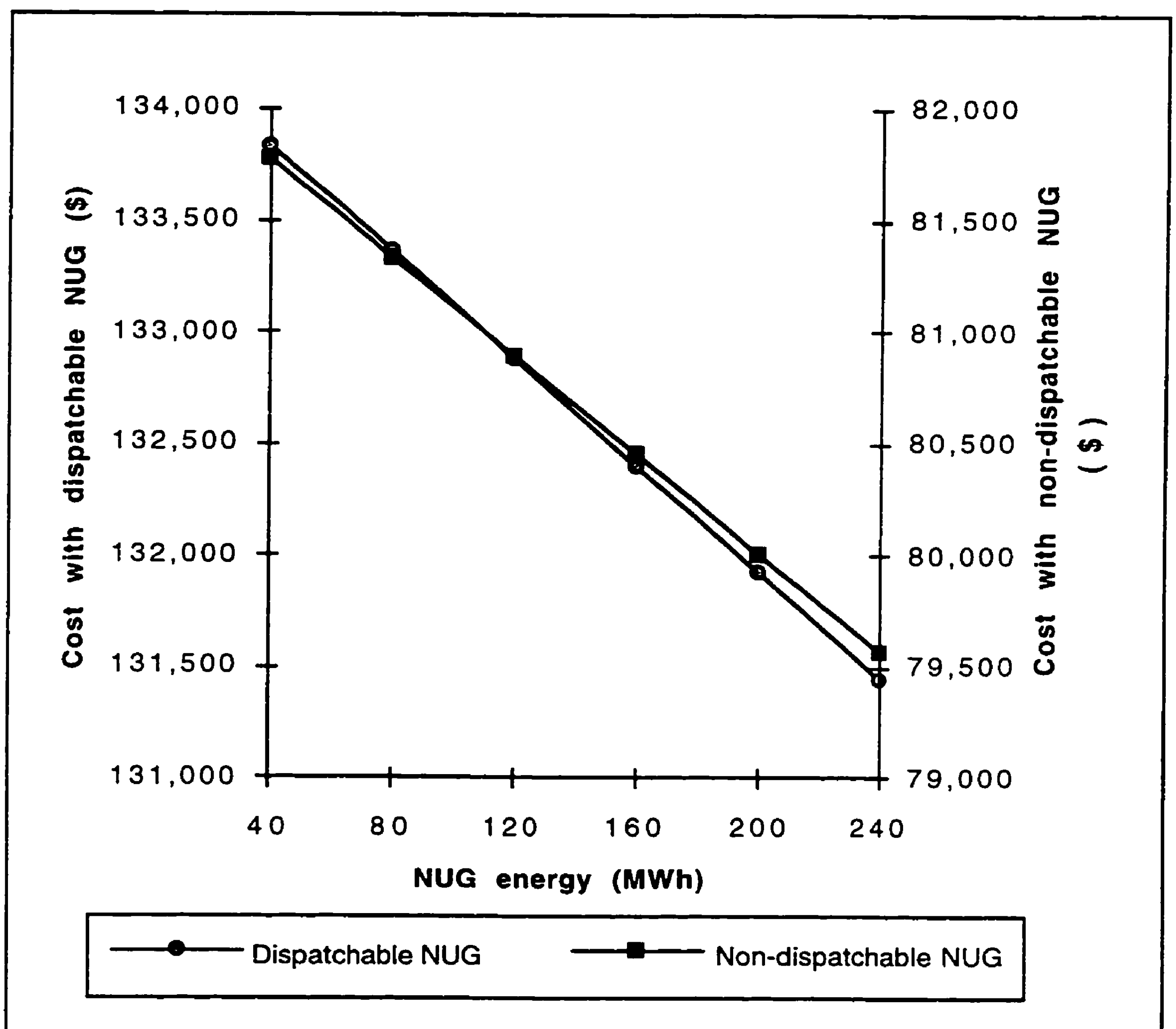


Figure 3.14. Utility running cost comparison.

3.4.2.3. Avoided Operating Cost and NUG energy

A comparison of the AOC of a utility evaluated due to dispatchable and non-dispatchable NUG energy in short term operation planning is shown in Figures 3.15 and 3.16. The AOC varies as a function of the energy purchased by the utility from NUG in one day. It can be observed from Figure 3.15 that as the energy sold by the NUG increases, the AOC per unit of energy from the dispatchable and non-dispatchable NUGs

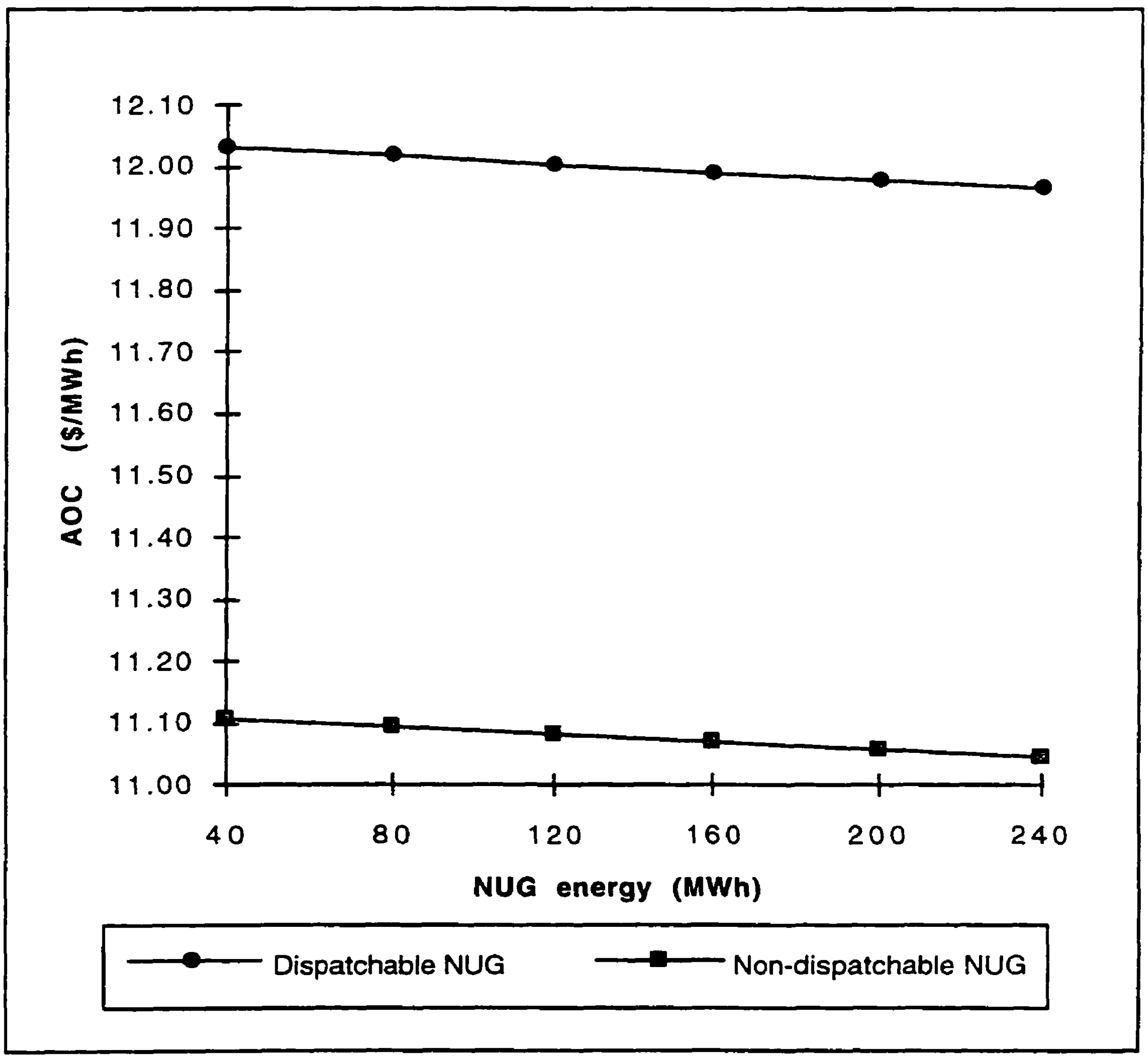


Figure 3.15. AOC per unit of energy comparison.

decreases. This is due to the fact that when the energy purchased by the utility increases, this increase in the NUG energy is accommodated by the utility's generating units with low marginal cost. The AOC which depends upon the marginal cost, therefore, decreases with an increase in the NUG energy. The daily AOC in both cases increase with increase in the NUG energy as shown in Figure 3.16. In the case of dispatchable NUG, the AOC increases at a higher rate than in the case of non-dispatchable NUG. It is, therefore, beneficial for the NUG to sell dispatchable energy to the utility.

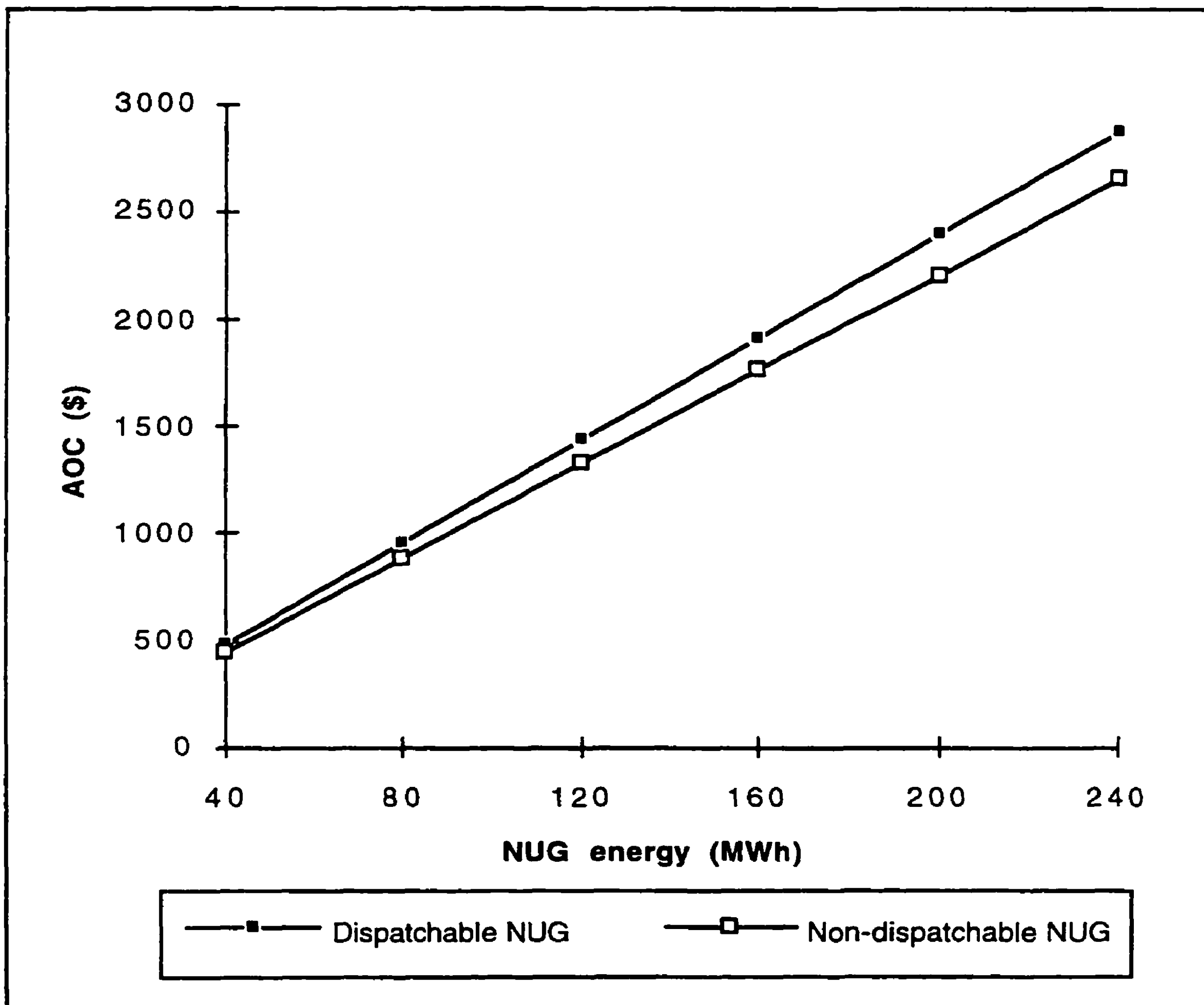


Figure 3.16. AOC comparison of dispatchable and non-dispatchable NUG

3.4.2.4 Time of use of NUG energy by using probabilistic technique

The hourly operating cost of a utility varies from one hour to another and the incremental operating cost varies from peak load to low load periods. Due to these variations, the AOC of a utility also varies throughout a day for a given NUG energy. Figure 3.17 shows the variation in the AOC as a function of the energy sold by a NUG in one day. It is assumed that this energy is equally distributed over 8 hours of the day.

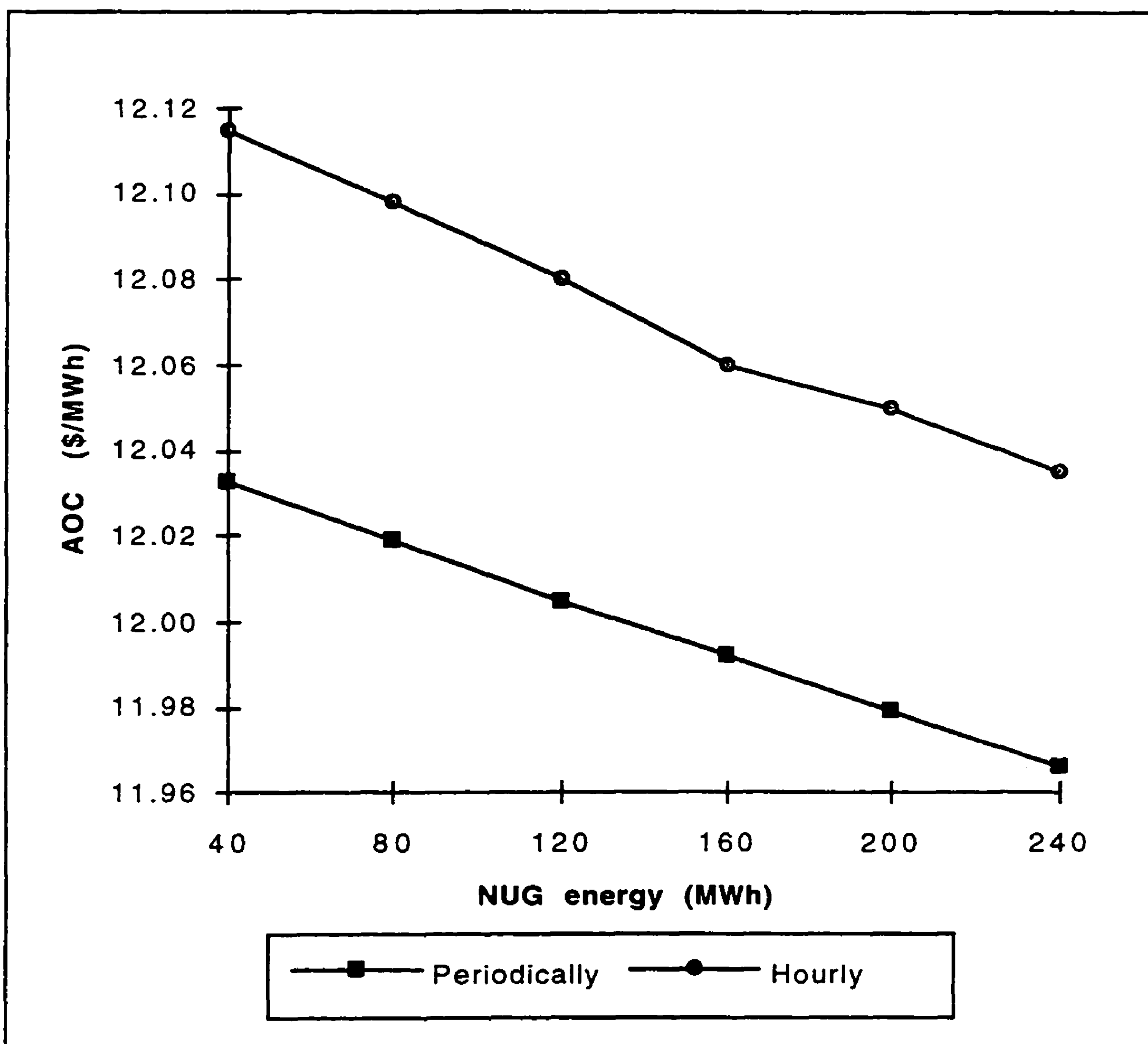


Figure 3.17. Variation of AOC for different loading schedules.

The variations in the AOC when the utility buys energy from the NUG at the most appropriate 8 hours of the day and the most appropriate 8 hour period of the day with variation of NUG energy are illustrated in Figure 3.17. In the case of a NUG energy purchase during the most appropriate 8 hours of the day, the AOC is higher than that of the purchase during the most appropriate 8 hour period of the day. This is due to the fact that there is an additional constraint added in the second case. A NUG which is flexible enough to provide energy to a utility at those times when the utility needs it the most, provides more economic benefit to the utility than one that provides energy over a period. In order to provide energy during the most appropriate hours of the day, a NUG is required to follow a prescribed loading cycle. Due to operational limitations, some NUGs may not be able to follow schedules requiring multiple loading and unloading during a day.

3.4.2.5. Avoided operating cost and unit commitment risk

Unit commitment risk in a system can be lowered by increasing the spinning capacity provided all other factors remain the same. Spinning reserve requirements and operating cost in a system increase as a direct consequence of lowering the specified system unit commitment risk. The cost of maintaining a certain risk level should be judged against the worth of maintaining that level. The selection of an acceptable risk level is, therefore, a management decision. Once a risk level is selected, sufficient generation should be scheduled to satisfy the risk criterion. Figure 3.18 shows the variation in the AOC and the utility running cost (UC) as the unit commitment risk is changed from 0.0001 to 0.002. Figure 3.18 shows that the AOC increases as the unit commitment risk increases. The running cost of the utility decreases as the unit commitment risk increases. The difference in the utility running cost without and with NUG increases with increase in the unit commitment risk. At a given system condition, the load is distributed to a smaller number of units when the unit commitment risk is increased. The marginal operating cost of a system usually increases as the unit commitment risk decreases. This may not be the case when NUG energy is considered. This can be seen by considering a particular hour and evaluating the AOC at different risks. Hour 18, which has a load of 2137 MW, and risks of 0.0001 and 0.002 are considered. NUG energy of 20 MW is considered to be included at this hour.

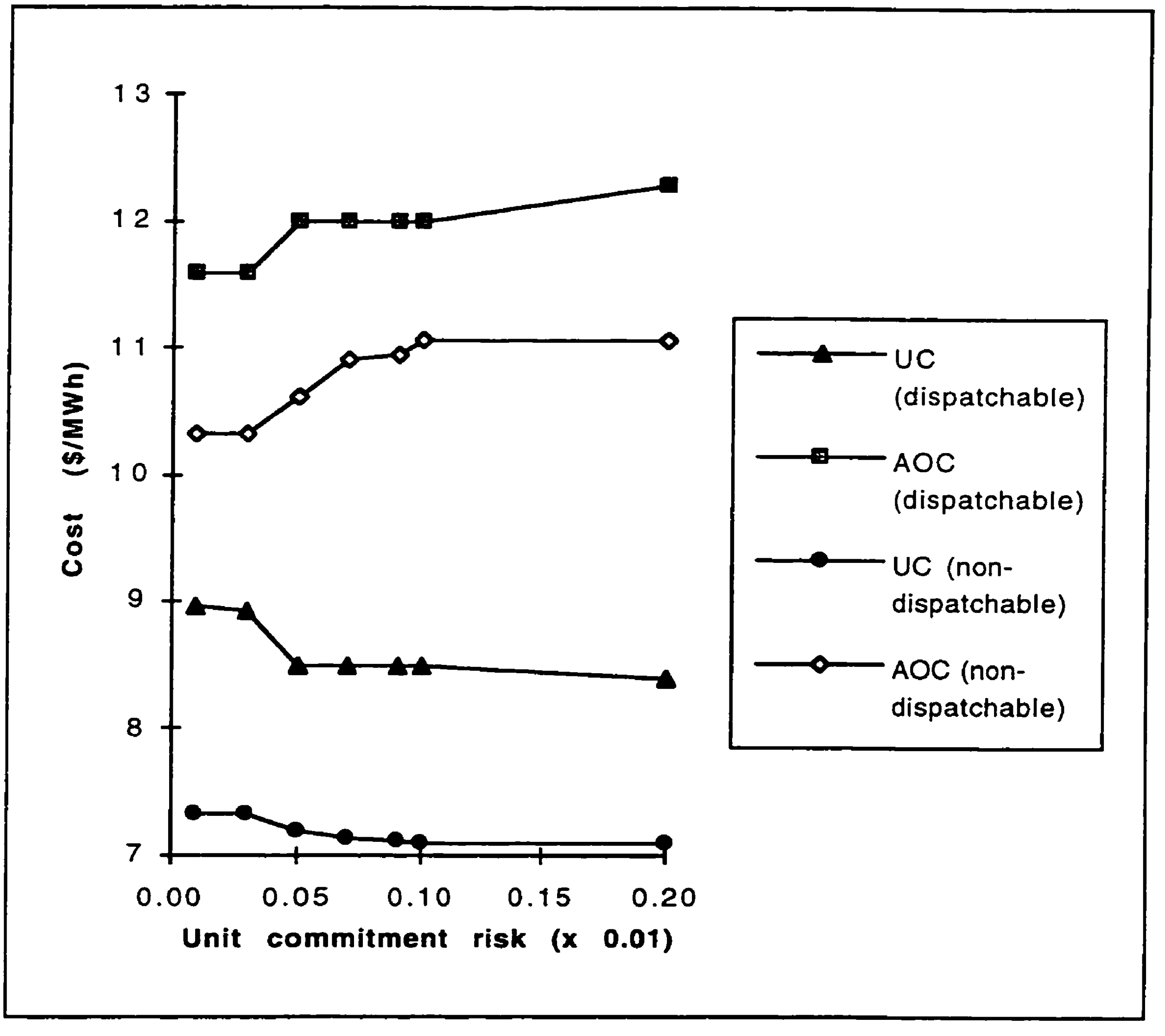


Figure 3.18 Variation of AOC with variation of unit commitment risk

It can be observed from Table 3.2 that the number of units committed to satisfy a given load decreases with increase in the unit commitment risk (R_{spec}). The loading of each unit is shown in the table. The first six units are loaded at their maximum output for all risk levels. A total of 18 units are committed when the unit commitment risk is 0.0001. The last seven committed units, i.e., unit 12 to unit 18, are loaded at their minimum permissible output. The output of units 7 to 11, therefore, are most likely to be reduced in order to accommodate the NUG energy. When the unit commitment risk is 0.002, 14 units are committed to satisfy the load. In order to accommodate the NUG energy, the output of units 12 to 14 are most likely to be reduced. In this case (R_{spec}=0.002), units 12 to 14 are carrying more load than that in the previous case (R_{spec}=0.0001), and, therefore, the marginal cost is higher in this case. The marginal cost, thus, increases with an increase in the unit commitment risk and the AOC is higher. The AOC, therefore, increases when the unit commitment risk changes from 0.0001 to 0.002.

Table 3.2: Hourly load dispatch (probabilistic technique)

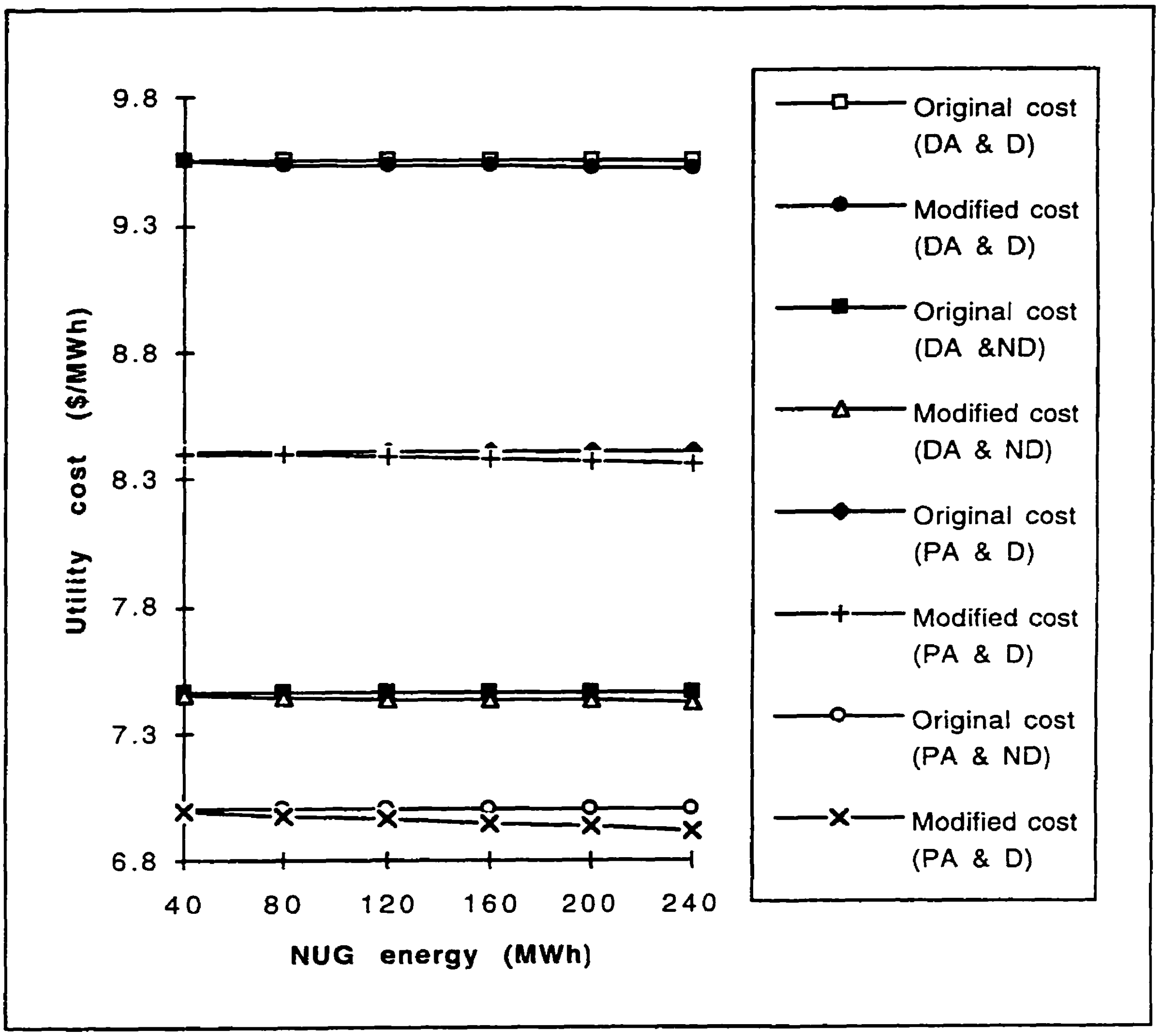
	Output of Each Unit in MW							Avoided Operating Cost
Unit Numbers (Min.out-Max.out)	1-4 (0-50)	5-6 (200-400)	7 (150-350)	8-11 (60-155)	12-14 (25-76)	15 (25-76)	16-18 (40-100)	
Rspec = 0.0001								
Without NUG	50.00	400.00	305.13	152.97	25.00	25.00	40.00	225.76
With NUG	50.00	400.00	299.16	149.46	25.00	25.00	40.00	
Rspec = 0.002								
Without NUG	50.00	400.00	350.00	155.00	55.67			273.66
With NUG	50.00	400.00	350.00	155.00	49.00			

If the risk level is lowered, units with progressively higher running costs are loaded at their minimum permissible level and their outputs cannot be reduced due to NUG inclusion. The output of the economic units are, therefore, reduced to accommodate the NUG energy. These units have smaller marginal costs compared to the additional units required to lower the unit commitment risk. The AOC, therefore, increases with an increase in the unit commitment risk.

3.4.3. Comparison of Deterministic and Probabilistic Applications

3.4.3.1. Economic benefit to the utility

The objective of a utility is to minimize the total cost of supplying the system energy requirements at an acceptable level of reliability. The total cost depends upon the capital cost and the utility running cost which includes the fuel cost. By integrating NUG energy in its grid, a utility achieves economic benefit through savings in fuel costs. Figure 3.19 shows the economic benefits incurred by a utility utilizing both deterministic (DA) and the probabilistic (PA) approaches. The variation in the cost per MWh incurred by the utility as a function of the average NUG energy supplied to the utility, while keeping other parameters constant, is illustrated in Figure 3.19. It can be observed from the figure that the running cost of the utility is higher if it did not buy energy from the NUG (original cost) than if it bought energy from the NUG.(modified cost.). The utility modified cost decreases gradually with an increase in the amount of NUG energy purchased by the utility. The savings increase with an increase in the energy that the NUG sells to the utility in both cases of dispatchable (D) and non-dispatchable (ND) NUG energy. The economic benefit to the utility, in general, increases with an increase in the energy. It can be further observed from Figure 3.19 that the results obtained by utilizing the deterministic approach have higher values than those obtained utilizing the probabilistic approach. This is due to the fact that the spinning reserve specified in the



DA= Deterministic approach

PA = Probabilistic approach

D = Dispatchable NUG energy

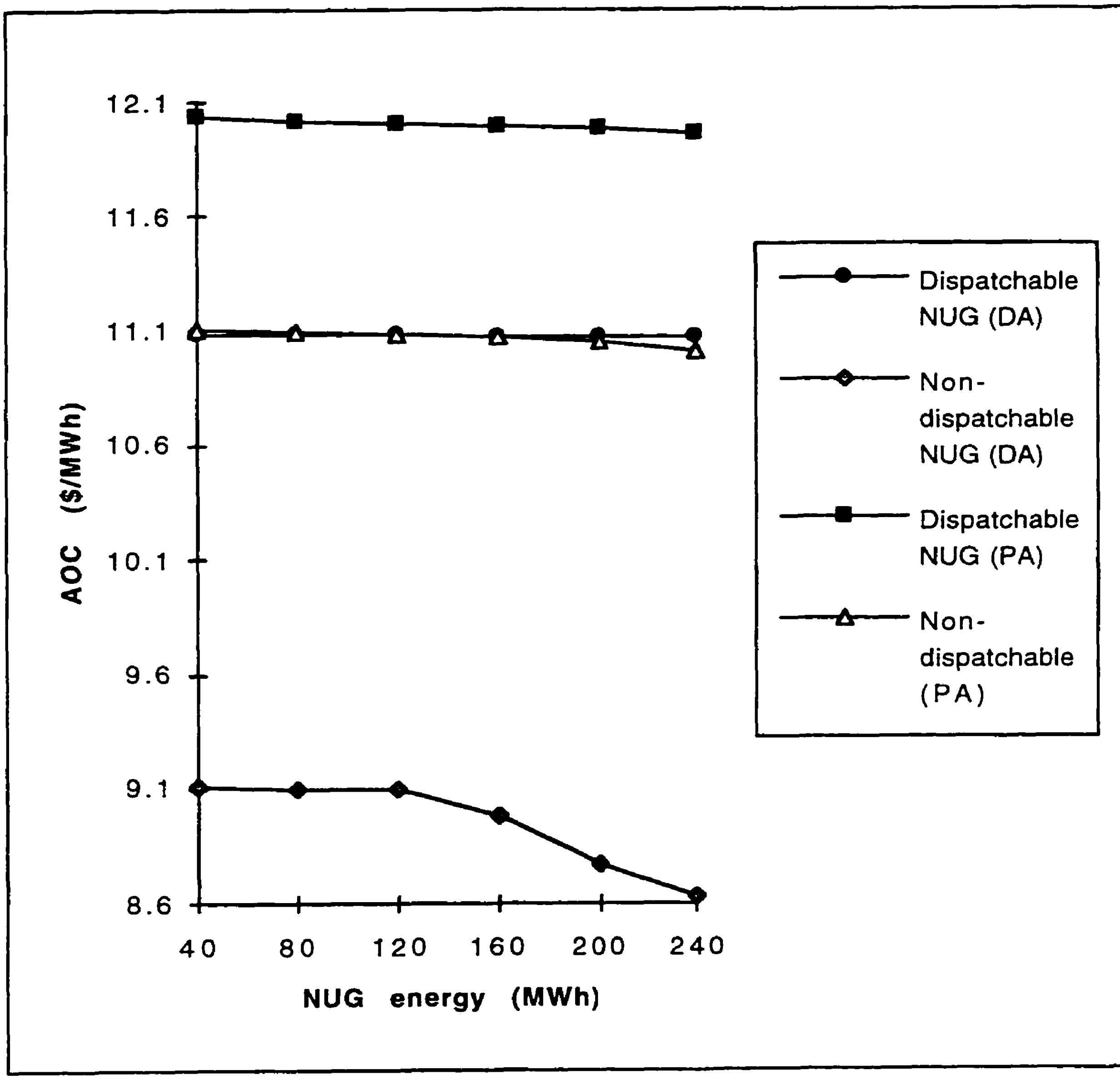
ND = Non-dispatchable NUG energy

Figure 3.19. Utility economic benefit due to the inclusion of NUG

case of the deterministic approach is higher than that dictated by the unit commitment risk. A larger number of units are committed and hence the fuel cost is higher in the deterministic approach. The savings in terms of the difference between the original and the modified costs are, however, greater in the case of the probabilistic approach than in the case of the deterministic approach.

3.4.3.2. Economic benefit of dispatchable NUG

The variation in the AOC per MWh as a function of the average NUG energy supplied to the utility in the case of dispatchable and non-dispatchable NUG is illustrated in Figure 3.20. The deterministic (DA) and probabilistic (PA) approaches have been utilized in the evaluation of AOCs in this figure. In both cases of dispatchable and non-dispatchable NUG energy, the AOC per unit of energy decreases with an increase in energy that a utility purchases from the NUG. This is due to the fact that the marginal cost of the utility unit decreases as the load on the unit decreases. The AOC is dependent upon the marginal cost of the utility. The load on the utility unit decreases with an increase in the purchase of NUG energy which results in a decrease in the marginal cost and hence the AOC decreases. It can be further observed from Figure 3.20 that the results obtained by utilizing the probabilistic approach are higher than that obtained by utilizing the deterministic approach. These values depend upon the spinning reserve, unit commitment risk and response risk. In the case of the deterministic approach, the specified spinning reserve is higher than that in the probabilistic approach. A larger number of units are, therefore, committed in the deterministic approach. The last units with higher marginal costs, in the case of the deterministic approach, are loaded at their minimum permissible outputs and therefore these units are not disturbed to accommodate the NUG energy. The units with lower marginal costs are used to accommodate the NUG energy. In the probabilistic approach, the last units are not loaded at their minimum



DA= Deterministic approach

PA = Probabilistic approach

Figure 3.20. AOC of dispatchable and non dispatchable NUG

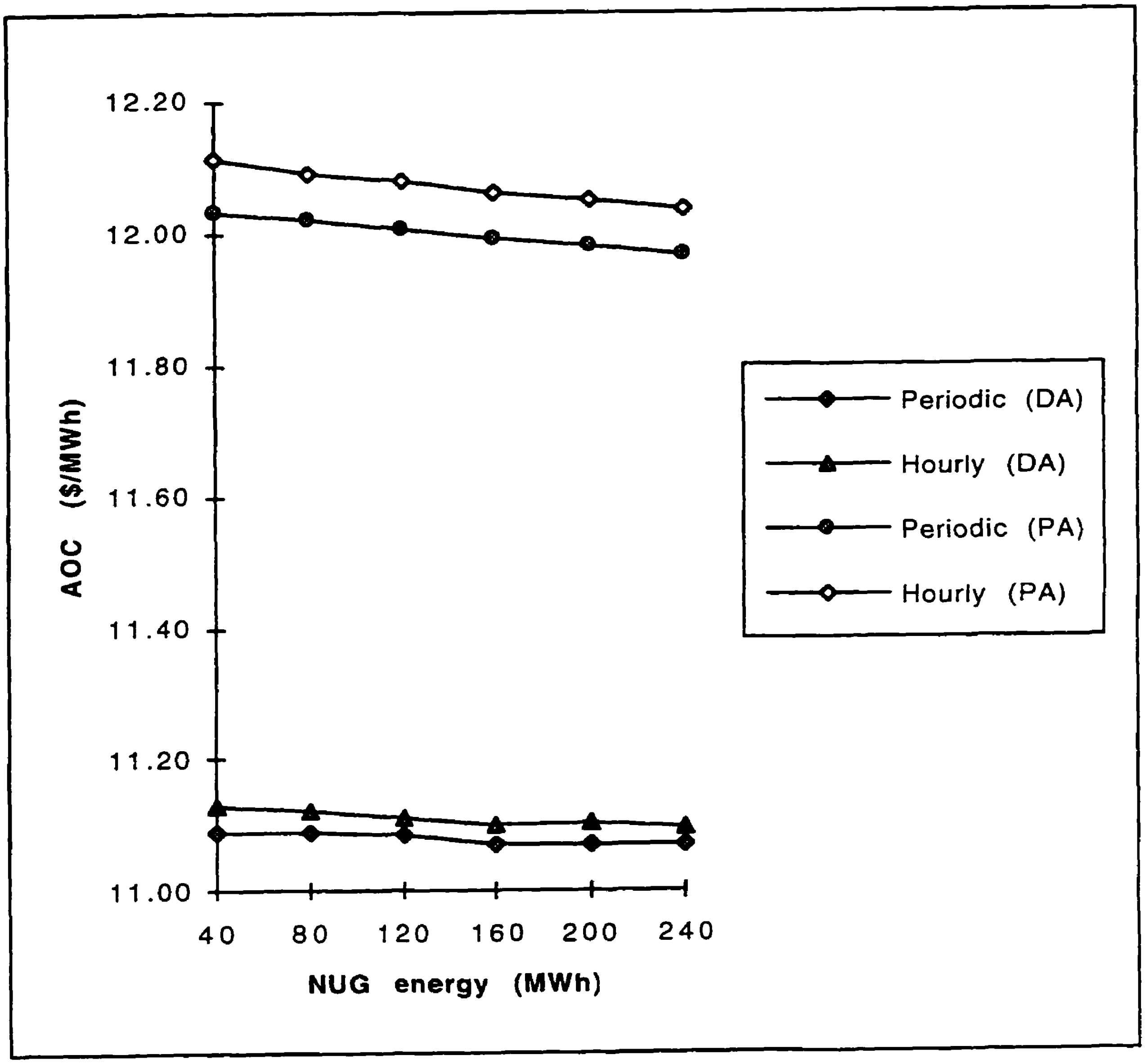
permissible limits and, therefore, these units are used for adjusting NUG energy. These units have higher marginal cost than those that are used to accommodate NUG energy in the deterministic approach. The AOCs are, therefore, higher in the case of probabilistic approach than for the deterministic approach.

3.4.3.3. Time of use of the NUG energy

As previously noted, the hourly utility operating cost varies from one hour to another and the incremental operating cost varies from peak load to low load periods. Due to these variations, the AOC of a utility varies throughout a day for a given NUG energy. Figure 3.21 shows the variation in the AOC as a function of the energy sold by the NUG in 8 hours utilizing both deterministic (DA) and probabilistic (PA) approaches. The variation in the AOC, when a utility buys energy from NUG at the most appropriate 8 hours of the day and the most appropriate 8 hour period of the day with the variation of NUG energy, is illustrated in Figure 3.21. In the case of energy purchased during the most appropriate hours of the day, the AOC is higher than that purchased during the most appropriate 8 hour period of the day due to the fact that there is an additional constraint added in the second case. A NUG which is sufficiently flexible to provide energy at times when the utility need it most receives more economic benefit than one that provides energy on a period basis. The results obtained utilizing the probabilistic approach are higher than those obtained utilizing the deterministic approach.

3.5. Summary

A thermal power system planner faces the difficult task of determining the most appropriate buyback rate to pay to the NUG in exchange for the energy received from the NUG. This rate should be based on the AOC. Two algorithms for evaluating the AOC utilizing deterministic and probabilistic techniques are illustrated in this chapter. These



DA= Deterministic approach

PA = Probabilistic approach

Figure 3.21. AOC as a function of time of the day.

algorithms can be utilized by a utility to analyze some of the economic issues related to the inclusion of NUG in short term operational planning. A time differentiated pricing system is adopted in both algorithms to reflect the different utility purchase price at different times of the day. The two algorithms show the effect of dispatchable and non-dispatchable NUG energies.

The IEEE-RTS has been utilized to illustrate the applicability of these algorithms. Studies were performed to determine the amount of energy and the time period during which utilities and NUG can maximize their economic benefits. They also illustrate the cost at which a NUG should generate energy to sell to a utility in order to obtain economic benefit. The results indicate that for both deterministic and probabilistic approaches, the running costs incurred by the utility without NUG are higher than that with NUG and the AOC for dispatchable NUG is higher than for non-dispatchable NUG. The studies also show that the AOC increases with an increase in the unit commitment risk. A comparison is made between the AOCs evaluated utilizing deterministic and probabilistic methods. The results show that the AOC depends upon the operating practices used by a utility and are different when evaluated utilizing the two approaches. The two algorithms discussed in this chapter can be utilized by a utility to make financial decisions regarding NUG. Studies similar to those illustrated in this chapter will enable a system planner to appreciate the economic implications associated with NUG purchases and facilitate operation planning. The evaluation of the AOC in the case of a hydrothermal system is more complex than in a pure thermal system and is presented in the next chapter.

4. ECONOMIC IMPACT OF NON-UTILITY GENERATION ON HYDROTHERMAL POWER SYSTEMS

4.1. Introduction

One of the most important problems faced by a power utility planner when hydroelectric plants are a part of the power system is to decide upon the short term hydrothermal coordination. This problem is magnified when NUG energy is included in the system. In addition to operating the system economically and at a certain level of reliability, the system planner also has to decide on the rate to pay the NUG in exchange for the energy it receives in the short term. This rate is dependent upon the AOC. Relatively little work has been published on short term hydrothermal planning of power systems with NUG energy. A technique is illustrated in this chapter that can be utilized to include the NUG energy in the hydrothermal generation schedule in an economic manner. It can also be utilized to evaluate the rate that a utility has to pay to the NUG.

Approaches for integrating the operation of hydro and thermal generation in an overall system in order to achieve minimum cost of generation are called hydrothermal scheduling procedures. In hydrothermal systems, schedules are developed to minimize thermal generation costs recognizing all the diverse hydraulic and thermal constraints that may exist. In this thesis, a hydroelectric system is considered to be a small part of the complete hydrothermal system and schedules are developed to minimize thermal generation costs.

Hydrothermal scheduling can be a long term or a short term problem. The long term hydrothermal scheduling problem is concerned with effective utilization of water inflow to a hydro reservoir during the period of interest, usually one year. It involves optimizing a policy in the context of unknowns such as load, hydraulic inflows, and unit unavailability. These unknowns are treated statistically, and, therefore, long term scheduling involves optimization of statistical variables. The solution to this problem consists of the determination of a plan for the withdrawal of water from the hydro reservoirs for power generation throughout the period and the determination of the corresponding thermal generations so that the total cost of the fuel is minimized, subjected to the operating constraints of the hydro and thermal plants. The short term hydrothermal scheduling problem is concerned with an optimization interval of one day at hourly scheduling intervals. The solution to this problem gives a plan for the optimal quantity of water to be discharged from the hydro plant and the corresponding thermal generation such that the total fuel cost of the thermal plants over a day is minimized subjected to the operating constraints of the hydro and thermal plants. The load, hydraulic inflows and unit availability are assumed to be known. A set of starting conditions is given and the optimal hourly schedule that minimizes a desired objective while meeting hydraulic, steam and electric system constraints is sought. This chapter illustrates the incorporation of NUG energy in short term hydrothermal scheduling.

Fixed head and variable head hydrothermal systems are considered in this chapter. Most of the work done on hydrothermal scheduling in the past had been concentrated on the assumption of fixed head for short range studies [65-72]. The rate of water discharge in a hydrothermal system with fixed head hydro is a function of the active power generation of the unit and is usually taken as a quadratic function of power output. In situations where the hydraulic head is variable, the rate of water discharge is given as the product of the active power generation and the hydraulic head. In addition, the dynamics of reservoir flows must be incorporated in the problem formulation. Variable head hydrothermal scheduling is, therefore, more complex than fixed head hydrothermal scheduling. Work has been conducted on the optimum scheduling of hydrothermal systems with variable head hydro [73-75]. Optimal operation of a variable head hydrothermal system with the inclusion of NUG energy has received much less attention, partly because such systems are rare and also because the problem is very complex. In this chapter, algorithms are presented that can be utilized to determine the optimal operation of fixed head and variable head hydrothermal systems with NUG energy in their short term schedule.

This chapter discusses the characteristics of hydro plants and algorithms for the evaluation of the AOC for fixed head and variable head hydrothermal systems and provides a set of corresponding sensitivity curves.

4.2. Characteristics of a Hydroelectric Plant

No two hydro electric systems are alike. The diversity of hydro-electric plant makes it essential for each plant to be mathematically modeled individually. A schematic diagram of a typical hydro electric installation is shown in Figure 4.1.

A hydroelectric power station consists of a dam, a hydro plant and an exiting channel. The energy available for conversion to electrical energy of the water impounded by the dam is a function of the gross head. The head available to the turbine itself is slightly less than the gross head due to the friction losses in the intake, penstock and draft tube. This is expressed as net head and is equal to the gross head less the flow losses. The flow losses can be very significant for low head plants and for plants with long penstocks. The water level at the tailrace is influenced by the flowout of the reservoir including plant release and any spilling of water.

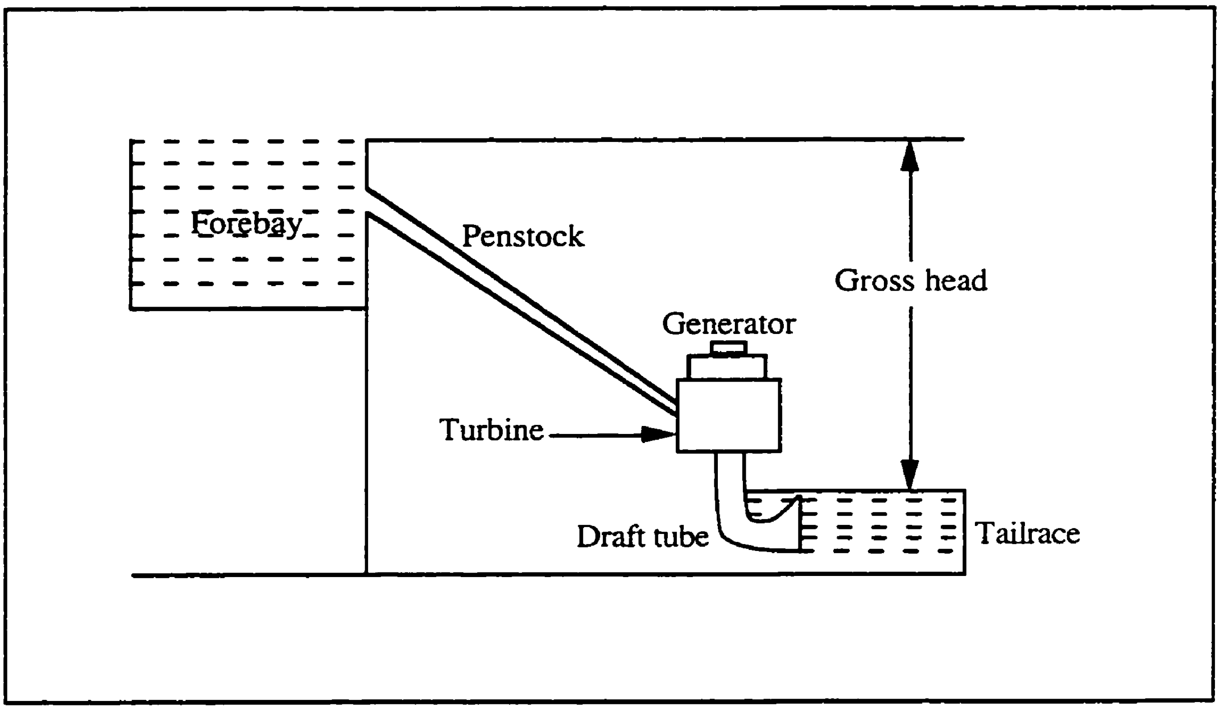


Figure 4.1. Schematic diagram of a hydro-electric power station

In the case of a fixed head hydroelectric system, active power, P_h^j, at hour j is a function of the discharge, q^j. Mathematically,

$$q^j = q^j(P_h^j) \tag{4.1}$$

The relationship between the active power generated by a variable head hydro unit at hour j, P_h^j, in MW, the rate of water discharge at hour j, q^j, in m^3/s and the effective head at hour j, h^j in meters is given by [75]

$$P_h^j = 0.0085 q^j h^j \eta(q,h) \tag{4.2}$$

The efficiency, $\eta(q,h)$, is a function of both q and h. The Glimn-Kirchmeyer model [75] is utilized in this thesis for characterizing variable head hydro plant performance in the optimal economic operation studies. As the water discharge increases, frictional effects are also increased. The result of this is to decrease the net head. For the sake of simplicity, a rectangular reservoir is considered in this work.

4.3. Scheduling of a Fixed Head Hydrothermal System

A short term fixed head hydrothermal scheduling is considered in this section. It has been assumed that there is a single hydroelectric plant in the system which is not sufficient to supply the entire load demand during a period of 24 hours and that there is a maximum total volume of water, V, that will be discharged throughout the period of 24 hours. The hourly load and inflow of water at each hour is fixed. The total running cost of the hydrothermal system is assumed to include the fuel cost of the thermal units. The transmission losses are neglected. The hydraulic constraints are shown below.

a) The total volume of water discharged is defined as

$$\sum_{j=1}^{24} q^j = \mathrm{V} \tag{4.3}$$

b) Discharge constraint

$$q_{min} \le q^j \le q_{max} \tag{4.4}$$

where

q_{max} and q_{min} are the maximum and minimum water discharges respectively.

c) Power output constraint

$$P_{h(min)} \le P_h^j \le P_{h(max)} \tag{4.5}$$

where $P_{h(max)}$ and $P_{h(min)}$ are the maximum and minimum power outputs of the hydro plant.

The hydro output at each hour, j, should be utilized to replace thermal generation in such a manner that it (hydro output) should not force the thermal units to operate below their minimum or above their maximum permissible levels. The replacement should be done in a way that the resulting saving is maximized. The inclusion of hydro output may also result in the change in unit commitment of the thermal units. In order to determine the loading schedule modified by the hydro units, a discrete amount of the hydro energy, ΔP_h^j, is considered in each hour corresponding to a discharge of Δq^j and the corresponding saving is evaluated. The saving in running cost due to a hydro unit can be expressed as:

$$\Delta F_{hi}^j = a_i\{2P_{si}^j(\Delta P_h^j) - (\Delta P_h^j)^2\} + b_i \Delta P_h^j \tag{4.6}$$

where

$\Delta F_{hi}^j =$ savings in the running cost of unit i due to a discrete amount of hydro energy during hour j

$\Delta P_h^j =$ discrete amount of hydro energy utilized in hour j.

The savings due to a change in the unit commitment is also taken into consideration. The unit giving maximum saving (kth unit) during hour j can be found by selecting k such that the following equation is satisfied.

$$\Delta F_{hk}^j = Max\{\Delta F_{h1}^j, \Delta F_{h2}^j, \Delta F_{h3}^j, \ldots\ldots, \Delta F_{hN}^j\} \tag{4.7}$$

The kth unit is selected as a candidate for a load reduction of ΔP_h^j MW. ΔF_{hi}^js for j=1, 2, 3,...., 24 are evaluated. The possible savings due to the incorporation of ΔP_h^j MWh of hydro energy is:

$$\Delta S_{hk}^L = Max\{\Delta F_{hk}^1, \Delta F_{hk}^2, \Delta F_{hk}^3, \ldots\ldots, \Delta F_{hk}^{24}\} \tag{4.8}$$

where

$\Delta S_{hk}^{L} =$ discrete savings in 24 hours due to the incorporation of ΔP_h^j MWh of hydro power.

The Lth hour is selected for a load reduction of ΔP_h^j MWh.

The discharge and power output constraints are checked at the Lth hour. The same procedure is repeated until the total volume of water, V, is used up.

4.4. Scheduling of a Variable Head Hydrothermal System

The optimal short term scheduling of a hydrothermal system with a variable head hydro plant is considered in this section. The optimal hydro-thermal schedule is obtained by satisfying the hydro, thermal and reservoir constraints. The objective of the algorithm is to find active power generation of the hydrothermal system as a function of time over a 24 hour period under the following conditions.

a) The total running cost of the thermal plants in the system over the optimization interval, 24 hours, should be minimum.

b) The total active power generation in the system matches the load.

$$P_D^j = \sum_{i=1}^{N} P_{si}^j + P_h^j \tag{4.10}$$

where

P_D^j = system load during hour j-MW

P_h^j = output of hydro unit during jth hour - MW.

c) Transmission losses are neglected for the sake of simplicity.

The constraints considered in the algorithm are the following:

a) Discharge constraint.

$$q_{\min} \leq q^{j} \leq q_{\max} \tag{4.11}$$

where $q_{\max}$ and $q_{\min}$ are the maximum and minimum water discharges respectively.

b) Reservoir head constraint.

$$h_{\min} \leq h^{j} \leq h_{\max} \tag{4.12}$$

where $h_{\max}$ and $h_{\min}$ are the maximum and minimum permissible reservoir head levels respectively.

c) Power output constraint.

$$P_{h(\min)} \leq P_{h}^{j} \leq P_{h(\max)} \tag{4.13}$$

where $P_{h(\max)}$ and $P_{h(\min)}$ are the maximum and minimum power outputs of the hydro plant.

The flowchart shown in Figure 4.2 indicates the steps of the algorithm based on dynamic programming. An initial reservoir head, h_{ini} is assumed at the beginning of the optimization interval. The level of water in the reservoir, ht, is assumed to vary between h_{min} and h_{max} with discrete intervals of I at a particular hour hr. The size of I affects the accuracy of the results and the computation time. In this thesis, reservoir head is increased by a unit value. Water discharged, q_I, is evaluated at each I by considering the difference in the level of reservoir head, surface area of the reservoir, SA, and water inflow into the reservoir, q_{in}. If the discharge constraint is satisfied, the hydro power output P_{hI} at each I is evaluated utilizing the Glimn Kirchmeyer hydro unit model [75]. The hydro power output P_{hI} is used in the scheduling of thermal units. The running cost of the hydro unit is assumed to be negligible as compared to that of the thermal units. The cost saving, $Sav(hr,I)$, is evaluated at each I by taking the difference in the cost before and after the inclusion of P_{hl} in the thermal scheduling. For the first hour, the total saving, *Savt(hr,I)*, at each I is the same as *Sav(hr,I)*. The total saving, *Savt(hr,II)*, beyond the first hour at each I is evaluated by determining the maximum saving, *Sa*, from a set of savings which is obtained by taking the summation of *Sav(hr,I)* and *Sav(hr-1,II)*. The total saving, *Savt(hr,II)*, is evaluated for all I at each hour. At the 24th hour, the maximum saving is determined using N savings, *Savt(hr,N)* where N is the number of discrete intervals in one hour. The path for the maximum saving is retraced to determine hydro discharges at each hour. Hydro power output is then determined from hydro discharge.

4.5. Evaluation of the Avoided Operating Cost

The AOC is evaluated after the units in the hydrothermal system are economically dispatched. The technique for AOC evaluation is the same for both fixed head and variable head hydrothermal systems and is based on the marginal cost of the hydrothermal system. It is assumed that ξ MWh of energy is supplied by the NUG to the utility in 24 hours. The NUG energy is utilized to replace the already reduced thermal generation in an optimal manner. A discrete amount of NUG energy, $\Delta\xi$, is used to determine the loading schedule modified by NUG. The iterative process continues until all the NUG energy is injected into the system. The saving in the running cost due to the inclusion of $\Delta\xi$ MWh of NUG energy is given by

$$\Delta F_i^j = a_i\{2P_{ti}^j(\Delta\xi) - (\Delta\xi)^2\} + b_i\Delta\xi \tag{4.14}$$

where

P_{ti}^j =thermal output at hour j.

All the loaded units are searched except the ones that have reached their minimum output limits. The unit giving maximum saving (kth unit) during hour j can be found by selecting k such that the following equation is satisfied.

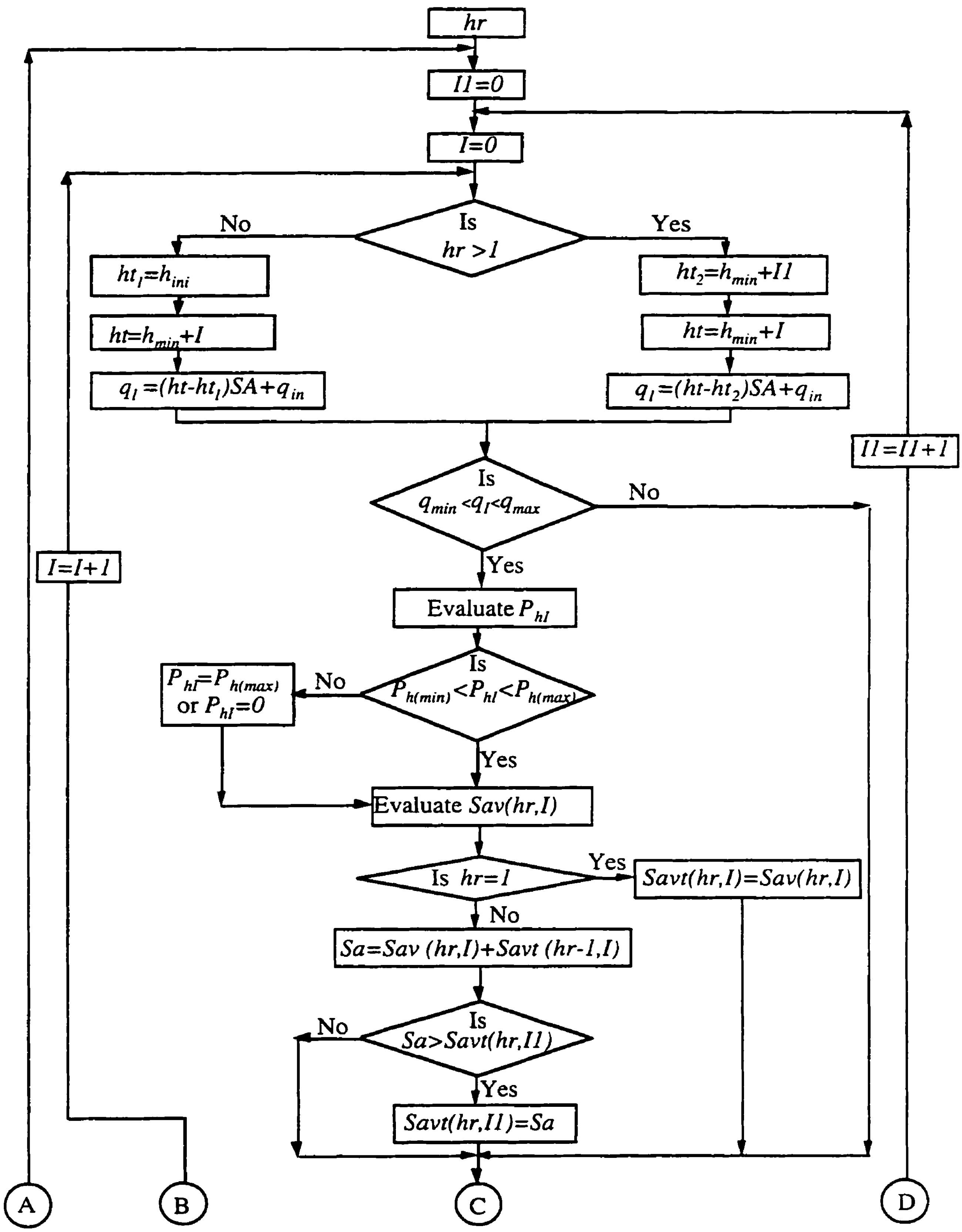


Figure 4.2. Flowchart for the optimal scheduling in a variable head hydrothermal system

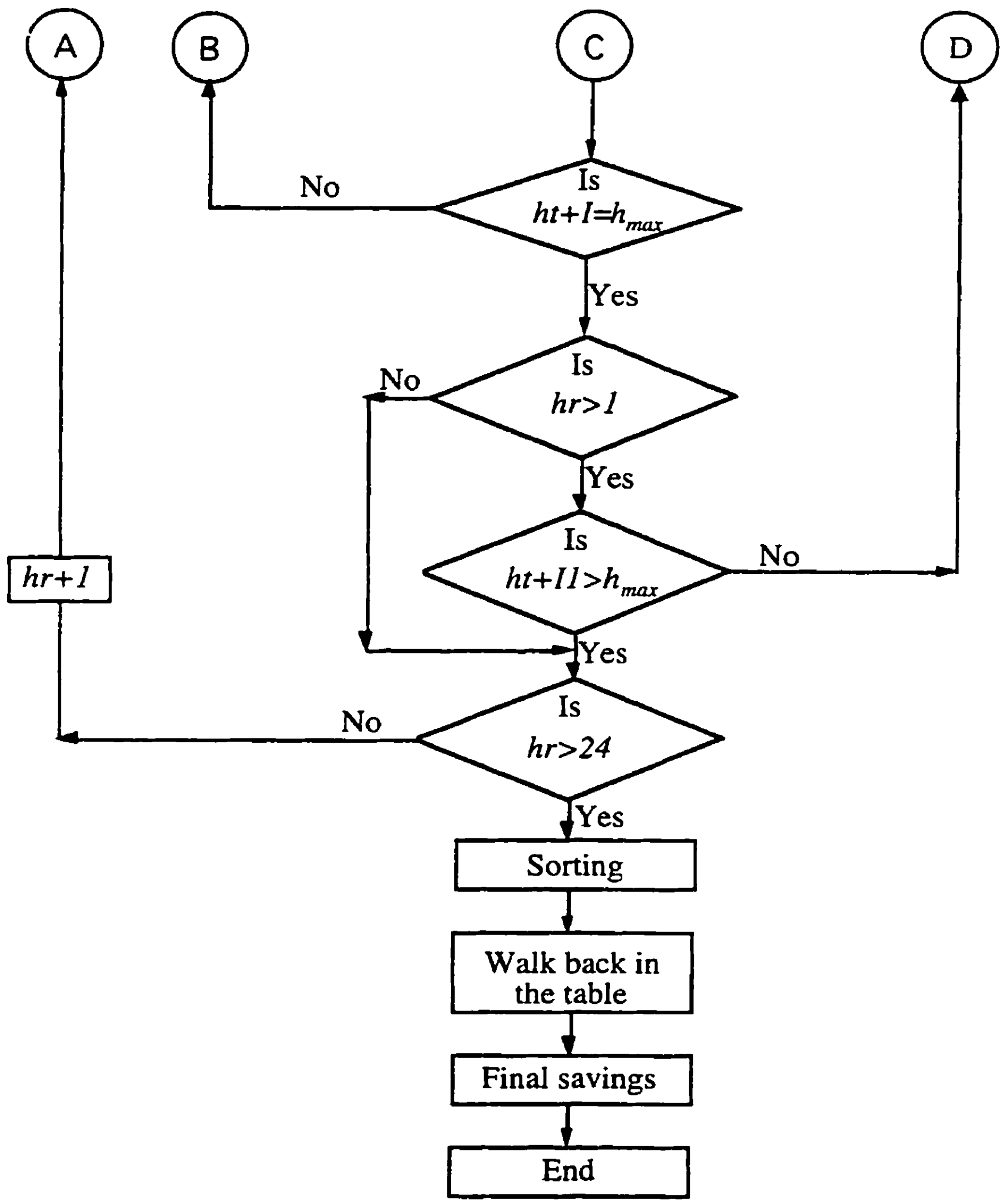


Figure 4.2. Flowchart for the optimal scheduling in a variable head hydrothermal system.......continued

$$\Delta S_k^j = Max\{\Delta F_1^j, \Delta F_2^j, \Delta F_3^j, ..., \Delta F_N^j\} \tag{4.15}$$

The kth unit is selected as a candidate for a load reduction of $\Delta\xi$ MW. The iteration continues for hour j+1 and ΔS_k^{j+1} is evaluated. After evaluating ΔS_k^j where j=1, 2, 3, ...24, the hour with the largest ΔS_k^j is selected to receive $\Delta\xi$ MWh of NUG energy. In the next iteration k+1, the evaluation starts with a NUG energy of $\xi = \xi - \Delta\xi$. The process continues until all the NUG energy is exhausted. The AOC is, then, evaluated utilizing the following equation

$$\psi = \sum_{k=1}^{l} Max\{\Delta S_k^1, \Delta S_k^2, \Delta S_k^3, ..., \Delta S_k^{24}\} \tag{4.16}$$

where

l = the number of iterations required to utilize ξ MWh of NUG energy.

4.6. Hydrothermal System Sensitivity Studies

In this chapter, the IEEE-RTS is considered as the utility and sensitivity studies are performed to show the economic implications of NUG energy. All the existing generating units in the IEEE-RTS are considered to be thermal or thermal equivalents. Fixed head and variable head hydro units are considered to be a part of the IEEE-RTS in addition to the already existing units. Studies on a fixed head hydrothermal utility are illustrated in the following sub-section followed by studies on a variable head hydrothermal utility.

4.6.1. Fixed Head Hydrothermal System Applications

4.6.1.1. Effect of water volume

It is assumed in this thesis that the cost associated by a hydro unit is negligible compared to that of the thermal units. The utility economic savings due to a hydro unit depends upon the volume of water and on the size of the unit. Figure 4.3 illustrates the variation in utility economic savings due to the presence of a hydro unit as a function of

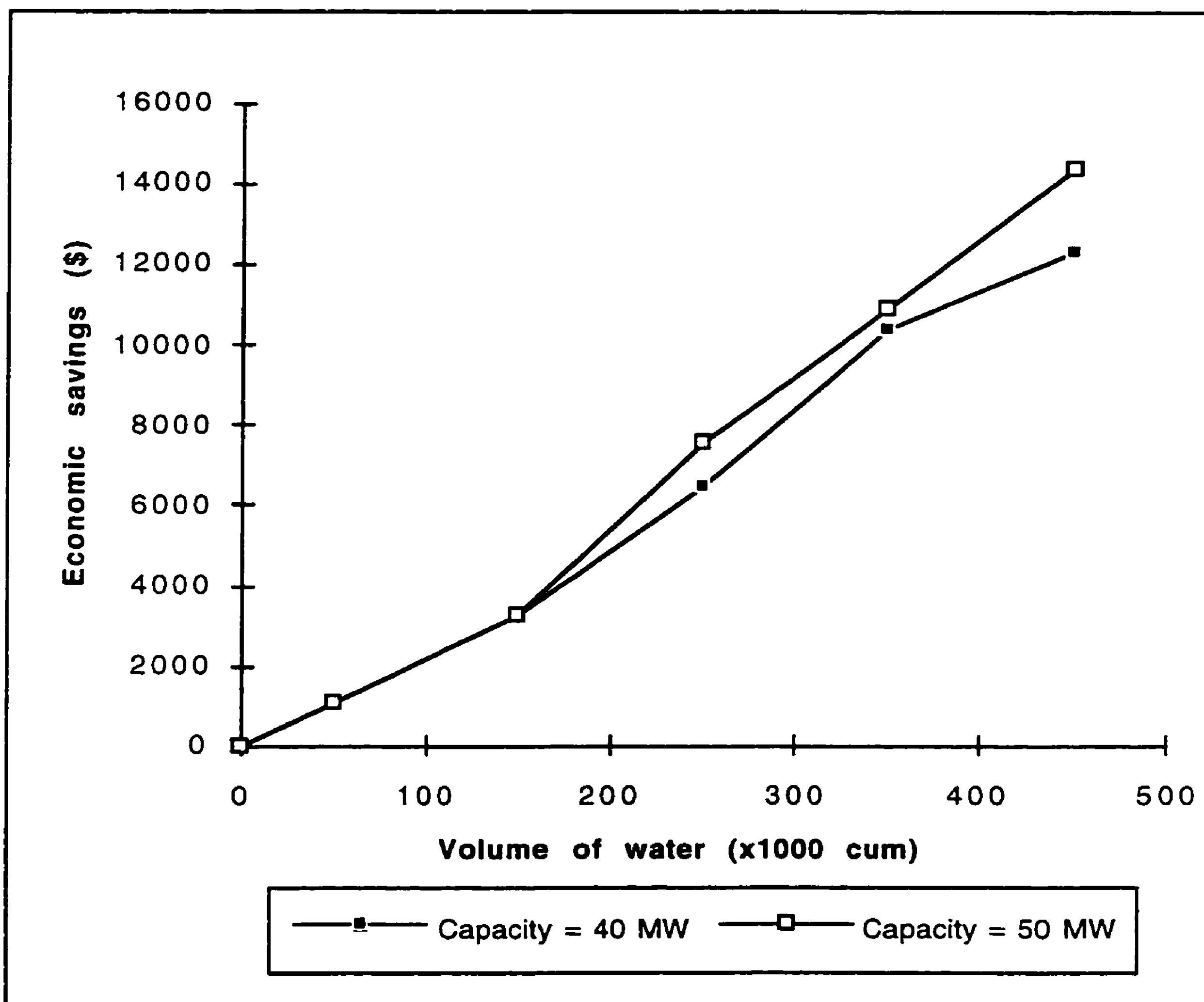


Figure 4.3. Economic savings due to a hydro unit

the volume of water available in one day. Utility savings are evaluated for hydro units of 40 MW and 50 MW capacities. It is assumed in this study that 600 MWh of energy is purchased by the utility from NUG. It can be observed from Figure 4.3 that the economic savings of the utility increases with an increase in the volume of water in the reservoir. The savings due to the hydro unit increase with higher hydro unit capacity for the same volume of water. This is due to the fact that in a particular hour, the system operator has access to greater hydro energy in the case of the 50 MW hydro unit than in the case of the 40 MW hydro unit.

The change in economic savings due to a hydro unit is reflected in the system AOC. Figure 4.4 shows the variation in the AOC as a function of the volume of water available in one day. The AOCs were evaluated for two cases of 40 MW and 50 MW hydro units. An increase in the volume of water causes an increase in the power generated by the hydro unit. This results in a decrease in the marginal cost of the hydrothermal system. The AOC depends on marginal cost and, therefore, decreases with an increase in the volume of water as observed from Figure 4.4. The AOC depends upon the savings due to the hydro unit.

4.6.1.2. Effect of NUG energy

A hydrothermal system achieves savings in fuel costs by integrating NUG energy into the system. This is due to the presence of a hydro unit that results in the lower marginal cost of the hydrothermal system. The economic benefit to the hydrothermal system and the NUG is illustrated in Figure 4.5. The variation in the utility running cost per unit of energy and the AOC as a function of the energy purchased by the utility from the NUG is shown in this figure. The running cost of the utility without the NUG is $ 8.67 per unit of energy. This is higher than that with the NUG and decreases with increase in the NUG energy purchased by the utility.

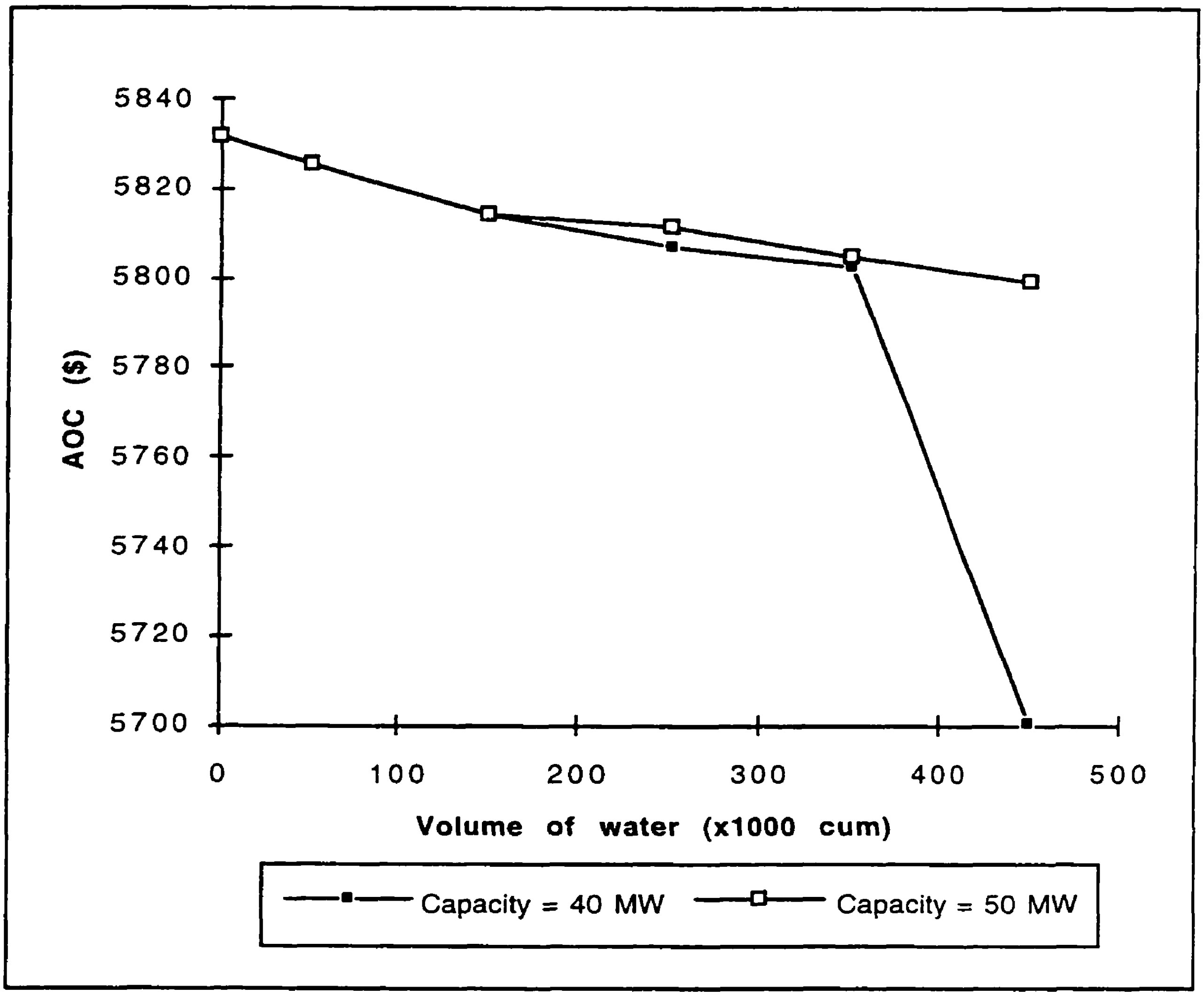


Figure 4.4. AOC vs volume of water in the reservoir

The AOC increases with an increase in the NUG energy. The units committed to satisfy the load are based on the priority loading order of the units which in-turn is dependent upon the fuel cost of each unit. Units with lower fuel cost are higher in the priority table and vice-versa. When a utility satisfies the customer load without NUG, expensive units that are at the lower end of the priority table are committed and loaded to higher values thus increasing the marginal cost. When NUG energy is included, expensive units produce lower energy and the utility running cost is, therefore, higher without NUG than that with

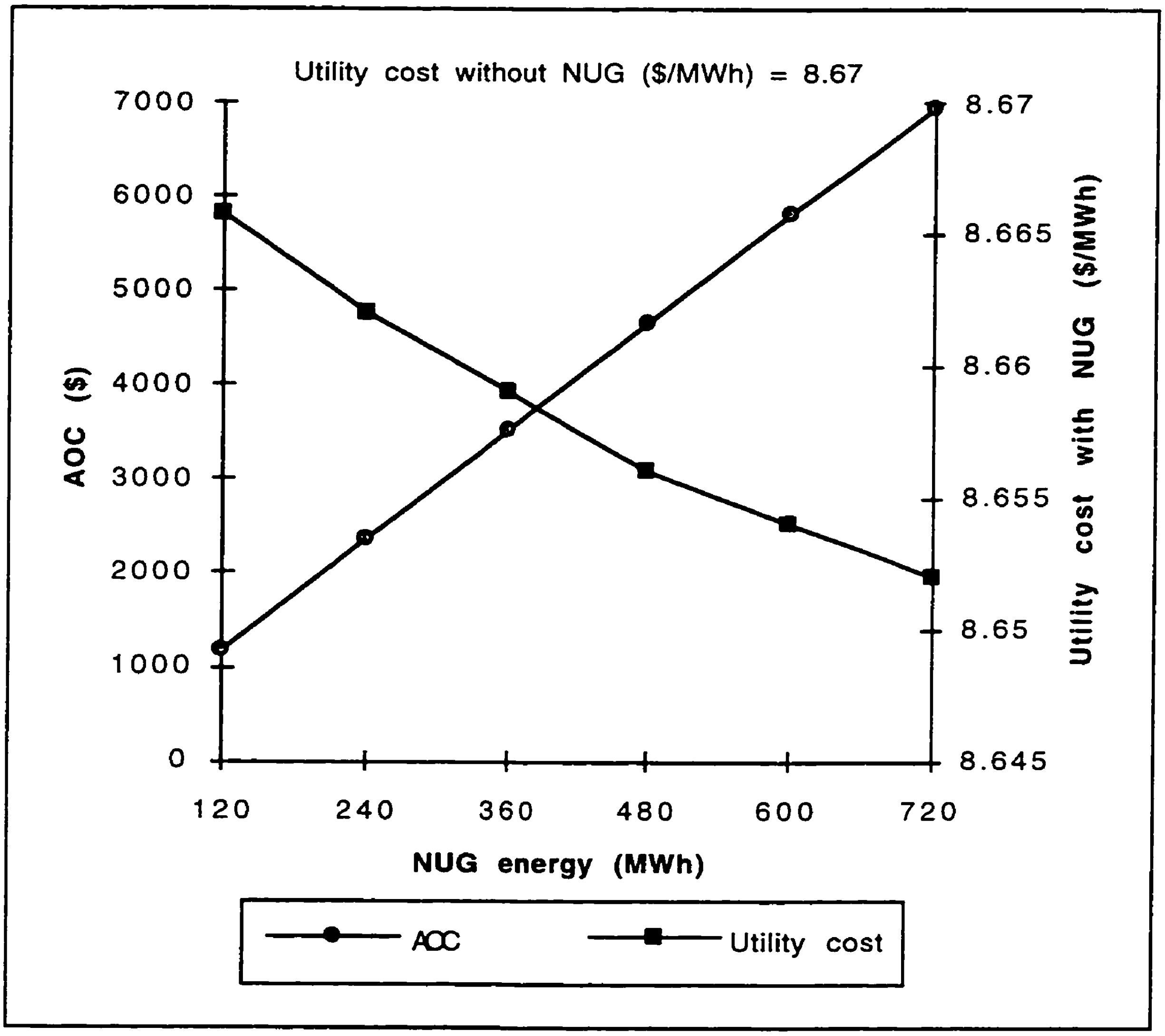


Figure 4.5. Economic benefit to utility and the AOC

NUG and decreases with an increase in the NUG energy. The fuel cost can, therefore, be reduced in a hydrothermal system as in a pure thermal system by including NUG energy into the system.

4.6.1.3. Optimum duration of NUG energy

A NUG can increase the economic value of its energy by selling to the utility in the optimum duration (OD). The OD is the number of hours in a day for which the NUG sells same energy to the utility, such that it (NUG) receives maximum economic benefit. The duration changes with a change in the NUG energy purchased by the utility. Variations in AOCs as a function of the OD for two cases of 200 MWh and 600 MWh of NUG energies are illustrated in Figures 4.6 and 4.7. The NUG energy is assumed to be equally spread out

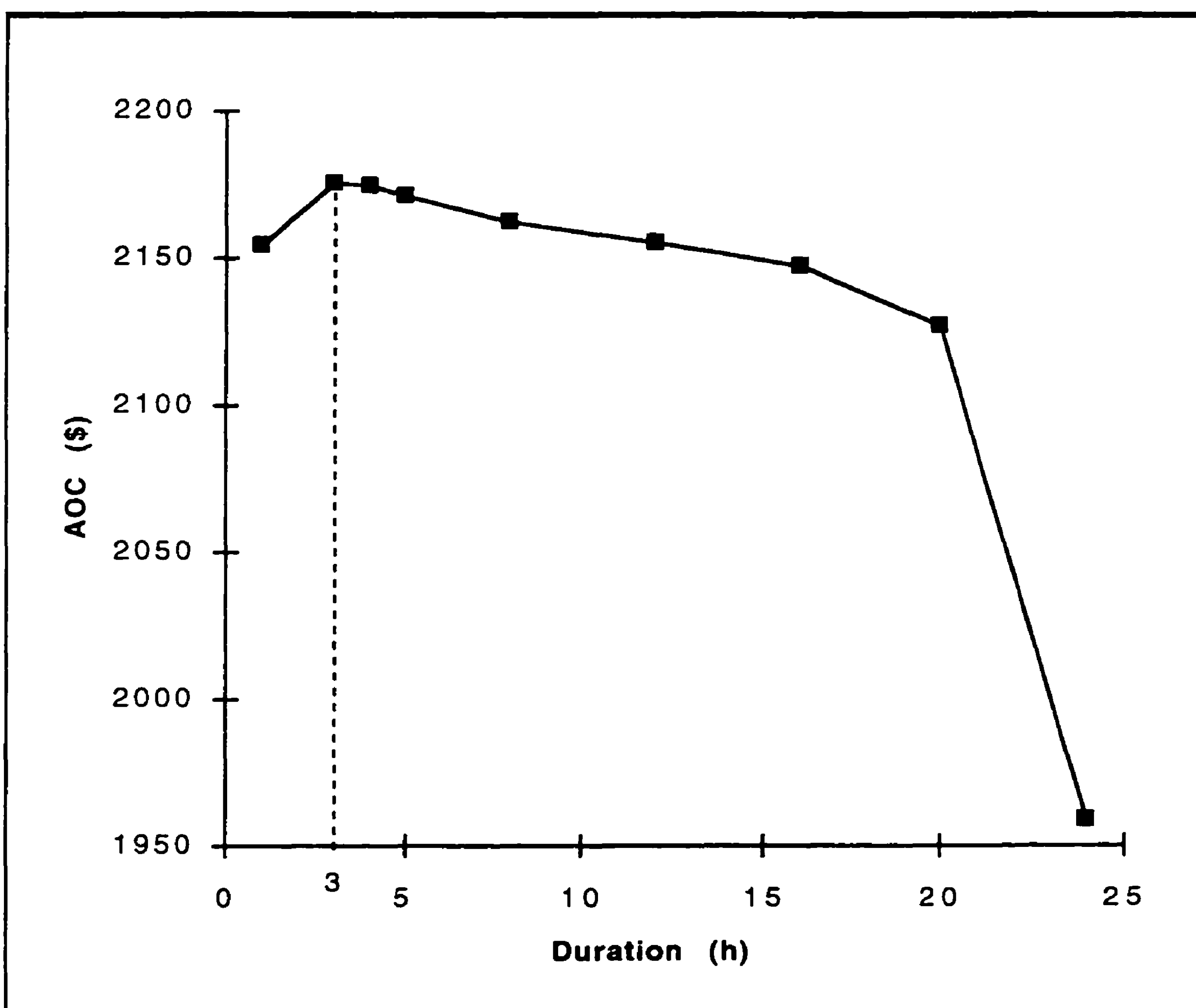


Figure 4.6. AOC as a function of the duration with 200 MWh of NUG energy

over the hours indicated in the abscissa in Figure 4.6 and 4.7. It can be observed from Figures 4.6 and 4.7 that the AOC first increases and then decreases with increase in the number of hours in the sales period. The AOC are maximum when the OD is 3 hours for 200 MWh of NUG energy and 5 hours for 600 MWh of NUG energy. The OD is dependent upon the priority loading order of the utility, dispatch of each committed unit and the amount of the energy supplied by the NUG. This study shows that the OD can be evaluated and is different for different NUG energies.

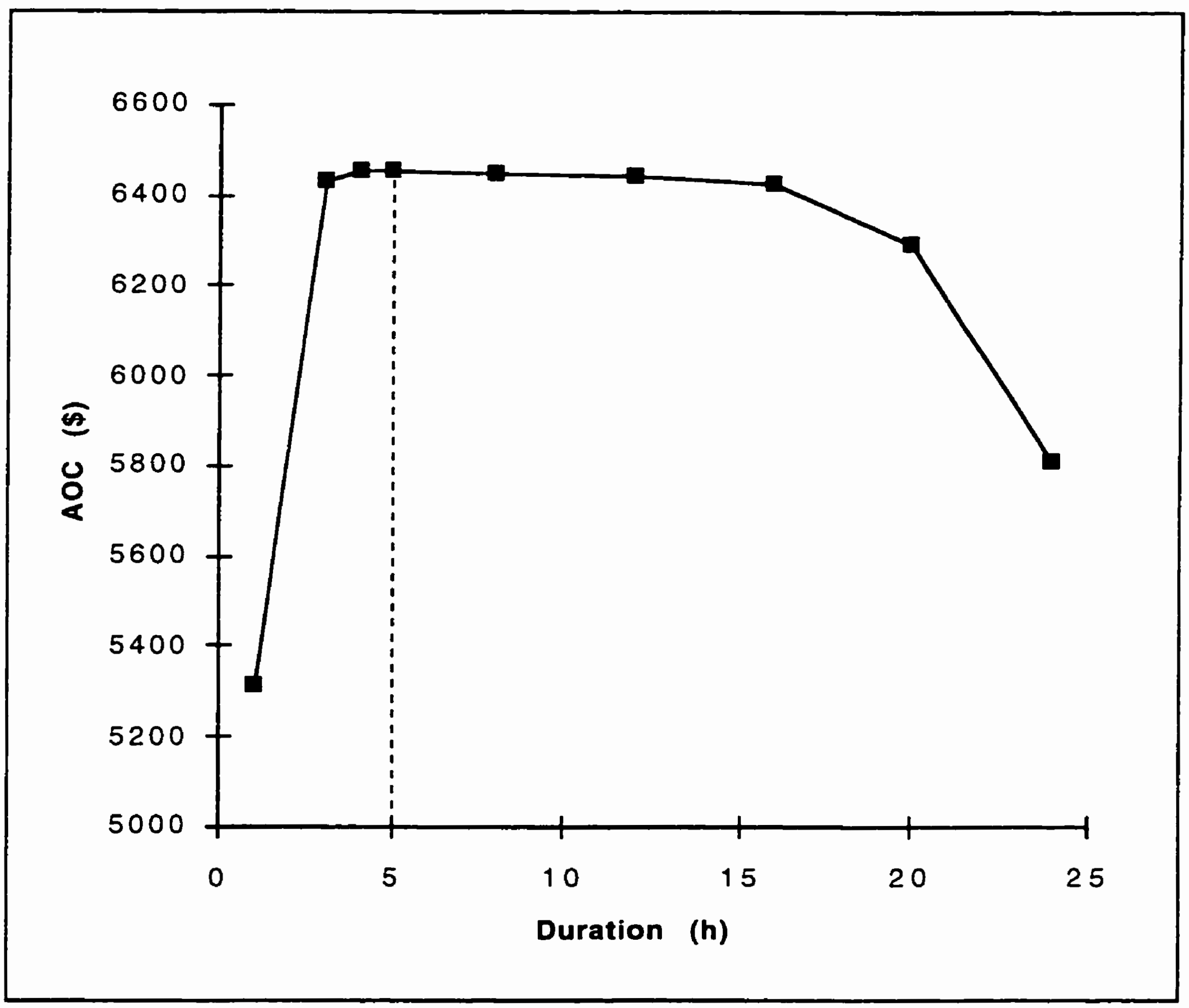


Figure 4.7. AOC as a function of the duration with 600 MWh of NUG energy

4.6.2. Variable Head Hydrothermal System

4.6.2.1. Effect of hydro generation on the load and the AOC

Energy contributions made by a hydro unit in a variable head hydrothermal system depend upon the daily available water, inflow of water into the reservoir and the level of water in the reservoir. The total energy generated by a hydro unit affects the thermal unit generation and therefore the AOC. The daily energy generated by the 100 MW hydro unit and the AOC profiles are illustrated in Figures 4.8 and 4.9.

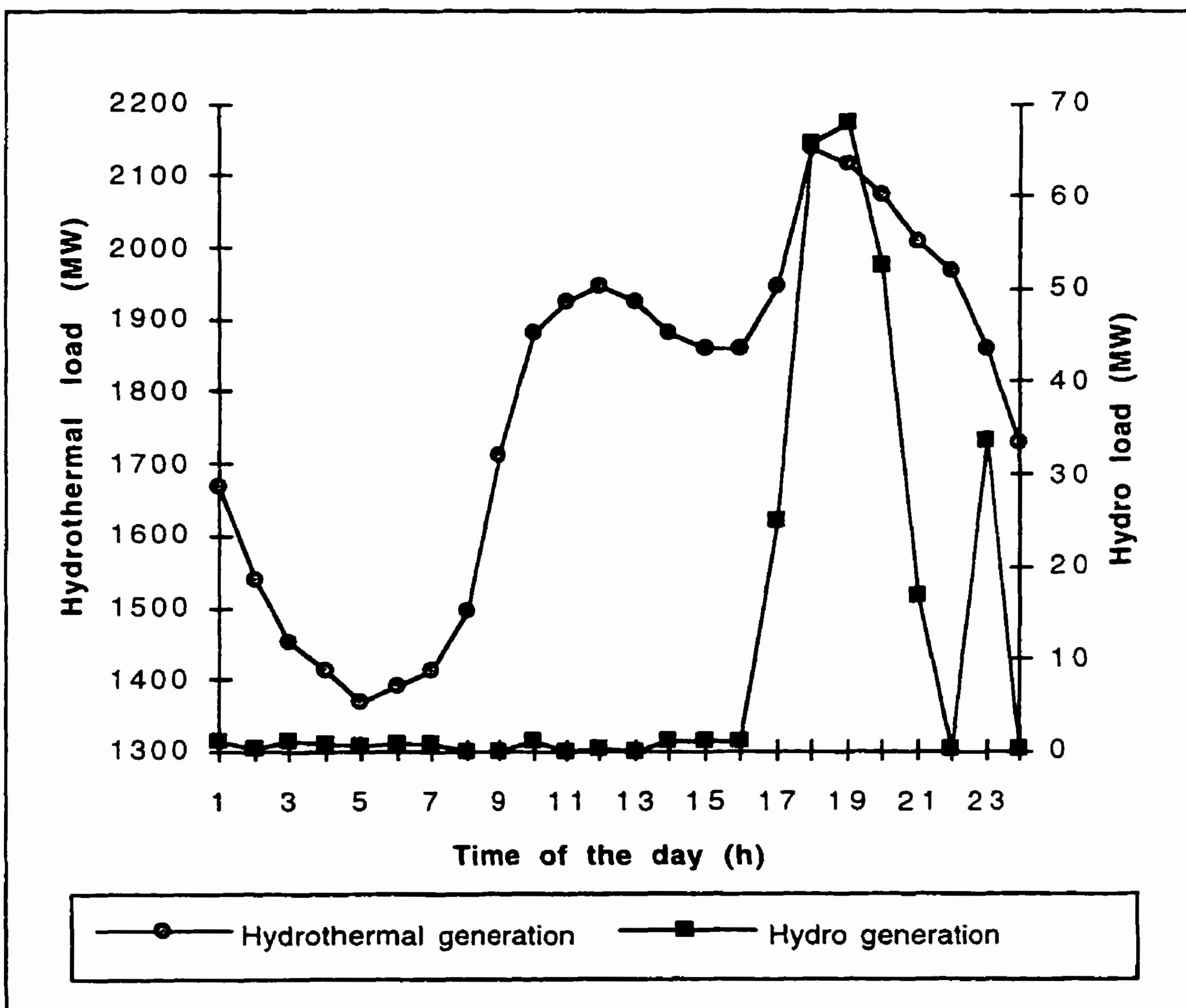


Figure 4.8. Total hydrothermal vs hydro generation

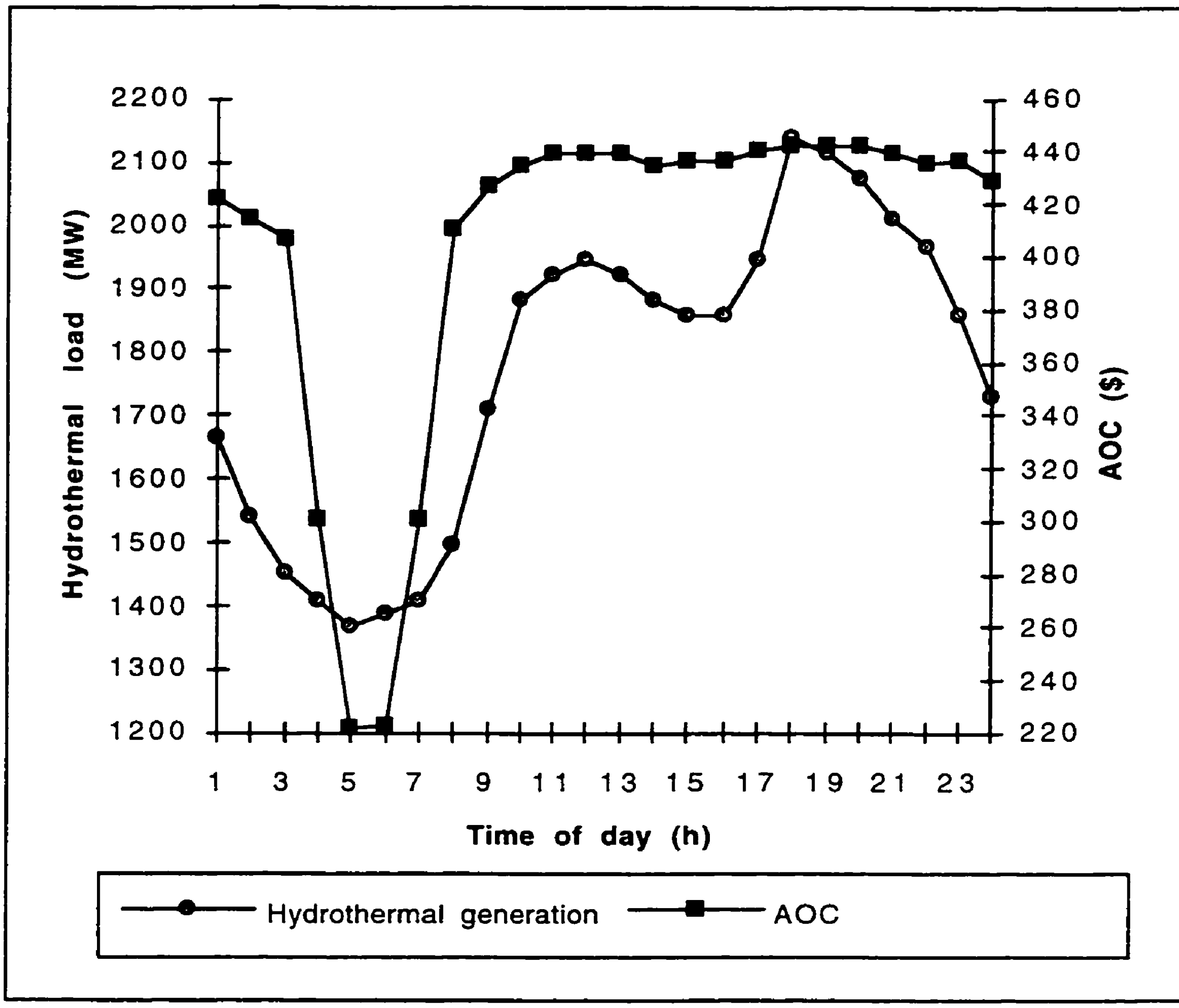


Figure 4.9. AOC profile in 24 hours

The load satisfied by the hydrothermal system is also shown. It was assumed in this study that 100,000 cubic meters of water is available in one day and the initial reservoir head is 175 meters. It was also assumed that the inflow of water into the reservoir is constant and 40 MWh of energy per hour is purchased by the hydrothermal system from a NUG in one day. It can be observed from Figures 4.8 and 4.9 that the load satisfied by the hydrothermal system has two peaks, one at noon and the other in the evening. Figure 4.8 shows that the major energy contribution made by the hydro unit occurs during the second peak where the load is at its daily maximum. It can be observed from Figure 4.9

that the AOC is lowest at the low load but becomes high at the first peak load period and remains high until the next peak load period. The variation of the hydro generation and the AOC at the different hours of the day is due to the variables noted earlier.

4.6.2.2. Effect of volume of water on the AOC

The AOC is a function of the utility running cost which depends upon the volume of available water to the hydro unit. The effect of available water in the reservoir on the AOC is illustrated in Figure 4.10.

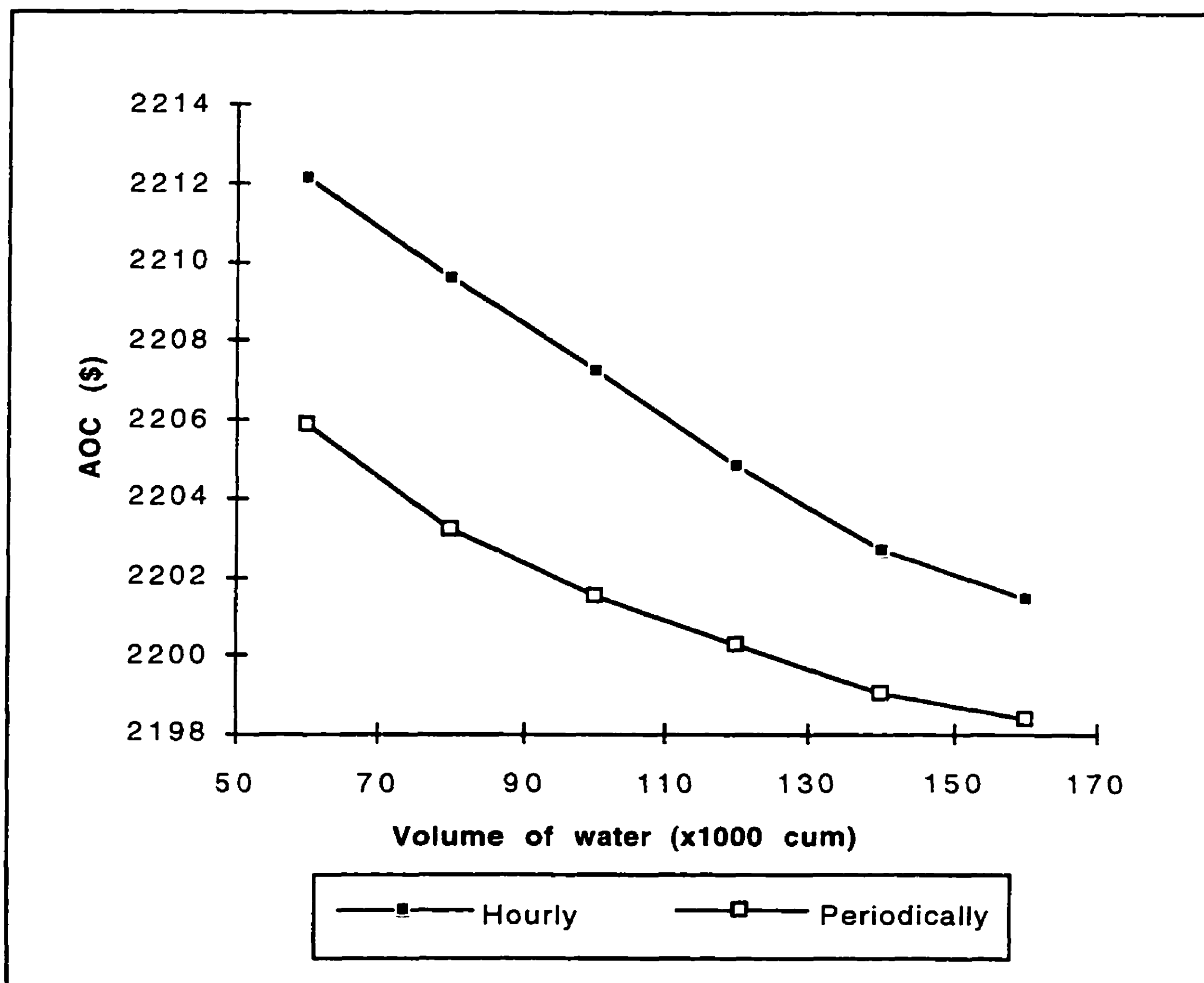


Figure 4.10. AOC as a function of the volume of water in the reservoir

It was assumed in this study that the NUG sells 200 MWh of energy in a day and the utility can dispatch this energy over 8 hours. The AOC is evaluated hourly over 8 hours of the day, and periodically over 8 successive hours of the day. It can be seen from Figure 4.10 that increasing the volume of water causes a decrease in the AOC. This is due to the fact that the economic savings achieved by the hydrothermal system increase as the volume of water increases. The marginal cost of the hydrothermal system decreases as the savings due to the hydro unit increases and, therefore, the AOC decreases. It can be further observed from Figure 4.10 that the AOC is higher when the NUG sells energy to the utility at non-contiguous hours of the day than that when the NUG sells energy to the utility for an 8 hour period. It can be, therefore, inferred from this study that a NUG achieves higher economic benefits if it sells energy on an hourly basis rather than on a period basis.

4.6.2.3. Effect of the volume of water on utility running cost

In this case, it has been assumed that the daily water volume is fixed. The hydro unit output that affects the thermal output depends upon the available volume of water. The running cost of the utility is a function of the thermal output and, therefore, also depends upon the volume of available water. The variation in utility running cost per unit of energy with and without NUG energy as a function of the volume of water is shown in Figure 4.11. It can be observed from Figure 4.11 that the running costs reduce as the volume of water in the reservoir increases. The utility running cost without the NUG energy is higher than the corresponding running cost with the NUG energy.

4.6.2.4. Effect of initial water level on the AOC

The power output of a hydro unit in a variable head hydrothermal system is a function of the reservoir water level. The AOC which is dependent on the hydro power output, therefore, changes with change in the water level. The effect of the initial water level in the

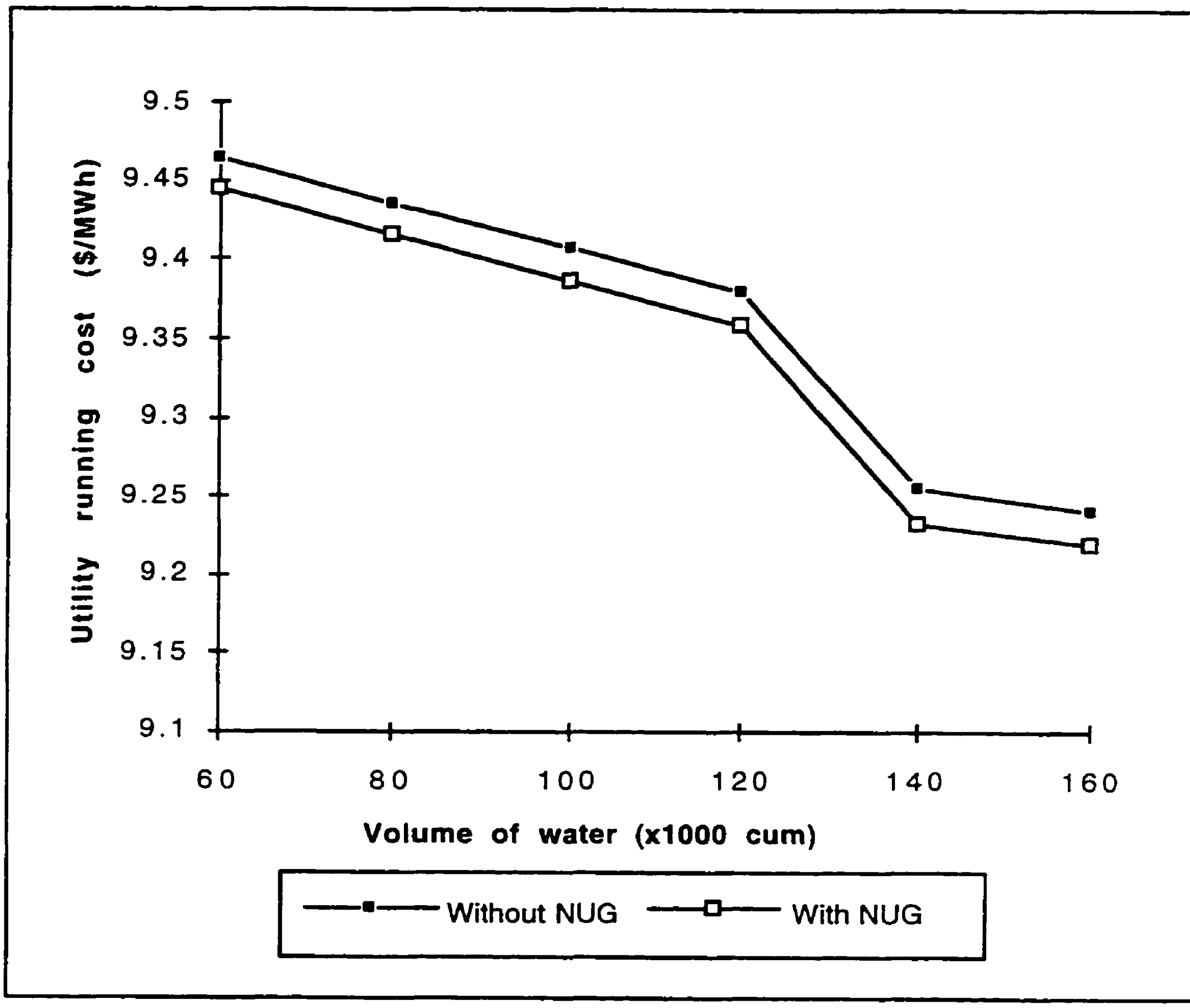


Figure 4.11. Utility running cost as a function of the volume of water in the reservoir

reservoir on the AOC is shown in Figure 4.12. In this study the head at the beginning of the study period is as shown in this figure and AOCs were evaluated on both hourly and periodic bases. It can be seen from Figure 4.12 that the AOC decreases with an increase in the initial reservoir water level as the power output of the hydro unit is higher at higher initial water levels. The economic savings achieved by the hydrothermal system due to the hydro unit are, therefore, higher. This results in a lower marginal system cost and the

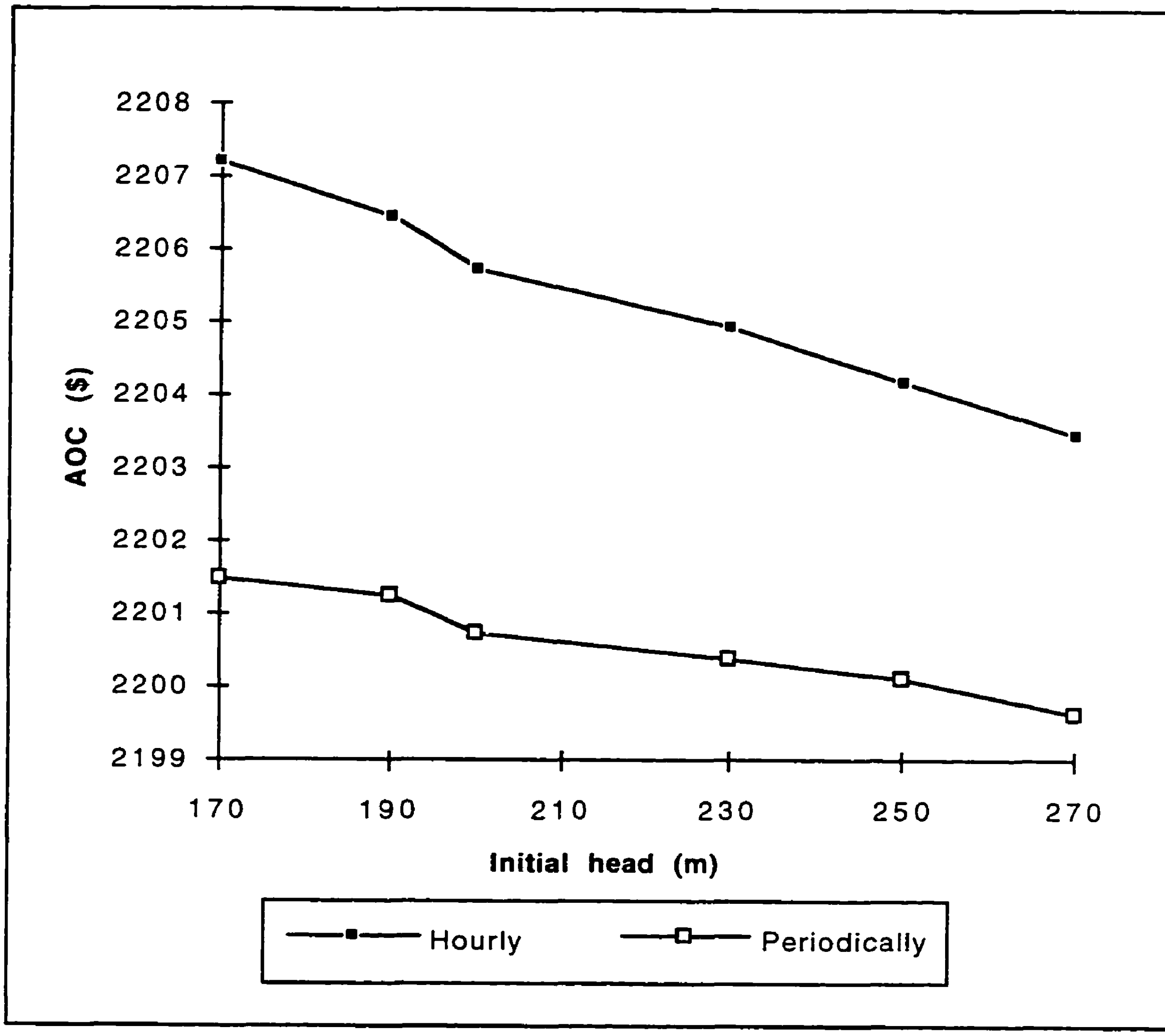


Figure 4.12. AOC as a function of the initial water level in the reservoir

AOC is, therefore, lower at the higher initial water levels. Figure 4.12 also shows that the AOC is higher when evaluated on an hourly basis than when evaluated on a periodic basis.

4.6.2.5. Effect of initial water level on utility running cost

The level of water in the reservoir is assumed to be constant in a fixed head hydrothermal system but changes continuously in a variable head system. The initial water level plays an important role in determining the hydro output which dictates the running cost of the utility. In this study it was assumed that the head at the beginning of the study period varies from 170 meters to 270 meters. The advantage of buying NUG energy and having a higher initial water level is illustrated in Figure 4.13. The utility running cost decreases with increase in the initial water level.

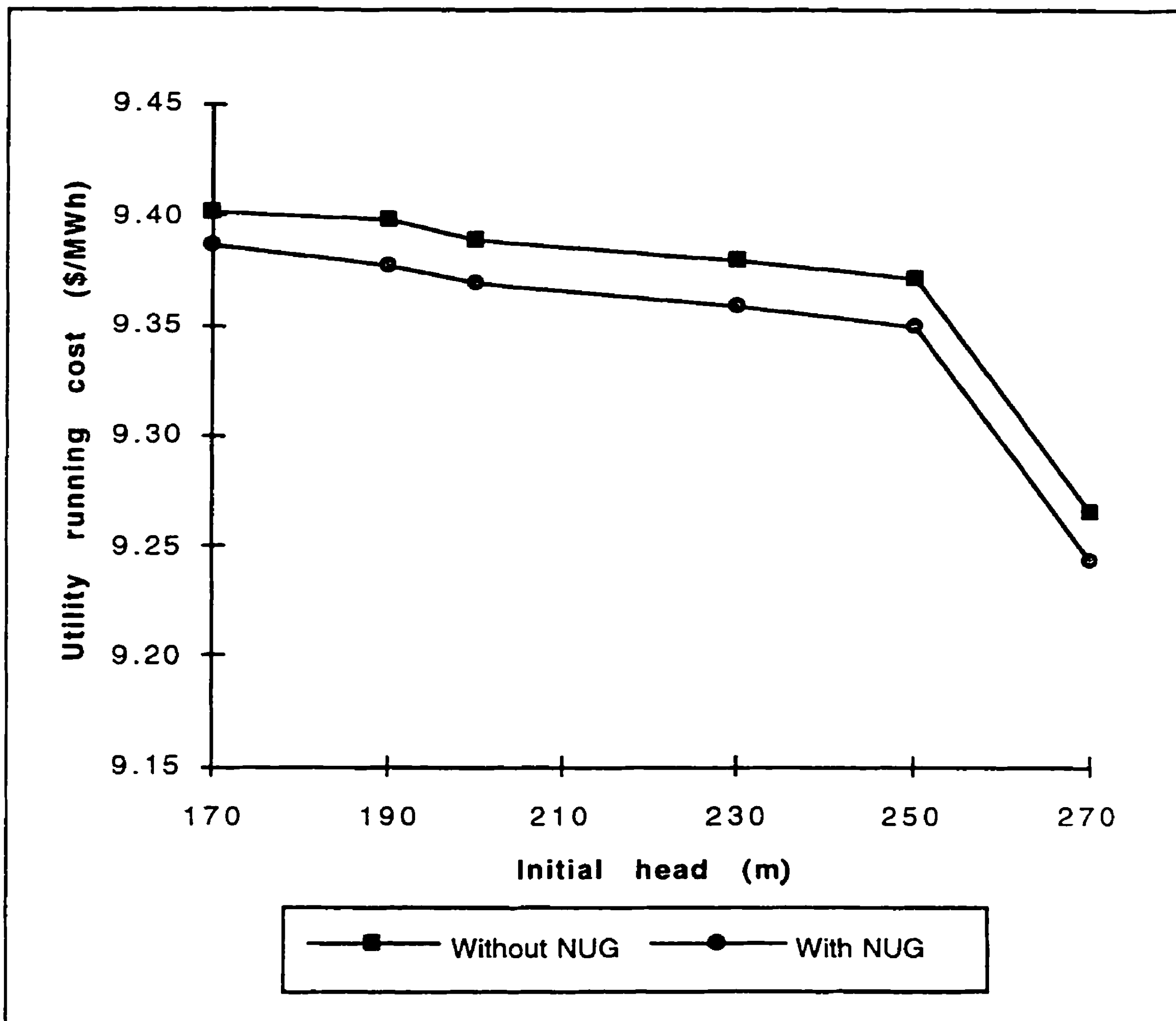


Figure 4.13. Utility incremental running cost as a function of the initial height of water in the reservoir

4.7. Summary

This chapter illustrates the economic implications of incorporating NUG energy in the short term planning of a fixed head and a variable head hydrothermal system.

Deterministically based algorithms have been proposed to deal with the short term scheduling problem of a fixed head and a variable head hydrothermal system as NUG energy is included in the system. The technique starts with the evaluation of hydrothermal scheduling, which is different for fixed head and variable head hydrothermal systems. Once the hydrothermal scheduling is performed, the AOC is evaluated. The procedure for evaluating the AOC is the same in both systems. The evaluation of the AOC is based on the optimum operation of the hydrothermal system both before and after the utilization of NUG energy.

Computer programs have been developed to evaluate and examine the economic implications of NUG energy on hydrothermal systems. The IEEE-RTS, discussed in Chapter 2, was utilized as an example system to perform sensitivity studies. The effects of water volume on the AOC and the utility running cost were examined for a fixed head hydrothermal system and are illustrated in this chapter. The results show that the AOC and the utility running cost per unit of energy decrease with increase in the volume of water in the reservoir. The OD for NUG energies of 200 MWh and 600 MWh were evaluated and it was observed that the OD are different for different NUG energies. In the case of a variable head hydrothermal system, the effects of water volume and initial height of the reservoir on the AOC and the utility running cost were examined. The AOC and utility running cost per unit of energy decrease with increase in the volume of water in the reservoir and with an increase in the initial height of the reservoir.

This chapter shows that it is feasible to evaluate the AOC of fixed head and variable head hydrothermal systems and that the economic benefit to the utility and the NUG can be quantified.

Sensitivity studies, similar to those performed on the example system, can be utilized for a hydrothermal system to estimate the savings in the running cost of the utility when it buys electrical energy from a NUG. The studies can also be utilized to determine the amount of energy and the OD during which a utility and a NUG can maximize their mutual economic benefit.

The NUG can produce electrical energy from conventional or non-conventional sources and the AOC depends upon the inherent characteristics associated with the source used for the generation. The economic impacts of NUG producing energy from non-conventional sources, cogeneration and wind, are considered in the next chapter.

5. ECONOMIC IMPACT ON A UTILITY OF COGENERATED AND WIND ENERGIES PRODUCED BY NON-UTILITY GENERATION

5.1. Introduction

Due to an increase in the cost of energy and fall in the rate of growth of electricity demand, utilities and governments are looking beyond the conventional sources of electrical energy to identify alternative, flexible sources to meet a part of the forecast load growth. Industrial cogeneration and wind are two such alternatives that could be utilized economically and are therefore, considered in this chapter.

In a conventional thermal utility, the most significant variable cost component is fuel, which accounts for approximately 76% of the total variable cost [80,86]. Approximately 65% of the fuel input is rejected to the environment while another 2.5% is lost in transmission and distribution. Only about 33% of the input energy is, therefore, delivered to the end user and an increase in the efficiency of the energy conversion process can result in significant cost savings. An industrial cogeneration facility utilizes the heat that is normally rejected to the atmosphere and converts it into useful process heat. The efficiency of an industrial cogeneration facility is, therefore, much higher than that of a conventional generating unit. Depending upon the power plant mix and the end user ratio of electrical to thermal energy, the overall end user fuel efficiency typically ranges between 30% and 65%. In contrast, a cogeneration facility is capable of operating at an overall energy efficiency of 75%. The cogeneration system, therefore, requires a lower amount of fuel to satisfy the same energy requirements. This system, thus, can significantly reduce an end user's utility costs. NUG, therefore, finds cogeneration an attractive option for generation of electrical energy.

Wind has emerged as a promising non-conventional source of energy and it is in some cases quite cost competitive with conventional sources. Wind energy is considered to be the most competitive renewable source of energy. More and more NUG are, therefore, choosing wind as a source of energy. The viability of a wind energy project depends on its ability to generate energy almost free of cost after a certain period of time. The initial investment by a NUG to install a wind turbine can be recovered in a relatively short period of time and the energy after this period is quite inexpensive as the energy source is free. The NUG, therefore, see the project paying for itself even if the initial investment is large. In addition, attractive incentives provided by the government in some countries have enticed a lot of private industries into setting up wind power projects.

A literature survey [76-85] shows that a considerable amount of work has been performed in the area of long term economic evaluation of wind power and cogenerated power. Some algorithms and computer programs have been developed that can be utilized to assess the most economic electric utility alternatives with and without wind and cogenerated power. In this chapter, some of the important characteristics of cogeneration and wind are discussed. Based on these characteristics, techniques are illustrated in the chapter to evaluate the AOC resulting from a short term energy transaction between a utility and NUG utilizing cogeneration facilities and wind as sources for energy production. The utility was assumed to be a pure thermal power system. The AOC has been evaluated from the marginal energy cost of the utility. This cost has an hourly time-of-day (TOD) profile and, therefore, the AOC is dependent on the hourly TOD profile of the energy purchase. The IEEE-RTS has been used to perform sensitivity studies based on the developed techniques. The studies can be utilized to determine the amount of energy and the time period during which a utility and a NUG can maximize their economic benefits.

5.2. Cogenerated Energy Produced by Non-Utility Generation

5.2.1. Historical Development of Cogeneration

In the early 1900's, on-site electric generation was more reliable and less costly than utility-generated power. Companies installed steam turbine generators, including the equivalent of cogeneration systems which recovered steam from production processes. As demand grew, the utility industry expanded and consolidated. Technological advances led to economies of scale in the generation and transmission of electricity. The decline of unit capital costs and the availability of relatively inexpensive fuel led to the decline in the cogeneration activity. Cogeneration became limited to industrial facilities, such as petroleum refineries, pulp and paper mills or chemical plants, where a unique combination of energy requirements and the availability of by-product fuels and on-site engineering made cogeneration cost effective. In the United States of America, the amount of power produced by cogenerators fell from almost 60% of the nation's power requirements in 1900 to about 4% of the total generation in 1977 as shown in Figure 5.1 [86]. In the 1990's, cogeneration facilities are allowed to sell electricity to the utility at reasonable rates in some countries. The option to sell electrical energy to a utility has again raised interest in industrial cogeneration.

5.2.2. Characteristics of Cogeneration

The most commonly employed, commercially available cogenerator prime movers are gas turbines, steam turbines (combustion turbine) and diesel engines (internal combustion

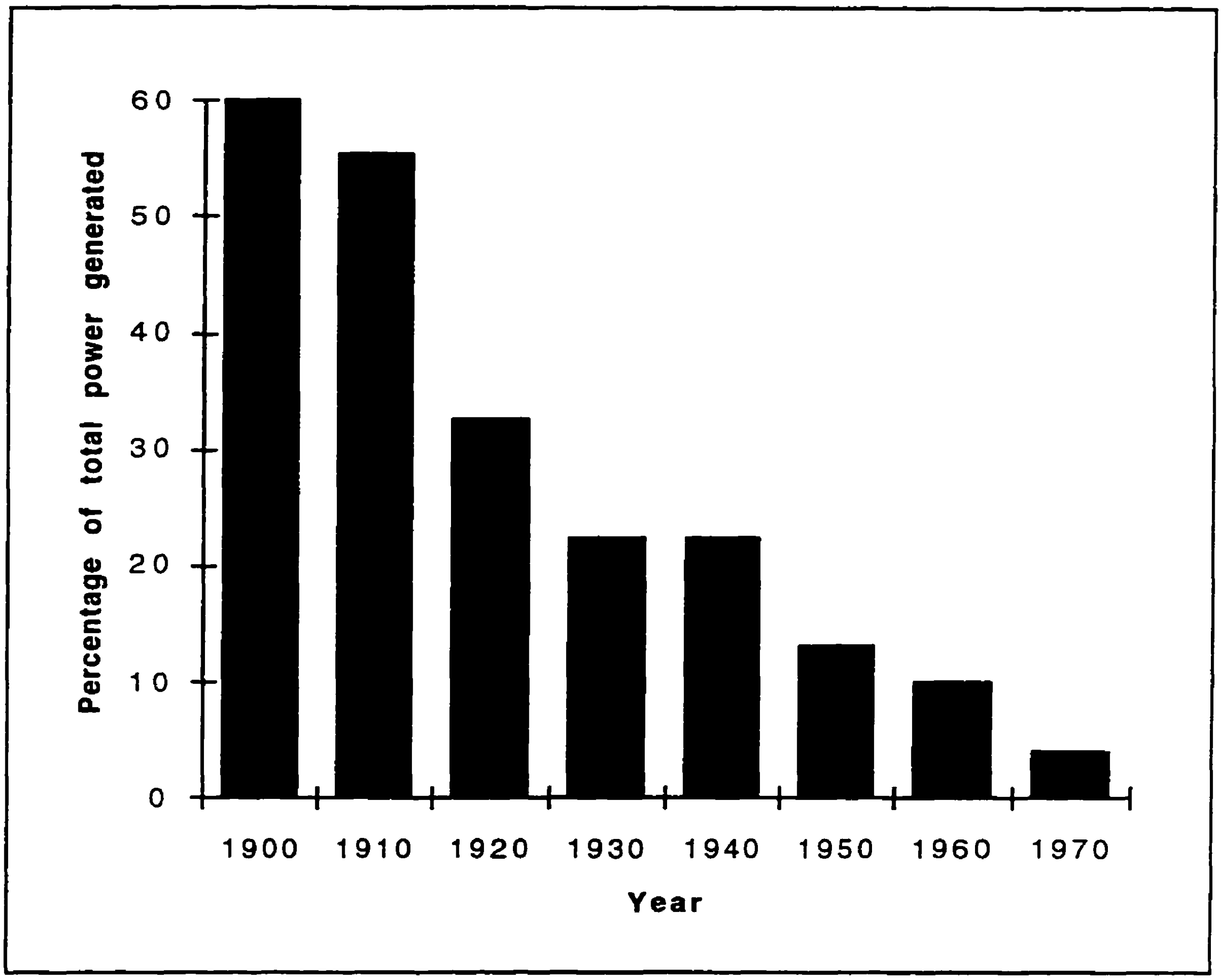


Figure 5.1. Cogeneration trend in the United States of America

reciprocating engines). All these engine alternatives have proven to be reliable and cost effective, based on the energy and performance requirements of a specific application.

Figure 5.2 [86] illustrates a typical cogeneration system where fuel is burned in a combustion turbine producing shaft power which drives an electric generator. The electricity can be used on-site in the facility, sold to a utility or a combination of both. The cogeneration facility whose energy is used on-site is referred to as internal use cogeneration. A second use of cogenerated facility is to sell energy to an electric utility, and this type of facility is referred to as sell back single cogeneration. A facility can also produce power both for sale to a utility and for on-site use.

It is considered in this chapter that industrial cogeneration is a facility that produces its own process steam for production purposes and also includes a turbine/generator unit in the steam line for the generation of electricity. The resulting electricity is used to meet the needs of the industry and any excess electricity is sold to a utility.

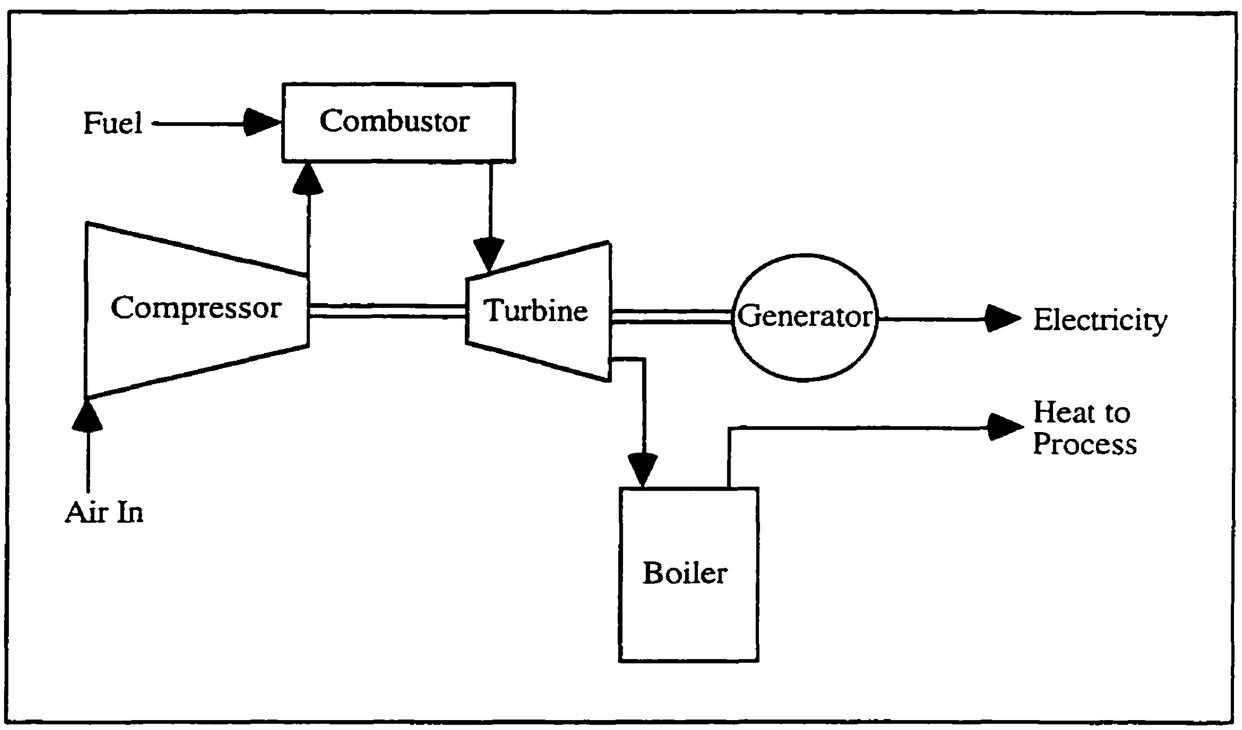


Figure 5.2. Typical cogeneration system

5.2.3. Integration of Cogeneration in an Electric Utility

NUG with cogeneration facilities can be connected to the utility grid to export cogenerated power, to receive additional power, to deliver power to another end user, or to sell power to some other utility which may be at different location. The studies illustrated in this chapter assume that the cogenerated electric power produced by the NUG is exported to the utility. For the sake of simplicity, it is assumed that the transmission losses are negligible. The ability to connect a cogenerator to the utility grid has resulted in significant improvements in cogeneration economics. It raises concerns in the minds of utility planners regarding system stability and security. In addition, planners want to use the energy produced from the cogeneration facility in an economic manner. The utility, therefore, wants to maintain dispatch rights over the electric power entering into the grid. If the power purchased from the cogeneration facility is significant, the utility also requires guarantees as to the time of delivery, the amount and the length of the agreement together with other considerations.

When a utility buys electrical energy from a NUG, it has to pay a charge to the NUG. which is dependent upon the type of the contract. In this chapter, it is considered that a cogeneration facility may provide energy on an 'as available' basis i.e. without legal obligation of contract. An electric utility is also not obligated to purchase energy from the NUG if such purchases will result in an increased operating cost.

5.2.4. Proposed Technique

When cogenerated energy is integrated into the utility planner's list of possibilities, it becomes crucial to accurately model this effect on system reliability and economics. The impact of cogeneration on system reliability is discussed in detail in Reference [87]. In order to investigate the economic impact of cogeneration on a utility, the fluctuating nature of energy production for these sources has to be taken into account. Utilities have normally modeled cogenerating units as "peaking units" because of the tendency for the cogeneration to follow the working day. That is, the cogeneration energy is available during the time when load is the greatest. Due to its variability and other characteristics, cogeneration is, however, typically an intermittent base load plant with no storage.

In order to model systems containing both utility units and industrial cogeneration sources, the total generating sources are divided into two categories, i.e., the utility units, that are in the direct control of the utility and the cogenerating units that are industry owned and operated. A utility does not have any control on the industry operating and dispatching policies and can only predict them using statistical methods. Two cases of non-energy limited (NEL) and energy limited (EL) cogenerating units have been considered and are discussed in the following [87]:

a) NUG with non-energy limited cogenerating units

Cogeneration units are assumed to be very reliable in this study. The probability of failure of a unit in the next 24 hours is, therefore, negligible. This seems reasonable as most failures in a conventional steam unit occur in the boiler. The steam produced by a NUG is crucial to its industrial process and, therefore, every possible effort is made to ensure that the boiler is operating. It is also assumed that cogeneration units are available 24 hours of the day and the output energy is constant for the study period.

b) NUG with energy limited cogenerating units

When the power output of the cogeneration sources are not dispatched by the utility operators but instead depend on a working day schedule, cogenerating units are called energy limited cogenerating units. These units differ considerably from conventional power generating units in their performance and operating characteristics. The dependence between the power available and the load has to be reflected in the development of the model. The cogeneration units are integrated into the utility network at a reduced level of output reflecting the energy available over the entire period of study.

Consider a cogenerating unit of 10 MW capacity and negligible probability of failure in the next 24 hours. The maximum energy available to the unit for 24 hours is 240 MWh. It is assumed that the cogenerating unit is energy limited and has only 80% of its maximum energy which is 192 MWh. Since the cogeneration output cannot be scheduled by the utility operator, it can be considered as a non-dispatchable energy limited unit.

The equivalent capacity of 8 MW is considered an equivalent energy of 8 MWh in one hour. The equivalent capacity is obtained by:

$$C_{eq} = \frac{(C_r \times E_a)}{E_m} \tag{5.1}$$

where

C_{eq} = equivalent capacity of the cogenerating unit

C_r = rated capacity of the cogenerating unit

E_a = energy available to the cogenerating unit

$$E_m = C_r \times T \tag{5.2}$$

= maximum energy available to the cogenerating unit if it were not energy limited

T = study period in hours

The energy constrained generation model reflecting both characteristics of non-dispatchability and energy limitation for the cogeneration source is given in Table 5.1.

A 10 MW cogenerating unit with 80% of the required maximum energy can be considered as a unit with an equivalent capacity of 8 MW.

Table 5.1 Energy constrained capacity distribution table for the cogenerating unit

Capacity (MW)	Individual probability
8	1.00
0	0.00

The AOC at each hour, ψ^h, can be computed by utilizing the following formula.

$$\psi^h = \sum_{i=1}^{S} \Phi_i \times A_i \tag{5.3}$$

where

S = the total number of states in the energy constraint capacity distribution table.

Φ_i = AOC evaluated for a cogenerating unit at state i

A_i = probability of the cogeneration unit at state i

Φ_i can be evaluated by utilizing the generalized algorithm discussed in Chapter 2.

5.2.5. System Studies

Sensitivity studies have been performed on the IEEE-RTS in order to illustrate the effect of a cogeneration facility on utility short term operational planning. Studies similar to these can be used by the system operator to make valid decisions.

5.2.5.1. Economic benefit of a cogeneration facility

Many industries that used to produce heat for their own purposes have started considering the implementation of a cogeneration facility on their premises due to the opportunity to sell electricity to the utility. By doing so, the industry achieves economic benefit. This can be explained by the following example [86]. Assume that an industry which produces heat for its own purposes spent \$X to produce Y unit of heat at an efficiency of 95%. The industry, now, decides to implement a cogeneration facility using a gas turbine with an efficiency of 80%. Assume that M% of fuel is converted into electricity and N% into useful heat. After satisfying its heat demand, the industry sells the electricity that is generated as a byproduct to the utility that operates at an efficiency of 33%. The utility spends 3 units of fuel to produce one unit of electricity. It, therefore, pays the cost of 3 units of fuel to the industry for one unit of electricity purchase. Figure 5.3 shows the variation in the cost that the industry incurs to satisfy its heat demand as a function of the percentage of the input fuel that is converted into electricity. Total efficiency, i.e., efficiency of heat and electricity, is kept constant at 80%. It can be observed from the figure that the industrial cost goes down as the electrical output increases. The figure also shows a case designated as steam turbine cogeneration in which the overall efficiency is 85%. The downward trend in industrial cost as a function of electrical outputs has encouraged the development of industrial cogeneration.

5.2.5.2. Effect of NUG energy on the AOC

A comparison of AOCs and the costs incurred by the utility evaluated for NEL and EL cogenerating units, with and without the probability of cogenerating unit failure is illustrated in Figures 5.4 and 5.5. A constant probability of failure of 0.0027 has been applied in each hour. This is based on 1 failure per year and a lead time of 24 hours. The curves with and without considering probability of cogenerating unit failure are virtually

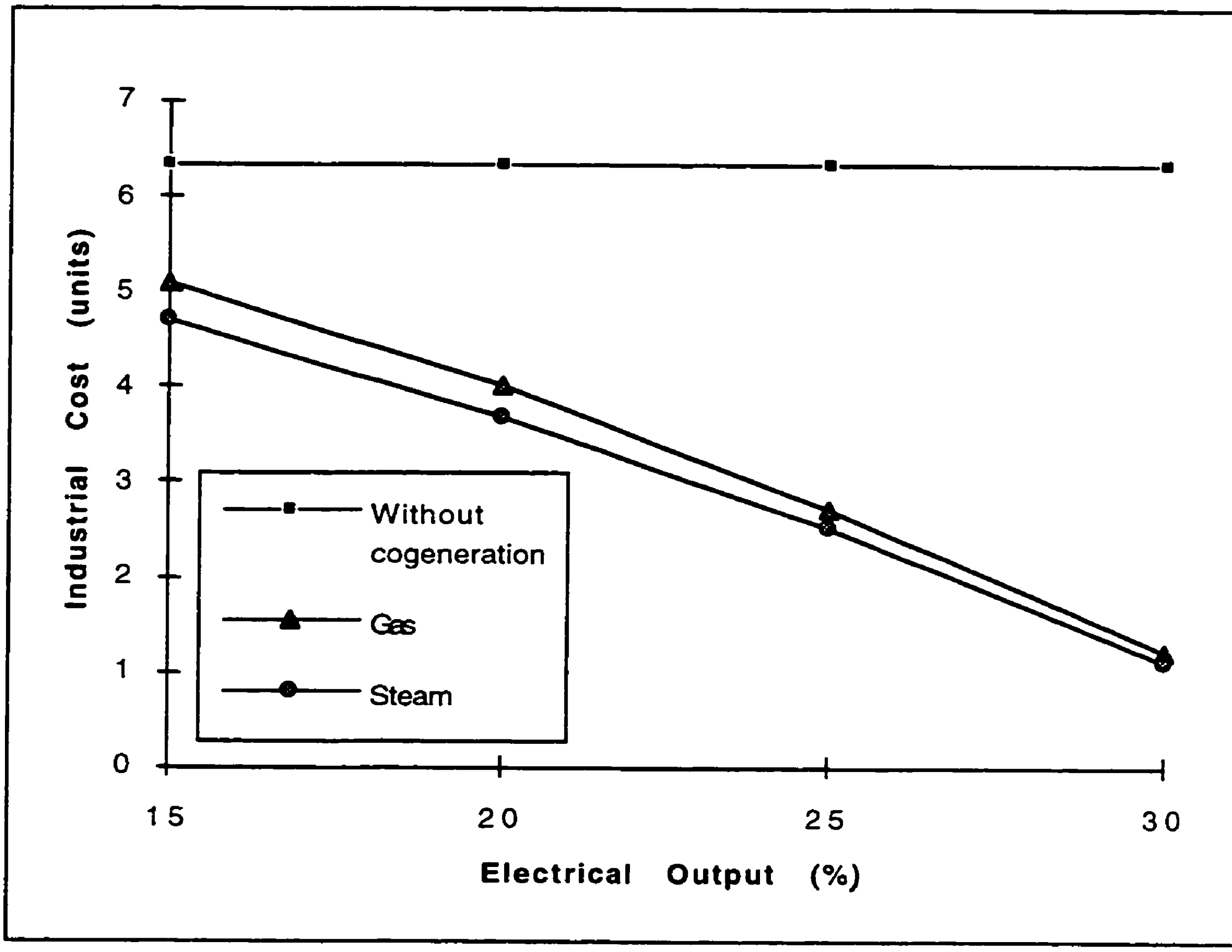


Figure 5.3. Economic benefit incurred by an industry

identical in each case. It can be observed from the figures that the AOC increases and the costs incurred by the utility decrease with increase in the cogeneration energy that the NUG sells to the utility over 24 hours. This is due to the fact that an increase in the NUG energy causes the utility to reduce the output of its expensive units. It can be further observed from Figures 5.4 and 5.5 that for a particular cogeneration energy, the AOC is lower and the cost incurred by the utility is higher in the case of the EL cogenerating unit than that in the case of the NEL unit and the difference is considerable. It is, therefore, important to correctly identify the cogenerating facility as NEL or EL. The AOC and the

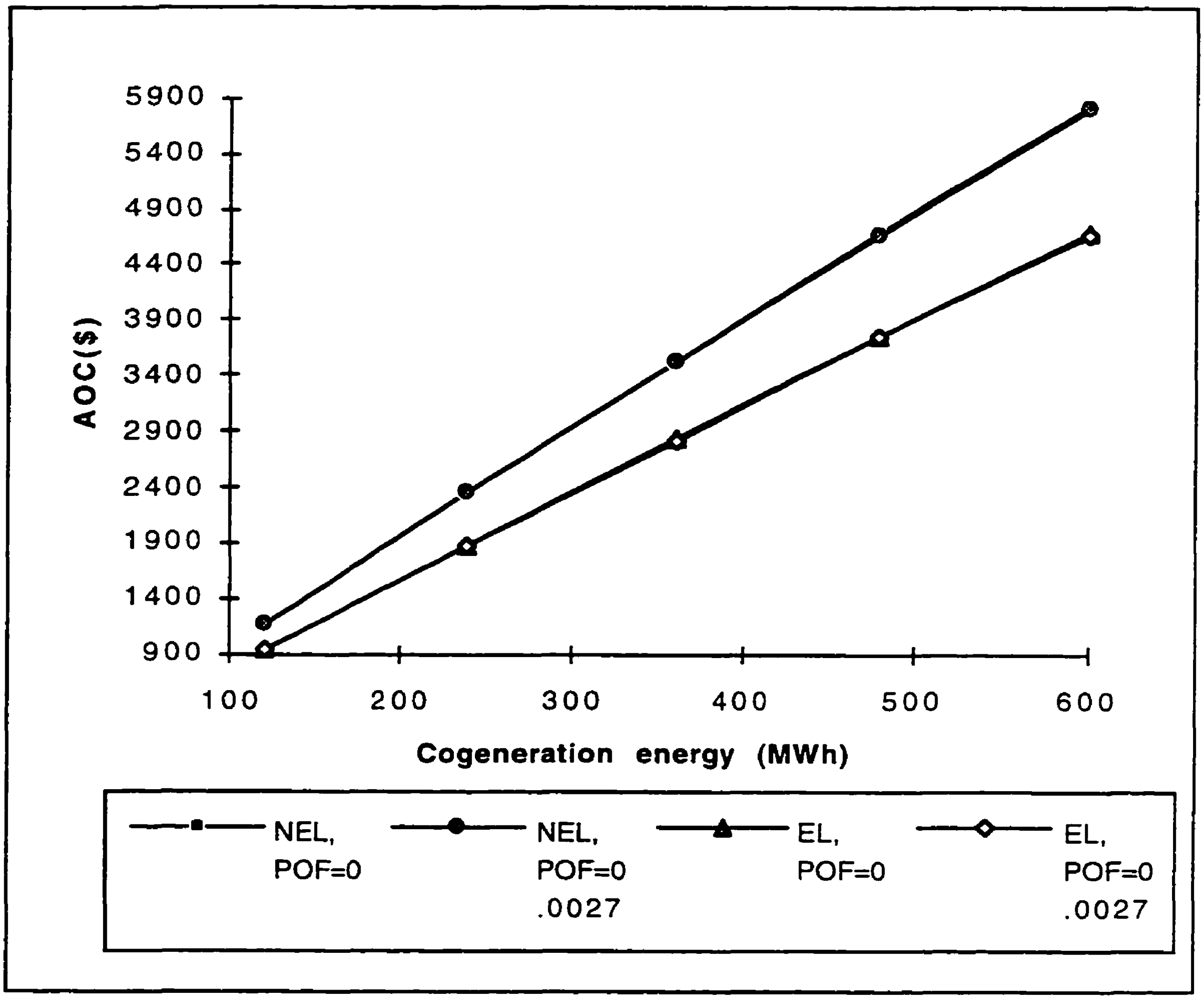


Figure 5.4. Comparison of the AOCs

utility cost do not change significantly due to incorporation of the probability of cogenerating unit failure and, therefore, this can be neglected.

5.2.5.3. Effect of the number of cogenerating units on the AOC

The effect of the number of cogenerating units on the AOC is shown in Figure 5.6. It is assumed in this study that a total of 20 MWh of energy is supplied by the cogenerating facility in one hour and the probability of cogenerating unit failure is 0.0027. A period of 24 hours was considered for the AOC evaluation. Both NEL and EL cogenerating units

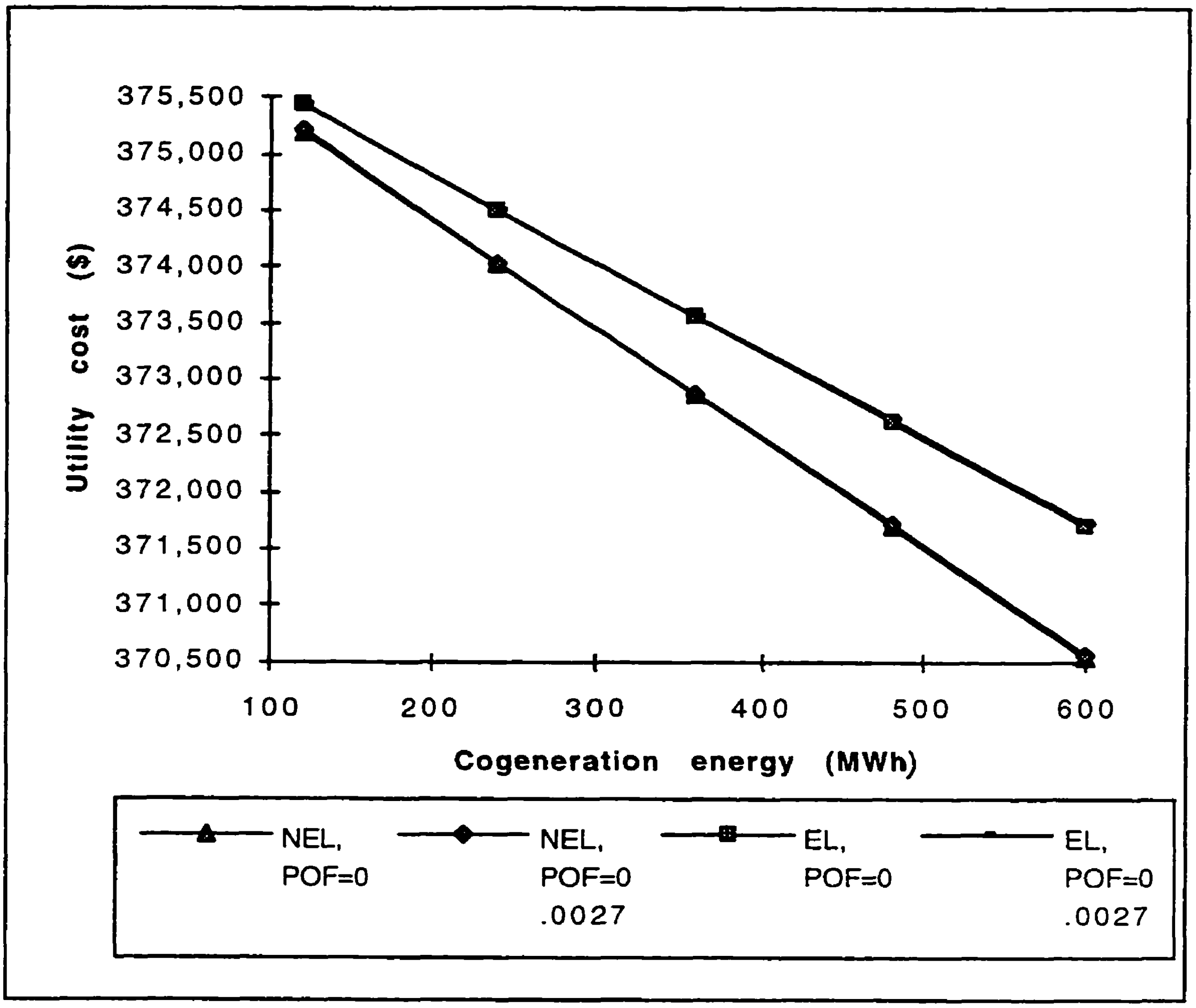


Figure 5.5. Comparison of utility costs

were considered in this study. It can be observed from Figure 5.6 that an increase in the number of units causes an increase in the AOC. The increase in the AOC is, however, insignificant due to the fact that the probability of failure associated with a cogenerating unit is very small. In each case, the AOC for NEL cogenerating units is higher than that for EL cogenerating units.

5.2.5.4. Effect of the probability of cogenerating unit failure

The probability of failure of a cogenerating unit in the next 24 hours is very low due to the high reliability of these units. The effects of probability of unit failure on the AOC and the cost incurred by the utility due to a NUG energy purchase were examined in the case where cogenerating units are prone to frequent failures. This effect is illustrated in Figures 5.7 and 5.8. It was assumed that 20 MWh of energy is purchased by the utility from the NUG in one hour. It can be observed from Figure 5.7 that the AOC decrease

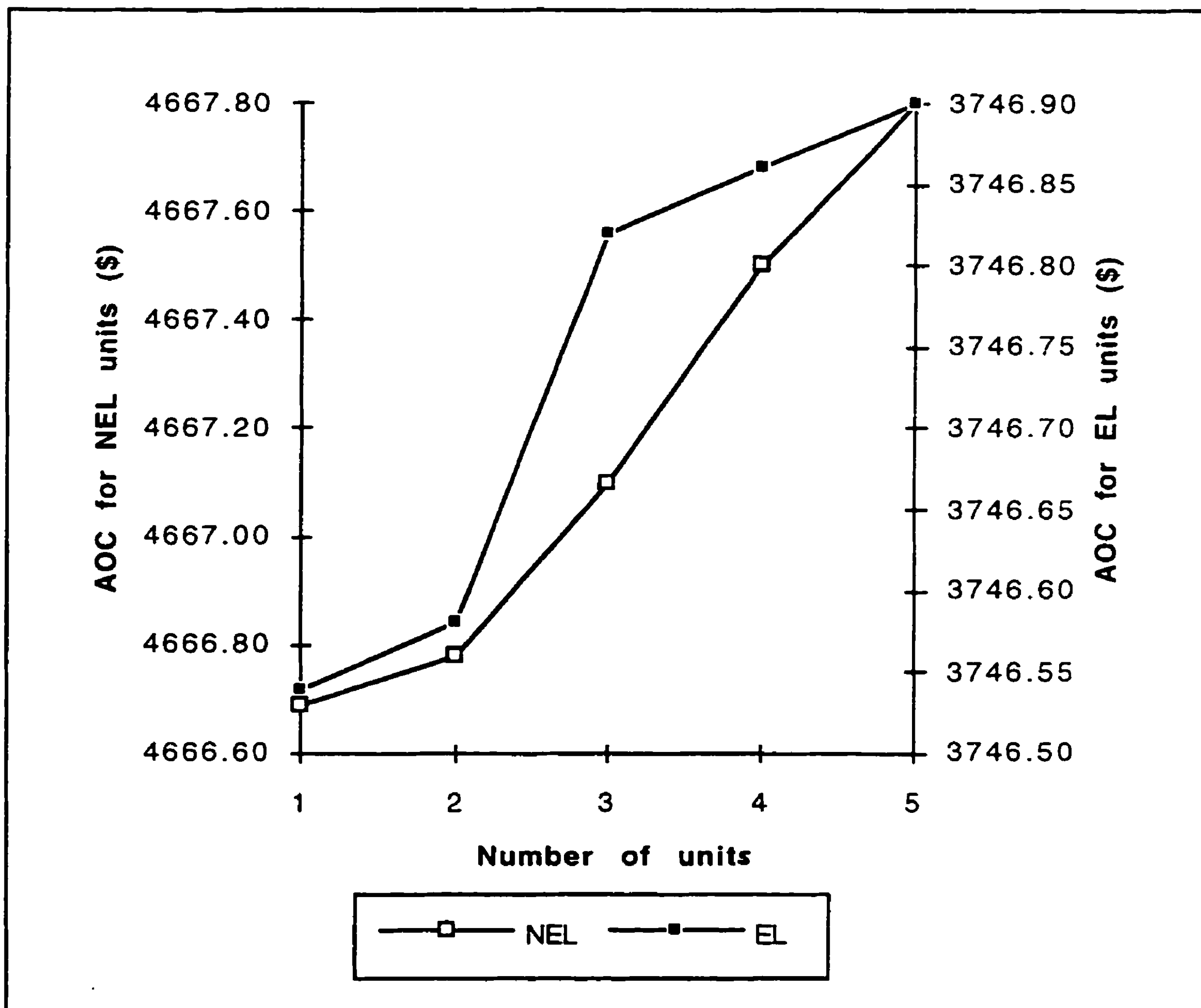


Figure 5.6. Number of cogenerating units and the AOC

with increase in the probability of failure for both NEL and EL cogenerating units. The slopes of the AOC are, however, different in the two cases. The AOC for an EL cogenerating unit is higher than that for a NEL cogenerating unit for a particular probability of failure and the difference in the AOC increases as the probability of failure is increased. Figure 5.8 shows the change in the utility cost as a function of the probability of NUG unit failure. The cost incurred by utility without the NUG is $376381.50 and is higher than that with the NUG in both cases of NEL and EL units.

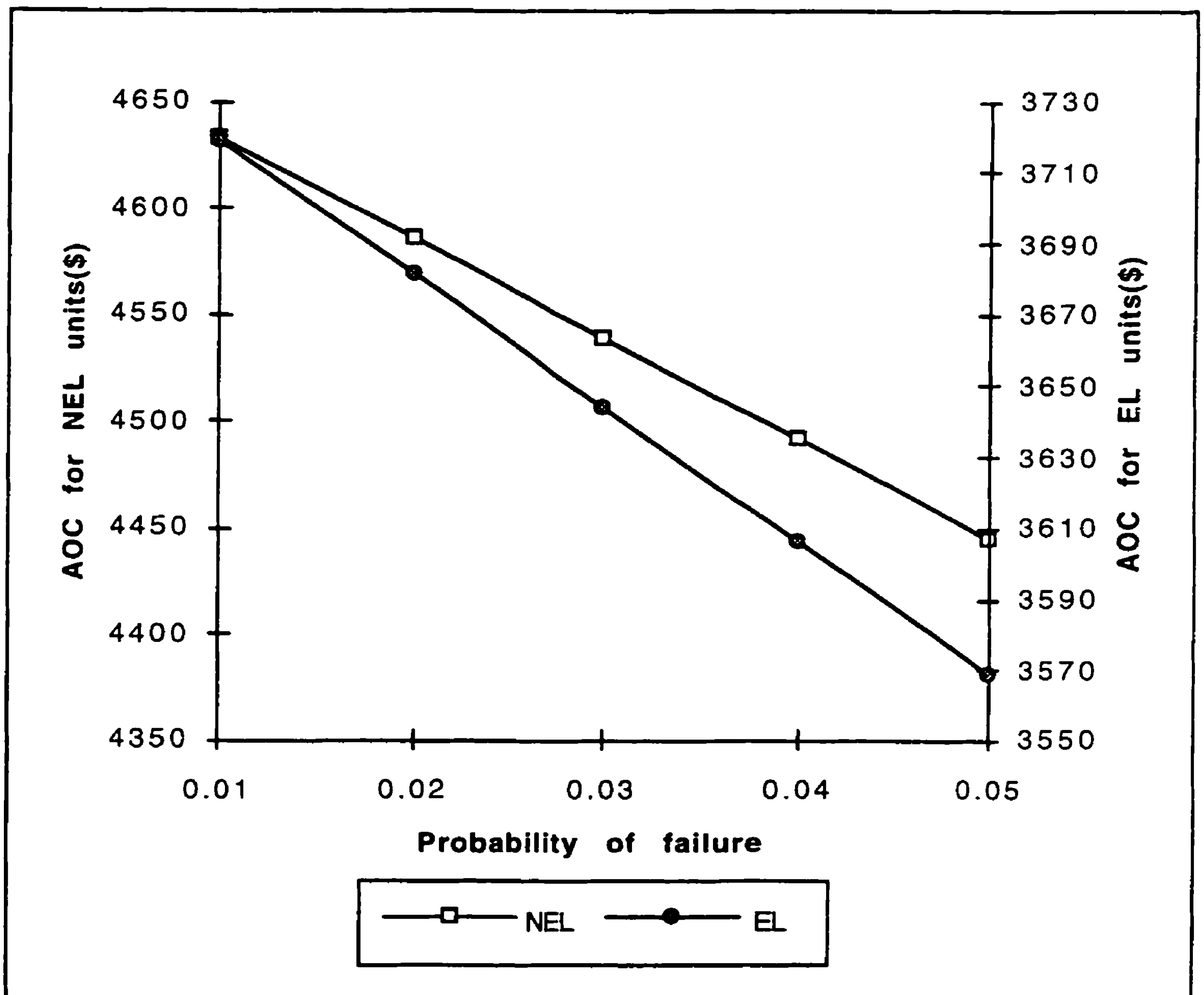


Figure 5.7. AOC as a function of the probability of failure of the cogenerating unit

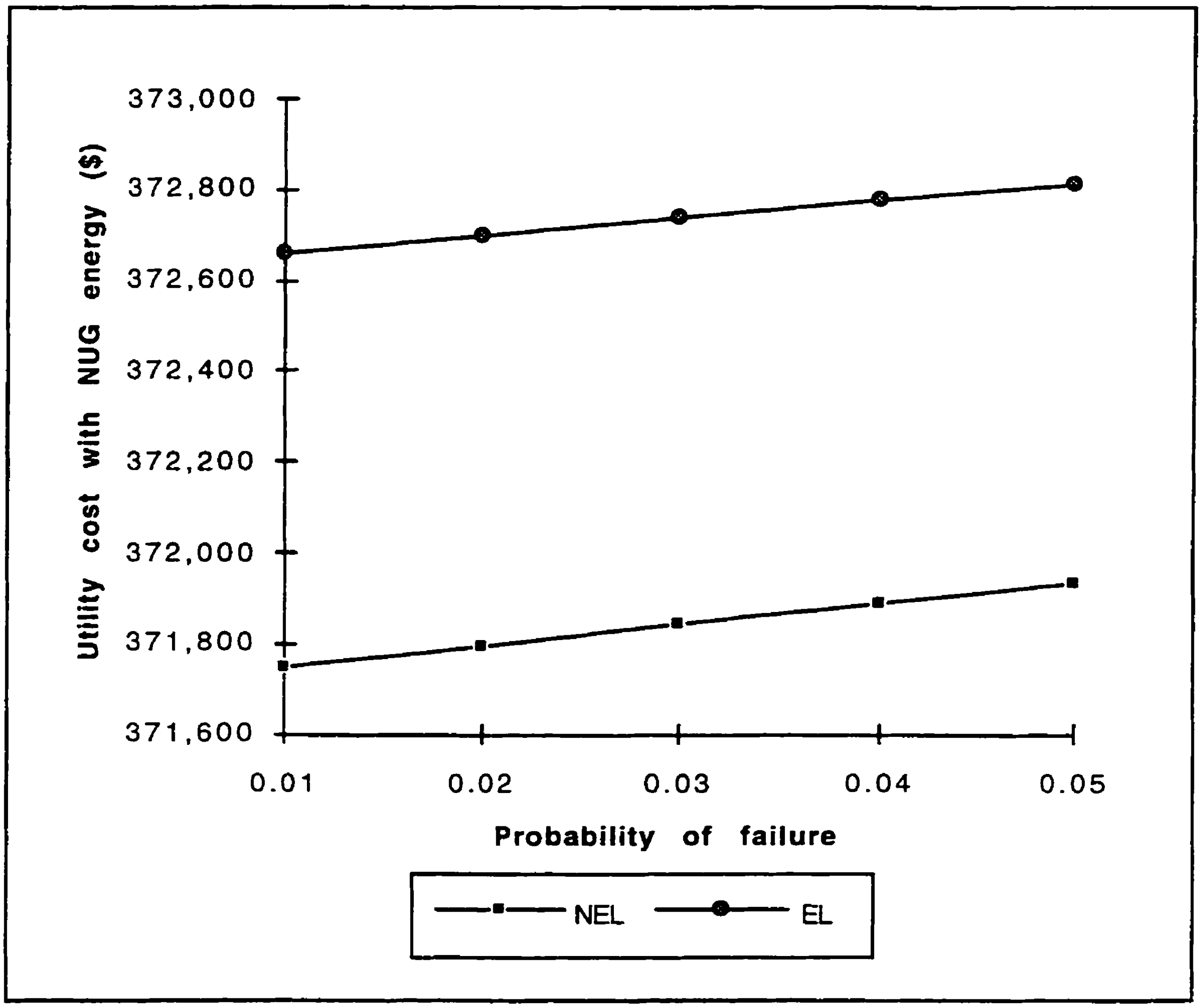


Figure 5.8. Utility cost as a function of the probability of failure of the cogenerating unit

5.2.5.5. AOC at peak load

Cogeneration energy may or may not be available for twenty four hours a day, due to its dependence on a working day schedule. A cogeneration unit will, therefore, contribute intermittently to utility generation during the peak, cycling and base load periods. This study presents a method which incorporates the time dependent energy production of cogeneration sources in the analysis. The method develops a model which uses the unit hourly energy over an assigned hourly load period. Two periods have been selected, a 24 hour period and an 8 hour period extending over the peak loads. The effect of NEL and EL cogenerating unit on utility economics using a peaking operation and 24 hour operation schemes is illustrated in Figures 5.9 and 5.10 respectively. Variations in the AOC evaluated for the NUG energy transaction over 24 hours and during the peak load period as a function of the NUG energy is shown in the figures. It can be observed from Figures 5.9 and 5.10 that the AOC per unit of energy decreases with increase in the energy sold by the NUG to the utility. The AOC is considerably higher at the peak load

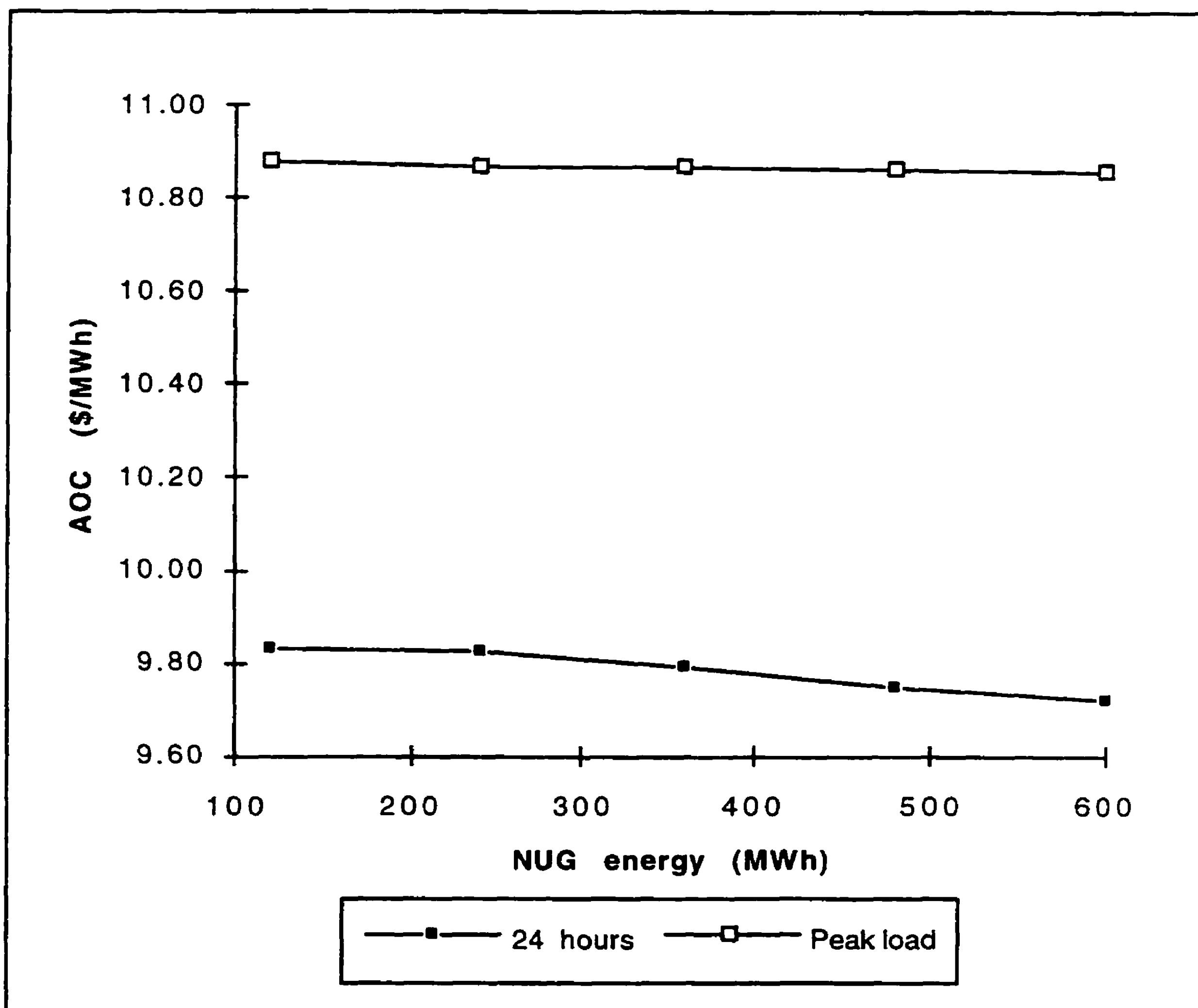


Figure 5.9. Effect of NEL cogenerating unit on the AOC

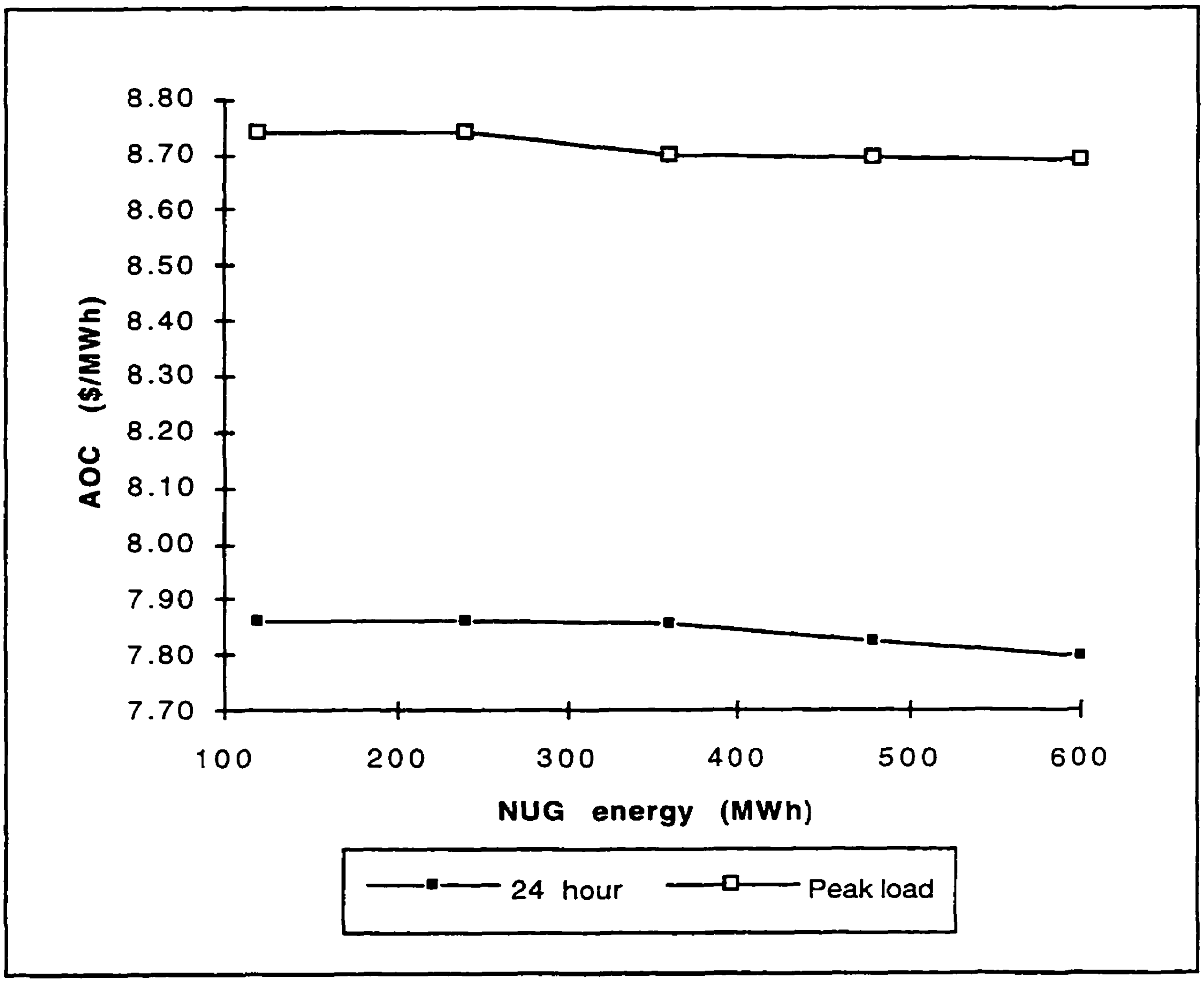


Figure 5.10. Effect of EL cogenerating unit on the AOC

than over the 24 hours due to the fact that the utility is operating its expensive units at the peak load. The marginal cost of the utility is thus higher and, therefore, the AOC is higher at the peak load.

5.3. Wind Energy Produced by Non-Utility Generation

5.3.1. Historical Development of Wind Energy Systems

The earliest wind system was developed in the near east and Egypt [88]. By the thirteenth century it had begun to spread to Europe. Through the centuries, its use expanded and wind became useful for providing mechanical power, electricity and pumping water. The use of wind in the early 20th century declined due to the development of coal and gas resources. In the 1930s, very little attention was paid to this technology and limited experimental work was carried out in few countries. There was a small base of scientific and engineering knowledge gained from some large turbine experiments conducted in Europe and the United States in the 1940s and 1950s. Though there were a few electricity producing machines, major wind machine manufacturers disappeared in the 1960s. Conventional energy prices increased sharply in 1974 due to the oil crises. Many countries, therefore, initiated wind energy research programs. Since 1974, significant advances have been made in wind energy conversion technology. Wind systems are currently operating successfully in a large number of countries. A high degree of progress has been made in reliability and availability gains for commercially installed equipment. Medium scale machines (100-500 kW) with availabilities of 95% to 98% and capacity factors nearing 30% in ideal wind sites have been developed. The market growth that has occurred, has been due to a combination of factors: location of excellent wind resources in high cost energy areas, over dependence on oil and gas, public policy designed to encourage alternative energy use in the utility sector, and government investment incentives attracting capital to large projects. Although wind energy has been exploited for many years, the actual development of grid connected, efficient and reliable wind turbines have proved to be a major challenge. Due to the many technical developments that have occurred over the last 20 years, a range of commercial wind turbine is now available. The most dramatic rise in wind energy generation occurred in the USA, when favorable tax credits and energy rates for IPP resulted in 1600 MW of installed capacity. An additional 1500 MW of wind capacity is under negotiation in California that could launch a new wind rush [89]. About 1372 MW of wind turbines were installed in Europe by 1994, mostly in Denmark. Table 5.2 shows the installed wind capacity in Europe [89].

A 9 MW wind farm was built in Alberta (Pincher Creek) in 1993. A second 9.8 MW wind farm has been operational on the same site since May 1994. Kenetech has an agreement with Hydro-Quebec for the sale of electricity from two wind farms totaling 100 MW of installed capacity, on the coast of Gaspe peninsula [89].

Table 5.2. Wind capacity in Europe

Country	IC (MW)
Denmark	520
Netherlands	132
Germany	429
UK	154
Spain	70
Belgium	6
Italy	20
Greece	30
Portugal	2
Sweden	2
Ireland	7
Total	1372

IC = Installed capacity

5.3.2. Characteristics of Wind Energy

The integration of NUG wind power in a power utility results in fuel saving for the utility. It may also allow future capital expenditure on conventional plants to be reduced or deferred. The integration is, however, not without problems mostly due to the unpredictable nature of wind. The daily and seasonal patterns in the wind speed distribution and the distance of the resource from the customer also creates problems. The other important factors that affect the integration of wind turbines include: array interference, level of penetration, the extent of dispersion, and the weather. The array efficiency is the ratio between the actual output from clustered turbines to the output that would be obtained without interference. The array efficiency depends upon spacing between turbines and the nature of wind regime. Wind energy penetration in a large system creates fewer problems than in a small system. If the installed wind capacity is small relative to the total demand, wind fluctuations are simply lost among the fluctuations in the electricity demand. If the installed wind capacity is large then many wind turbines spread out among different sites will smooth the overall output. In addition, large systems have a greater natural reserve, with many thermal generating units connected at any time. Most large systems also have sources such as hydropower generators and gas turbines that can respond rapidly to changing conditions. Consequently, wind energy can be exploited without the need for storage and it may be available at the critical moment when demand is high and other units have failed. It, thus, reduces a system's overall risk of failure and allows the conventional plant reserve margin to be reduced.

The cost of wind energy has gone from 14 ¢/kWh to 5 ¢/kWh from 1982 to 1992 [89]. In Denmark, wind energy is competitive today with conventional sources: 4 ¢/kWh for a wind velocity of 8.5 m/s and 6.8 ¢/kWh for a wind velocity of 6.5 m/s. The installed cost of wind farms has dropped from $2400/kW in 1985 to about $800-

$1200/kW in 1994. Price per kWh reduces with increase in the size and the number of manufactured units. With the current international wind energy targets, the manufacturing needs for commercially mature wind turbines is growing. Among the renewable energy sources, wind is the most likely source to compete with conventional technologies on costs.

5.3.3. Integration of Wind Energy in Electric Utility

Inspite of the fact that wind generation has many advantages in terms of its interaction with the environment, concern has been raised about its variable nature and how it will affect an electric power utility. Unpredictability from moment to moment and place to place is not the only problem. The wind's variability also covers a wide range of velocities. The effect of velocity is enlarged by the fact that wind force varies with the square of velocity, whereas the power varies with the cube of velocity. Wind has a second major characteristic in addition to variability: its diffuseness. It is not a concentrated source of energy. Its drag force on a square meter of surface is quite small at ordinary wind velocities, and the power of the wind passing through a square meter of area is modest. In order to generate a significant power, a wind mill must, therefore, harvest a large cross-section area of wind. Potential problems also revolve around the possibility of no wind or wind generation at peak hours and full generation during minimum hours, thus making NUG and thereby utility dependent upon weather patterns. Wind technology, therefore, differs considerably from conventional power generation technologies in its performance and operating characteristics. The energy output from the wind is a non-dispatchable form of energy. This is because it is dependent upon natural factors that are beyond the control of a system operator and, therefore, cannot be dispatched by the system operator.

When wind energy produced by a NUG is integrated into a system planner's list of possible generation, it becomes important to accurately model its effect on system economics. NUG do not have any control over the energy produced by wind. No commitment is made by the NUG to provide wind energy on any guaranteed basis. In order to accommodate the non-firm energy, a utility system planner has to modify the existing generation schedule. The inclusion of NUG energy may take place at the price of a reduction in the reliability and an increase in the cost. The integration of the NUG in the utility grid, thus, becomes an economic and reliability concern. A utility usually attempts to maintain a fixed level of reliability and at the same time make the system economical. In the proposed rescheduling technique, illustrated in the next section, the generation schedule is modified to accommodate NUG energy such that the reserve is maintained at a pre-specified level and the system operates at the most economical manner.

Since the NUG energy is not under the direct control of the utility and information received by the utility operator regarding the availability of this energy is very late, it is not considered as commitable energy in the technique. The NUG energy is, therefore, not considered in the unit commitment process. When a NUG sells energy to the utility, it (NUG) is not responsible for carrying any reserve. The utility, therefore, ensures that sufficient spinning reserve is allocated to its units to meet the system requirement.

When wind energy provided by a NUG is included, the major economic benefit to the utility is the saving in the conventional fuel cost. The ability of wind turbines to be installed rapidly reduces the planning margin required for installed capacity over maximum demand and, thus, saves capital. But despite the interest in capital issues, the major savings come from the savings in fuel that is displaced by wind energy. Operational penalties arising from fluctuations in wind energy and uncertainties in wind prediction do not become significant until wind energy penetration is high.

A technique is illustrated in the next section that can be utilized to evaluate the expected energy produced from a Wind Turbine Generator (WTG) and to evaluate the AOC when a NUG sells this energy to a utility.

5.3.4. Proposed Technique

The power output characteristic of a WTG is quite different from the conventional generating units found in most utility systems. Wind generator output depends upon the wind characteristics as well as on the aero-turbine performance and the efficiency of the electric generator. These factors must be combined to obtain a probabilistic profile of the WTG output.

The aero-turbine is operated at a constant speed and a synchronous machine converts the mechanical input to constant frequency electrical output. When induction generators are employed, the aero-turbine must slip a little and consequently operate at nearly constant speed. In either case the unit starts delivering electrical output at a wind speed called the cut-in speed and reaches the rated electrical output at a wind speed called the rated speed. The electrical output is maintained constant at the rated value for further increases in the wind speed up to the cut-out speed, beyond which the unit is shut down for safety reasons. Between the cut-in and the rated speed, the relationship between the electrical output and the wind speed is considered to be non-linear due to the combined effect of aero-turbine and generator characteristics. The output of a WTG lies between zero and the rated value for nearly half of the time (or even longer for poor wind regime days) because of constant variations in the wind input. A typical WTG electrical output curve is shown in Figure 5.11 [87,90].

The parameters in Figure 5.11 are

P_r = rated power output

V_{ci} = cut-in wind speed

V_r = rated wind speed

V_{co} = cut-out wind speed.

The power output can be calculated as

$$POWER(V) = 0 \qquad 0 \le V < V_{ci} \tag{5.4}$$

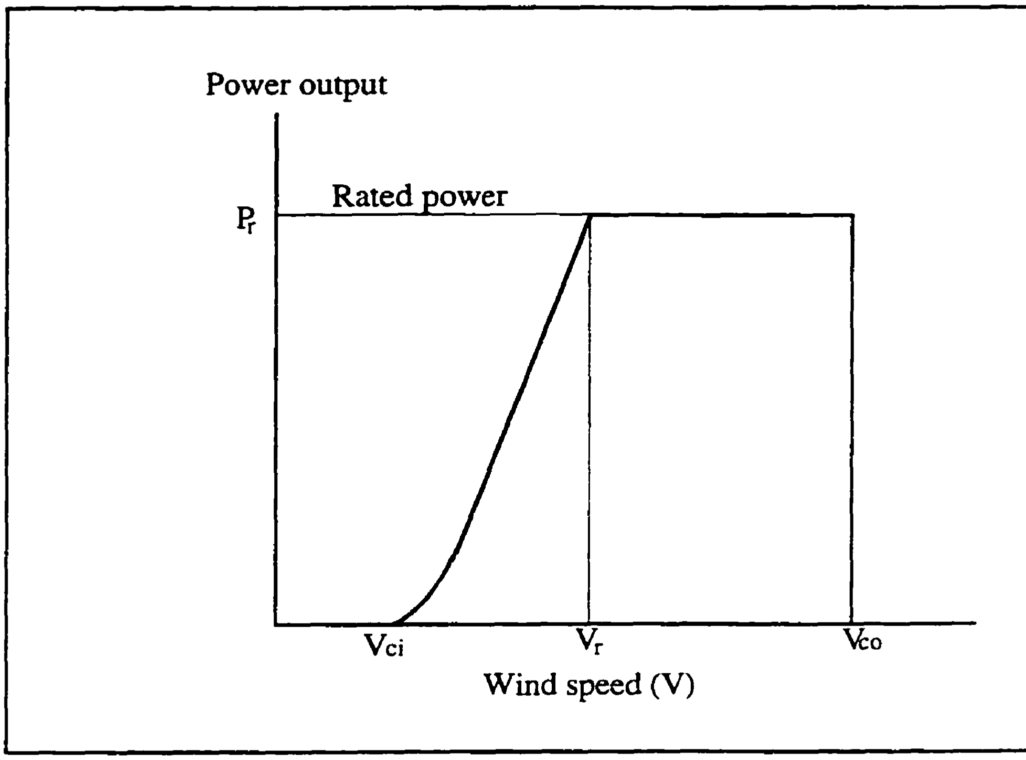


Figure 5.11. A typical WTG output characteristics

$$= (A + BV + CV^2)P_r \qquad V_{ci} \le V < V_r \tag{5.5}$$

$$= P_r \qquad V_r \le V < V_{co} \tag{5.6}$$

$$= 0 \qquad V \ge V_{co} \tag{5.7}$$

The constants A, B and C may be found as functions of V_{ci} and V_r using the following equations [87,90]:

$$A = \frac{1}{(V_{ci} - V_r)^2}\left\{V_{ci}(V_{ci} + V_r) - 4(V_{ci}V_r)\left(\frac{V_{ci} + V_r}{2V_r}\right)^3\right\} \tag{5.8}$$

$$B = \frac{1}{(V_{ci} - V_r)^2}\left\{4(V_{ci} + V_r)(\frac{V_{ci} + V_r}{2V_r})^3 - (3V_{ci} + V_r)\right\} \tag{5.9}$$

$$C = \frac{1}{(V_{ci} - V_r)^2}\left\{2 - 4(\frac{V_{ci} + V_r}{2V_r})^3\right\} \tag{5.10}$$

The uncertainty associated with the energy obtained from other types of NUG, thermal or hydro, is small compared to that associated with wind. The actual wind energy coming from the NUG may be considerably different from the forecast value. The uncertainty associated with the wind energy is, therefore, considered in this chapter. The wind energy is dependent upon the velocity of the wind. The uncertainty in the velocity of the wind can be included in the evaluation of wind energy by dividing the hourly forecasted probability distribution into class intervals. The number of class intervals depends upon the accuracy desired. The distribution mean is the forecast velocity of the wind. The velocity representing the class interval mid-point is assigned the designated probability for that class interval. The energy computed for each velocity is multiplied by the probability that the velocity exists. The sum of these products represents the energy for the forecast velocity. Published data indicate that the uncertainty can be reasonably described by a normal distribution. A seven step distribution is assumed in this chapter. This is shown in Figure 5.12 [2].

In addition to the output variations with wind speed, a WTG unit has a probability of failure (POF). Once the expected energy is determined by using the seven step approximation technique, the average output energy using the conditional probability method is determined considering the POF of WTG. The AOC is then evaluated. The technique for determination of the AOC is the same as that of the generalized algorithm illustrated in Chapter 2.

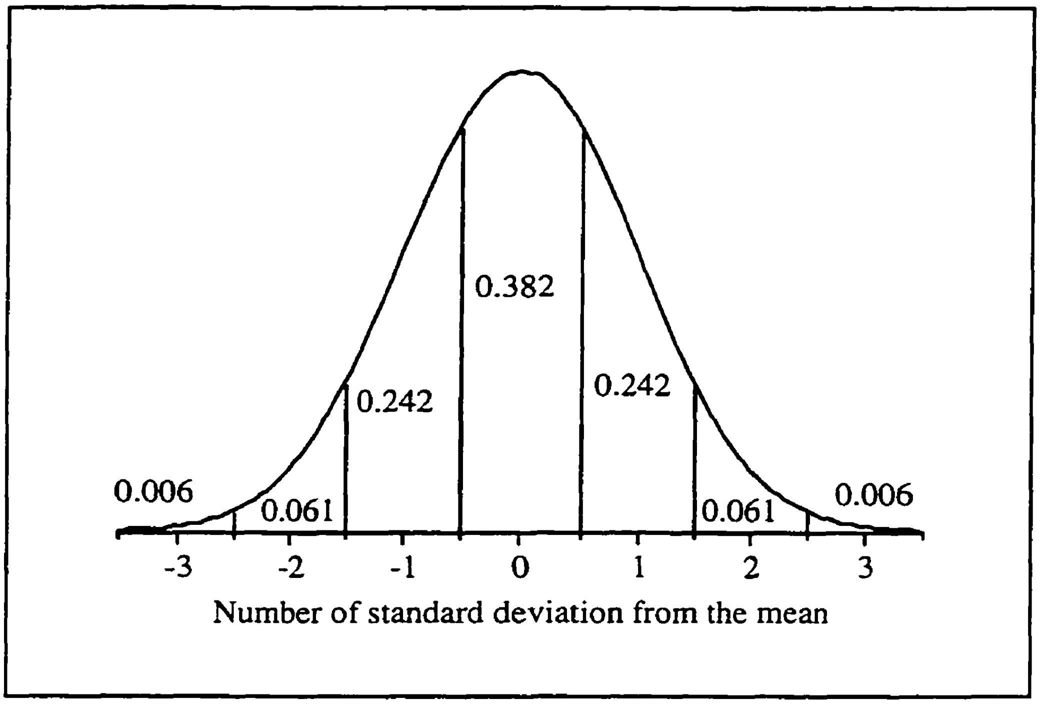


Figure 5.12. Seven step approximation method

5.3.5. Sensitivity Studies

The proposed technique has been applied to an IEEE-RTS that purchases energy from a NUG which generates energy from a Wind Energy Conversion System (WECS). Unlike a conventional generating unit, a WECS cannot be committed by a NUG to provide a certain amount of energy at a desired time. The energy output of a WECS is a function of the wind regime at the location where it is installed. The average hourly wind speeds used in this chapter are modification of a designated Saskatoon location [91,92] and are illustrated in Figure 5.13. An hourly load profile of the IEEE-RTS is also shown in the figure. It can be seen from the figure that the wind speed profile has a similar pattern to that of the load. Table 5.3 shows the standard deviation (SD) of the average wind speed at each hour.

A WTG of 2 MW was considered in these studies. The cut-in speed, rated speed and cut-out speed are assumed to be 14.15 km/h, 46.02 km/h and 75.5 km/h respectively. On the basis of this data, sensitivity studies were performed and are illustrated in the following sub-sections.

5.3.5.1. Effect of uncertainty of wind energy

Wind is highly unpredictable in nature and therefore wind speed is usually predicted on the basis of past experience. The actual speed and, therefore, the energy obtained from wind will differ from the forecast value. The significance of the uncertainty associated

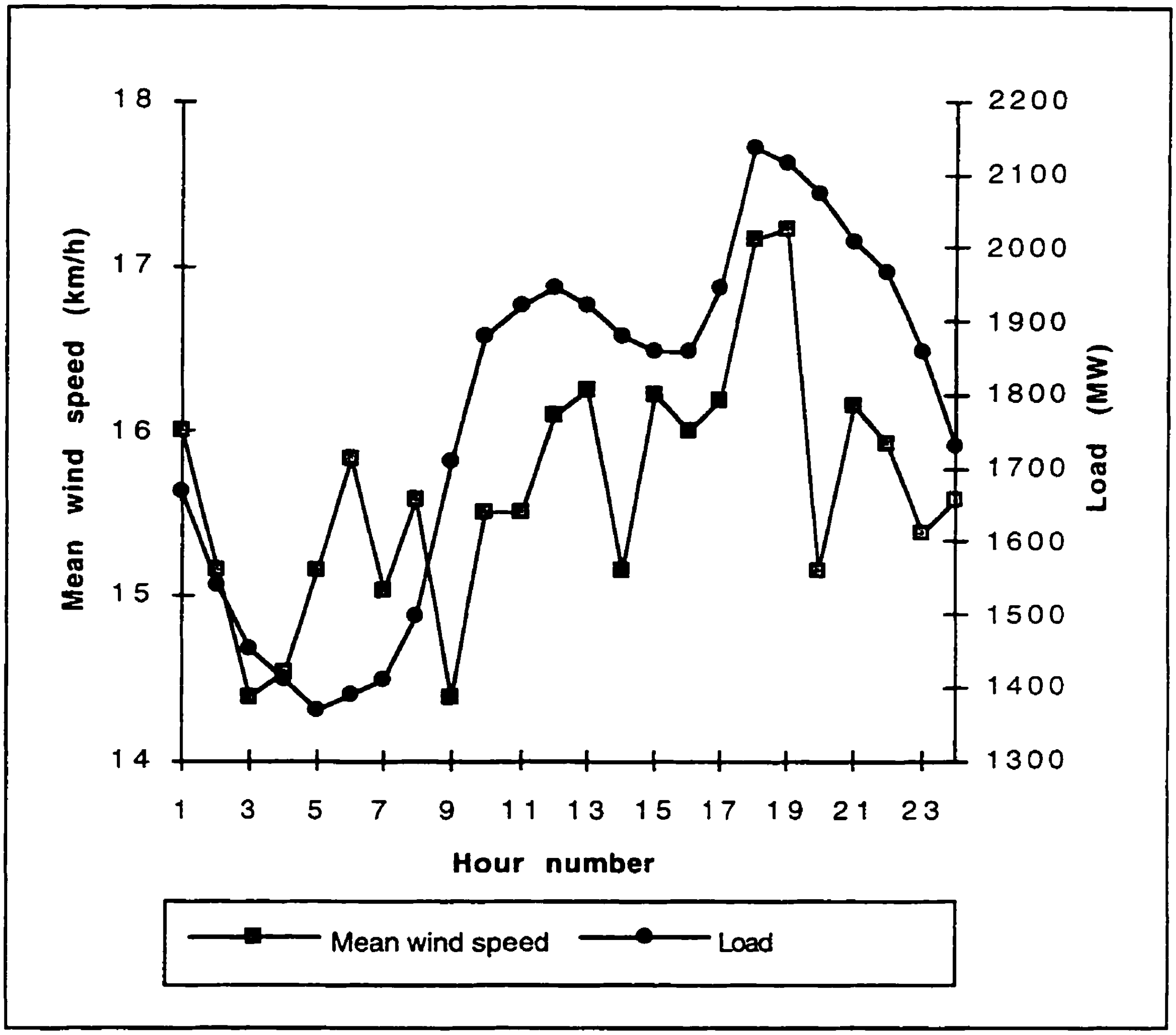


Figure 5.13. Wind speed and load profiles for a 24 hour period

with the forecast wind velocity is illustrated in Figure 5.14. The effect of the probability of failure of a WTG in the next 24 hours on the wind energy is also shown in the figure. It is assumed in this study that a NUG generates energy from 20 WTGs each having a capacity of 2 MW. A constant probability of failure of 0.0137 has been applied for each hour. This is based on 5 failures per year and a lead time of 24 hours. Figure 5.14 shows a wind energy profile for a period of 24 hours for three cases. In the first case, the uncertainty in wind speed and the probability of failure (POF) of WTG were not

Table 5.3. Standard deviation of the average wind speed

Hour	SD	Hour	SD	Hour	SD	Hour	SD
1	5.58	7	6.61	13	7.58	19	7.45
2	6.76	8	7.26	14	8.05	20	6.71
3	6.93	9	6.84	15	8.13	21	7.78
4	5.60	10	7.17	16	7.84	22	7.71
5	6.78	11	7.34	17	7.74	23	8.09
6	6.42	12	7.17	18	7.42	24	7.46

considered. In the second case, only the uncertainty in wind speed was considered. Both wind speed uncertainty and the probability of WTG failure were considered in the third case. It can be observed from Figure 5.14 that the wind energy profile is considerably lower in the first case compared to that in the second and third cases where the wind energy profiles are quite close together. This study suggests that it is very important to consider the uncertainty associated with the wind speed forecast to obtain realistic results. A seven step approximation of the wind model is used in this study.

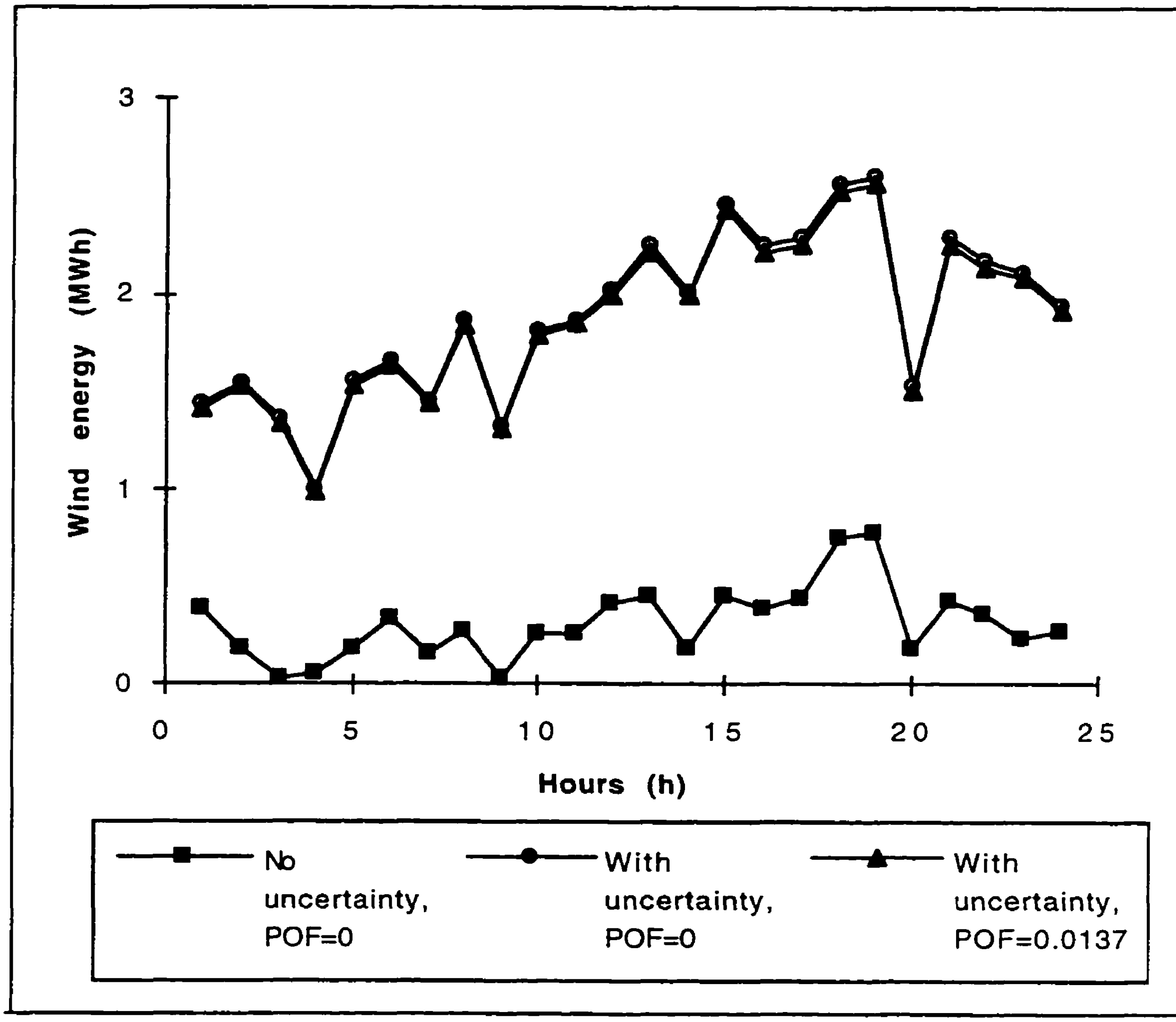


Figure 5.14. Wind energy profile over 24 hours

The difference in the AOC with and without the probability of WTG failure over the next 24 hours is very small and, therefore, can be neglected.

5.3.5.2. Effect of wind speed

The energy output of a WECS will increase if the facility is located at a point in the system which experiences high wind velocities. This, in turn, will have an impact on the economics of the NUG and also on the utility that purchases energy from the NUG. In order to illustrate this phenomenon, the hourly mean wind speeds were modified by a simple multiplication factor and used to evaluate the AOC of the IEEE-RTS containing NUG. Variations in the AOC and the AOC per unit of energy with variation in the wind speed multiplication factor are illustrated in Figures 5.15 and 5.16. Figure 5.17 shows the variation in the utility cost to satisfy a load after purchasing energy from the NUG as a function of the wind speed multiplication factor. It can be observed from Figure 5.15 that the AOC increases as the wind speed multiplication factor (i.e. wind speed) increases.

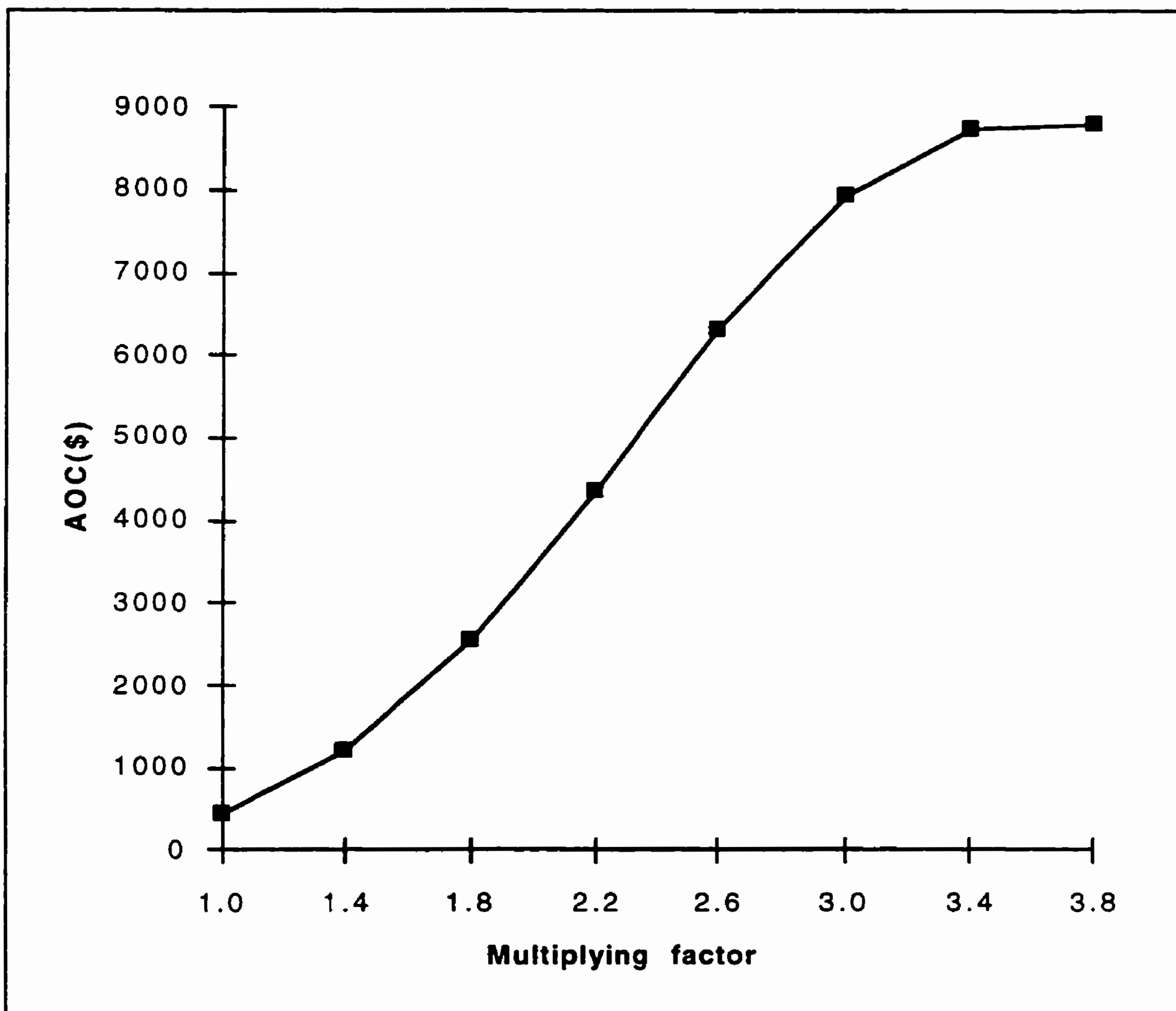


Figure 5.15. AOC as a function of wind speed multiplication factor

The AOC per unit of energy decreases with increase in the wind speed multiplication factor as observed from Figure 5.16. The utility cost decreases with an increase in the wind speed multiplication factor as observed from Figure 5.17. The utility will have a higher economic benefit at higher wind speeds. It can be seen from Figures 5.15 and 5.17 that the AOC increases and the utility cost decreases as the wind speed multiplication factor increases and then saturates when the wind speed continues to increase. This is due to the non-linear characteristics of a WTG.

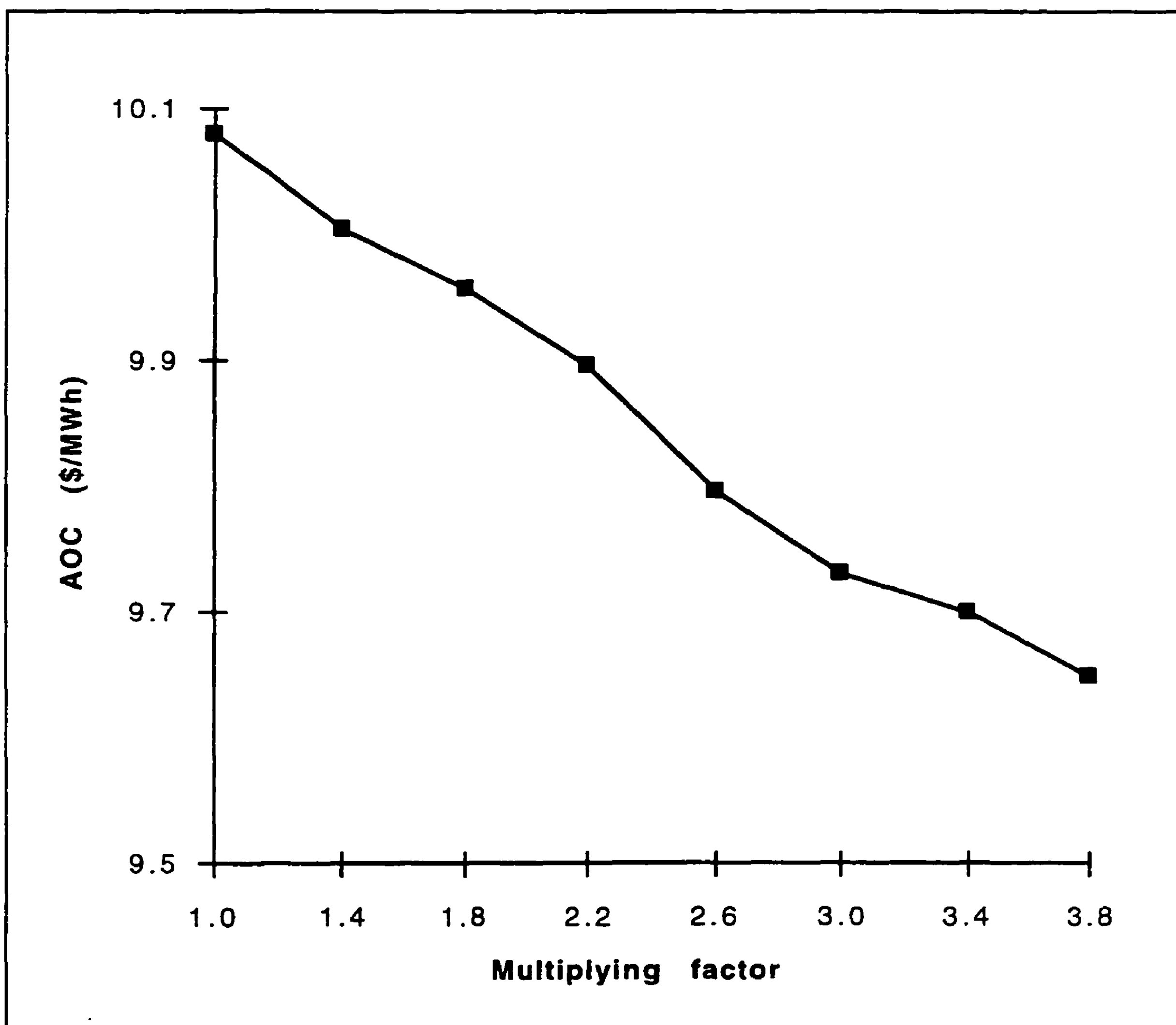


Figure 5.16. AOC per unit of energy as a function of wind speed multiplication factor

A wind machine is not operational when the wind speed is below the cut-in speed and will be shut down for safety reasons if the wind speed is above the cut-out speed. In both cases the power output is zero. The power output of a WTG unit increases with the wind speed between the cut-in speed and the rated speed after which the power output remains constant. Studies such as this can be utilized to determine the optimal equipment parameters, such as V_c, V_r, V_{co} for a specific wind site.

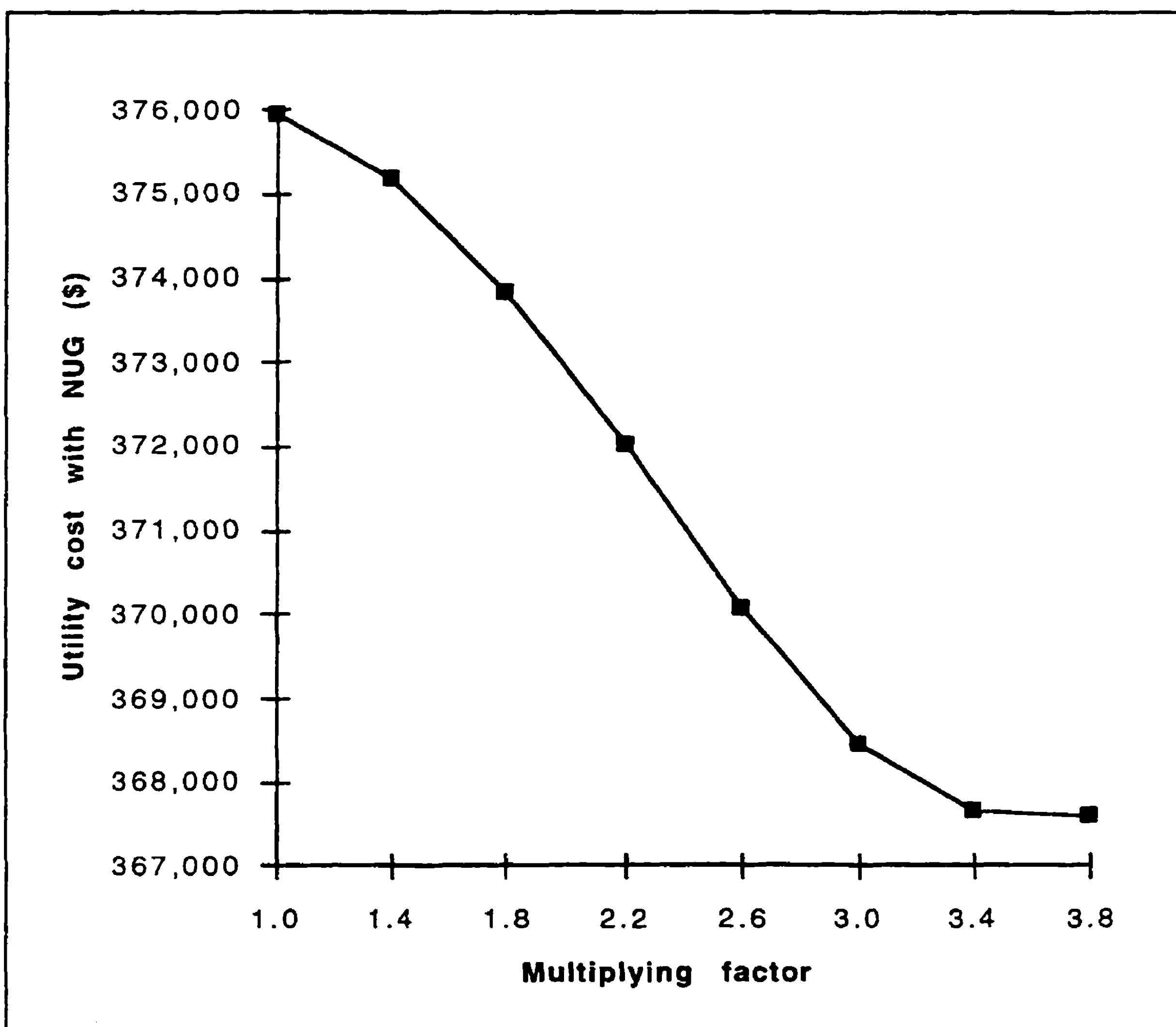


Figure 5.17. Utility cost as a function of wind speed multiplication factor

5.3.5.3. Effect of wind penetration

In order to show the effect of wind penetration on the economics of the NUG and the utility system, the AOC and the cost incurred by the utility were calculated as a function of the number of WTG units. The results are shown in Figures 5.18 and 5.19. The effect of the uncertainty in wind velocity on the AOC and the cost is also illustrated in these figures. Each WTG unit was assumed to have a rated capacity of 2 MW.

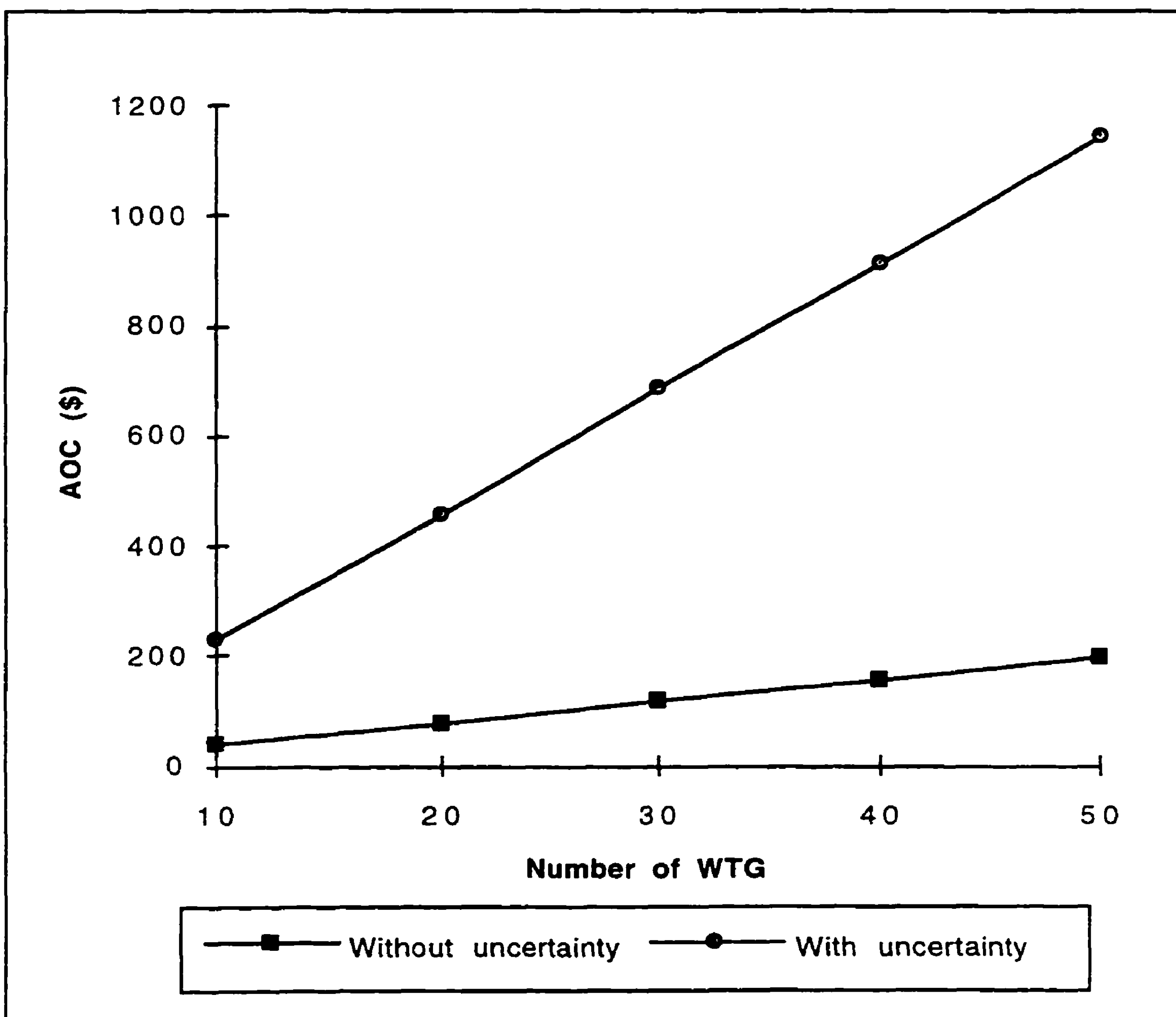


Figure 5.18. AOC as a function of number of WTG

It can be observed from Figures 5.18 and 5.19 that the AOC increases and the utility cost with NUG decreases with an increase in the number of WTG. The effect of uncertainty in wind velocity on the AOC is more prominent at a higher number of WTG.

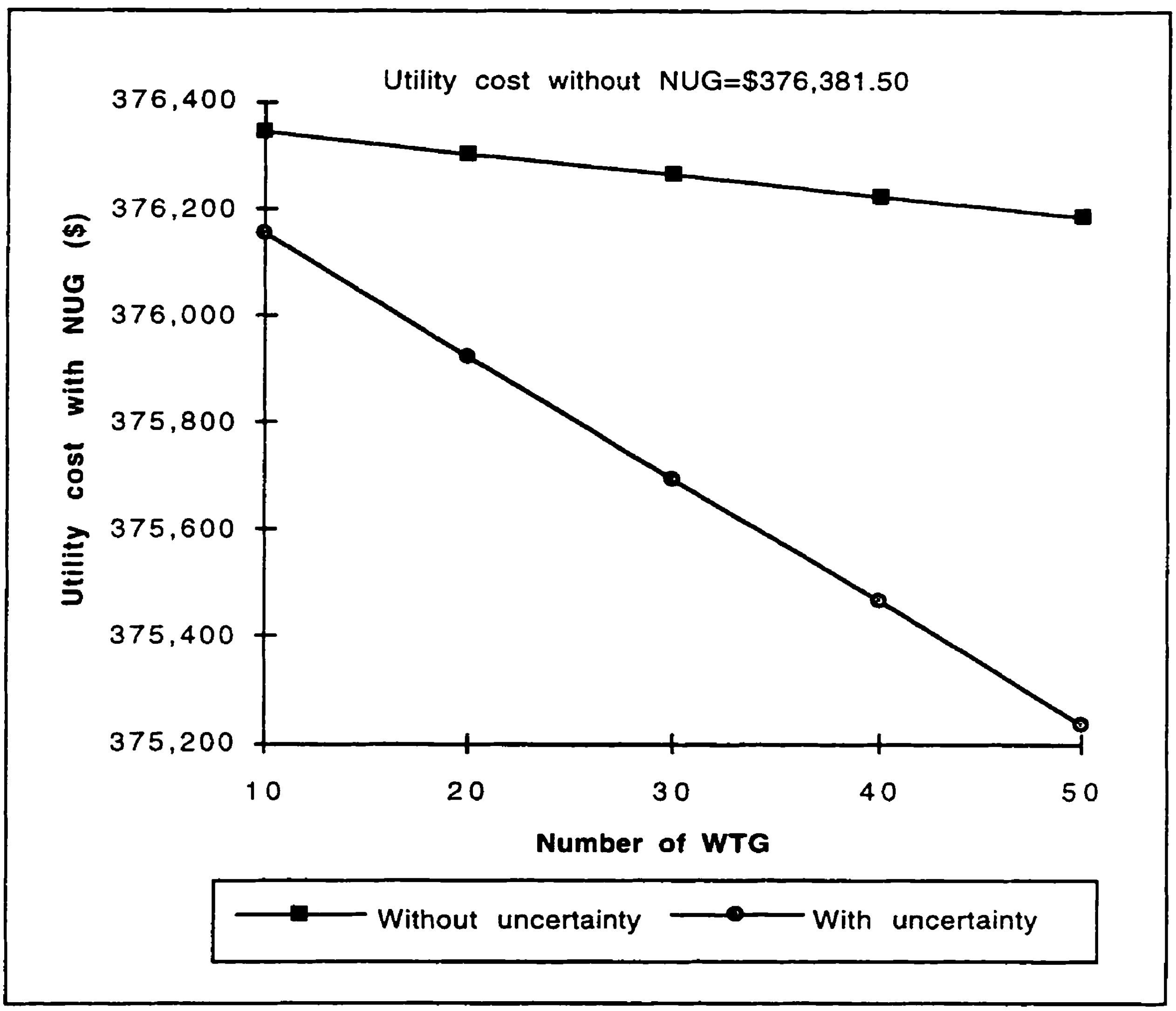


Figure 5.19. Utility cost as a function of number of WTG

5.3.5.4. Effect of probability of failure of WTG

The probability of failure of a WTG over the next day is very low. This effect on the AOC is illustrated in Figure 5.20. It was assumed that 20 WTG each with a capacity of 2 MW sell energy to a utility in one day. It can be observed from Figure 5.20 that the AOC decreases with an increase in the probability of WTG failure. This is due to the fact that higher failures in the WTG results in a lower wind energy and thereby lower AOC.

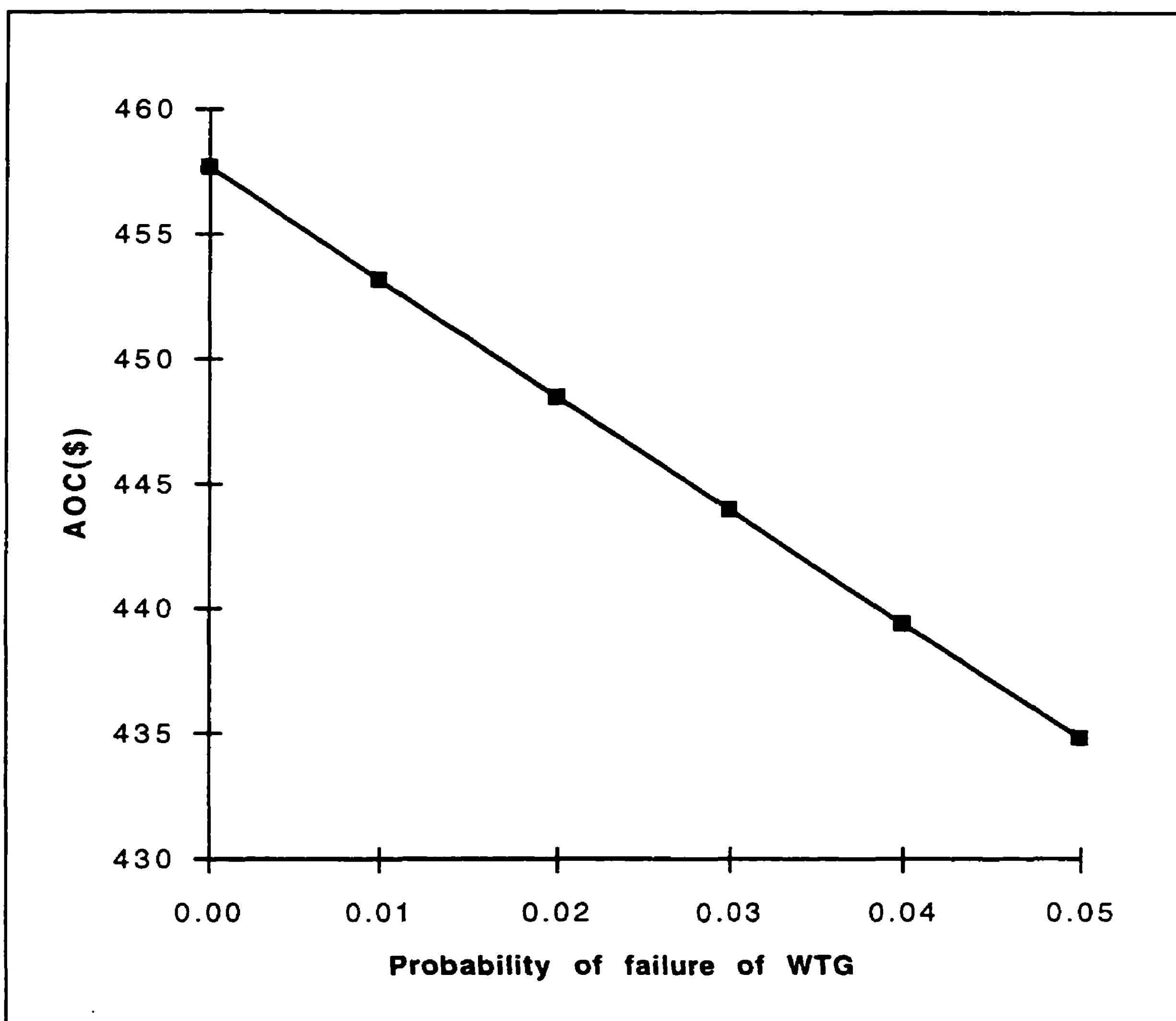


Figure 5.20. AOC as a function of the probability of failure of cogenerating unit

5.4. Summary

The increase in the popularity of NUG clearly dictates the need for close cooperation between electric utilities and NUG facilities. In most cases, a cogeneration facility is considered to provide energy on an 'as available' basis, i.e. without legal obligation of contract and the wind energy is treated as non-dispatchable form of energy. Techniques are presented in this chapter that can be utilized to include wind energy and cogenerated energy produced by a NUG into a utility generation schedule in an optimal manner and to evaluate the AOC. The techniques have been tested on the IEEE-RTS and studies are illustrated in this chapter. The results show that the AOC differs considerably for NEL and EL cogenerating facilities and, therefore, it is very important to clearly identify these facilities before evaluating the AOC. In the case of wind energy, the uncertainty associated with the wind velocity is an important factor that should be taken into account in the evaluation of the AOC. The system examples shown in this chapter illustrate that the economic benefit achieved by the NUG and the utility can be quantitatively evaluated.

The techniques can be utilized to provide enhanced appreciation of the inclusion of cogeneration and wind energy produced by a NUG in short term utility operational planning. Studies, similar to those performed on the test system, can be utilized to determine the amount of energy and the time period during which utilities and NUG can maximize their economic benefit.

The economic impacts of NUG on thermal and hydrothermal power systems are examined in Chapters 3, 4 and 5 with regards to HL I. The evaluation of the AOC at HL II becomes complex due to the inclusion of transmission losses. A technique for the determination of the AOC at HL II and the studies associated with the technique are illustrated in the following chapter.

6. ECONOMIC IMPACT OF NON-UTILITY GENERATION IN A COMPOSITE SYSTEM

6.1. Introduction

The evaluation of monetary transactions resulting from HL I energy purchases by a utility from a non-firm NUG is illustrated in previous chapters of this thesis. This chapter deals with the economic implications of the incorporation of NUG energy in short term utility operation at HL II. Different network locations for the same NUG will have different economic impacts on the utility due to the associated transmission losses. Transmission losses are a part of the cost of supplying the system load requirements and are, therefore, considered in the proposed method of evaluating the AOC. Many papers have been published on the subject of transmission loss evaluation and on methods of including transmission losses in the on-line dispatch process [21, 92-102].

A new algorithm is illustrated in this chapter, which can be used for short term rescheduling of utility generation as NUG energy is utilized by the utility. Transmission losses are also evaluated while assessing the incremental costs of the generating units. A deterministic criterion is utilized to maintain the reliability of the utility generation system at a desired level. The AOC can be evaluated utilizing the algorithm discussed in the following section. A computer program has been developed to evaluate and examine the economic implications of the NUG energy. The Roy Billinton Test System (RBTS) [39] is utilized in order to illustrate the usefulness of the algorithm and sensitivity studies performed on the example system are presented. Studies such as these provide power system planners with a better understanding of the effect of NUG inclusion in the short term utility operation at HL II. A comparison of the AOC evaluated with and without transmission losses is made in order to show the economic impact of including transmission losses.

6.2. Evaluation of the Avoided Operating Cost

An optimal approach is used in the proposed technique to incorporate the NUG energy into the loading schedule of the utility. A least costly adjustment technique with a discrete step size is utilized to reload the utility units. Operating cost in a system, in general, increases with an increase in the magnitude of operating reserve. A higher operating reserve also translates to a higher assurance of the availability of supply provided all other factors remain the same.

The AOC of a utility depends on the time, and the duration of energy transfer from a NUG and also on the location of the NUG in the network. A utility will derive maximum benefit when the NUG is connected at a load bus. At other locations, the economic benefit is decreased by the cost associated with the transmission losses. This decrease is a complex function of network configuration, load profile, unit loading, etc.. The effect of transmission losses is considered in the proposed algorithm for evaluating the AOC. A flow chart of the algorithm is illustrated in Figure 6.1.

The algorithm is divided in five sections. In the first section, real power, P, and reactive power, Q, at each bus are evaluated without considering transmission losses, utilizing the classical economic load dispatch (ELD) technique. The objective of the economic load dispatch is to minimize the cost of meeting the energy requirements of a system over a 24 hour period in a manner consistent with reliable service. The load is distributed among the utility units in such a manner that the total cost of supplying the hourly load requirements of the system is minimized.

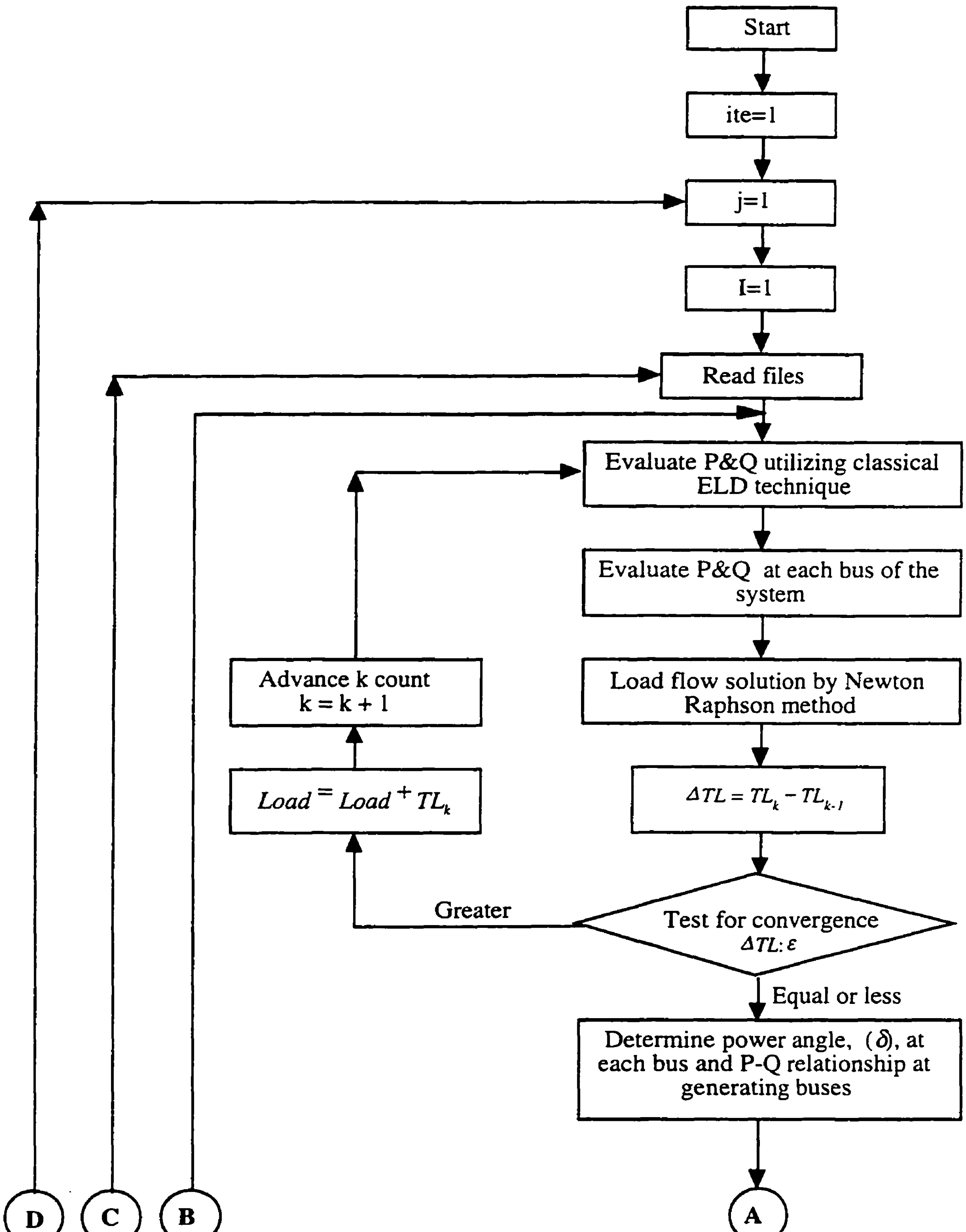


Figure 6.1. Flowchart for evaluation of the AOC

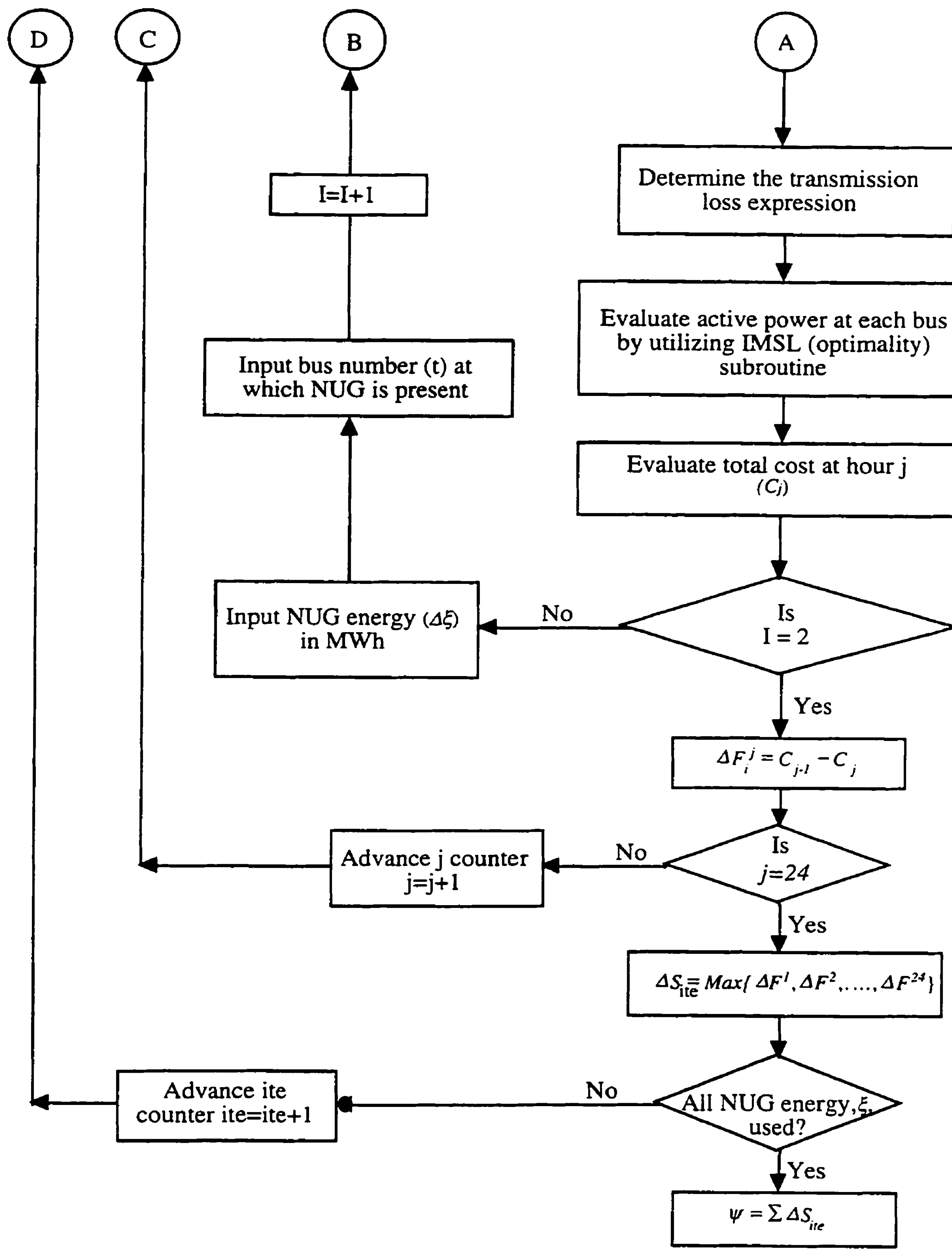


Figure 6.1. Flowchart for evaluation of the AOC........continued

A load flow solution is obtained utilizing the real and reactive powers at all buses of the network in the second section of the algorithm as shown in Figure 6.2 [103]. The Newton-Raphson method is used for the load flow solution [103]. Transmission losses, TL_k, are evaluated in this section based on the real and reactive powers from the previous section of the algorithm. Transmission losses are used as an input to the first section and a new set of real and reactive powers are evaluated. The modified real and reactive powers are utilized to update the transmission losses. This cycle continues until the difference in transmission losses, ΔTL, falls below a tolerance level, ε, in two successive iterations. The lower the tolerance level, the higher will be the accuracy and also the computation time, and vice-versa. The objective of the load flow is to evaluate the power angle δ, at each bus and the P-Q relationship at the generating buses. It is assumed that the δ and P-Q relationships remain constant for a small change in the load. The angle δ is obtained directly from the load flow solution. The P-Q relationship is obtained by changing the load by a small value and developing a curve-fit between P and Q. The δ at each bus and the P-Q relationship at each generating bus are utilized to develop the following transmission loss formula.

$$TL_k = K_{LO} + \sum_{i \in R_G} B_{io} P_i + \sum_{i \in R_G} \sum_{j \in R_G} P_i B_{ij} P_j \tag{6.1}$$

where

TL_k = transmission losses

K_{LO} = constant

B_{io} and B_{ij} = loss coefficients

R_G = set of generating plant

Equation 6.1 is called Kron's formula [102].

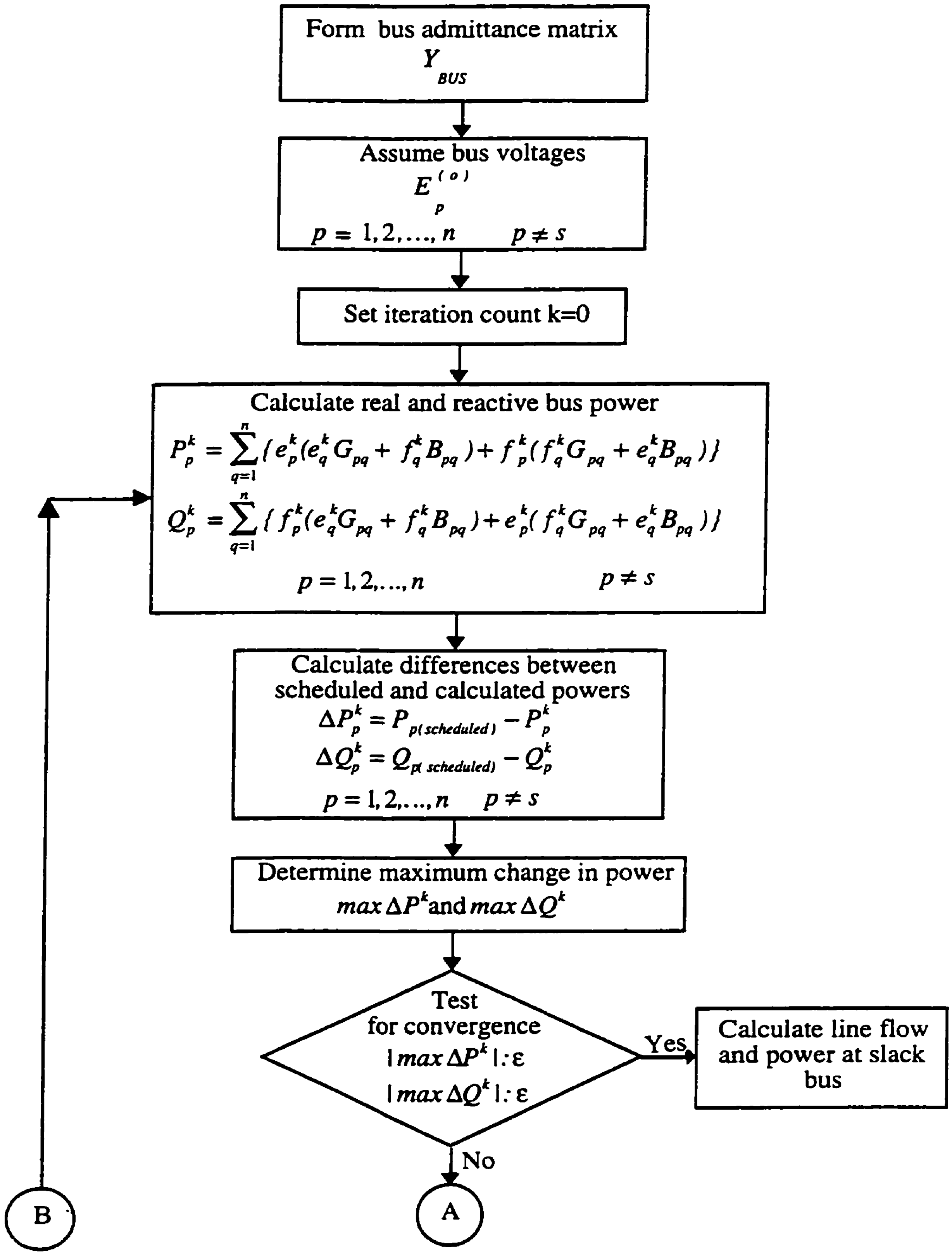


Figure 6.2. Flowchart for the load flow solution

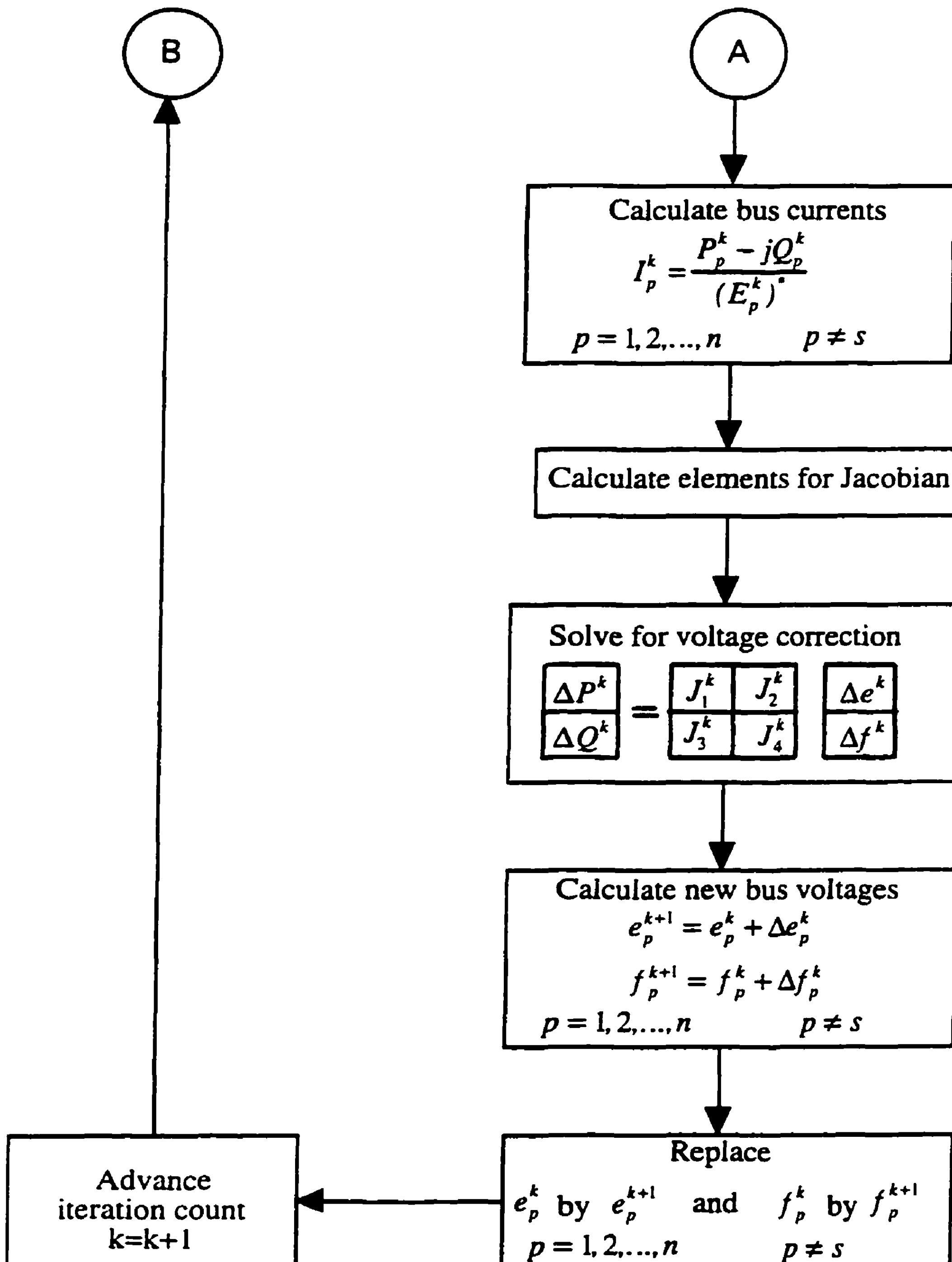


Figure 6.2. Flowchart for the load flow solution.......continued

The transmission loss expression is used to evaluate the active power at each bus following which the total generation cost at each hour is evaluated. Once the active power at each bus is evaluated, the active power output of each unit, i, at each bus, P_{si}^{j}, is evaluated for hour j. The savings in running cost at hour j, ΔF_i^j, for unit i is evaluated from the total cost without NUG and the total cost with a discrete amount of NUG utilized in one hour, $\Delta\xi$. The active power output of a thermal unit is decreased by a level equivalent to the discrete NUG energy input of $\Delta\xi$. The saving in running cost can be expressed as

$$\Delta F_i^j = a_i\{2P_{si}^j(\Delta P_{si}^j) - (\Delta P_{si}^j)^2\} + b_i \Delta P_{si}^j \tag{6.2}$$

where

$$\Delta P_{si}^j = \Delta\xi - \Delta P_{loss} \tag{6.3}$$

Once the saving in the running cost is determined, the AOC is evaluated. The procedure for evaluation of the AOC is given by the generalized algorithm in Chapter 2.

6.3. The Roy Billinton Test System

The Roy Billinton Test System (RBTS) [39] was utilized to examine the usefulness of the algorithm and to perform sensitivity studies. The test system has evolved from the reliability education and research programs conducted by the Power System Research Group at the University of Saskatchewan. The test system is sufficiently small to permit the conduct of a large number of reliability studies with reasonable solution time but sufficiently detailed to reflect the actual complexities involved in a practical reliability analysis. The single line diagram of the RBTS is shown in Figure 6.3. The system has 2 generator (PV) buses, 4 load (PQ) buses, 9 transmission lines and 11 generating units. The voltage level of the transmission system is 230 kV and the voltage limits for the

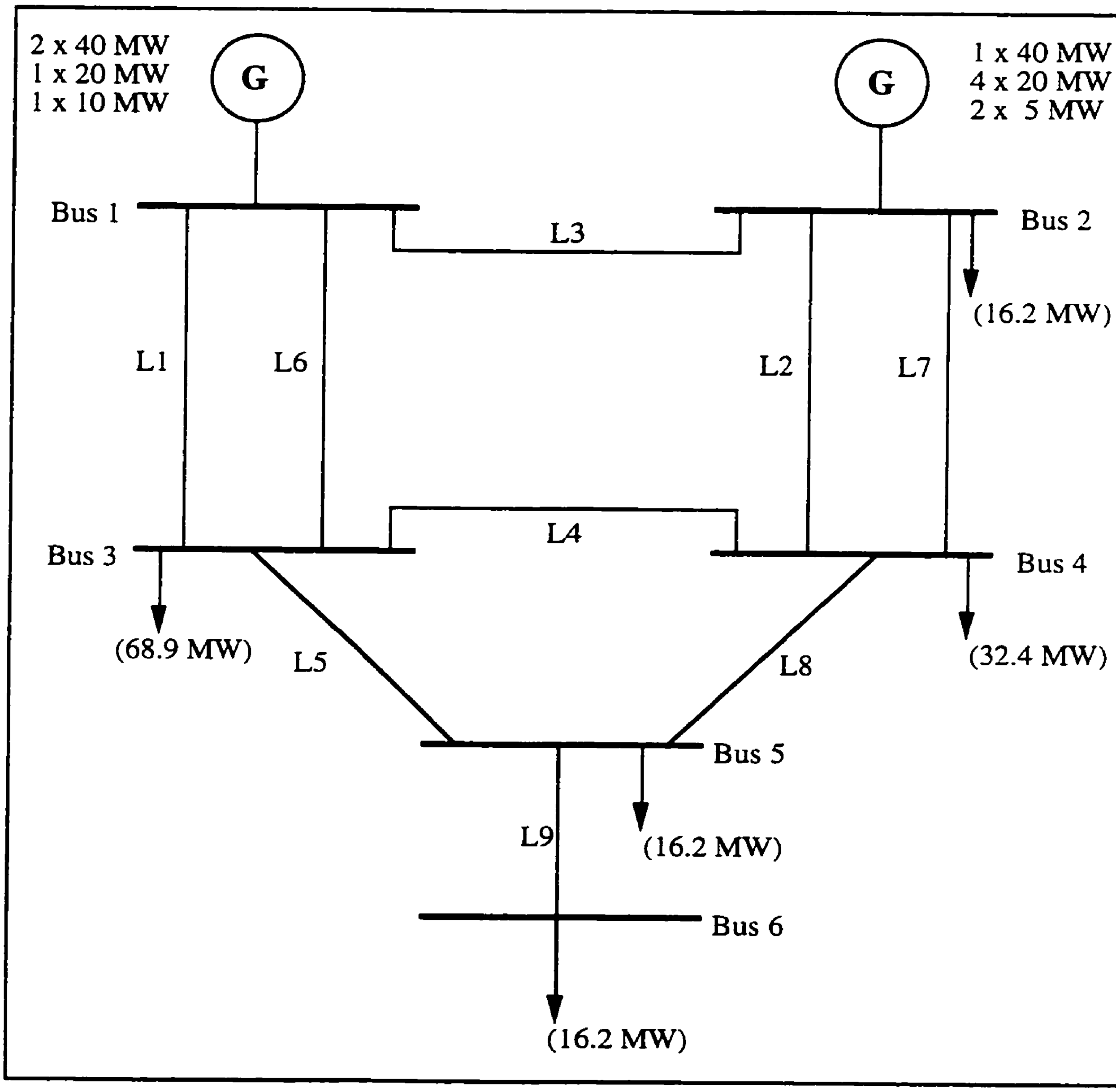


Figure 6.3. Single line diagram of the RBTS

system buses are assumed to be 1.05 p.u. and 0.97 p.u. The system peak load is 150 MW and the total installed generating capacity is 240 MW.

The generating unit ratings, loading order and cost data are shown in Table 6.1. The cost coefficients a, b and c represent the fuel costs, i.e. costs directly associated with energy production. The loading order allocates some low cost units as peaking units.

Table 6.1. Generating unit cost data of the RBTS

		Unit Cost data		
Loading order	Ratings (MW)	a	b	c
1	40	0	0.5	0
2	20	0	0.5	0
3	20	0	0.5	0
4	40	0.01	12	26
5	40	0.01	14	28
6	20	0.02	16	24
7	10	0.02	18	25
8	20	0	0.5	0
9	20	0	0.5	0
10	5	0	0.5	0
11	5	0	0.5	0

The transmission network consists of 6 buses and 9 transmission lines. The generating units locations, bus load data at the time of system peak in MW and in percentage of the total system load are shown in Table 6.2. It has been assumed that the reactive load Mvar requirements at each bus is 20% of the corresponding MW load. The transmission line data are given in Table 6.3. The hourly peak load variations in the RBTS during the specified 24 hour scheduling period are shown in Figure 6.4.

Table 6.2. Generating unit locations and bus load data of the RBTS

Bus number	Generating unit		Load (MW)	Bus load in % of system load
	Number	Capacity (MW)		
1	4 to 7	110		
2	1 to 3, 8 to 11	130	16.22	10.81
3			68.91	45.95
4			32.43	21.62
5			16.22	10.81
6			16.22	10.81
		240	150.00	100.00

Table 6.3. Line Data of the RBTS

Line number	Impedance (p.u.)			Current rating (p.u.)
	R	X	B/2	
1, 6	0.0342	0.18	0.0106	0.85
2, 7	0.1140	0.60	0.0352	0.71
3	0.0912	0.48	0.0282	0.71
4	0.0228	0.12	0.0071	0.71
5	0.0228	0.12	0.0071	0.71
8	0.0228	0.12	0.0071	0.71
9	0.0228	0.12	0.0071	0.71

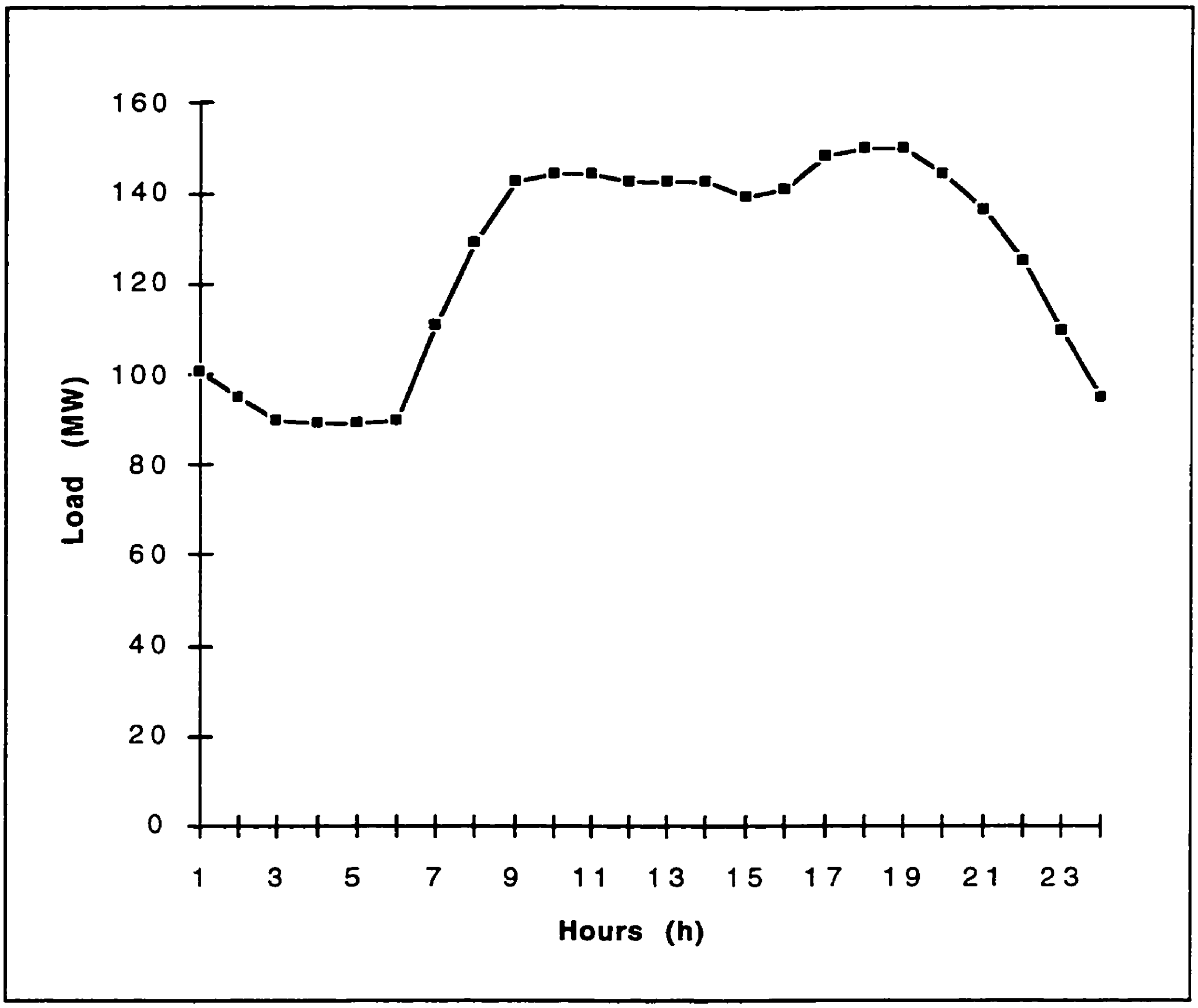


Figure 6.4. Hourly load variations in the RBTS

6.4. Sensitivity Studies

6.4.1. AOC and transmission losses

The ELD and generation rescheduling due to NUG energy become much simpler and straightforward if transmission losses can be neglected. Transmission losses, however, contribute to the operating cost, and, therefore, affects the AOC. The benefits obtained by a utility from NUG energy also depend on the level of transmission losses. A NUG with a certain energy becomes equally valuable at any bus location when transmission losses are neglected. A NUG is, therefore in this case deprived of any credit that it should receive for mitigating transmission losses. A utility, in general, will derive increased benefit from a NUG if it is connected to a load bus instead of a generation bus. This fact will be reflected on the AOC, only if transmission losses are included in the algorithm. Three AOC are shown in Figure 6.5, one without transmission losses and two with transmission

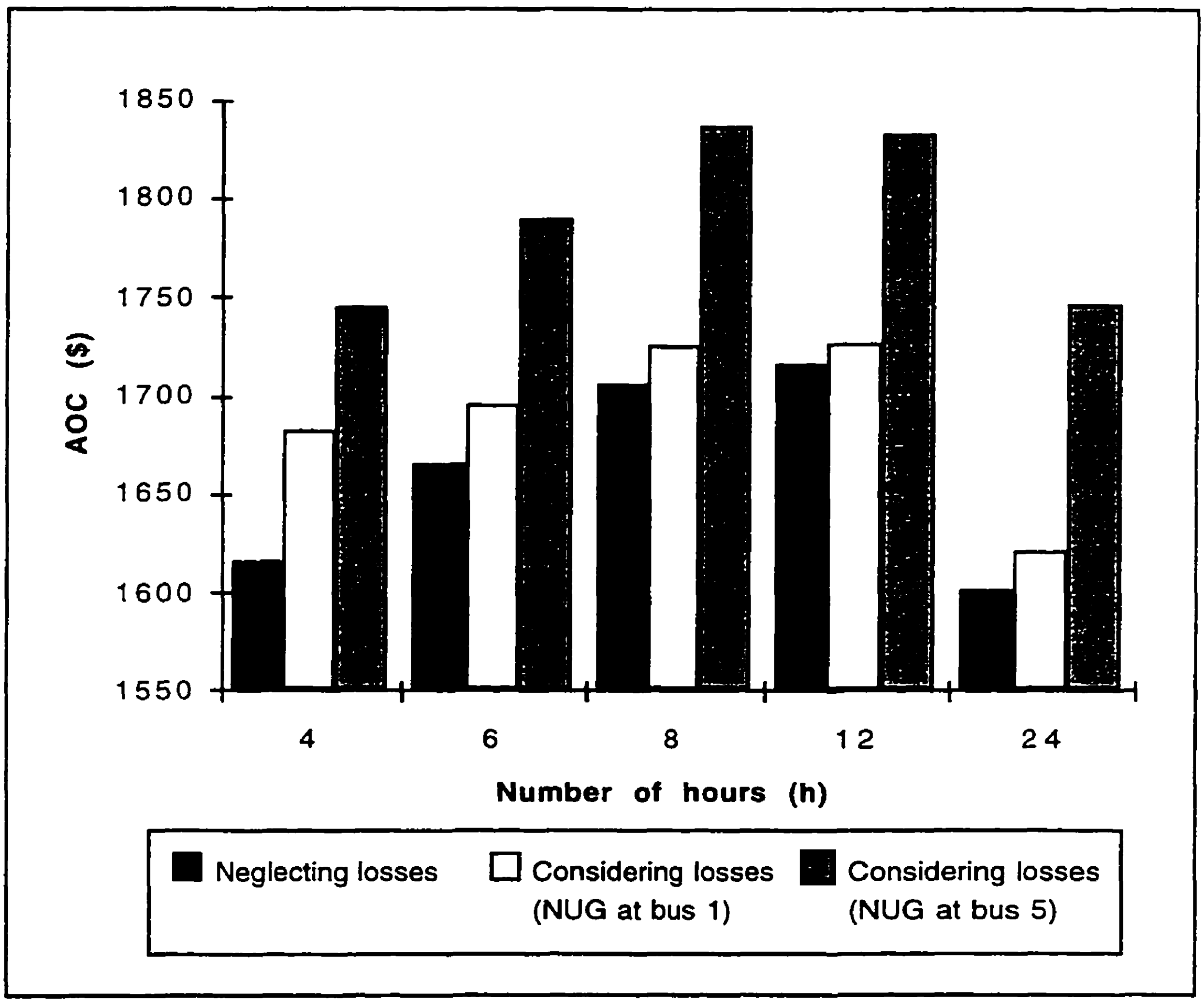


Figure 6.5. AOC with and without considering transmission losses

losses. The AOC with transmission losses included were obtained for two NUG locations, one at a load bus (bus 5) and the other at a generator bus (bus 1). A NUG energy of 120 MWh was considered in all three cases. It can be observed from the figure that the AOC, in the case where transmission losses are neglected, is lower than those where transmission losses are considered. This implies that transmission losses contribute considerably to the AOC and should be taken into account in the evaluation of the AOC in order to obtain more realistic results. The contribution of transmission losses towards the AOC depends upon the location of the NUG in the network. The AOC is higher when the NUG is located at bus 5 (load bus) than that when the NUG is located at bus 1 (generation bus). The maximum AOC, $ 1717.40, is realized when 120 MWh of energy is supplied by the NUG to the utility in a period of 12 hours with the transmission losses neglected. When the transmission losses are considered, the maximum AOC are, $ 1836.90 and $ 1727.39, for NUG located at bus 5 and bus 1 respectively. As shown in Figure 6.5, NUG located at bus 5 and bus 1 sell energy to the utility in periods of 8 hours and 12 hours respectively in order to maximize AOC.

6.4.2. Location of the NUG

A number of factors have to be considered in assessing the economic benefits obtained by a utility from a NUG. One of the important factors mentioned in Section 6.4.1 is the location of the NUG in the network. Figure 6.6 illustrates the variation in the system AOC ($) evaluated for one day for alternate NUG locations in the network. The NUG was moved from bus 1 to bus 6 to create six cases. It was assumed in this study that 120 MWh of energy is supplied to the utility by a NUG in one day. The daily system load was that shown in Figure 6.4 in all six cases.

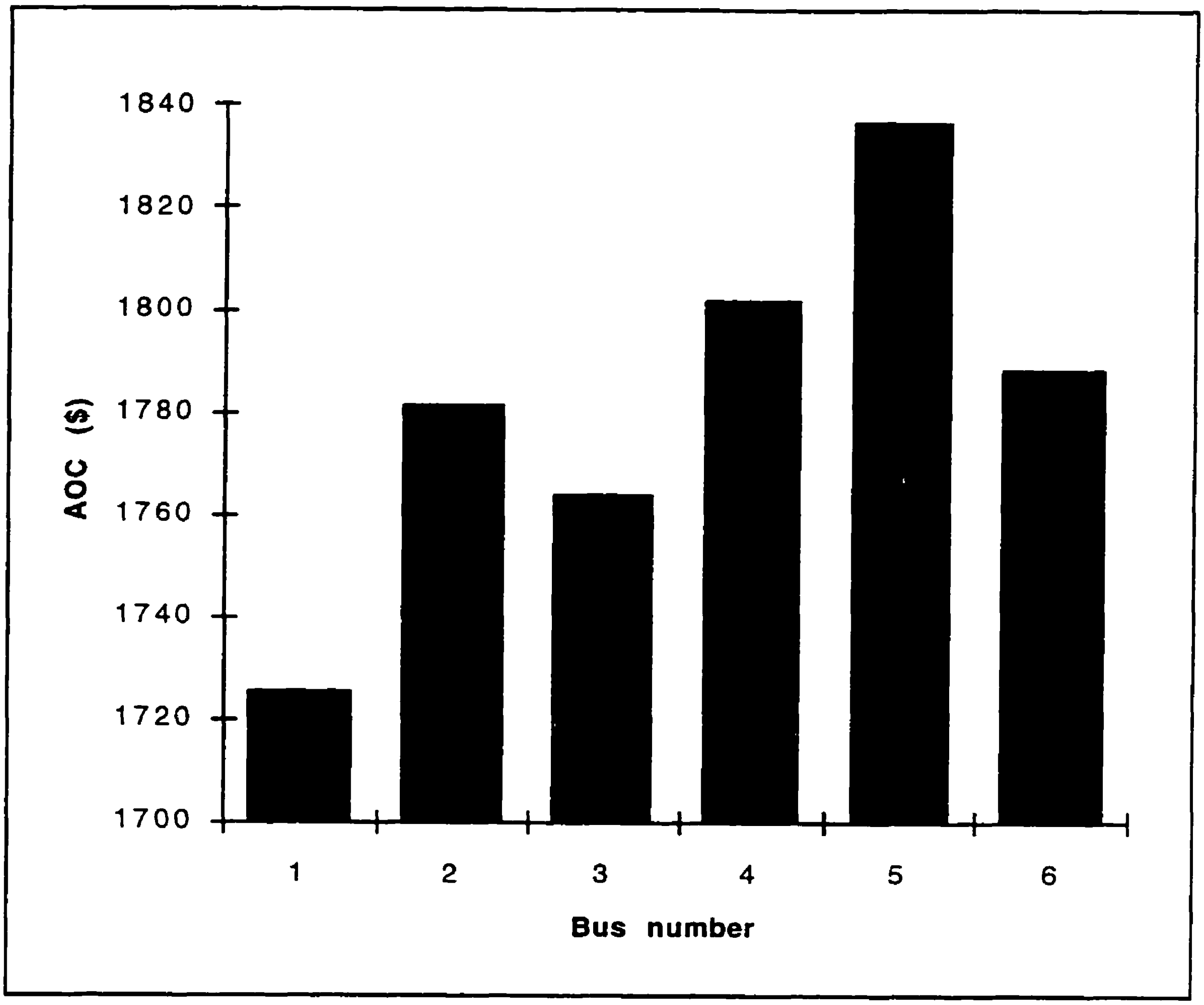


Figure 6.6. Effect of location of NUG in the network on the AOC

It can be observed from Figure 6.6 that the AOC are higher when NUG energy is supplied at load buses 3, 4, 5 and 6 than when NUG energy is supplied at generation bus 1 and generation and load bus 2. The NUG located at bus 1 supplements the existing utility generation and contributes little to the reduction of the transmission losses. The transmission losses are almost the same before and after the injection of NUG energy at bus 1. The AOC is, therefore, dependent only on the energy from the NUG. There is almost no contribution in the AOC due to transmission losses. The NUG, when situated at a load bus, contributes to a reduction in transmission losses. The AOC is, therefore, dependent upon the energy from the NUG and also on the savings due to the reduction in the transmission losses. The AOC is the highest at bus 5. It can be, therefore, inferred that the most suitable location in the RBTS for a NUG, providing 120 MWh of energy in a day, is bus 5. Studies such as this are important when deciding the most suitable location in the network for NUG insertion.

6.4.3. Duration of the NUG energy

Some NUGs, e.g. cogenerators, have control over the amount of energy sold to the utility. It is, therefore, important for these NUGs to determine the number of hours during which a specific amount of energy is sold. It was shown in the previous study that NUG should be located at bus 5 in the RBTS network in order to obtain maximum AOC for 120 MWh of energy. The important question faced by a NUG operator, is to determine the number of hours at which the 120 MWh of energy is to be generated and sold to the utility to obtain maximum economic benefit. Figure 6.7 illustrates the variation in the daily system AOC as a function of the number of hours during which the 120 MWh of energy is sold by the NUG. The AOC corresponding to 4 hours represents the running cost savings that the utility will achieve due to the purchase of 120 MWh of NUG energy in 4 hours. It can be observed from Figure 6.7 that with an increase in the number of hours, the AOC increases, becomes maximum and then decreases gradually. The AOC, in general, increases with an increase in the marginal production cost of the utility. A NUG may obtain maximum benefit by providing its energy during the system peak. If the NUG, however, provides all its energy within a narrow time frame, it diminishes the marginal production cost of the system and thereby generates less benefit for itself and the utility. If the NUG spreads its energy transfer over a wide time frame, energy exchange will occur at load levels where the marginal production cost of the system is considerably lower than that at the peak load. For a finite NUG energy, there is an optimum duration of energy transfer that will result in the maximum AOC. The duration of energy transfer will include the system peak. In this case, NUG will achieve maximum benefit, i.e., maximum AOC, when it sells 120 MWh of energy in 8 hours, starting from 12 noon to 7 p.m., of the day. This is due to the fact that 120 MWh of energy is divided equally in a period of 8 hours, i.e., 15 MWh per hour and the most optimal accommodation of NUG energy into the RBTS schedule occurs when 15 MWh of energy is sold by the NUG at each hour for 8 hours.

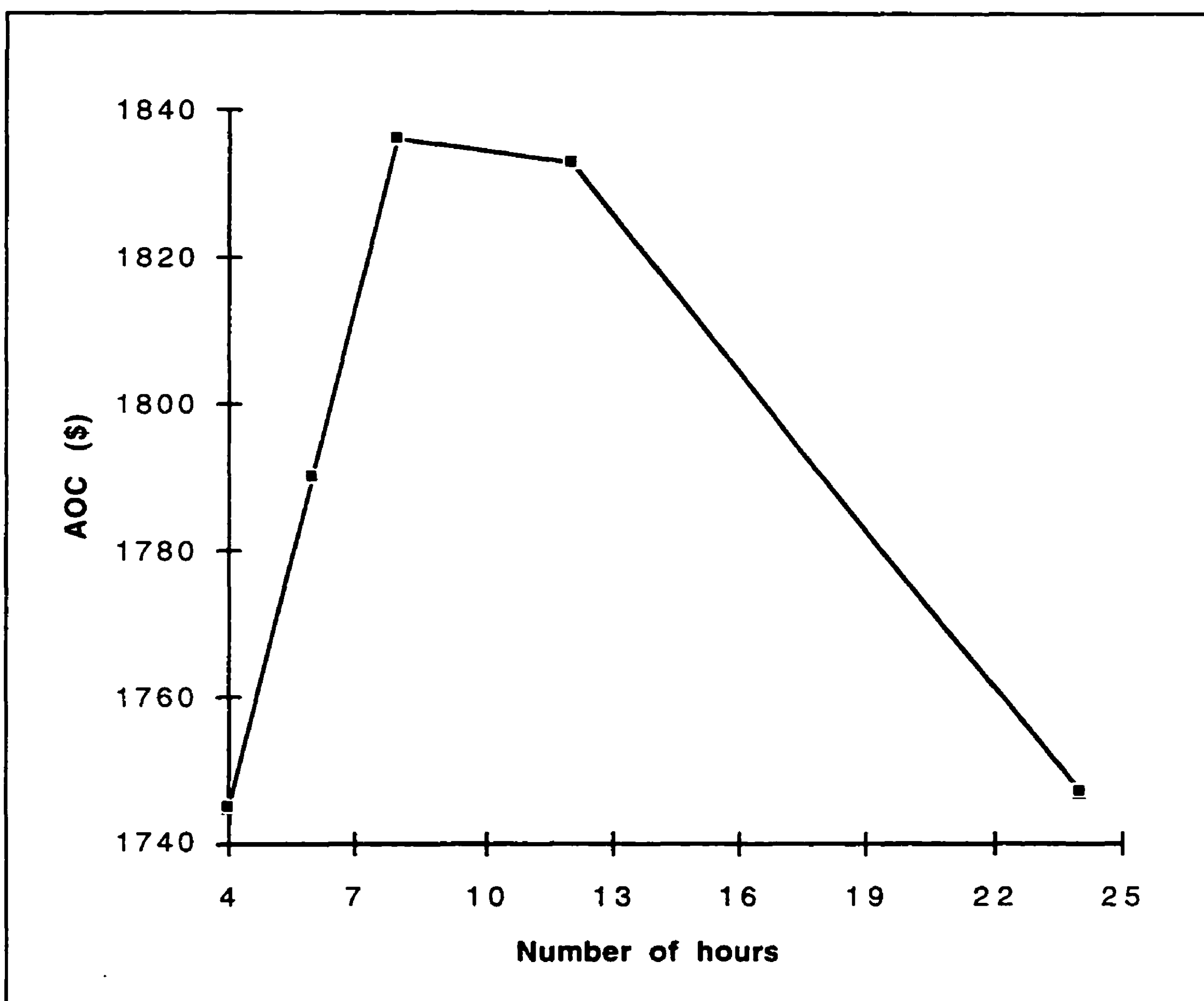


Figure 6.7. Effect of duration of NUG energy on AOC

6.4.4. Effect of load level on the AOC

Figure 6.8 illustrates the variation in the AOC with variation in the NUG energy purchased by a utility during the peak load and the low load periods. A peak load of 150 MW and a low load of 100 MW was considered in the study. It was also assumed that the NUG energy was injected at bus 5 of the RBTS. It can be observed from Figure 6.8 that the AOC increases with an increase in the NUG energy purchased by the utility. During the low load, the AOC increases rapidly and then starts to saturate when the NUG energy

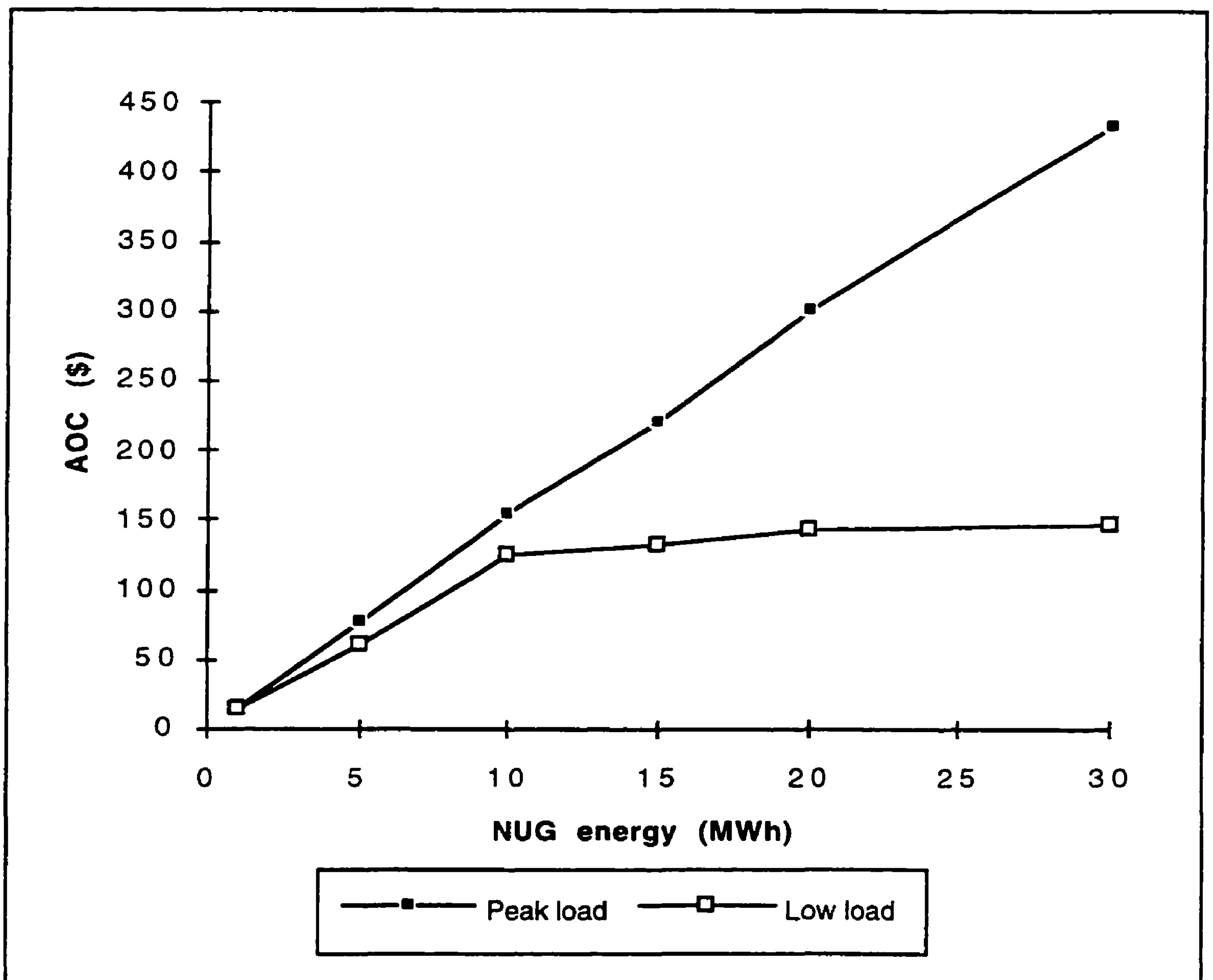


Figure 6.8. AOC at utility peak load and low load

exceeds 20 MWh in this case. The AOC increases rapidly during the peak load. The difference in the AOC between the peak load and the low load increases with an increase in the NUG energy transaction. A utility receives more economic benefit by purchasing NUG energy during peak load than during low load due the fact that the marginal energy cost at the peak load is higher than that at the low load.

6.4.5. Effect of NUG energy on transmission losses

Transmission loss accounts for a significant portion of the cost incurred by a utility during the transmission of electricity. Figure 6.9 illustrates the daily system transmission loss as a function of the NUG energy purchased by a utility from different locations in the network. Six locations in the RBTS, bus 1, bus 2, bus 3, bus 4, bus 5 and bus 6, were considered in this case. System transmission loss in the RBTS in absence of NUG energy is 68.91 MWh for 2991 MWh of energy demand in a day.

It can be observed from Figure 6.9 that the transmission losses decrease when NUG energy is supplied at any one of the six buses except bus 1. Bus 1 is a generation bus without any load connected to it. Any generation at bus 1, therefore, has to be transported to a load bus resulting in transmission losses. NUG energy supplied at bus 1, therefore, does not significantly affect the overall transmission loss of the RBTS. NUG energy supplied at a load bus reduces the load seen by the rest of the system. The transmission losses decrease when the rest of the system has to transport a reduced amount of energy to that load bus. The difference in transmission losses due to NUG energy injections at different buses is dependent on the topology of the network.

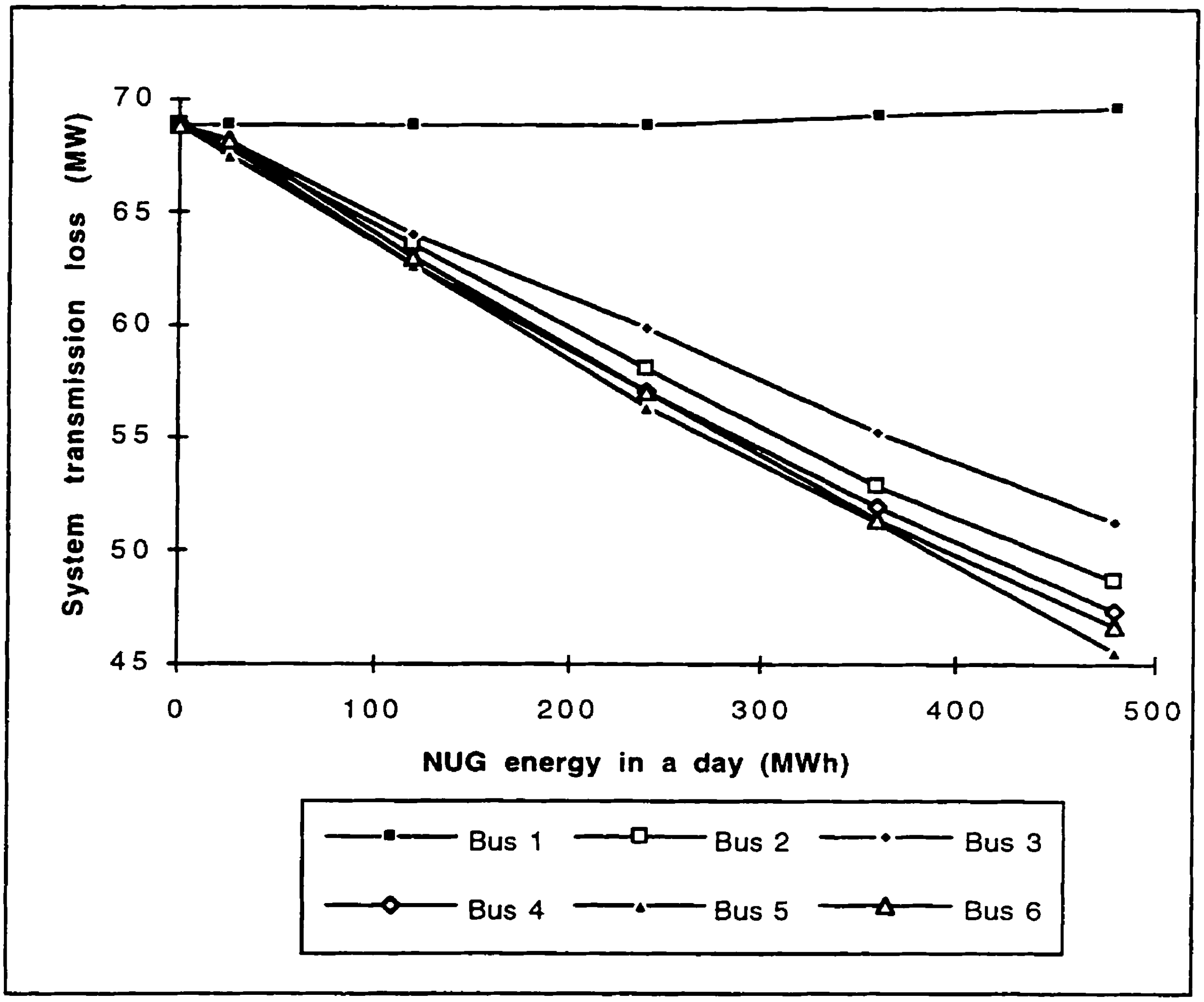


Figure 6.9. Effect of NUG energy on system transmission loss

6.4.6. Operating reserve criteria

The economic impact of NUG energy depends upon the spinning reserve criteria utilized by a utility. Figure 6.10 shows the AOC for different levels of spinning reserve in the RBTS. Two alternate locations, bus 1 and bus 5, were considered for NUG energy injection. The spinning reserve was considered as a percentage of the peak load. It was assumed that a NUG sells 120 MWh of energy to the utility over a period of 8 hours. It can be observed from Figure 6.10 that the AOC is higher when the NUG is located at bus

5 than when the NUG is located at bus 1. It can be further observed from Figure 6.10 that the AOC decreases with an increase in the spinning reserve. The AOC is a complex function of unit commitment and reserve criterion and changes with variations in load profile and priority loading order. A general relationship between spinning reserve and AOC cannot be ascertained.

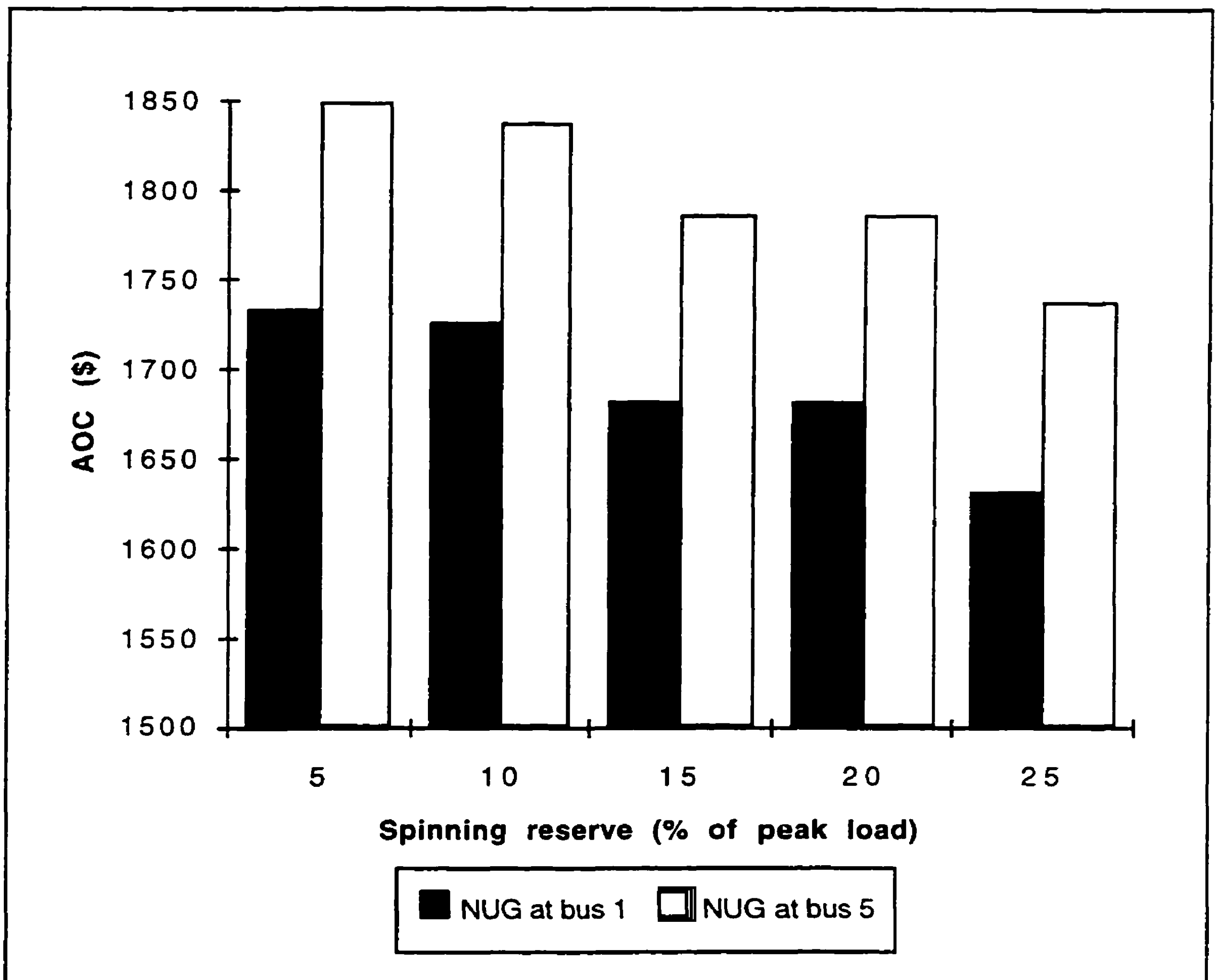


Figure 6.10. AOC as a function of spinning reserve

6.5. Summary

When NUG is included in the list of options for possible generation, it becomes important to accurately model their effect on system reliability and economics. An algorithm is illustrated in this chapter that modifies the utility generation schedule to incorporate the NUG in an optimal manner. Transmission losses are taken into account in the rescheduling of generation, thus, making the evaluation more realistic.

The RBTS was utilized to illustrate the usefulness of the algorithm and to perform a range of sensitivity studies. These studies demonstrate the impact of NUG on the economics of a thermal power system recognizing transmission losses. The investigation shows that it is possible to determine the time period and location in the network at which a NUG should sell energy to the utility in order to achieve maximum economic benefit. The results show that for 120 MWh of NUG energy, the most optimum duration is 8 hours and the most suitable location is bus 5 in the RBTS. The effects of spinning reserve, load level and NUG energy on the AOC and transmission losses were also examined. The results indicate that the AOC is higher at peak load than at low load and decreases with an increase in the spinning reserve. The transmission losses depends upon the location of the NUG in the network. They do not change significantly when NUG is located at a purely generating bus but decrease considerably due to the presence of NUG at load buses. The location of a NUG in the network is, therefore, very important for system economic assessment in HL II studies. This chapter clearly illustrates that transmission losses can be incorporated in the evaluation of AOC.

7. SUMMARY AND CONCLUSIONS

Electrical power generation, once viewed as a sign of growth and prosperity, has become the subject of intense public scrutiny. Considerable attention is being focused on utilizing the existing facilities within power companies in a more efficient manner and also to tap in to the wide variety of traditional and non-traditional energy sources outside the domain of the electric power companies. Non-utility generation (NUG) has become increasingly important mainly due to environmental concerns, possible depletion of oil supplies and government regulations. Power system planners have to make important decisions when NUG energy is included into their system network. NUG sometimes faces difficulties in selling their energy to a utility due to the absence of information regarding the short term buyback rate and some NUG, especially those that sell considerable energy, are not convinced that the published buyback rate is valid. This thesis illustrates methods which can be utilized to evaluate the buyback rate in a just and reasonable fashion and can be verified by both utility and NUG.

The studies described in this thesis focus specifically on the economic assessment of incorporating NUG in the short term planning of power systems at HL I and HL II. The total system generation was examined to assess the impact of NUG energy at HL I. Two types of power systems, thermal and hydrothermal, were utilized to examine the effect of NUG energy in a system generation schedule. A further study assumed that NUG generates energy from cogeneration and wind facilities. These sources of energy have some typical characteristics that make them different from conventional sources of electricity. The characteristics were taken into account in modeling the NUG and studies were performed to show their effect on a thermal power system. HL II assessment involves a composite appraisal of both the generation and transmission facilities and their ability to supply adequate, dependable and suitable electrical energy to the major load point. Studies were performed at HL II to show the impact of NUG in a thermal power system.

A brief introduction to the overall area of power system planning and the economics of system operation are provided in Chapter 1. Some current operational planning problems are also discussed.

Chapter 2 presents an introduction to NUG and to some of the system operational problems due to the inclusion of NUG energy into a system. The contributions from NUG to the total energy in selected countries are also illustrated in this chapter. The buyback rate should be dependent upon the avoided operating cost (AOC) of the system. A generalized algorithm is illustrated in the chapter that can be utilized to evaluate the AOC. The technique is based on the optimum utilization of the committed units both before and after the inclusion of the NUG energy. A time differentiated price system is adopted to reflect the different value placed by a utility on purchase price at different times of the day. Most Canadian utilities use deterministic methods in their operational planning and, therefore, this algorithm is based on a deterministic approach [15]. The algorithm treats both the NUG and the utility fairly and can be easily implemented in any system using appropriate cost parameters and system operating constraints. The IEEE-Reliability Test System (RTS) was used as a test system in this thesis to illustrate the applicability of the algorithm at HL I. A detailed description of the IEEE-RTS is provided in Chapter 2.

The impacts of NUG in the short term operational planning of a thermal power system are presented in Chapter 3. A general review of the economic operation of thermal power systems followed by deterministic and probabilistic techniques for the evaluation of the AOC are also presented in this chapter. The generalized algorithm illustrated in Chapter 2 is utilized to show the impact of NUG in a thermal power system using a deterministic method. In this approach, the spinning reserve of the system is the sum of the rated capacity of the largest unit plus 10 % of the peak load. The advantages of probabilistic methods over deterministic approaches are clearly recognized and a probabilistic method to assess the AOC in a thermal power systems was also developed and is illustrated in Chapter 3. Based on these techniques, computer programs have been developed to evaluate and examine economic implications of NUG on a utility. The IEEE-RTS, discussed in Chapter 2, is used as a vehicle to illustrate a range of numerical applications. The results of the study involving the variation in the system AOC with the NUG energy reveal that the AOC increases with an increase in the NUG energy purchased by the utility. In the case of dispatchable NUG energy, the AOC is higher than that in the case of non-dispatchable energy. The impacts on the AOC of selected operating practices used by a utility on the AOC were also investigated. The results indicate that the AOC increases with an increase in the unit commitment risk. A significant observation in this study is that AOC decreases as the number of committed units are increased for a particular load. A comparison was made between the deterministically evaluated AOC and the probabilistically evaluated AOC. It should be noted that the AOC depends upon the criteria utilized in the deterministic and probabilistic methods. The major observation from this chapter is that the AOC is not fixed but depends upon the system load, operating reserve criteria, priority loading order of generating units and unit commitment of the system.

The short term scheduling of fixed head and variable head hydrothermal systems with NUG energy are considered in Chapter 4. Short term hydrothermal scheduling is concerned with an optimization interval of one day at hourly scheduling intervals. Techniques are presented in this chapter, that can be utilized to economically incorporate NUG energy into a hydrothermal system with fixed and variable heads units. The proposed technique can be utilized to develop a plan for the optimal quantity of water to be discharged from the hydro plants and the corresponding thermal generation such that the total thermal plant fuel cost over the day is minimized subject to the operating constraints of the hydro and thermal plants. In the case of a fixed head hydrothermal system, the active power is a function of the discharge. An iterative method was utilized in the optimal scheduling. The Glimn Kirchmeyer model of a variable head hydro plant performance was selected and a forward dynamic programming approach was utilized. Once the units in the hydrothermal system are economically dispatched, the AOC is evaluated utilizing the generalized technique discussed in Chapter 2. Sensitivity studies were performed on the IEEE-RTS and the results are discussed in this chapter. The results indicate that the volume of water in the reservoir of fixed head and variable head hydrothermal systems and the initial levels of a variable head hydrothermal system are instrumental in setting the value of the AOC. The AOC decreases with an increase in the volume of water and an increase in the initial water level in the reservoir. A comparison of dispatchable and non-dispatchable NUG energy in hydrothermal systems was also made. A study to investigate the effect on the AOC of the length of time during which a NUG sells energy to a utility was carried out. The optimal duration (OD) was evaluated from this study and it was shown that the OD is different for different NUG energies. From the studies presented in this chapter it can be concluded that it is possible to evaluate the AOC in hydrothermal systems and the inherent characteristics of the system affects the AOC.

Chapters 3 and 4 examine the short term economic impact of NUG in thermal, fixed head and variable head hydrothermal systems. It is also important to appreciate the economic impact of different types of NUG on a given power system. Intermittent sources of energy such as industrial cogeneration, wind, solar, etc. are receiving increasing interest from both NUG and electric power utilities. The economic impact on a thermal power system of a NUG providing electrical energy from industrial cogeneration and wind sources was examined and the results are presented in Chapter 5. The historical development and the inherent characteristics of industrial cogeneration and wind are discussed. The integration of NUG in the form of industrial cogeneration and wind, into a utility generation schedule involves additional constraints. Two inherent characteristics of cogeneration sources, intermittent nature of power generation and the uncertainty associated with an industrial operation were considered in the cogeneration model. The AOC was evaluated utilizing a conditional probability approach. A range of comparative studies were conducted on the IEEE-RTS to show the difference between non-energy limited (NEL) and energy limited (EL) cogeneration facilities. The effect on the AOC of NUG energy and the number of cogeneration units were examined. The results indicate that the AOC increases with an increase in the NUG energy and the number of cogenerating units. The impact on the AOC of the probability of failure of a cogenerating unit in the next 24 hours was also examined in this chapter. The principal observation is that NEL cogenerating unit yields higher AOC than EL cogenerating units.

A probabilistic profile of the Wind Turbine Generator (WTG) output was obtained by considering the uncertainty of wind and the non-linear relationship in electrical output and wind speed due to the combined effect of aero-turbine and generation characteristics. The uncertainty associated with the wind was modeled by a seven-step representation. The probability that a WTG will fail to operate in the next 24 hours was also included in the model. Studies were performed on the IEEE-RTS in order to illustrate the effect on the AOC of different variables associated with a WTG. The effect of wind speed and wind energy penetration on the economics of the utility were examined. The AOC of the system increases with an increase in the wind speed and wind energy penetration. It is also shown that a reasonable increase in the probability of failure of a WTG causes an insignificant decrease in the AOC. The probability of failure of a WTG unit can, therefore, be neglected in the evaluation of the AOC. The studies in this chapter show that it is possible for a utility planner to make valuable short term decisions regarding NUG producing energy from non-conventional sources.

The HL I analyses done in Chapters 3 through 5 were performed utilizing the IEEE-RTS. Chapter 6 deals with analyses at HL II and applies the developed concepts to the Roy

Billinton Test System (RBTS). The developed technique is based on the deterministic approach and provides an optimal method to incorporate NUG energy into a utility loading schedule. The studies illustrated in this chapter show the importance of considering transmission losses in the evaluation of the AOC. The results obtained from the analyses suggests that there can be a considerable change in the value of the AOC when transmission losses were considered compared to cases when transmission losses are neglected. A study using the RBTS to determine the most suitable location for a NUG in the network was carried out. This study illustrates the importance of NUG location in a network in order to provide maximum economic benefit to both the NUG and the utility. The results indicate that the most suitable location for NUG in the RBTS is bus 5. The optimum duration for which a specific amount of energy is sold by the NUG to the utility was also determined. The optimum duration at which the AOC is the maximum was found to be 8 hours for 120 MWh of NUG energy in a day. This chapter shows that the AOC can be evaluated considering transmission losses and can be used to make planning decisions regarding NUG energy.

It is shown in this thesis that the AOC can be evaluated for thermal, fixed head and variable head hydrothermal systems. It is also shown that the AOC is not fixed but varies with the type of utility, the operating practice of the utility, the duration of time for which a NUG sells energy to the utility, the system load level and the location of a NUG in the network. It is, therefore, important to appreciate that the buyback rate is not be a fixed parameter. The studies and examples presented in the thesis show that the proposed techniques for the evaluation of the AOC will treat both parties involved in a NUG energy transaction fairly and can include the standard operating practices used by a utility. The techniques can be used to assess the AOC in a consistent manner, and are sufficiently flexible to include other system operating criteria. They can be used by a utility as a basic framework upon which other relevant system operating criteria and cost parameters can be added to provide a generic buyback rate. Sensitivity studies similar to those performed on the two test systems can be utilized by a utility to estimate savings in the running cost incurred when buying energy from NUG. The studies can also be utilized to estimate the amount of NUG energy, the time period of an energy transaction and the location of a NUG in the network for which both the utility and the NUG can each maximize their economic benefits.

The research presented in this thesis illustrates that quantitative economic assessment of the AOC can be performed in systems containing NUG, at both HL I and HL II. These analyses should be performed for the utility in question before decisions are made regarding the merits and demerits associated with the inclusion of energy from NUG.

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