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Economic Benefits of Pumped Storage Units in Probabilistic Production Costing

by

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In the Name of Allah, Most Gracious, Most Merciful

Abstract

Storage in power systems can have several roles and can affect system costs in many ways. The two principal roles are load-levelling and system reserve for frequency control. The saving from load-levelling has two components - the fuel cost saving arising from the transfer of power from times of low marginal cost to those of high marginal cost - artificial energy exchange (AEE), and the cycling avoidance which arises from the reduced number of start-ups and shut-downs of thermal units. Planning studies based on probabilistic production costing (PPC) models now use equivalent load duration curve techniques which only take into account the cost benefits of AEE by pumped storage units.

This thesis formulates the cost benefits of pumped storage units to provide for AEE and reduced start-up and shut-down costs of thermal units in probabilistic production costing methodology. The algorithm also finds the optimal reservoir utilization level of pumped storage units.

A very efficient and accurate technique is developed, which does not require deconvolution to off-load the thermal units by the discharging side of the storage units.

Issues concerning optimization of the assigned-energy units or units limited in their energies e.g., hydro, competing for the same or part of the same position in the loading order is also properly accomplished. Realistic case studies are presented.

The algorithm developed is faster than the Monte Carlo approach and more accurate than conventional PPC models, as start-up and shut-down costs are also assessed. It is useful for determining the likely usage of pumped storage plants in operational planning and fuel budgeting. The proposed algorithm can easily be integrated into the long range generation expansion planning tools based on PPC models.

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Acronyms

A/N	unit available needed
A/NN	unit available not needed
AE	assigned-energy
AEE	artificial energy exchange
CP	capacity point
D/N	unit down needed
D/NN	unit down not needed
DE	demand-energy
ELDC	equivalent load duration curve
ELFC	equivalent load frequency curve
EUE	expected unserved energy
FD	frequency and duration
FOR	forced outage rate
LDC	load duration curve
LOLP	loss of load probability
LP	loading point, linear programming
MTTF	mean time to failure
MTTR	mean time to repair
PCBC	piecewise constant benefit/cost
PPC	probabilistic production costing
RTS	reliability test system
SUBPC	storage unit benefits in production costing

Functions

$F(x)$	reverse cumulative distribution
$F_e(x)$	equivalent load distribution
$F'_i(x)$	intermediate equivalent load duration curve seen by the i^{th} unit after the discharging generation convolved
$F'_j(x)$	intermediate equivalent load duration curve seen by the j^{th} unit after the charging load of the

	storage unit convolved
$F_l(x)$	reverse cumulative load distribution
$F_n(x)$	equivalent load duration curve seen by the n^{th} unit, it includes the forced outage loads of units 1,2,...,n-1
$F_{t+1}(x)$	final equivalent load duration curve after convolving total capacity
$F_{1-m}(x)$	load duration curve when the generation mix contains storage units (m is the number of storage units)
$f(x)$	transition frequency
$f_e(x)$	equivalent transition frequency
$f'_i(x)$	intermediate equivalent load frequency curve seen by the i^{th} unit after the discharging generation convolved
$f'_j(x)$	intermediate equivalent load frequency curve seen by the j^{th} unit after the charging load of the storage unit convolved
$f_l(x)$	load transition frequency
$f_n(x)$	equivalent load frequency curve seen by the n^{th} unit, it includes forced outage loads of units 1,2,...,n-1
$f_{t+1}(x)$	final equivalent load frequency curve after convolving total capacity
$f_{1-m}(x)$	load frequency curve when the generation mix contains storage units
$M_s^c(R_s)$	the efficiency adjusted marginal cost of charging as a function of the reservoir utilization level of storage unit s
$M_s^d(R_s)$	the marginal benefit of discharging as a function of the reservoir utilization level of storage unit s
$P_l(x)$	cumulative load distribution
$p_l(x)$	probability density at load x

Indices

g	demand-energy unit

i,j,k,n	indicate any unit
l	negative/positive index ranging over the storage units so that after convolving charging storage load l becomes equal to 1
r	assigned-energy unit
s	storage unit

Parameters

AE_n	assigned-energy of unit n
C	total capacity of the unit
C_n	generating capacity of unit n
C_{nD}	derated capacity of unit n
C_{nT}	total capacity of unit n
C_r	total generating capacity of assigned-energy unit r
C_s^c	charging capacity of storage unit s
c_n^{csu}	cold start-up cost of unit n
c_n^{ts}	turbine start-up cost of unit n
IF_n	incremental fuel cost of unit n
m	number of storage unit
L_{max}	peak customer demand
k,n	number of units
P_s	start-up failure probability
p	availability of the unit
p_n	availability of unit n
q	forced outage rate of the unit
q_n	forced outage rate of unit n
p_s^c	availability of the charging side of storage unit s
p_s^d	availability of the discharging side of storage unit s
R_s^{max}	maximum reservoir utilization level of storage unit s
R_s^0	initial reservoir utilization level of storage unit s
T	duration of the time period
λ	failure rate of the unit

η storage cycle efficiency of the unit
η_s storage cycle efficiency of unit n
η_s^c storage charging cycle efficiency of unit n
η_s^d storage discharging cycle efficiency of unit n
τ total cycle time of the unit
τ_n total cycle time of unit n
τ_s^c charging mean cycle time of storage unit s (this time is mean time to failure plus mean time to repair of charging side of storage unit s)
τ_s^d discharging mean cycle time of storage unit s (this time is mean time to failure plus mean time to repair of charging side of storage unit s)
μ repair rate of the unit

Variables

$CP_{s,n}^c$ efficiency adjusted cumulative potential charging energy provided by n number of demand-energy units to storage unit s
$CP_{s,k}^d$ cumulative potential discharging energy off-loaded from k number of demand-energy units by storage unit s
c_n^T expected turbine start-up cost
c_n^B expected mean boiler cost
c_n^P expected production cost of unit n
E expected energy of the unit
E'_i expected energy of unit i after being off-loaded by the storage discharging side
E'_j expected energy of unit j when charging load added
E_n expected energy of unit n
$\overline{f}$ average frequency of loss-of-load events
H_s^0 complementary reservoir utilization level of storage unit s
OH_n operating hours of unit n
$\overline{P}$ average power deficit during loss-of-load events
$P_{s,j}^c$ potential charging energy of storage unit s with respect to demand-energy unit j
$P_{s,i}^d$ potential discharging energy of storage unit s

	with respect to demand-energy unit i
P1	probability the unit is in state 1 etc. etc. (number indicates the state)
p'	equivalent availability
p'_n	equivalent availability of unit n
q'	equivalent forced outage rate of the unit
q'_D	equivalent derated forced outage rate of the unit
q'_T	equivalent full forced outage rate of the unit
q'_n	equivalent availability of unit n
q'_{nD}	equivalent derated forced outage rate of unit n
q'_{nT}	equivalent full forced outage rate of unit n
R_s	reservoir utilization level of storage unit s (referred to discharging)
R_s^*	optimal reservoir utilization level of storage unit s (referred to discharging)
$\overline{T}$	average duration of loss-of-load events
T_n^{off}	mean off-line time of unit n
X_{n-1}	loading point of unit n
X_n	capacity point of unit n
ρ_+	departure rate (unit needed)
ρ_-	departure rate (unit not needed)
μ'	equivalent repair rate of the unit
μ'_n	equivalent repair rate of unit n
μ'_D	equivalent repair rate of derated outage of the unit
μ'_T	equivalent repair rate of full forced outage of the unit
μ'_{nD}	equivalent repair rate of derated outage of unit n
μ'_{nT}	equivalent repair rate of full forced outage of unit n

NOTE

Functions, parameters and variables with same charcters, but different indices or numeric subscripts, are not repeated here. List provided here in author's view is quite sufficient and general.

Chapter 1

Introduction

1.1 PROBLEM STATEMENT

The most crucial step in planning the expansion of an electric utility is the generation system [26]. The problem of generation system expansion planning is finding the minimum cost of generation to serve a given load forecast over a long range horizon with a specified level of reliability. Prediction of the cost of generation includes capital and construction costs, effects of maintenance and forced outages of the generating units, the cost of fuel, starting and shut down costs and environmental considerations. The reliability standard is defined by a probabilistic measure of load fluctuations and plant outages. Besides the above decision-making factors in capacity expansion planning, there are other factors which can affect the decisions making policy such as [56]:

- Planners need to consider alternative technologies;
- Safety and pollution regulations;
- Long construction periods;
- Uncertain load growth;
- Fluctuating and high interest rates;
- Financing uncertainties;

- Unit reliabilities.

The business structure of the utility industry itself is changing. Utilities are using alternatives such as capacity purchases from other utilities, demand-side management, and non-utility generation before investing in capital-intensive base-load generating plants [55]. As a result, a major concern of electric utility is the appropriate planning of the expansion of its generating capacity.

The calculations of the financial aspects and other considerations listed above are large domains of expertise themselves and are either performed within a single optimization model (as [33,57,58]) or through separate models within a planning process involving several simulation and financial models. Both these approaches require a repetitive evaluation of the production costs incurred by the power system at different times.

Production cost calculations may be found in many modern control centres as part of the overall "application program" structures where appropriate models are usually intended to produce shorter term computations of production costs (i.e., a few hours to the entire week) in order to facilitate negotiations for energy (or power) interchange between systems or else to compute cost savings in order to allocate economic benefits among pooled companies [35].

Production cost computations are also needed in fuel budgeting. This involves making computations to forecast the need for future fuel supplies at specific plant sites so that proper arrangements can be made sufficiently in advance of requirements.

In the operating centre, production cost needs may have a 7-day time horizon, but the fuel budgeting time span may encompass 1 to 5 years. System expansion studies usually encompass a minimum of 10 years and in many cases extend 30-45 years into the future. Since the operating life of power plants varies from 25 years or so for nuclear up to 40 years for coal-fired plants, the long range planning horizon covers the operating life of all existing and committed plants.

Expansion planning and fuel budgeting production cost programs require load models that cover weeks, months, and /or years. The expected load patterns may be modelled by the use of typical, normalized hourly load curves for the various types of days expected in each subinterval (i.e., month or week) or else by the use of load duration or load distribution curves.

A load duration curve expresses the period of time (say number of hours) in a fixed interval (day, week, month or year) that the load is expected to equal or exceed a given megawatt value. The benefit of the load duration curve approach is its computational speed. The disadvantage of the method lies in its inability to recognize the time chronology of plant operation and therefore time-dependent constraints, such as minimum up-time or down-time requirements, ramping rate restriction of thermal units, start-up and shut-down costs, etc..

This thesis is aimed at the improvement of the calculation of energy production cost of a power system. It uses the approach of the load duration curve but also includes start-up and shut-down costs and detailed description of different generating units; i.e., nuclear units, conventional thermal units, hydroelectric units and storage units. The electric power utilities under study are those whose generation systems are predominantly thermal but the primary concern of this thesis is to evaluate any pumped storage load-levelling benefits in the power system.

A storage unit is a two sided device whose:

(1) charging side stores energy produced at certain time intervals by cheap base-loaded thermal units,
(2) discharging side discharges that energy (adjusted by the charging/discharging cycle efficiency) at some other

time intervals to off-load expensive peak-loaded thermal units.

The process of charging during periods of low demand and discharging at times of high demand is called load-levelling. The transfer of energy produced at times of low demand (and hence low marginal cost) to displace the more expensive energy at times of high demand (and hence high marginal cost) results in fuel cost savings i.e, artificial energy exchange (AEE). Such an operation also alleviates minimum-load conditions at night and over weekends. By increasing the capacity factor of base-loaded coal-fired units, pumped storage reduces their cyclic operation, both in terms of the number of loading cycles as well as the number of start-ups and shut-downs. This in turn alleviates thermal stresses on the units and reduces their maintenance costs. Such cycling avoidance is an additional major benefit from load-levelling.

Load duration curve based models cannot estimate the start-up and shut-down costs of units and hence cycling avoidance benefits of pumped storage since time is not treated explicitly in this approach. Infield (1984) noted that cycling avoidance is by far the most important benefit from storage load-levelling [45]. The intrinsic time dependent nature of the time-dependent technologies (solar, wind, and the like) which are being incorporated into the generation system of many electric utilities make the installation of storage units necessary if the capability of these time dependent technologies is to be fully utilized. Bossanyi pointed out in reference [62] that the additional start-up costs imposed by tidal power may reduce the value of energy by 10% if there is little or no storage available for load-levelling. Omitting such benefit thus introduces a potentially significant bias inaccuracy in assessments if pumped storage is among the options in generation expansion planning.

The technique used for integrating the start-up costs of the units is the Frequency and Duration approach. A separate load model called a load frequency curve is used besides the load duration curve model which retains some information of time dependency of load. It determines the frequency or number of times each load level is crossed by customer demand in an upward direction.

Within the aforementioned context, the modelling of pumped storage plants is carried out in this thesis. More specifically,

> "it addresses the problem of determining the load-levelling benefit of pumped storage units by finding their level of reservoirs utilization so that the total production cost is minimized in the considered time period".

It should be noted that

(1) the considered storage units are independent of each other, and

(2) they are not integrated into a complex multi-reservoir hydro system.

1.2 PREVIOUS SOLUTION METHODS

To the author's knowledge none of the previous approaches based on a load duration curve technique have fully estimated the load-levelling benefit of pumped storage units. The benefit from artificial energy exchange has been estimated but the benefit from cycling avoidance was never assessed. Although the frequency and duration approach together with the load duration curve technique for production costing have been reported (see e.g., [7,9,15]), either pumped storage units were not modelled at all or were modelled in a crude manner in which they were assumed as another thermal generating unit with some incremental fuel cost. As a result, their cycling avoidance benefits were never assessed.

Three previous approaches to the solution of the reservoir utilization problem have been reported in the literature: the PCBC (which stands for Piecewise Constant Benefit Cost) method, the decomposition method and the non-looping method. A brief summary of the different approaches is presented in the following.

Manhire [6] developed the PCBC method which considers storage units one at a time and, for each builds up two piecewise constant functions:

(1) the marginal benefit of discharging as a function of the storage unit reservoir utilization level, and

(2) the efficiency adjusted marginal cost of charging as a function of the storage unit reservoir utilization level.

The optimal reservoir utilization level of the considered storage unit occurs when its net marginal benefit vanishes. This optimal reservoir utilization level is given by the intersection of the two piecewise constant functions defined above (the charging side is adjusted by the cycle efficiency of storage) as illustrated in figure 1.1. This method is also computationally burdensome because it needs several production cost simulations and a huge solution space.

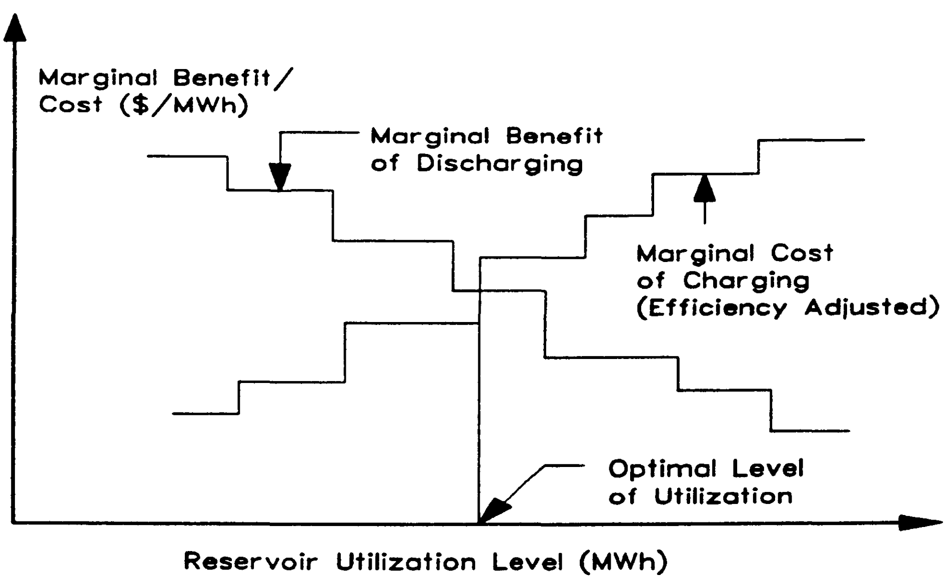


Figure 1.1 Marginal benefit of discharging and marginal cost of charging.

Bloom [5] proposed an iterative Benders decomposition type framework where reservoir utilization decisions were made by a Linear Programming (LP) master problem and the associated marginal costs and benefits were evaluated by a subproblem. The subproblem is a production cost simulation performed for trial reservoir utilization levels and the solution of the subproblem is production cost and net marginal benefits (Langrange multipliers) of using the storage reservoir level. A master problem generates new trial reservoir utilization levels using the information of the subproblem. The iteration between the master problem and the subproblem continues until a given convergence criterion is met. For instance a typical criterion may be that the cost difference between the master problem and subproblem production cost values should be less than a specified cost threshold value. The decomposition method is computationally demanding in two respects; it requires multiple production cost simulations and it requires multiple LP solutions.

Conejo, Caramanis and Bloom [29] proposed a non-looping method which does not require multiple solutions and achieves the same solution with minor modifications of charging and discharging schedules: hence it is the fastest in this type of framework. It uses the PCBC curve concept but moves the charging and discharging sides of each unit toward their optimal locations within a single production costing run. It revises the reservoir utilization level using an iterative algorithm which is conceptually equivalent to Bloom's Decomposition method, but does not require repeated production cost calculations and LP solutions. The algorithm requires only impact values (marginal cost of charging and marginal benefit of discharging) and not total production costs for each iteration of a trial reservoir utilization level. On its computational efficiency, Conejo [32] says that the non-looping method is $1/(m+o.5)$ times faster than PCBC approach, where m is the number of storage units, and $2/\alpha$ times faster than the decomposition technique (without including solution of linear programs) where α has a typical value of 5.

However, the algorithm has the following drawbacks [32]. It stops optimization for the considered storage unit when the next unit to charge the charging side of the considered storage unit is (i) the discharging side of another storage unit or (ii) a limited energy unit, e.g., hydro. Alternatively, it stops when the next unit off-loaded by the discharging side of the considered storage unit is (i) the discharging side of another storage unit or (ii) a limited energy unit. This problem is mentioned as a "logic" problem in reference [32]. Also, the algorithm cannot find the global optimal if one or several reservoir capacity limit constraints are binding in a locally optimal solution which has been obtained using a decreasing cycle efficiency storage plant order. This "order" problem is also mentioned in [29,31] and in fact, in essence, is the same as the "logic" problem. When encountered with the order problem, the non-looping method changes the loading order of the storage units to find the global optimal; in this way it loses its superior computational speed. Moreover, the algorithm is not independent of the load duration curve representation used by the production costing model. This point is discussed in chapter 4.

1.3 PROPOSED METHOD

This thesis proposes a solution method which extend the previous works, i.e., it takes into account the benefit of cycling avoidance of the thermal units and overcomes all the above mentioned problems faced by the non-looping method. It is based on the non-looping concept, and so does not require multiple solutions and thus retains its computational efficiency, whilst it also utilizes the PCBC approach to the problem. Whereas parallel recursive frequency equations, combining load model and thermal units model which were developed by Janssen [7,8] and then further developed by Malik and Cory [51] for pumped storage units model, are used to take into account the frequency of starts of the units to assess the cycling avoidance benefit. The proposed algorithm is independent of load duration curve representation for production costing model.

The non-looping concept is based on the fact that the thermal units affected either by charging or discharging sides of storage units constitute a small subset of the total thermal generating system. An initial solution of production cost with trial reservoir utilization level is accomplished. Multiple system production cost calculation runs are then not required since the only portion of the PCBC curve local to the current trial loading order and reservoir utilization level is modified at each iteration of the proposed algorithm.

1.4 RETROSPECTIVE

In 1967 three Belgian researchers, Baleriaux, Jamoulle, and Linard de Guertechin published a paper in a Belgian journal written in French [3] stating the basic idea of the probabilistic production technique and this, curiously, was specially concerned with pumped storage modelling. This paper did not catch the attention of the English speaking technical community until in 1972 an Australian researcher, Booth, published a paper [4] in IEEE Transaction on Power Apparatus and Systems, explaining and applying the probabilistic simulation technique. Since then this technique has been widely incorporated into production costing and generation expansion planning models and hundreds of papers have been published worldwide in the most relevant technical journals concerning its extensions and applications.

A frequency and duration approach to capacity evaluation was first introduced in 1958 [13]. This approach was not really utilized until a group of papers in 1968-1969 presented recursive algorithms for capacity model building and load model combination which facilitated digital computer application [13]. In 1981 [9] the frequency and duration method was applied to include the operating considerations of the units so that accurate forced outage rates (FOR) of the units could be used for production costing. Since then different kinds of models have been proposed and used for accurate representation of FOR for reliability studies and production costing.

The frequency and duration approach has also been employed for calculation of start-up costs of units, and was perhaps first formulated by Finger 1979 [2]. Janssen [8] also produced similar concepts but detailed calculations of start-up costs were published by Grubb [15-18].

Inside the probabilistic simulation framework the optimal reservoir utilization problem has been examined by the following contributions:

In 1980 Manhire [6] proposed a PCBC type framework in which multiple storage units are considered. The production costing used is fully probabilistic but the computation of the piecewise constant cost and benefit curves associated with the operation of every storage unit is approximate.

In 1981 Bloom [5] proposed an accurate but computationally burdensome mathematical programming and decomposition procedure. The energy invariance property was also formulated in this reference.

In 1982 Caramanis, Schweppe and Tabors [33] integrated the decomposition method of Bloom [5] into a fully fledged generation capacity expansion planning model.

In 1989 Conejo, Caramanis and Bloom [29] proposed the non-looping method.

In 1991 Malik, Cory, and Wijaytunga [52] reported an early version of the new algorithm, based on non-looping concept and PCBC approach , fully developed in this thesis.

The cycling avoidance benefits of storage units in probabilistic simulation were never assessed. Recently, however Malik and Cory [51] published a paper in 1991 and this technique is fully developed in this thesis.

The extension of the standard probabilistic production costing methodology to consider generating systems with high share of hydro power has been successfully developed using a decomposition approach by Nordlund, Sjelvgren, Preira and Bubenko [59] and Andersson and Sjelvgren [60]. The modelling of storage units integrated in a complex multi-reservoir system is an interesting problem complementary to the one treated in this thesis and the methodology of Andersson and Sjelvgren [60] may provide the appropriate framework for the aforementioned modelling.

A tutorial introduction to the probabilistic simulation technique can be found in Wood and Wollenberg [35] and IAEA [61]. The basic concepts associated with frequency and duration analysis are described in Billinton and Alan [13,14] and by Anders [34].

Interesting general references concerning generation expansion planning are Stoll [46], IAEA [61], and Sullivan [26].

1.5 CONTENTS

This work is organized as follows.

Chapter 1 is the introduction.

Chapter 2 develops the framework to simulate the operating costs plus the start-up and shut-down costs of thermal units in a probabilistic manner. Additional benefits of using the frequency and duration method regarding reliability indices and more accurate representation of forced outage rates of units is presented.

In Chapter 3 the method is extended to account for hydro units which are limited in reservoir capacity and hence energy output. Since some thermal units are also constrained in their energy production because of environmental limitations, therefore, a general categorization of such units is made here, called assigned-energy units. Other units which are not constrained in their energies are categorized as demand-energy units. The idea of an equivalent assigned-energy is formulated and in the author's opinion this sophisticated design factor could be used for designing the reservoir size for hydro-electric plants and storage plants and their unit sizes.

Chapter 4 explains the role of pumped storage in the grid system and is devoted to pumped storage modelling.

Chapter 5 presents the full algorithm developed to simulate the mixture of assigned-energy, demand-energy and pumped storage units. The algorithm efficiently finds the optimal reservoir utilization of storage units. The full benefits of pumped storage units for load-levelling can be estimated by the proposed algorithm.

Chapter 6 presents two case studies.

Chapter 7 is conclusions.

Appendix A describes the energy invariance property (which is the basis of understanding Clustering and Swapping technique), explains the clustering and swapping technique and do a comparison between this technique for off-loading the units and the proposed technique.

Appendix B includes the results and data of a study done for assigned-energy units in chapter 3, which is mainly the improvement of Manhire and Jenkins [1] algorithm.

Appendix C gives some details about the computer implementation of the proposed algorithm in this thesis.

Although, the appendices are written in such a way that, if omitted, the sequence of understanding the final algorithm is not affected, however, appendix A is needed in chapter 3 to understand the clustering and swapping technique. This technique was used in earlier research work, and its use was refined in the algorithm for simulating the demand- and assigned-energy units, by Malik and Cory and reported in [27,28] but later it has been discarded. The need arose to put this technique in appendix because of the two reasons; first because it is not employed in the final algorithm and second because the newly developed technique for off-loading units is compared with it.

The notations used in a given chapter/appendix is defined in that portion but a table of symbols is provided.

Some figures throughout this dissertation are drawn for clarity in a schematic simplified manner, but naturally this does not mean that equations are simplified in any fashion.

Chapter 2

Production Cost Simulation

Electric utility planning studies are based on production simulation and reliability analyses as the power demand on the utility varies with time. Figure 2.1 shows a typical weekly load variation. Chronological hourly production cost simulations offer more accuracy but require long computational times. Moreover, it is very difficult to predict the hourly loads for future time periods, more than a few days ahead. Therefore, most production simulation and reliability models use load duration curves (LDC) that give just the percentage of time that each demand level occurs.

The LDC method has been extended to include the random forced outages of generating units known as the equivalent load duration curve (ELDC) method, first introduced by Baleriaux et al. in 1967 [3] and later reintroduced by Booth [4]. Since then it has been applied and refined or formulated in different ways by numerous authors, e.g, [37,47-50]. Out of many different approaches available for representing the ELDC, it is worth mentioning the cumulant method [37] due to its commercial value e.g. [33]. Reference [38] is a nice comparison of different methods available for representing ELDC. We will not delve further into this area of ELDC's different ways of representation as the equations derived and

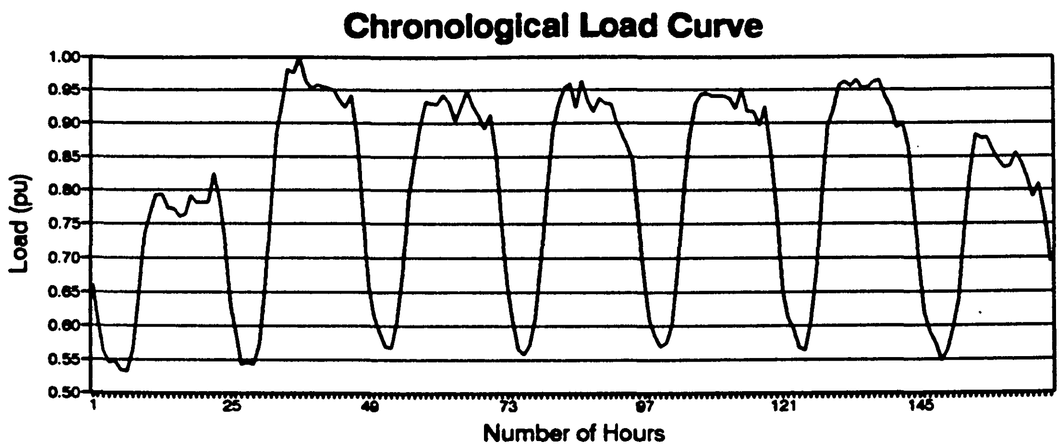


Figure 2.1 Chronological load curve.

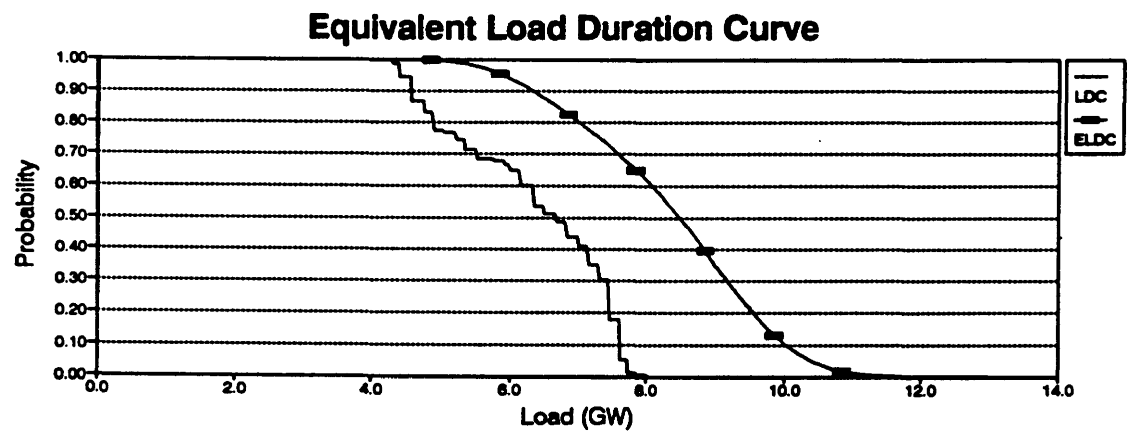


Figure 2.2 Equivalent load duration curve.

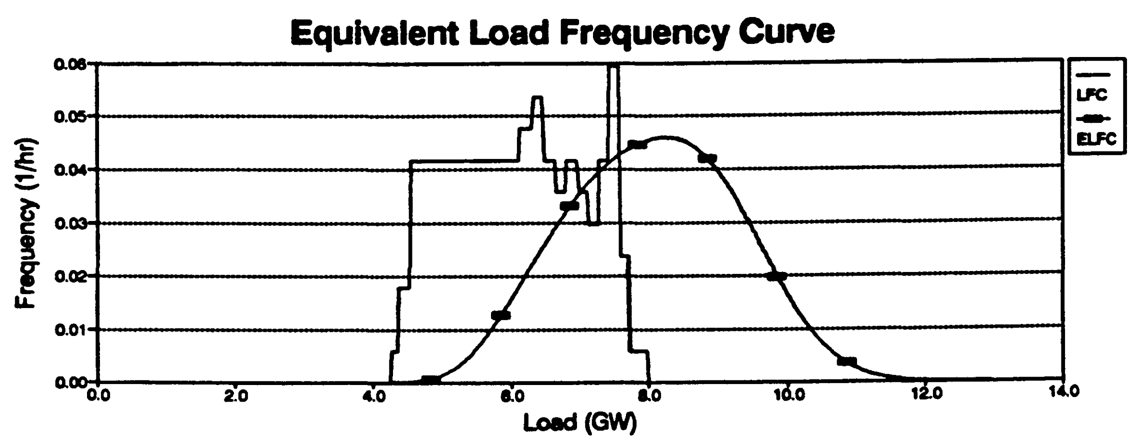


Figure 2.3 Equivalent load frequency curve.

conclusions drawn in this thesis are independent of the ELDC representation.

Production cost models based on an ELDC method, which include the probabilistic description of the customer demand and failure of the generating units, are therefore widely known as probabilistic production costing models (PPC). These models are the main constituents of any electric utility planning methodology whether they are performed within a single optimization model (as [33] or [57]), or through separate models within a planning process involving several simulation and financial models.

PPC models cannot take into account the start-up costs of the units since time is not treated explicitly in this approach. The importance of such costs varies greatly according to both the system and the particular plant investments under consideration. On large systems with a regular, predictable load cycle, they may form a small percentage of total generation costs (though this may be a considerable sum), whereas on smaller systems, perhaps with more rapidly varying load, start-up costs may contribute to a significant percentage of total generation cost [17]. The relevance of start-up costs become even more significant if the generating system contains pumped storage units because a fair part of the economic benefits deriving from these units is achieved by the reduced frequency of start-up and shut-down of thermal units. The technique used for integrating the start-up costs of the units in ELDC based methods is the Frequency and Duration approach.

The Frequency and Duration (FD) method can be considered as an extension of the ELDC based methods in that it retains some details of the time-dependent behaviour of system load and production units. The theory of the FD method for reliability studies can be found in the literature in various formulations; see, e.g. [12,13,24]. Janssen [7,8], and Patton and et al. [9] used this method to calculate forced outage rate (FOR) with different operating considerations like start-up time, postponability and duty cycle effect of the units for energy production and reliability studies. Grubb [15-17] extended the use of the method for assessment of start-up and banking costs of thermal units.

This chapter describes the ELDC technique for calculating the expected operating costs of the units and Frequency and Duration (FD) technique for calculating the expected start-up costs of the units. Both techniques are also widely used for system reliability analysis.

2.1 THEORY

The input to the ELDC and FD model calculations consists of frequencies and durations of system load levels, plus mean time to failure and mean time to repair of production units.

2.1.1 System Load

Chronological (e.g. hourly) load data (fig.2.1) for the time period e.g. week, month etc. must be available. From this data set two functions are derived, viz.:

1. The cumulative load distribution function $P_l(x)$, denoting the probability density $p_l(x)$ at load 'x', $= \int_0^x p_l(x)\,dx$ of load levels less than or equal to x. The density and distribution functions may be developed as histograms - for practical developments, where each load level, x, denotes a range of loads. The cumulative load distribution function is more easily conceived in its reverse cumulative form, $F_l(x) = 1-P_l(x) = \int_x^\infty p_l(x)\,dx$. $F_l(x)$ then denotes the probability of load $\geq$ x, and is simply the normalized form of the inverted load duration curve shown in fig 2.2.

2. The transition frequency function $f_l(x)$, shown in fig. 2.3, denoting the average frequency with which load level 'x' is crossed in an upward

direction of the load. It is also called as level crossing function in a stochastic process [20].

Although, the above two functions are derived from chronological load curves their crude approximations are used in the literature where this curve is not required. For example, in the case of LDC formation the hourly loads of specified time periods are arranged in decreasing load levels and a growth factor is applied to take into account the growth of the customer load demand [33]. Similarly, two level representation of load [13,34] and multi-level approximation [24] of daily load levels for system reliability studies in the FD method are also used in the literature.

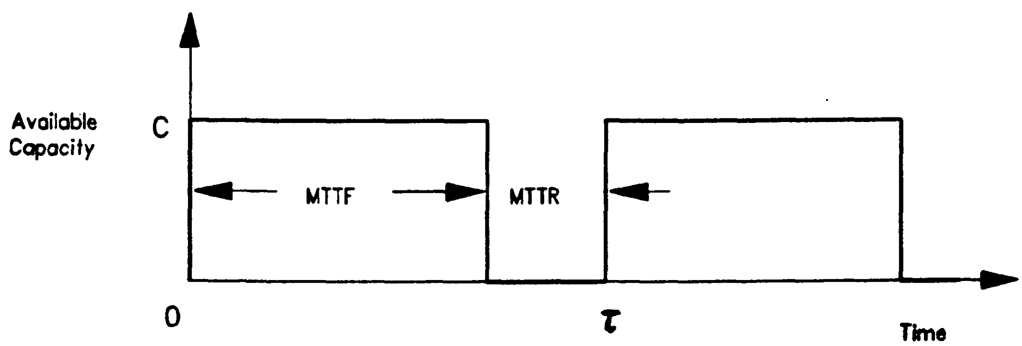


Figure 2.4. Two State Space diagram of a unit
MTTF = mean time to failure
MTTR = mean time to repair
τ = mean cycle time = MTTF + MTTR

2.1.2 Equivalent Load with Two State Unit

The equivalent load 'e' is defined as the sum of customer load 'l' and the fictitious load 'o' due to forced outages of the units. The two state model of the unit is shown in fig. 2.4. Since load and outage are independent variables, the distribution function $F_e(x)$ of the equivalent load, seen by the second unit, when the first unit is scheduled to serve the demand with the capacity C, can be derived with the convolution process

$$F_e(x) = p\,F_l(x) + q\,F_l(x-C) \qquad (2.1)$$

where p and q are respectively the availability and the FOR of the first unit.

The equivalent transition frequency function, $f_e(x)$ is made up of two independent contributions, the first one due to transition of load, viz.

$$p\,f_l(x) \;+\; q\,f_l(x-C)$$

and the second one due to a unit transiting between states, viz.

$$\frac{1}{\tau}\int_{x}^{x-C} dF_l(x) = \frac{1}{\tau}\,\{F_l(x-C) - F_l(x)\} \qquad (2.2)$$

where $1/\tau$ represents the frequency the unit switches between up and down states. Thus:

$$f_e(x) = p\,f_l(x) + q\,f_l(x-C) + \frac{1}{\tau}\,\{F_l(x-C) - F_l(x)\} \qquad (2.3)$$

The energy generated by the first unit, over the duration of the time period T can be calculated by integrating the customer load curve from 0 to the capacity of the unit C as follows:

$$E = pT\int_{x=0}^{x=C} F_l(x)\,dx \qquad (2.4)$$

$F_e(x)$ and $f_e(x)$ can be evaluated in a recursive way for every unit dispatched to serve the load and are called equivalent load duration curve (ELDC) and equivalent load frequency curve (ELFC) respectively. Fig. 2.2 and 2.3 also shows respectively the ELDC and the ELFC after the 50^{th} unit is dispatched in a typical study.

The energy generated by the n^{th} unit dispatched, with the capacity C_n and the availability p_n, can be calculated by loading it under the equivalent $F_n(x)$, seen by the unit.

$$E_n = p_n T \int_{X_{n-1}}^{X_n} F_n(x)\, dx \tag{2.5}$$

where X_{n-1} is the loading point of n^{th} unit and is the same as the capacity point of the $(n-1)^{th}$ unit and $X_n = X_{n-1} + C_n$, is the capacity point of n^{th} unit and mathematically

$$X_n = \sum_{i=1}^{n} C_i \tag{2.6}$$

The average frequency with which the n^{th} unit is called for energy production is $f_n(X_{n-1})$ and the average duration of the period during which this unit is needed is $F_n(X_{n-1})/f_n(X_{n-1})$. Here X_{n-1} is the loading point of the n^{th} unit which is also the capacity point of $(n-1)^{th}$ unit.

After all available units of the supply system are scheduled successively the following reliability indices can be determined:

(1) Loss-of-load probability, LOLP

$$LOLP = F_{t+1}(X_t) \tag{2.7}$$

where F_{t+1} is the final ELDC after convolving total capacity with the load and X_t is the total capacity.

(2) Average frequency of loss-of-load events, $\overline{f}$

$$\overline{f} = f_{t+1}(X_t) \tag{2.8}$$

where f_{t+1} is the final ELFC after convolving total capacity with the load.

(3) Average duration of loss-of-load event, $\overline{T}$

$$\overline{T} = LOLP/\overline{f} \tag{2.9}$$

(4) Expected unserved energy, EUE

$$EUE = T \int_{X_t}^{X_t+L_{max}} F_{t+1}(x)\ dx \tag{2.10}$$

Where L_{max}, is the peak customer load.

(5) Average power deficit during loss-of-load events, $\overline{P}$

$$\overline{P} = EUE \ / \ (T \times LOLP) \tag{2.11}$$

Thermal units are dispatched from lower to higher operating cost to minimize the production cost. This dispatching or loading order is often referred to as merit order and is the main criteria used to carry out the production cost simulation. The production cost c_n^p, in ($) for the n^{th} unit can be calculated as follows:

$$c_n^p = E_n \times IF_n \tag{2.12}$$

where, IF_n is the incremental fuel cost in $/MWh for unit n. Usually, the fuel costs of units are provided in $/MBtu in terms of heat rates, derived from heat rates given in Btu/kWh.

Similarly, total variable operating and maintenance (O&M) cost in ($) for a unit whose energy generated is known can be calculated by multiplying the energy generated by the unit and its O&M cost known in ($/MWh).

Furthermore, since for a given loading order the number of starts of a unit can be derived from the equivalent load frequency function $f_e(x)$, total start-up costs may be determined as well.

2.2 START-UP COSTS

Start-up costs normally include the fuel and manpower cost to start units. However, it should also include the dollar component to reflect the wear-and-tear and loss of equipment life, which may be caused by frequent cycling [19]. Thermal unit start-up costs are divided into turbine start-up costs - those associated with raising pressure in the system, and synchronization and boiler start-up costs - those associated with bringing the station to its operating temperature [17,18].

2.2.1 Turbine Start-up Costs

These costs are more or less fixed for different start-up conditions and also include the operation and maintenance cost of starting the unit [39]. The total expected turbine start-up cost, c_n^T, for the n^{th} unit over a period T is:

$$c_n^T = p_n T f_n(X_{n-1})\, c_n^{ts} \tag{2.13}$$

where c_n^{ts}, is the turbine start-up cost/start.

2.2.2 Boiler Start-up Costs

These costs depend upon the time for which units were off-line. Mean off-line time for the n^{th} unit can be calculated as $T_n^{off} = \{1 - F_n(X_{n-1})\}/f_n(X_{n-1})$. If the unit is allowed to cool after off-loading, the heat of the boiler will decay approximately exponentially with the time constant τ_n^B. If c_n^{csu} is the cold start-up cost of the unit the expected mean boiler start-up cost, c_n^B for the n^{th} unit would then be:

$$c_n^B = p_n c_n^{csu}\{1 - \exp(-T_n^{off}/\tau_n^B)\} T f_n(X_{n-1}) \tag{2.14}$$

Banking costs can also be included, if required, by knowing the mean off-line time. A restriction can be added in the algorithm that if the off-line time is less than a specific period the unit will be banked otherwise allowed to cool down [18].

2.2.3 Start-up Frequency Limitations

Frequency of start and stop of base-load units may be disadvantageous economically or may be even impossible technically. One may therefore, set a limit to the frequency of starts of such units. If, for a predetermined order of commitment, a unit would have to be started too often it should not be committed at all during the time period under consideration, but it should be replaced by units with more flexible operating characteristics.

2.3 SHUT-DOWN COSTS

The frequency of starting the unit is equal to the frequency of shutting the unit in any random period of time. Therefore, shut-down costs, which are more or less fixed, can be incorporated into the turbine start-up costs.

2.4 MODELLING OPERATING CONDITIONS AND RESTRICTIONS

The two state unit's space diagram was given in fig 2.4 is represented by the "classical" two-state Markov model as shown in figure 2.5: the unit is either available (with probability p) or on outage (probability q) the failure rate is λ, and is inverse of MTTF, and the repair rate is μ, and is inverse of MTTR. So far the equations derived for ELDC and ELFC were for two state units. A case of 2-state unit with a four state Markov model and a case of 3-state unit, with a derated state, with a six state Markov model is presented for generalizing the equations.

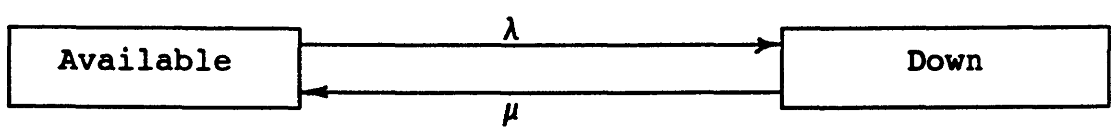


Figure 2.5 Two state Markov Model

2.4.1 2-State Unit with Four State Model

In 1972, the IEEE task group committee [21] reported that the forced outage rate was recognized to be unsuitable as a measure of outage risk when unit annual service hours were low. In peaking operation and cycling operation of units, periods of service are frequently interrupted by periods of economy shut-down such that relatively small numbers of service hours are accumulated in the course of a year. The frequent start-up and shut-down subjects the unit to additional stresses compared to those units which are base-loaded. This additional starting stress was recognized and reported as failure-to-start risk for gas turbines and diesel units, for example.

In addition, FOR makes use of two sets of statistics, service hours and forced outage hours, collected at two different bases. Forced outage hours are counted from the time the unit enters the forced outage state and accumulated until the unit is ready for service or has been placed back in service: by contrast, service hours count only during the time that the unit was synchronized to the bus. Thus, it is possible to greatly affect the FOR by the duty cycle required of the generating unit. The task group developed a recommended four state model.

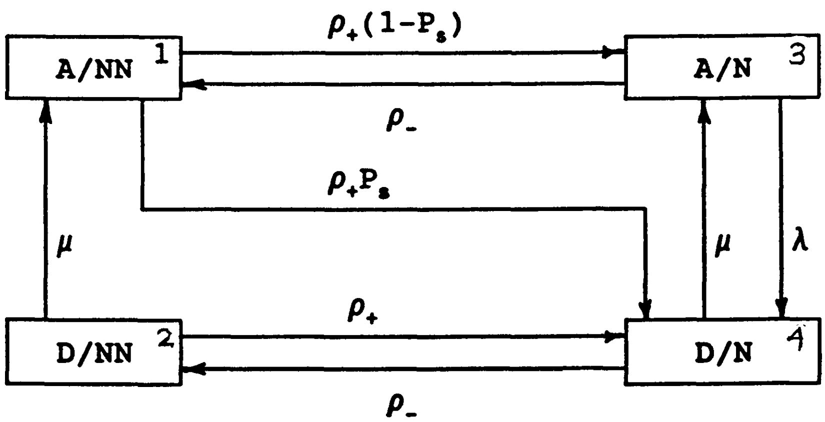


Figure 2.6 Four state Markov model for 2-state unit.

This four state model accounts for the duty cycle effect and start-up failure probability for units operating in cycles of in-service and economic shut-down. Fig. 2.6 shows the four state Markov model for a two state unit. The states described are available/needed (A/N), available/not-needed (A/NN), down/needed (D/N), and down/not-needed (D/NN). P_s is the start-up failure probability shown in the figure 2.6. The departure rates ρ_+ and ρ_- are determined by the properties of the load and by level in the commitment priority list assigned to the unit. The properties of the equivalent load are the cumulative probability, F(x), and the cumulative frequency, f(x), of load levels greater than or equal to x. If the n^{th} unit is committed as shown in fig. 2.7 then the transition rates can be found as follows:

$$\rho_{+} = \frac{f_n(X_{n-1})}{1 - F_n(X_{n-1})} \tag{2.15}$$

and

$$\rho_{-} = \frac{f_n(X_{n-1})}{F_n(X_{n-1})} \tag{2.16}$$

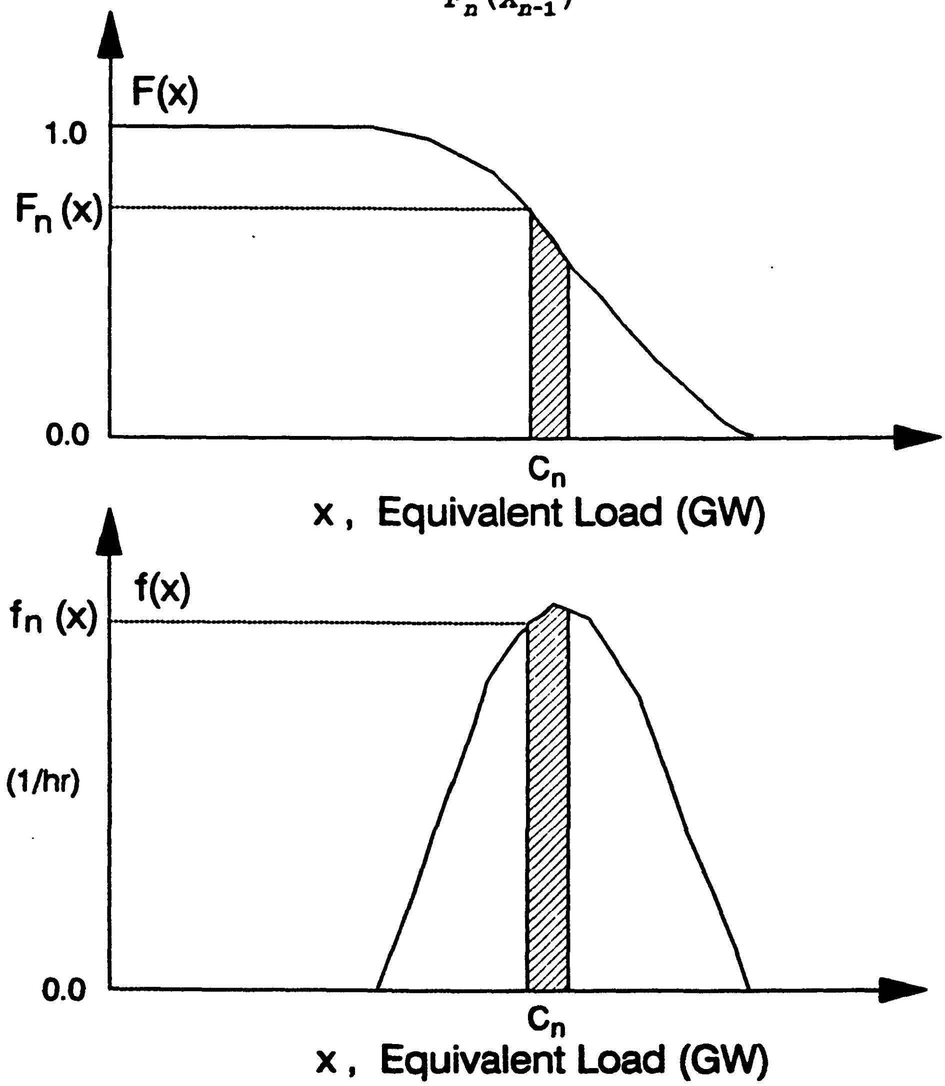


Figure 2.7 Probability $F_n(x)$ and frequency $f_n(x)$ of equivalent load levels greater or equal to x for n^{th} unit.

The knowledge of all transition rates in fig. 2.6 enables the computation of the steady-state probabilities of the unit under consideration (P1,P2,P3,P4). For each possible state we have a balance equation which can be formed on the basis that the total frequencies of leaving a state is equal to total frequencies of entering a state, [14].

The equations are:

$$P_1 \{\rho_+ (1-P_s) + \rho_+ P_s\} = P_3 \rho_- + P_2 \mu \tag{2.17}$$

$$P_2 \{\mu + \rho_+\} = P_4 \rho_- \tag{2.18}$$

$$P_3 \{\lambda + \rho_-\} = P_1 \{\rho_+ (1-P_s)\} + P_4 \mu \tag{2.19}$$

$$P_4 \{\mu + \rho_-\} = P_1 \{P_s \rho_+\} + P_2 \rho_+ + P_3 \lambda \tag{2.20}$$

Furthermore, we have the condition:

$$\sum_{i=1}^{4} P_i = 1 \tag{2.21}$$

The equivalent forced outage rate, q', is the probability that the unit is unavailable when it is needed. Mathematically it can be written as:

$$q' = \frac{P_4}{P_3 + P_4} \tag{2.22}$$

And the equivalent availability, p', is:

$$p' = 1 - q' \tag{2.23}$$

Similarly the equivalent repair rate, μ', is:

$$\mu' = \frac{P_4\mu}{P_4} = \mu \tag{2.24}$$

With the equivalent probabilities and departure rate defined in equations (2.18-2.20) the equivalent cumulative probability function $F_{n+1}(x)$ and equivalent frequency function $f_{n+1}(x)$ becomes after the n^{th} unit of capacity C_n is added as follows:

$$F_{n+1}(x) = p'_n F_n(x) + q'_n F_n(x-C_n) \tag{2.25}$$

$$f_{n+1}(x) = p'_n f_n(x) + q'_n f_n(x-C_n) + q'_n \mu'_n \{F_n(x-C_n) - F_n(x)\} \tag{2.26}$$

Similarly, for finding the energy generated by the unit and for expected start of the unit the equivalent availability would be used.

The formulas can easily be extended straight forwardly for partial or derated states of the unit. Large thermal generation units operate under derated capacity conditions for a considerable part of their up-time as a result of the failure of one or more auxiliary units. It is not normally necessary however to include more than one or possibly two derated states [40] to obtain a reasonably exact value of reliability indices.

2.4.2 3-State Unit with Six State Model

The three state unit model is widely used for reliability studies which represents an up state, a down state and a derated state shown in fig. 2.8.

The peaking or cycling unit with three states can be modelled as a six state Markov model taking into account the start-up failure probability and duty cycle effect. The six states are shown in fig. 2.9. The equivalent full forced outage rate, q'_T is:

$$q'_T=\frac{P_4}{P_3+P_4+P_6} \tag{2.27}$$

where P is the probability of staying in the state and the subscript denotes the number of that state. Similarly the equivalent derated forced outage rate, q'_D is:

$$q'_D=\frac{P_6}{P_3+P_4+P_6} \tag{2.28}$$

The equivalent availability, p', of the unit is:

$$p'=1-q'_T-q'_D \tag{2.29}$$

The equivalent repair rate, μ_T, from full forced outage is:

$$\mu'_T=\mu_T \tag{2.30}$$

And the equivalent repair rate, μ_D, from derated outage is:

$$\mu'_D=\mu_D \tag{2.31}$$

The equivalent cumulative probability function $F_{n+1}(x)$ and equivalent frequency function $f_{n+1}(x)$ becomes after the n^{th} unit of total capacity C_{nT} and the derated capacity C_{nD} is added as follows:

$$F_{n+1}(x)=p'_nF_n(x)+q'_{nT}F_n(x-C_{nT})+q'_{nD}F_n(x-C_{nD}) \tag{2.32}$$

$$\begin{aligned} f_{n+1}(x)=p'_nf_n(x)+q'_{nT}f_n(x-C_{nT})+q'_{nD}f_n(x-C_{nD})\ + \\ q'_{nT}\mu'_{nT}\{F_n(x-C_{nT})-F_n(x)\}\ + \\ q'_{nD}\mu'_{nD}\{F_n(x-C_{nD})-F_n(x)\} \end{aligned} \tag{2.33}$$

The energy generated would then be

$$E_n=p'_nT\int_{X_{n-1}}^{X_{n-1}+C_{nT}}F_n(x)\,dx+q'_{nD}T\int_{X_{n-1}}^{X_{n-1}+C_{nD}}F_n(x)\,dx \tag{2.34}$$

The equations described here are quite general and could be extended for any state level representation of units.

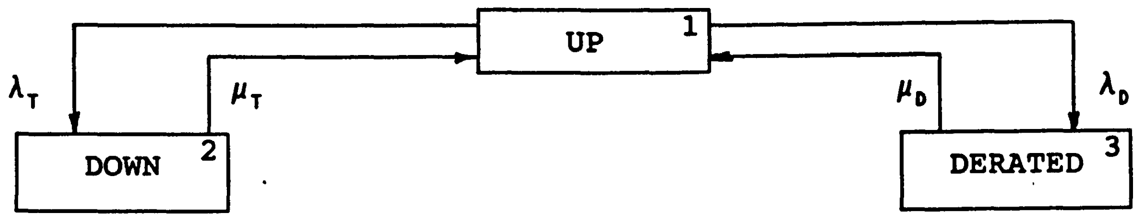


Figure 2.8 State transition diagram of a 3-state unit.

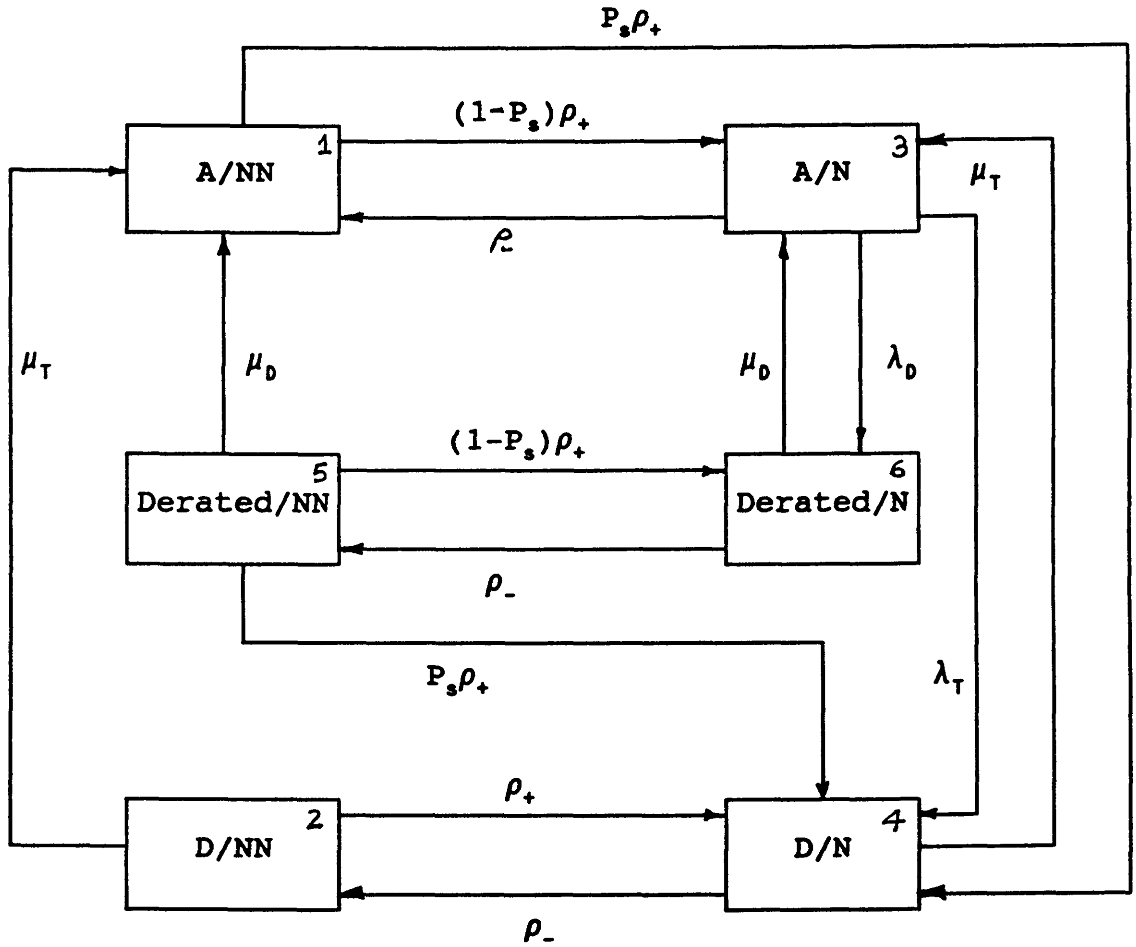


Figure 2.9 Six state model for a 3-state unit.

There are a variety of generating unit reliability models in the literature. Reference [10] gives a comparison of these models for reliability studies and reference [11] is a comparison of production costing with a model which explicitly recognizes the unit duty cycle effects and the traditional model of 2 or 3 state representations of the units.

Extensions of the FD approach as explained in [7,9] to include six state Markov representation for 2-state thermal unit and nine state Markov representation for 3-state thermal units, which can take into account the effect of start-up delay and the possibility of outage postponement were tried. It was found that the probability of staying in those states which represent a start-up delay was in the order of 10^{-4}. Moreover, the data for outage postponements were not available and hence these models were not used in the final development of the algorithm.

In the final development of the algorithm the 2 and 3 state models are used for base-loaded thermal units and 4 and 6 state models are used for peaking and cycling thermal units. The hydro units or the units with limited energy and pumped storage units are modeled as 2-state units.

2.5 CONCLUDING REMARKS

This chapter has presented the theory of the ELDC technique for calculating the expected operating costs of the units and the ELFC technique for calculating the expected start-up and shut-down costs of the units. Methods of calculating different reliability indices were also presented. Extension of the FD method to model operating considerations and restrictions of the units was also demonstrated.

If the generation mix consisted of thermal units only then the framework presented in this chapter, to calculate the operating costs and start-up costs, is enough to carry out production costing. However, if the generation mix contained limited energy and pumped storage units together with thermal units then the algorithm developed here has to be modified and extended.

The next chapter deals with the simulation of generation mix of thermal units and limited energy or hydro units, generally classified as assigned-energy units.

Chapter 3

Simulation of Assigned- and Demand-Energy Units

This chapter portrays the calculation of expected operating costs of a power system consisting of demand-energy units and assigned-energy units.

A Demand-Energy (DE) unit is any generating unit which serves customer load upon demand [1]. The energy generated by a DE unit is limited only by its generating capacity and availability. Examples of such units are coal-fired, oil-fired, gas turbines and nuclear units.

An Assigned-Energy (AE) unit is any generating unit constrained by energy available [1]. Sometimes it is also called a Limited Energy Plant or LEP [5]. The energy to be generated is a fixed (assigned) value. In the case of a hydroelectric unit this constraint may be due to limited reservoir size, a run-of-the-river constraint or seasonal rainfall limitations. The cost associated with production of this energy is essentially zero and it is most advantageous to use all of the available energy. In the case of a fossil fuelled unit the constraint may be due to limited fuel supply or the limits on emissions. In the case of a nuclear unit, the constraint may be due to insufficient core energy which prevents the unit being run on base load. Beside this fixed energy constraint, an AE unit's energy is also limited by it's generating capacity and availability.

If the generation mix only consists of DE units, without energy constraints, the operating costs of the units can be easily found by loading the units, under their corresponding ELDCs, according to increasing incremental fuel cost which is the framework of Baleriaux algorithm explained in the earlier chapter. However if the power system consists of a generation mix of AE and DE units then the algorithm is modified. In the case of a hydro unit, for example, if it is dispatched according to increasing incremental fuel cost criterion its natural loading order position would be at the lowest position among any other type of generating units. But if it is dispatched at full capacity in its natural loading order position, there is a chance that it will be generating more energy than it has in its reservoir - which contradicts the constraint. This implies that we have to find some alternative way to dispatch it where its energy is fully utilized, as it is economical to do. The techniques used are derating, peak shaving and off-loading [2,6].

In the derating method, an AE unit is loaded under the LDC at its natural loading order position but with its derated capacity. The energy generated is same as that assigned to it. This method gives incorrect results for cost calculations because the energies divided among the DE units are incorrect. In the peak shaving method, an AE unit is used to peak shave energy at full capacity from the most expensive thermal units occupying the highest positions in the loading order - which is most economical and is consistent with actual system operation. Figure 3.1 illustrates the hydro peak shaving operation. In the off-loading method, an AE unit is loaded under the LDC at that position where its energy is exactly utilized (figure 3.2). However in doing so it would usually be the case that the AE unit has to "split" a DE unit. That is, a part of the capacity of the DE unit will be loaded, followed by the AE unit with full capacity, which in turn would be followed by

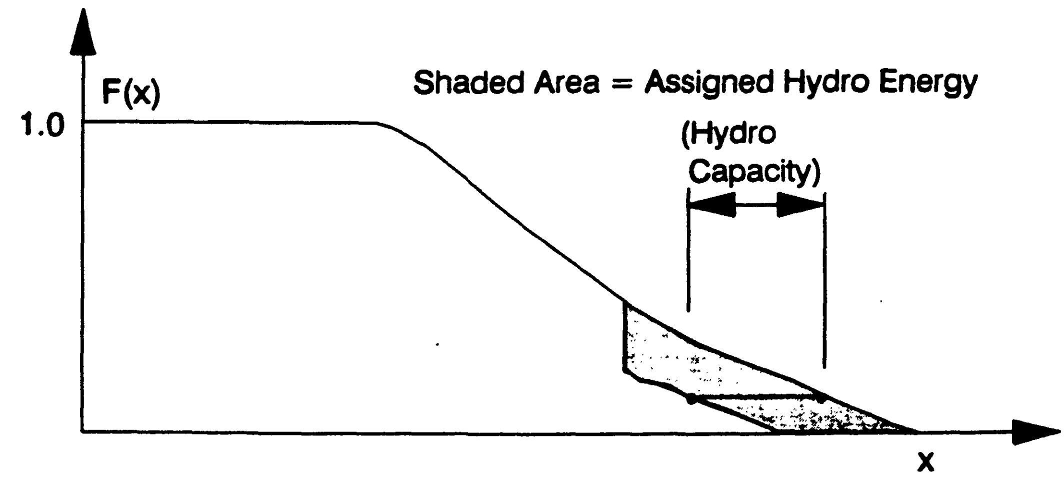


Figure 3.1 Hydro peak shaving operation

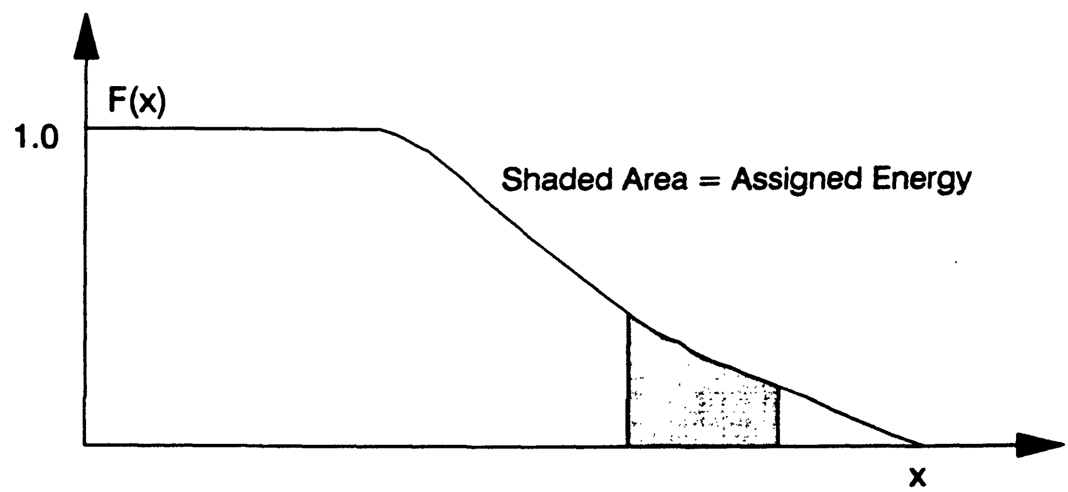


Figure 3.2 Hydro off-loading equivalent to peak shaving operation

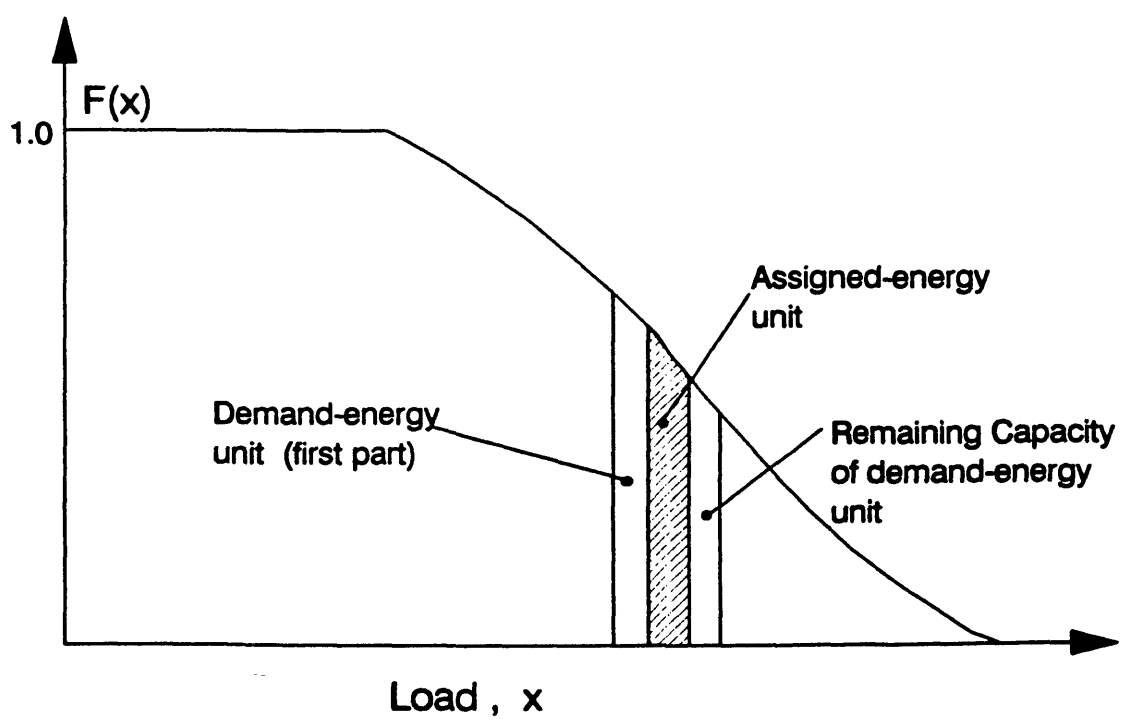


Figure 3.3 Split of the demand-energy unit by the assigned-energy unit.

the remaining capacity of the DE unit being split. Figure 3.3 illustrates the split of the DE unit by the AE unit. In development of the algorithm the AE unit is placed in the loading order after that DE unit which has been split by it. Off-loading method is equivalent to peak shaving in terms of system operation and produces identical loading on the DE units [1,2].

For the probabilistic case, where generating units are subject to random forced outages, the direct application of the peak shaving operation on the original load duration curve will not result in the lowest total system operating cost. This is because the reserve value of AE unit operation would be disregarded. Therefore, for probabilistic simulations, the off-loading method is more correct.

In probabilistic simulations, the load duration curve changes for every outage considered. So finding an exact loading position for an AE unit, under the ELDC, where it can use all of its assigned energy becomes a moving target. The complexity of the problem increases if many AE units compete for the same loading position. Manhire and Jenkins [1], developed a nice technique for simulating multiple AE generating units in probabilistic production costing models. The next section explains the Manhire & Jenkins algorithm in brief, where details are left to the appendix A, and then further improvements to this method are reported.

3.1 MANHIRE & JENKINS ALGORITHM

This algorithm uses blocks instead of units. A unit can be represented by a single block or multiple blocks depending on the complexity of the model used. Loading order for DE units is formed in order of increasing incremental fuel costs of the units. Loading order for AE units is formed by decreasing attempted operating hours of the units. The attempted operating hours, OH_n, of the n^{th} unit are found as:

$$OH_n = \frac{AE_n}{C_n \times p_n} \tag{3.1}$$

where, AE_n, C_n, p_n, are the assigned energy, capacity and availability of the n^{th} unit respectively.

The algorithm starts searching for the loading positions of AE units immediately below the loading order. The position for an AE unit is selected in the loading order by computing the expected energy generated at each loading point and this expected energy is compared with the assigned energy of the unit. If the expected energy is more than the assigned energy than the AE unit is moved above it in the loading order. This process is repeated until a loading point in the corresponding ELDC is reached where the expected energy to be generated by the AE unit is less than the energy assigned to it. This is then the place for an AE unit to be positioned in the loading order.

When two AE units compete for the same position, or part of the same position, in the loading order, a 'cluster' is formed. Note, however, that the units compete for the same position if their operating hours are same. Clusters are then arranged to make a test swap to an adjacent DE unit which is just below in the loading order. Clustering and swapping methodology is explained in appendix A. The swap is accepted if the cluster expected energy at the new position is less than the energy assignment of the cluster. The test swap is then continued for the next unit below in the loading order. If this unit is an AE unit or a cluster, then a bigger cluster is formed by merging the cluster with the AE unit or cluster, and the process of swapping the units continues until the expected energy produced by the cluster becomes more than its assignment. In the end, when all the units are loaded, then trimming or adjusting of energy is performed for all AE units or clusters until the exact assigned energy for each unit or cluster is obtained by transferring an appropriate amount of energy from the preceding DE unit in the loading order to the AE unit or cluster.

3.2 IMPROVEMENTS IN THE ALGORITHM

3.2.1 Proper Clustering

Clustering of more than two AE units competing for the same, or part of the same, position in the loading order is more properly accomplished by adding a simple 'clustering check'. A check is performed, fig. 3.4, before clustering the AE units, that is to see if the next unit in the loading order could be an AE unit. This check ensures that clustering is performed first and then the swapping process of the units start. Consider a case, where three AE units are competing for the same, or part of the same position, in the loading order. The algorithm, without the above mentioned clustering check, tries to swap the preceding DE unit once two AE units make a cluster. And if the DE unit is swapped, then the third AE unit will not be able to see the cluster because the preceding unit would be a DE unit. This will result in incorrect cost calculations. However, the reliability of the system will stay the same because it is dependent on the available generating capacity and its forced outages.

Appendix B.1 gives the IEEE reliability test system [30]. Additional data to include the start-up costs of the units and AE units data is provided. The AE data is chosen in such a way that the units compete for the same loading position. A winter week of IEEE data is chosen for the load duration curve and load frequency curve. Appendix B.2 shows the costs/reliabilities with improper clustering and with proper clustering. The reliability of the system is the same, whereas costs differ by $1,059 in $5,048,968.

A cost comparison shows that costs are lower with improper clustering. However, this should not be the case because with proper clustering more assigned energy is exploited as the cluster swaps the preceding DE units and takes a lower

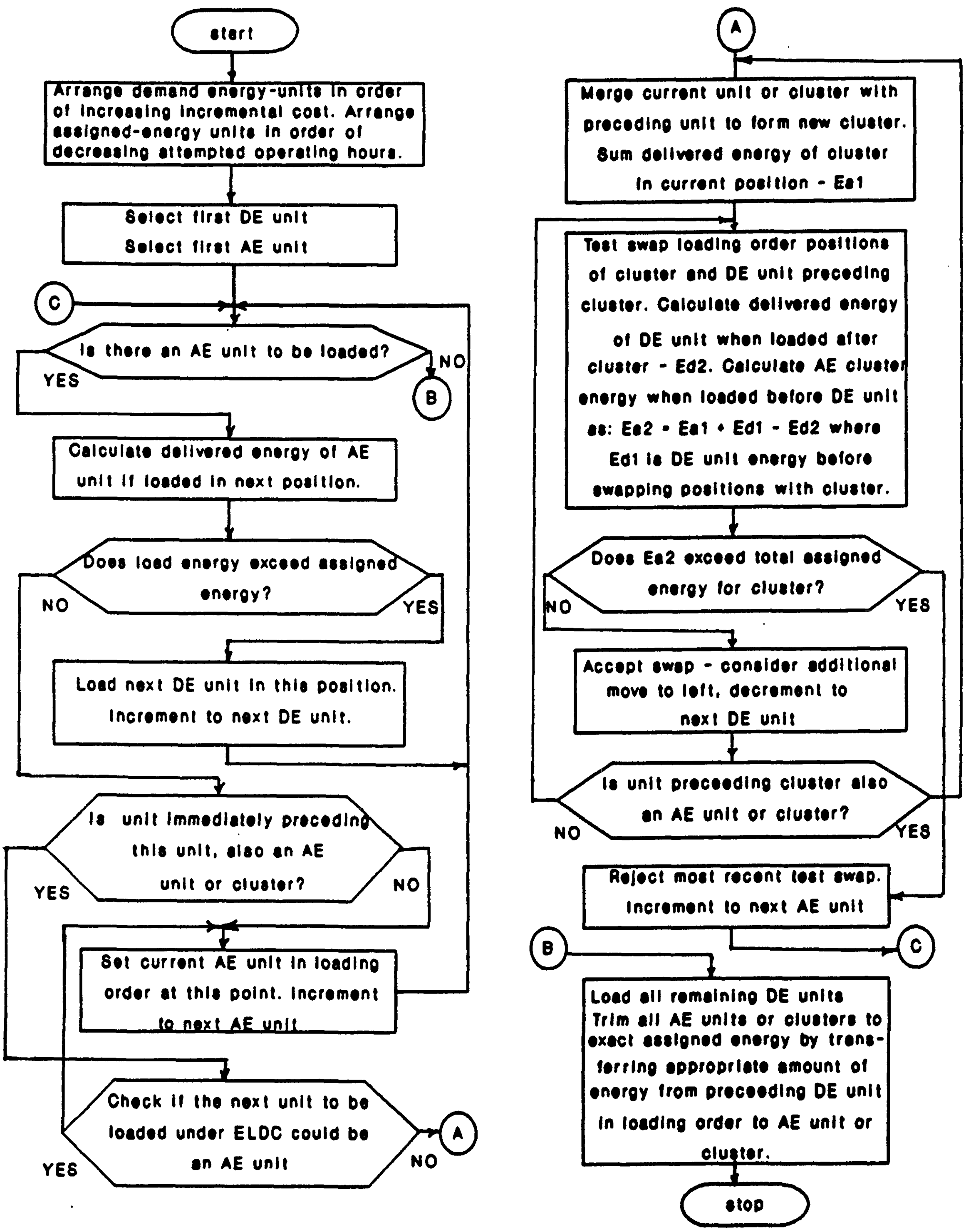


Figure 3.4 Flowchart of procedure used to simulate mixture of assigned- and demand-energy units in probabilistic simulations.

position in the loading order. The inconsistency is due to the trimming effect which ensures that all AE units or clusters utilize their exact designated energy by transferring appropriate amounts of energy from the preceding DE unit in the loading order to the AE unit or cluster. Since the third AE unit is trimming energy from an expensive DE unit, the total operating cost turns out to be less in the improper clustering case than the proper clustering case.

3.2.2 Equivalent Assigned Energy Concept

The position of AE units are selected in the loading order by the criterion for their correct placement as described earlier.

However, since the AE units are also subject to forced outages, they cannot necessarily exhaust all their assigned energies for the duration considered for simulation. Therefore, the method described above for positioning the AE units in a loading order tends to over-estimate their use. The correct result would be to compare the expected energy to be generated by an AE unit with its equivalent assigned energy - found by taking the product of assigned energy of the AE unit and its forced outage rate. If the discharging side of the pumped storage unit is modelled as an AE unit then the reservoir utilization level, supplied as an input parameter, should also take into account the forced outage rate of the discharging side of the pumped storage unit. Also while finding the loading order for AE units, the attempted operating hours should be computed from the equivalent assigned energy of the unit, otherwise an incorrect loading order may form (see equation 3.1).

Results have been verified using this technique by assuming that the single AE unit is not available for generation and performs the calculations, followed by a case assuming the unit is available for generation and again performing all the calculations. In the end, the calculations are weighted with the availability of the AE unit (Appendix B.3.1, Table B.6).

Table B.7, is a solution obtained by placing the AE unit in the loading order by it's assigned energy. Table B.8, is the solution by placing the AE unit in the loading order according to its equivalent assigned energy. Results of Table B.6 and B.8 are the same, whereas, Table B.7, shows the over-estimation of cost benefits due to placing the AE unit (whose availability was assumed 99%) in the loading order by its assigned energy. The over estimation in terms of percentage was 1.1% for the case studied. Although this over estimation is not all that significant, if the FOR of the unit is increased the effect becomes larger.

Appendix B.3.2 shows the over estimation of cost benefits by assuming the availability of the AE unit to be 80%, keeping in mind that the AE unit could be a thermal unit with designated emission limits. This time the over estimation of the cost benefits are up to 21.5%. In another study reported in [28] the over estimation was as high as 34% by assuming an availability of 80% for an AE unit. The conclusion is that the AE units should be loaded in the loading order according to their equivalent assigned energy.

3.2.3 Multi-Unit Reservoir System

To assign energy in a multi-unit reservoir system, the calculations of costs, LOLPs and unserved energies were done assuming no AE unit was available until all AE units were simultaneously available as in a multi-unit reservoir. The availabilities of the AE units were assumed 100%. The body of the algorithm was again the same as shown in fig. 3.4, except that in the end all the calculations of costs, LOLPs, unserved energies etc. were weighted by the binomial distribution of forced outages of the AE units. Appendix B.4 shows the AE units data and cost comparison of 3 hydro units with shared and separate reservoirs. In percentage terms the under estimation of cost benefits of employing a one-unit, one-reservoir system is 1.0%. Again the availability of the units taken is very high, but the under estimation effect becomes very pronounced if the availabilities of the units are reduced because now the assigned energy of an AE unit on forced outage would be assigned to other AE units in a shared reservoir system.

3.3 CONCLUDING REMARKS

a. Clustering of more than two AE units competing for the same, or part of the same, position in the loading order is properly accomplished which gives a more correct estimation of the cost. However this concept of clustering and swapping will not be taken further and a
completely new approach is developed in chapter 5 for swapping units which will be used in the final algorithm.

b. The concept of Equivalent Assigned Energy has been formulated. It's relevance and importance in terms of cost calculations is shown by numerical comparisons. It's importance becomes significant if the AE unit FOR is high. For calculating the benefits of pumped storage in LDC based techniques the maximum size of the reservoir should include the effect of FOR of the storage unit.

c. Proper assignment of energy in a multi-unit reservoir system is accomplished by a binomial distribution method. For multi unit multi reservoir systems the method becomes cumbersome and computing time excessive. This problem is not further investigated and hence it is assumed in the development of the algorithm that AE units and pumped storage units have individual reservoirs.

The idea of equivalent assigned energy can be perceived in another perspective. While determining a reservoir size to accumulate the seasonal rainfalls for a hydro plant, it could be important to take into account the effect of forced outages of the hydro units otherwise a larger reservoir than necessary will appear to be required. Conversely, for a specific size of reservoir, the designation of unit size could be estimated by taking into account the forced outages of the units, implying that the necessary generating unit capacities would need to be slightly larger. The same would be true for sizing a reservoir for a pumped storage plant which is specifically designed for load shifting.

The theory developed for AE units - the concept of equivalent assigned energy - is used for modelling the discharging side of pumped storage units which is dealt with in the next chapter.

Chapter 4

Modelling of Pumped Storage Units

4.1 INTRODUCTION

Hydroelectric pumped storage is the only method of large scale electrical energy storage in widespread use today [53]. Figure 4.1, taken from reference [32], illustrates the basic simple concept. Cheap base-loaded thermal units provide energy (E) to store as hydraulic potential energy by pumping water from a low-level (LOW) into a high-level (HIGH) reservoir (charging or pumping operation) at certain time intervals (T_{chg}). The right hand side of the figure illustrates the charging operation. This operation involves an additional cost ($) over the cost of serving the customer demand. The recovery of the energy (ηE) is carried out at some other time intervals (T_{dchg}) to off-load expensive peak-load thermal units, by allowing the water to return to the lower reservoir through turbines which drive electrical generators (discharging or generating operation). The left hand side of the figure illustrates the discharging operation of the storage unit. This operation involves the benefit (avoided cost, $$$) of not using expensive peaking thermal units. The energy efficiency involved in the charging / discharging storage cycle is denoted by η. If the benefit achieved by the discharging operation minus the cost incurred by the charging operation is positive, the economic advantage of using storage is apparent.

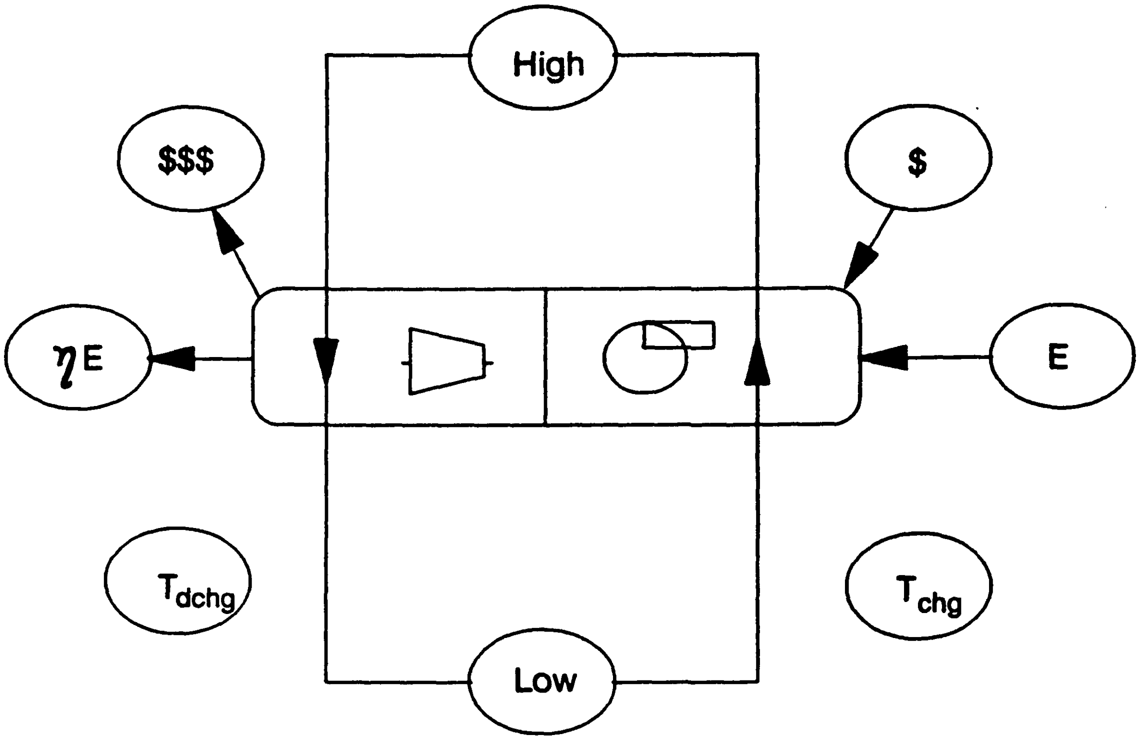


Figure 4.1 Economic operation of a storage unit.

Pumped storage was first installed by manufacturing industries in Italy and Switzerland in the 1890s to enable them to store surplus nighttime output from run-of-the-river hydro stations for use in meeting their peak power requirements the following day [41]. It was introduced to public electricity supply in a number of European countries during the early years of the present century and its role has extended to include economic operation in association with thermal generating plant, particularly nuclear.

Before 1920, the majority of pumped-storage machines were of the 4-unit type, in which the turbine-generator and pump-motor units were mounted on two separate shafts. Later, preference changed in favour of 3-unit sets, comprising a turbine, pump and generator-motor arranged in tandem on a single horizontal or vertical shaft. This type of plant has been widely adopted in Europe but now accounts for only a small proportion of new installations. Modern trends in this technology are 2-unit sets incorporating reversible pump-turbine.

Since the early years of pumped storage, unit capacities have increased from a few tens of kilowatts to over 400 MW, operating heads from less than 200m to above 1400m and overall efficiencies from around 40% to well above 75%. Parallel advances have been made in the associated civil engineering techniques.

The largest project in the UK is the Dinorwig pumped storage scheme [43]. The station consists of six 300 MW generators with the turbines capable of both generating and pumping. In addition, the units have the facility of spinning at no load, giving rapid response times between zero and full load. The flexibility of plant make it cost effective, replacing high-cost oil or low-efficiency coal plant, particularly for short-run periods.

4.2 THE FUNCTIONS OF STORAGE ON AN ELECTRICITY GRID

Storage has variety of roles which it can perform. It acts as a source of power when required (subject to availability), in common with conventional plant. It transfers demand across time, which is its unique role, and in common with hydro, it can rapidly change its output - major changes within seconds - without incurring standby costs.

Summary of Possible Functions of storage

The functions which storage can perform broadly falls into four categories and are summarised as follows:

Load Levelling: The transfer of energy produced at times of low demand (and hence low marginal cost) to displace the more expensive energy at times of high demand (and hence high marginal cost) results in fuel cost savings - artificial energy exchange (AEE). This is perhaps the most obvious function of storage (when generation is used only to save operating the peaking plant this is known as peak shaving, which in essence is the same thing). Such operation also alleviates minimum-load conditions at night and on weekends. By increasing the capacity factor of base-loaded coal-fired units, the pumped storage reduces their cyclic operation, both in terms of the number of loading cycles as well as the number of start-ups and shut-downs. This in turn alleviates thermal stress on the units and reduces their maintenance costs. Such cycling avoidance is an additional major benefit from load levelling.

System Control and Reserve Displacement: The rapidity of response enables storage, when it is not itself on full load, to reduce the system costs in three ways. Its ability to spin in air whilst not on full load gives response in seconds, so it acts in place of thermal spinning reserve to cover for plant breakdown or unexpected rapid changes in net demand. This eliminates the fuel wastage associated with spinning thermal reserve where fuel is lost both because of the lower efficiency of thermal units on part load and because of the replacement generation required. Second, it will contribute to the longer-term (minutes and hours) reserve required to cover for scheduling and dispatch errors (mostly due to uncertainty in demand forecast). Finally, if the storage is run on part or full load, the turbines contribute to frequency control, reducing the less efficient operation of thermal unit on governor action at part-load.

Capacity Displacement: Storage plant has a very high peak availability - often in excess of 95% - and hence contributes to system reliability as very firm plant, giving a capital value equal to the cost of the displaced construction.

Transmission Costs: Storage will alter the path of power flows on the grid, and thus potentially change the resistive and reactive losses. If the store is located far from demand (as with Dinorwig pumped storage scheme [43], UK; surface pumped storage requires hilly areas often far from major demand centres), the losses increases, certainly locally (nationally this may be offset by greater control over power flows). The local effect can generally be included in the overall input/output efficiency.

It is less easy to account for transmission savings which may arise if it is distributed or sited close to major demand centres, which should enable more local plants to meet the demand and so reduce losses. Such storage will also tend to change the peak required power transfer, which may have a transmission capital value where it enables local grid reinforcement to be postponed or avoided.

Storage facilities can also be used for voltage and power factor correction [54]. Besides the conventional roles of pumped storage technology, a number of Japanese utilities are now considering variable- speed pumped storage plants, which can pump at variable levels and can therefore contribute toward load regulation during off-peak periods [42].

The several roles of storage in power systems mentioned earlier, can effect system costs in many ways. PPC models based on ELDC concept only take into account the part of the cost benefits of load levelling, i.e benefits achieved from artificial energy exchange, by pumped storage plants whereas the benefits received from cycling avoidance is not included for the obvious reason that the time chronology of the events is lost. However, since the frequency and duration method can capture some of the time dependent effects, and can estimate the frequency of start of the units, therefore, the benefits from cycling avoidance can be assessed. The next section models pumped storage in ELDC and ELFC models to estimate the complete benefits of load levelling produced by pumped storage.

4.3 MODELLING OF PUMPED STORAGE IN ELDC AND ELFC MODELS

Pumped storage units operate on a daily or a weekly cycle and are inherently chronological, i.e., they store energy at certain time intervals and generate at other time intervals, whereas ELDC representation in PPC models loses the time chronology. Simulation models based on load duration curves tend to overestimate the benefits of pumped storage. This is particularly true when the LDC represents a long period of time; e.g., six months, during which the load may vary considerably. For example, a six-month simulation period might include both winter and spring seasons of a winter peaking utility. Over this six-month time period it is quite possible that substantial portions of the lowest and highest demand periods (hours) are widely separated in chronological time. Energy storage simulation techniques which are based on a single LDC will inherently assume that energy is pumped into and released from the energy storage unit reservoir during the lowest and highest demand periods (hours) respectively. Since substantial portions of these periods may be widely separated in chronological time, the results of a simulation - which uses a single LDC - may differ substantially from the feasible operation of the storage unit. An extreme example, which might form a simulation based on a single load duration curve, would be pumping most of the hours in May - including perhaps the peak load hours - for peak shaving operation in January. This type of operation is clearly infeasible for any of the energy storage technologies which are anticipated to be suitable for use by electric utilities [6]. Therefore, care must be taken when selecting time intervals in the load duration curve.

Before modelling pumped storage, it is necessary to understand some of its important parameters which make it different from other generating units modelling.

A key parameter of the performance of every storage plant is its efficiency, i.e, the energy efficiency of the whole charging/discharging cycle. The cycle efficiency of the storage unit s can be expressed as follows:

$$\eta_s = \eta_s^c \times \eta_s^d \tag{4.1}$$

where η_s^c and η_s^d are the efficiencies of the storage charging and discharging process respectively. Without loss of generality, it can be assumed that all the losses occur in the charging mode [46].

Another important parameter which characterizes the functioning of a given storage plant is its reservoir capacity limit, R_s^{max}. When the storage plant operates in a daily, weekly or seasonal fashion, determining its reservoir capacity limit for load levelling is a difficult task. The problem is to find how much energy to allocate for load-levelling. Infield in his study [45] reports that for optimal usage of the Dinorwig storage about 90% of the storage capacity (GWh) should be allocated for load-levelling with the remaining 10% being intended for use as spinning reserve, including the effect of scheduling and dispatching errors. From the maximum energy allocated for load-levelling and the number of charging/discharging cycles performed by the storage plant under the considered load duration curve time span the reservoir capacity limit may be calculated in MWh. This reservoir capacity limit is the maximum limit of using the upper reservoir and hence it is the maximum discharging energy limit. The reservoir capacity limit of a storage unit should include the outage effect of the storage unit (remember the idea of equivalent assigned-energy formulated in chapter 3). The parameter of maximum reservoir limit should be provided as an input to carry out the production costing exercises.

4.3.1 Discharging Side Modelling

The discharging side of a storage unit is modelled as an assigned-energy unit with an amount of energy available for generation equal to the equivalent energy available for discharging.

4.3.2 Charging Side Modelling

Charging imposes an additional demand on the system. This additional demand can either be convolved in with the original customer demand - if the concept of fictitious assigned-energy unit is used [5] - or pumping load is sequentially added to the base-loaded thermal units which are not loaded up to their limits [6]. The concept of fictitious AE unit is not suitable, as will be shown later, if ELDC is represented numerically, e.g [4,47-49]. However, if the ELDC is represented analytically, e.g [37,50], then the fictitious AE unit concept may be exploited to get a slight computational advantage. The final algorithm developed, is made independent of the ELDC representation but both the cases will be discussed, i.e. the case with fictitious AE unit concept and without it.

4.3.2.1 The Case with the Fictitious AE unit Concept

Additional Demand: First of all, the additional demands imposed by the charging sides of the storage units being considered (charging storage loads) are convolved with the customer load duration curve and load frequency curve. Mathematically, the equivalent load duration curve after the charging load added can be expressed as follows:

$$F_{l+1}(x) = p_s^c F_l(x-C_s^c) + q_s^c F_l(x) \tag{4.2}$$

Similarly, the equivalent load frequency curve after the storage loads are added can be mathematically expressed as follows:

$$f_{l+1}(x) = [p_s^c f_l(x-C_s^c) + q_s^c f_l(x)] + [\frac{1}{\tau_s^c}\{F_l(x) - F_l(x-C_s^c)\}] \tag{4.3}$$

where:

l is a negative/positive index ranging over the storage plants so that after convolving charging storage loads l

becomes equal to 1; $l=1-m,2-m,\ldots,-1,0,1$; where m is the number of storage plants;
s is the storage index, c implies the charging side of storage,
$F_1(x)$ the ELDC after convolving all charging storage loads,
$f_1(x)$ the ELFC after convolving all charging storage loads,
$F_{1-m}(x)$ the original load duration curve,
$f_{1-m}(x)$ the original load frequency curve,
q_s^c the forced outage rate of the charging side of the storage unit s,
p_s^c the availability of the charging side of the storage unit s,
τ_s^c the mean cycle time (i.e., mean time to failure plus mean time to repair) of the charging side of the storage unit s, and C_s^c the charging capacity of the storage unit.

The order of these convolutions is immaterial. It should be noted that negative subscripts are used in order to end up with the initial ELDC, $F_1(x)$ and initial ELFC, $f_1(x)$ after convolving all charging storage loads.

The equation 4.2 can be compared with the equation 2.1. Equation 4.2 can heuristically be explained as follows: if the charging load is forced out the equivalent load will stay the same and if the charging load is available with probability, p_s^c, then the equivalent load will be extended with the capacity C_s^c.

Similarly, the equation 4.3 can be compared with equations 4.2 and 2.3 and can be explained heuristically. Note that the part in the first bracket of equation 4.3 is similar to equation 4.2 and can be explained similarly. The part in the second bracket will give a negative contribution to the upward transition of frequency if the charging load is forced out, hence the terms are reversed (compare equation 4.3 and 2.3).

This addition of load, as mathematically represented above, acts as a shift in load duration curve and load frequency curve and is graphically represented in figure 4.2 and 4.3 respectively. If the storage units were to charge at full capacity for the duration of the entire period, as this shift implies, the energy stored would, in general, be more than is required. Therefore, at some level of load, the storage unit must stop charging in order to store exactly the required amount of energy. In order to find the load level at which a storage unit stops charging, a fictitious AE unit is associated with it.

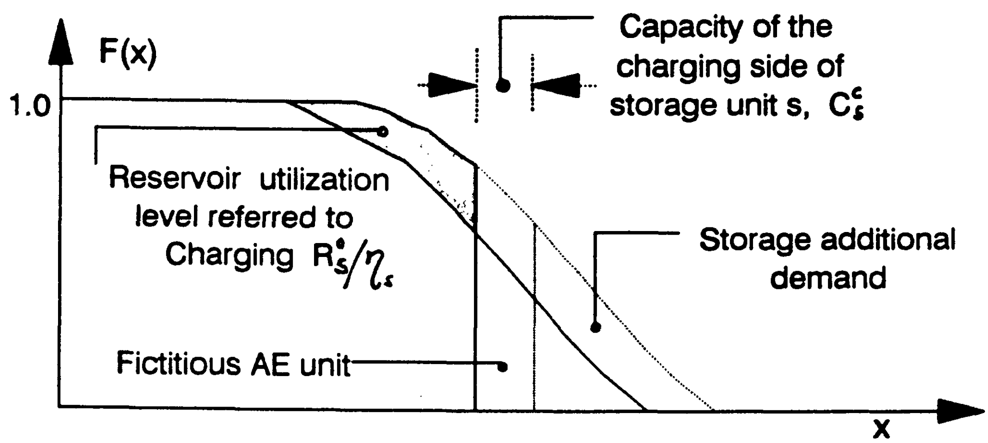


Figure 4.2 Equivalence between the reservoir utilization level of a storage unit and its associated fictitious AE unit.

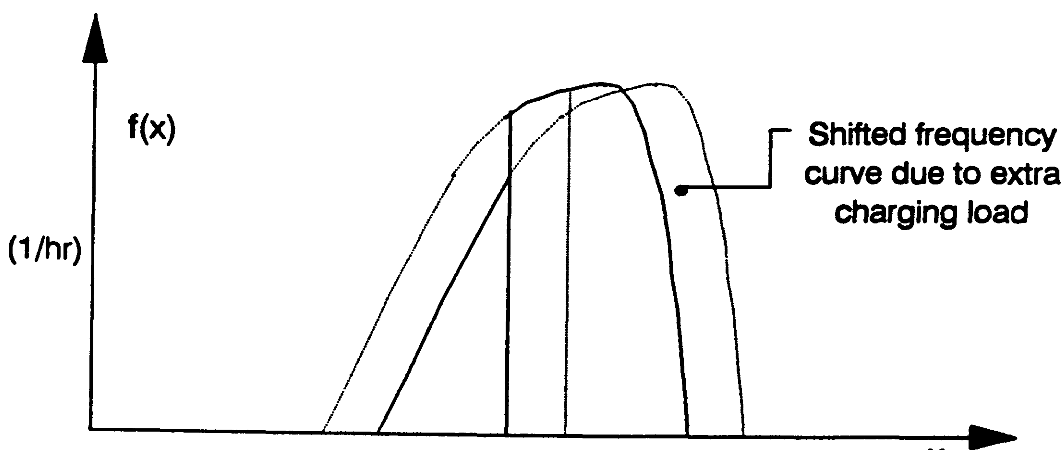


Figure 4.3 Shifted frequency curve due to extra charging load.

<u>Fictitious Assigned-Energy Unit:</u> The actual reservoir utilization of a given storage unit is represented by means of its associated fictitious AE unit [5,32,33] which has an amount of available energy to generate equal to the complementary reservoir utilization level of the storage unit being considered. This complementary reservoir utilization level or equivalent fictitious assigned energy is equal to the difference between the energy that the storage unit would store by charging throughout the whole time period and the storage reservoir utilization level referred to charging. It is denoted H_s^0 and computed as follows:

$$H_s^0 = p_s^c C_s^c T - R_s^0/\eta_s \tag{4.4}$$

where, R_s^0 is the reservoir utilization level of unit s and T is the time interval of the load duration curve.

It should be noted that R_s^0 and H_s^0 are dual variables which describe the same concept, i.e., the equivalent reservoir utilization of storage unit s.

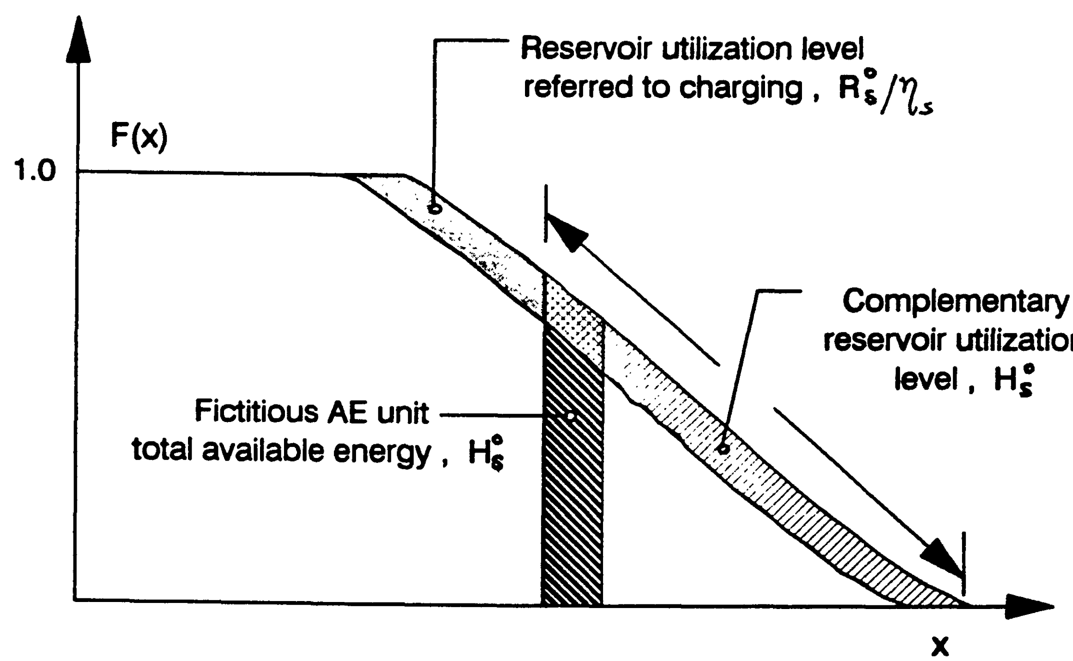


Figure 4.4 Relationship between the reservoir utilization level and the complementary reservoir utilization level of a storage unit.

Figure 4.2 shows the additional demand imposed by a storage unit and illustrates the equivalence between the utilization level of the storage unit and the fictitious AE unit. Figure 4.4 illustrates the relationship between the reservoir utilization level referred to charging (R_s^0/η_s) and the complementary reservoir utilization level (H_s^0) of a given storage unit. The equality relationship between the complementary reservoir utilization level of a given storage unit and the total available energy of its corresponding fictitious AE unit is also shown in the figure 4.4.

Loading of Fictitious AE Unit: After having convolved all the additional demands imposed by the charging sides of the storage unit being considered and having set up all the fictitious AE units corresponding to them, the production cost simulation is carried out in a standard fashion. Only the loading of a fictitious AE unit is performed in a special manner as stated below.

If the unit occupying the loading order position n is a fictitious AE unit representing the charging side of a storage unit, then deconvolve by solving for $F_{n+1}(x)$ the equation

$$F_n(x) = p_s^c F_{n+1}(x-C_s^c) + q_s^c F_{n+1}(x) \tag{4.5}$$

Similarly solve for f_{n+1} the frequency equation

$$f_n(x) = p_s^c f_{n+1}(x-C_s^c) + q_s^c f_{n+1}(x) + \frac{1}{\tau_s^c}\{F_{n+1}(x) - F_{n+1}(x-C_s^c)\} \tag{4.6}$$

and do not modify the current loading point

$$X_n = X_{n-1} \tag{4.7}$$

i.e. assign to X_n the value of X_{n-1}.

It should be noted that equation 4.5, 4.6 and 4.7 represents the removal of the charging load of the storage units. The loading point is not modified because charging does not represent actual generating capacity in the system. Since the loading point is not changed, when the fictitious AE unit is loaded, the next thermal unit loaded is at X_{n-1} and is considered split. The split thermal unit includes the outage effect of the fictitious AE unit because the split unit is loaded under the ELDC $F_n(x)$ and ELFC $f_n(x)$. The energy generated by the split unit is adjusted with the splitting AE unit.

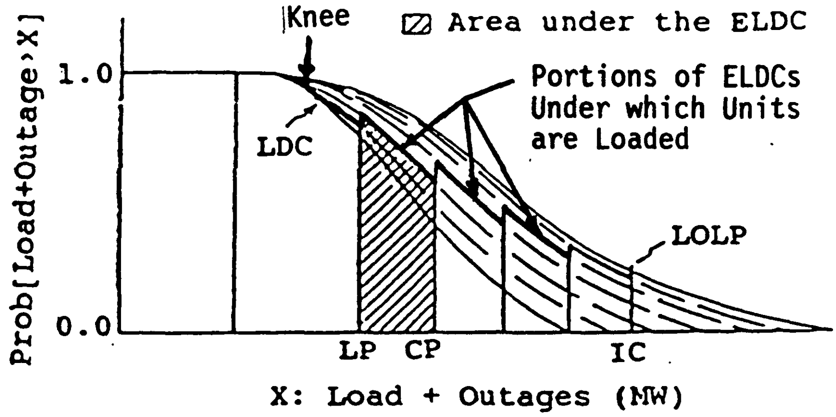
Note how difficult it is to achieve deconvolution numerically, as division takes place by q_s^c (see eq. 4.5 & 4.6), which is a very small number usually in the range of (0.01-0.05) for pumped storage units. When the division takes place with a small number over and over, as in the case with deconvolution, the error grows enormously and the method becomes unstable. The point about instability can be seen in the end discussion in reference [36]. This is the reason why we have said that if the ELDC is represented numerically the idea of a fictitious assigned energy unit should not be used. The next section discusses the case without this concept.

4.3.2.2 The Case Without Fictitious AE unit concept

If the concept of fictitious AE unit is not used then the pumping load can be added sequentially to the base-loaded units which are not loaded up to their limits. The first unit which is not loaded up to its limit has expected operating hours slightly less than the time interval, in number of hours chosen, for LDC. This unit is loaded on the knee of the effective load duration curve - formed by plotting the portions of ELDCs, under which units are loaded (figure 4.5). This effective LDC is also mentioned in the literature as the effective plant loading curve [6].

Mathematically, the pumping load or additional demand can be added to the base-loaded unit loaded at the knee of the effective LDC at position j as follows:

$$F_j'(x) = p_s^c F_j(x-C_s^c) + q_s^c F_j(x) \tag{4.8}$$



LP - Loading point of the unit
CP - Capacity point of the unit
IC - Installed capacity

Figure 4.5 Graphical representation of portions of ELDCs for making an Effective LDC.

Similarly for frequency equation the pumping load can be added as follows:

$$f_j'(x) = p_s^c f_j(x-C_s^c) + q_s^c f_j(x) + \frac{1}{\tau_s^c}\{F_j(x) - F_j(x-C_s^c)\} \quad (4.9)$$

$F_j(x)$ and $F_j'(x)$ represents respectively the ELDC of the j^{th} unit before and after the charging load was convolved. Similarly, $f_j(x)$ and $f_j'(x)$ represents respectively the ELFC of the j^{th} unit before and after the charging load was convolved. $F_j'(x)$ and $f_j'(x)$ are intermediate variables and all their values should be transferred back to $F_j(x)$ and $f_j(x)$ respectively. This is because if the j^{th} unit is again going to supply the charging energy to the next storage unit in the priority list it should see the modified ELDC and ELFC. The incremental potential pumped storage charging energy, $P_{s,j}^c$, can be calculated as follows:

$$P^c_{s,j} = E'_j - E_j = p_j T \int_{X_{j-1}}^{X_j} \{F'_j(x) - F_j(x)\} dx \qquad (4.10)$$

where p_j, X_{j-1} and X_j are the availability, loading and capacity point of j^{th} unit respectively. E_j and E_j' are the expected energies generated by the j^{th} unit before and after the charging load is added respectively. T is the time interval for LDC.

The frequency of start of the j^{th} unit at the loading point X_{j-1} can now be read from the new ELFC, $f_j'(X_{j-1})$.

The process of finding the pumping energy increments could be continued sequentially down the curve for the storage unit being considered. When all the charging increments add up to the total energy to be charged i.e, total discharging energy referred to charging R_s^0/η_s, the process of charging should be stopped. Note that this process of charging sequentially down the effective LDC until the increments add up to the total charging energy is equivalent to fictitious AE unit loading. Note also there is no deconvolution involved in this method, however, a slight increase of computing time is incurred due to the extra convolutions involved in finding the increments.

4.4 CONCLUDING REMARKS

This chapter has presented a brief overview of the role of storage units in a utility. Out of different roles of storage, the method to model the pumped storage units to assess their benefits of the most prominent role of load-levelling is presented.

Modelling the discharging side of the storage unit is the same as for assigned-energy units. Modelling of the charging side of the storage unit is performed with and without the fictitious AE unit concept. Also, the frequency equation 4.3 for charging side is developed and heuristically explained.

The fictitious AE unit concept gives a slight computational benefit, however if the ELDC is represented numerically the method becomes unstable when the fictitious AE unit is deconvolved.

The next chapter develops the full algorithm to simulate the generation mix of demand-energy units, assigned-energy units and pumped storage units with storage units reservoir utilization level optimized.

Chapter 5

Final Algorithm

For optimal reservoir utilization, i.e., economic operation of pumped storage units three different approaches were discussed in chapter 1. The non-looping method proposed by Conejo, Caramanis and Bloom [29] is the fastest among the three approaches but has logic and order problem. Moreover, if the ELDC is represented numerically e.g. [3,4,47,48,49] in the algorithm it gives instability when a fictitious AE unit is deconvolved as the division takes place with the forced outage rate, which is a small number compared to the availability of the unit. The point about instability is already mentioned in chapter 4.

None of the three approaches took into account the full benefits of load-levelling. The benefit achieved from artificial energy exchange was assessed but the benefit achieved from cycling avoidance of the thermal units, by pumped storage units was not assessed.

This chapter presents an efficient algorithm which extends the previous work, i.e., it takes into account the benefit of cycling avoidance of the demand-energy units and overcomes all the above mentioned problems faced by the non-looping method. It is based on the non-looping concept, which does not require multiple solutions, and utilizes the PCBC approach to the problem. Parallel frequency equations are developed/used to take into account the frequency of starts of the units to assess the cycling avoidance benefit.

The non-looping concept is based on the fact that the demand-energy units affected either by the charging sides or by the discharging sides of storage plants constitute a small subset of the total thermal generating system. The revision of the reservoir utilization level of every storage unit is carried out by performing systematic minor modifications of the charging and discharging schedules of every storage unit. These modifications affect the energy generated by a few DE units while the energy generated by the majority of the DE units remain unchanged.

The PCBC approach considers storage plants one at a time and builds up two piecewise constant functions, represented by two independent stairs in figure 5.1. The descending stair is obtained by evaluating the benefit associated with the potential energy produced by a storage unit, when the same amount of thermal energy is substituted. The ordinate represents the marginal value of substituted energy (marginal benefit of discharging) and is denoted by M_s^d. The abscissa represents the cumulative substituted energy or the reservoir utilization level, R_s. The ascending stair is obtained by evaluating the cost associated with the potential energy consumed by a storage unit. The ordinate represents the marginal cost of pumped energy (marginal cost of charging) and the abscissa represents the cumulative pumped energy. To represent both stairs together it is necessary to plot them both from the same point of view. Because the charged and discharged energy of a storage unit are related by its cycle efficiency, it is necessary to adjust either one of them. As represented in figure 5.1, the ascending energy has been adjusted. This means that the pumping marginal cost is divided by cycle efficiency, denoted by M_s^c and pumped energy is multiplied by cycle efficiency and represents the same reservoir utilization level, R_s. The area between the two stairs represents the total net benefit for a certain amount of energy pumped (and generated) by a storage unit. The optimal reservoir utilization level of the considered storage unit occurs when its net marginal benefit (marginal benefit of discharging minus efficiency adjusted marginal cost of charging) vanishes. The optimal reservoir utilization level, R_s^*, is therefore, given by the intersection of the two piecewise constant functions defined above, i.e., when

$$M_S^c(R_S^*) = M_S^d(R_S^*) \tag{5.1}$$

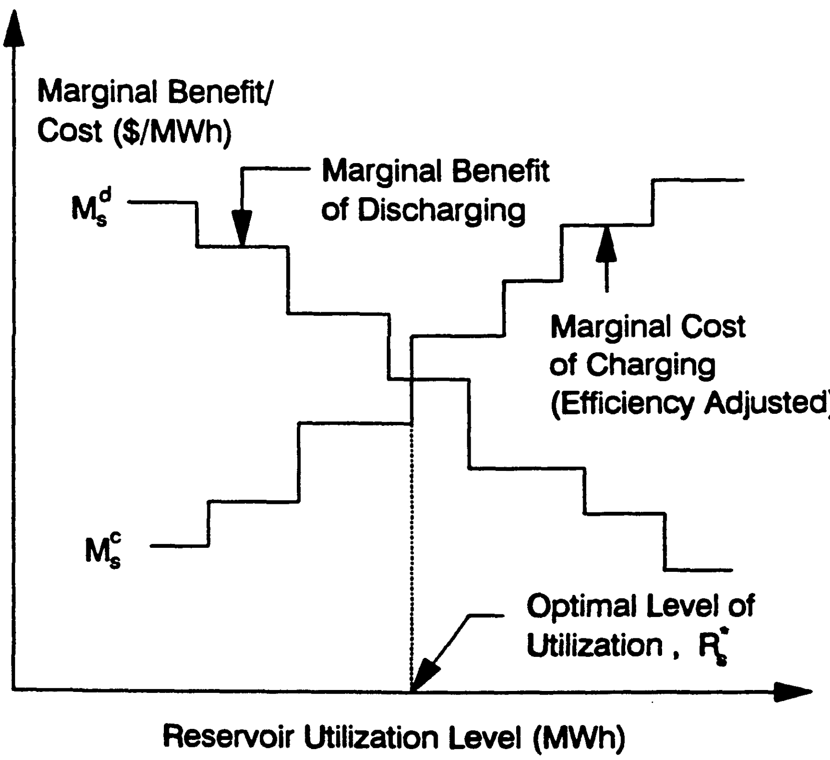


Figure 5.1 Piecewise constant benefit cost curves.

The PCBC approach together with the non-looping concept can be easily implemented even by a numerical representation of ELDC. The deconvolution of a fictitious AE unit can be avoided by not using this concept of fictitious assigned-energy but rather sequentially convolving the charging load with base-loaded DE units which are not loaded up to their limits. However, this will cause a slight time penalty. The deconvolution required to off-load a DE unit to provide extra discharge from storage is avoided by an efficient and accurate technique developed by Malik et.al [52] which requires convolution and the use of the energy invariance property, [1,5,31], described in appendix A. This new technique allows the optimization from the discharging side to continue even if the next unit to be off-loaded by the storage unit is an AE unit or the discharging side of an already optimized unit.

5.1 ALGORITHM

For production cost optimization DE units are ordered according to increasing incremental fuel cost. This order is often referred to as merit order. The pumped storage units are ordered according to decreasing cycle efficiency (including transmission loss penalty factors if any). The discharging side of a storage unit is modelled as an AE unit and its attempted operating hours (see chapter 3) are calculated by the initial reservoir utilization level, supplied as a data in MWh, of the storage. The charging side of the storage can be modelled as a fictitious AE unit and its attempted operating hours found by a complementary reservoir utilization level (see chapter 4). Both the (fictitious or otherwise) AE units are ordered according to decreasing attempted operating hours.

A single production costing run is then carried out by considering the trial reservoir utilization level. This is called an initial solution. If any of the trial values is not economically feasible then a new value for that reservoir level is produced. After the initial solution is formed, a gradient-type iterative algorithm is used to determine the optimal reservoir utilization level of the considered storage unit by finding the pumping and generating increments.

The storage units are considered for optimization one at a time. The initial solution proceeds as follows:

5.1.1 Initial Solution

1. If the ELDC is not represented numerically then pumping load can be convolved with the original LDC and LFC as described in chapter 4.

2. Start loading thermal units under the corresponding ELDCs and ELFCs in merit order and compute for each one its expected generated energy. If run-of-the-river plants are in the system they should be loaded first in merit order.

3. When the knee of the effective LDC is reached start testing for the AE (fictitious or not) unit position by computing its expected generated energy under the corresponding ELDC. If it is less than or equal to the equivalent energy assigned to that unit, then load it under the ELDC and the ELFC otherwise load another DE unit in merit order. When the fictitious AE unit is loaded the loading point on the effective LDC and the effective LFC is not changed because the fictitious unit does not represent the actual generating capacity and the next DE unit being loaded at the same position is considered split. The split unit could be an AE unit but that can rarely happens, because it means that the split unit has enough energy to charge the splitting unit. The corresponding charging load is deconvolved from that ELDC and ELFC on which the fictitious AE plus split units are loaded to remove the outage effect of the charging side of the storage unit being represented by the fictitious AE unit and the extra pumping load from the units higher in the loading order. Note that one or perhaps several fictitious AE unit can compete for the same position in the loading order and can split the same unit. If several fictitious AE units split the same unit, then deconvolve all their outages and loads from the corresponding ELDC and ELFC.

4. If the (fictitious or otherwise) AE unit cannot be loaded due to not meeting the criterion of loading, then the process of loading the DE units should be continued according to the merit order until all the available generating units are loaded.

These four steps are carried out in a single production costing run. Notice that there is a slight discrepancy in the charging and discharging energy of storage units initial reservoir utilization levels in the first solution, because the way the AE (fictitious or not) units are loaded. The discharging side of a storage unit represented by an AE unit when placed in the loading order means discharging less than the initial reservoir utilization level whereas, for the charging side, loading a fictitious AE unit in the loading order means charging more than the initial reservoir utilization level. This discrepancy can be adjusted for each storage unit in the initial solution by adjusting energies with the split units from the charging and discharging sides. However, since the optimization part of the algorithm follows (to determine the economic operation of storage units), there is no need to adjust energies at this time.

If several AE units are competing for the same or part of the same position they are loaded one after another in the initial solution. Their optimization is carried out after the storage units are optimized.

5.1.2 Storage units Optimization

The proposed method considers storage units one at a time according to a decreasing cycle efficiency criterion. It iteratively revises the reservoir utilization level of the storage unit being considered by systematically calculating the pumping and generating increments. The pumping increments are calculated by adding pumping load to the base-loaded DE units which are not loaded up to their limits. The generating increments are calculated by subtracting the generating load from the peak units and adding these to the storage discharging side. The method for finding the generating increment is equivalent to off-loading. These pumping/generating increments affect the energy generated by a few DE units while the energy generated by the majority of the DE units remains unchanged.

The method of finding the pumping and generating increments is as follows:

5.1.2.1 Pumping Energy Increments

For the pumping energy increments, the concept of a fictitious AE unit is no longer needed. A DE unit is selected, for providing first pumping energy increment, which, in the loading order, is just after the DE unit split by the fictitious AE unit - associated with the storage unit being considered for optimization. The DE unit at the j^{th} position which can provide the additional pumping energy is shown graphically in Figure 5.2. Now the increment of potential pumped storage pumping energy is determined by first adding the pumping load to the j^{th} unit ELDC and then finding the expected energy generated by the j^{th} unit. The expected energy generated now, minus the expected energy generated before the pumping load was convolved to the unit, gives the potential pumping energy. Mathematically, the pumping load can be added to the j^{th} unit ELDC and ELFC as follows:

$$F_j'(x) = p_s^c F_j(x-C_s^c) + q_s^c F_j(x) \tag{5.2}$$

$$f_j'(x) = p_s^c f_j(x-C_s^c) + q_s^c f_j(x) + \frac{1}{\tau_s^c}\{F_j(x) - F_j(x-C_s^c)\} \tag{5.3}$$

where, p_s^c, q_s^c, C_s^c, and τ_s^c represents respectively the charging side availability, forced outage rate, capacity and the mean cycle time of the storage unit s. $F_j(x)$ and $F_j'(x)$ represents respectively the ELDC of j^{th} unit before and after the charging load was convolved. Similarly, $f_j(x)$ and $f_j'(x)$

represents respectively the ELFC of j^{th} unit before and after the charging load was convolved. $F_j'(x)$ and $f_j'(x)$ are intermediate variables and all their values should be transferred back to $F_j(x)$ and $f_j(x)$ respectively. This is because if the j^{th} unit is again going to supply charging energy to the next storage unit in the priority list it should see the modified ELDC and ELFC. The incremental potential pumped storage charging energy, $P_{s,j}^{c}$, can be calculated as follows:

$$P_{s,j}^{c} = E_j' - E_j = p_j T \int_{X_{j-1}}^{X_j} \{F_j'(x) - F_j(x)\} dx \qquad (5.4)$$

where p_j, X_{j-1} and X_j are the availability, loading and capacity point of j^{th} unit respectively. E_j and E_j' are the expected energies generated by the j^{th} unit before and after the storage charging load added respectively. T is the time interval for LDC.

The frequency of start of the j^{th} unit at the loading point X_{j-1} can be read from the new ELFC, $f_j'(X_{j-1})$.

The process of finding the pumping energy increments can now be continued sequentially down the curve (effective LDC) for the storage unit being considered for optimization. Now, during the process of optimization, if the next unit to provide the incremental charging energy is an AE unit, or the discharging side of another storage unit, then jump to the next thermal unit down in the loading order which can provide the incremental charging energy. In this way the process of optimization does not stop from the charging side. Conejo [31,32] stops charging when encountered with this situation, i.e., when the next unit to charge is an AE unit or the discharging side of another storage unit, and call this as a logic problem. It can also be seen that, unlike Conejo [31,32], the marginal thermal unit of the charging side of an already optimized storage unit is no longer a binding constraint for the charging side of the next storage unit undergoing optimization.

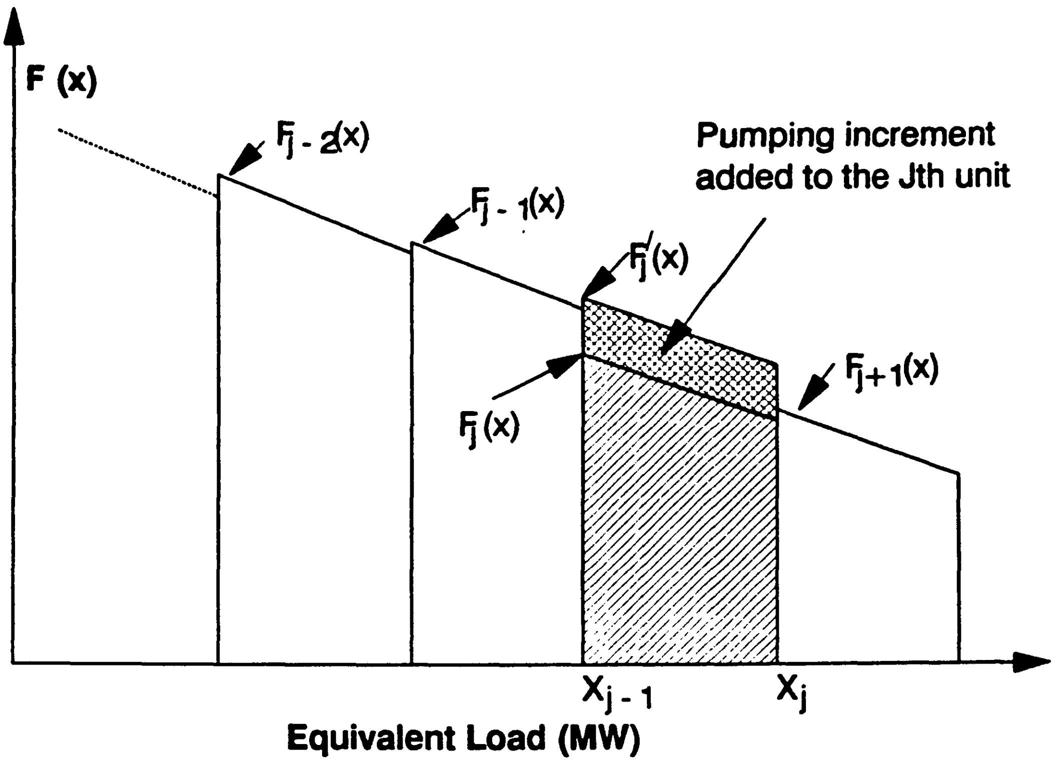


Figure 5.2 Additional Pumping energy provided by the j^{th} unit.

If after the initial solution the number of thermal units, which are charging energy for storage unit s, is n, the efficiency adjusted cumulative potential charging energy denoted by $CP_{s,n}^{c}$ is defined as

$$CP_{s,n}^{c} = \eta_s \sum_{j=1}^{n} P_{s,j}^{c} + R_s^0 \tag{5.5}$$

This represents the successive abscissa energy steps of the piecewise constant function $M_s^c(R_s)$. Where R_s^0 is the initial reservoir utilization level for storage unit s, and was represented by the corresponding fictitious AE unit. The n^{th} unit marginal cost of charging can be represented as

$$M_s^c(CP_{s,n-1}^c < R_s \leq CP_{s,n}^c) = IF_n/\eta_s \qquad (5.6)$$

where IF_n/η_s represents the efficiency adjusted incremental fuel cost of the n^{th} unit.

If the concept of fictitious AE unit was not used in the first place, then the charging increment for the storage unit being considered will start right from the knee of the effective LDC. By choosing the DE unit which is partially under utilized (loaded under the knee of the curve) and convolving the charging load for the considered storage unit, the pumping energy increment is found as described above. The charging increment will continue down the curve until the efficiency-adjusted cumulative pumping energy is equal to the initial reservoir utilization level of that storage. Afterwards, the process of optimization will start iteratively by finding the incremental charging and discharging energies.

5.1.2.2 Generating Energy Increments

For finding the generating energy increments an altogether different approach is used. It is, in fact, exactly the opposite of the charging procedure described above and mathematically equivalent to swapping the units (off-loading) as explained in Appendix A.2. The method is very powerful in dealing with several AE units or the discharging side of pumped storage if they are competing for the same or part of the same position in the loading order. The method developed is elegant, accurate, involves no deconvolution and is unique in its approach [52].

In charging, the extra load is added to the DE unit ELDC by equation (5.2), and then the energy generated by that unit is calculated again under the new ELDC. The difference between the energy generated after and before the charging load is convolved gives the incremental charging energy provided by that unit.

In discharging, the extra load is subtracted from the thermal unit ELDC by equation (5.7), and then the energy generated by that unit is calculated again. The difference between the energy generated before and after the discharging load is subtracted (it is not deconvolved) gives the incremental discharging energy taken from that unit.

That DE unit which is selected for off-loading the first generating energy increment, which in the loading order, is just before the discharging side of the AE unit associated with the storage unit being considered for optimization. The DE unit at the i^{th} position which can off-load the additional generating energy is shown graphically in Figure 5.3.

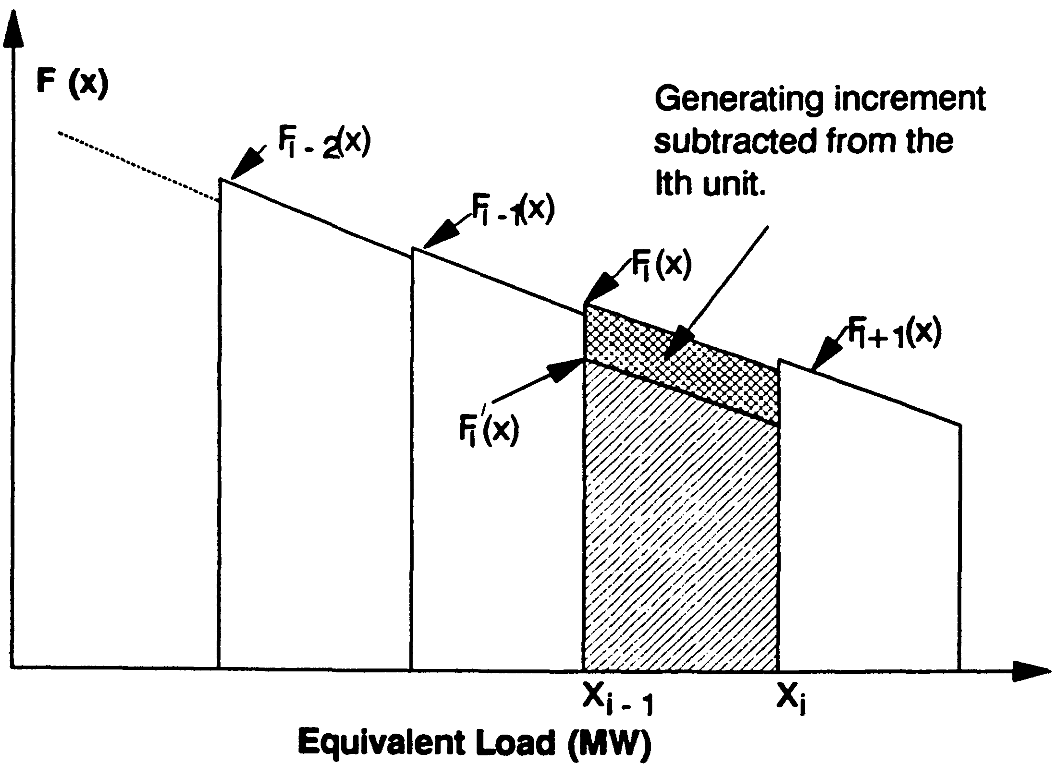


Figure 5.3 Off-loaded energy by the i^{th} unit.

The extra load is subtracted from the DE unit by the following equation:

$$F_i'(x) = p_s^d F_i(x+C_s^d) + q_s^d F_i(x) \tag{5.7}$$

Similarly, for the frequency equation, the extra load is subtracted from the thermal unit by the following equation:

$$f_i'(x) = p_s^d f_i(x+C_s^d) + q_s^d f_i(x) + \frac{1}{\tau_s^d}\{F_i(x) - F_i(x+C_s^d)\} \tag{5.8}$$

where, p_s^d, q_s^d, C_s^d, and τ_s^d represents respectively the discharging side availability, forced outage rate, capacity and the mean cycle time of the storage unit s. $F_i(x)$ and $F_i'(x)$ represents respectively the ELDC of the i^{th} unit before and after the discharging generation was convolved. $f_i(x)$ and $f_i'(x)$ represents respectively the ELFC of the i^{th} unit before and after the discharging generation was convolved. $F_i'(x)$ and $f_i'(x)$ are intermediate variables and all their values should be transferred back to $F_i(x)$ and $f_i(x)$ respectively. This is because if the i^{th} unit is going to off-load any discharging energy again to the next storage unit in the priority list it should see the modified ELDC and ELFC. The incremental potential pumped storage discharging energy, $P_{s,i}^d$, can be calculated from:

$$P_{s,i}^d = E_i - E_i' = p_i T \int_{X_{i-1}}^{X_i} \{F_i(x) - F_i'(x)\} dx \tag{5.9}$$

where p_i, X_{i-1} and X_i are the availability, loading and capacity points of the i^{th} unit respectively. E_i and E_i' are respectively the expected energies generated by the i^{th} unit before and after being off-loaded by the storage discharging side. T is the time interval for LDC.

The frequency of start of the i^{th} unit at the loading point X_{i-1} can be read from the new ELFC, $f_i'(X_{i-1})$.

The process of finding the generating energy increments can now be continued sequentially up the curve (effective LDC) for the storage unit being considered for optimization. Now, during the process of optimization if the next unit to off-load the incremental discharging energy is an AE unit or the discharging side of another storage unit, then a jump to the next DE unit up in the loading order is made which can off-load the incremental discharging energy (for further clarification of this point see appendix A). In this way the process of optimization does not stop from the discharging side. As can be seen, unlike Conejo [31,32], the marginal thermal unit off-loaded by an already optimized storage unit from the discharging side is no longer a binding constraint for the next storage unit discharging side undergoing optimization.

If after the initial solution the number of thermal units, which are off-loaded by the storage unit s, is k, then the cumulative potential discharging energy denoted by $CP_{s,k}{}^{d}$ is defined as:

$$CP^{d}_{s,k} = \sum_{i=1}^{k} P^{d}_{s,i} + R^{0}_{s} \qquad (5.10)$$

This represents the successive abscissa energy steps of the piecewise constant function $M_s{}^{d}(R_s)$. $R_s{}^{0}$ is the initial reservoir utilization level for storage unit s, and is represented by the corresponding AE unit. The marginal cost of off-loading the k^{th} unit can be represented as

$$M^{d}_{s}(CP^{d}_{s,k-1} < R_s \leq CP^{d}_{s,k}) = IF_k \qquad (5.11)$$

where IF_k represents the incremental fuel cost of the k^{th} unit.

5.1.2.3 Economic Operation

To reflect the economic operation of the storage unit, pumping and generating increments are traded against one another sequentially in the loading order. Whenever the incremental generation cost, i.e, the value of displaced energy is higher than the incremental pumping cost, it is economical to execute a pump-generate cycle. The optimization process can stop for the considered storage unit in three different ways, viz:

(i) charging constrained situation,

(ii) discharging constrained situation, and

(iii) reservoir limit constraining.

In the charging constrained situation, it is not profitable to take any more energy from the DE unit marginally charging the charging side of the storage unit i.e. it is still profitable to off-load energy from the DE unit currently being off-loaded by the discharging side of the storage unit. In the discharging constrained situation, it is not profitable to off-load energy from the DE unit marginally being off-loaded by the discharging side of storage unit, i.e, it is still profitable to take energy from the DE unit currently charging the charging side of the storage unit. In addition to the economic constraint, the generation energy of the pumped storage unit must not exceed the maximum allowable energy it contains.

Let n^* be the index associated with the potential charging energy step just before the intersection of the function $M_s^c(R_s)$ and $M_s^d(R_s)$; and let k^* be the index associated with the potential discharging step also just before the intersection.

The following set of inequalities characterises unequivocally the charging constrained situation (see figure 5.4).

$$\begin{array}{ccc} CP^d_{s,k^*} & < & CP^c_{s,n^*} \\ CP^d_{s,k^*+1} & > & CP^c_{s,n^*} \\ IF_{k^*} & > & IF_{n^*}/\eta_s \\ IF_{k^*+1} & < & IF_{n^*+1}/\eta_s \\ IF_{k^*+1} & > & IF_{n^*}/\eta_s \end{array} \qquad (5.12)$$

The optimal reservoir utilization level referred to the charging is

$$R_s^* = CP^c_{s,n^*} \tag{5.13}$$

In this case the unit split is at the $(k^*+1)^{th}$ position from the discharging side and its energy must be adjusted accordingly.

The following set of inequalities characterises unequivocally the discharging constrained situation (see figure 5.5).

$$\begin{array}{lcl} CP^c_{s,n^*} & < & CP^d_{s,k^*} \\ CP^c_{s,n^*+1} & > & CP^d_{s,k^*} \\ IF_{n^*}/\eta_s & < & IF_{k^*} \\ IF_{n^*+1}/\eta_s & > & IF_{k^*+1} \\ IF_{n^*+1}/\eta_s & < & IF_{k^*} \end{array} \tag{5.14}$$

The optimal reservoir utilization level referred to the discharging is

$$R_s^* = CP^d_{s,k^*} \tag{5.15}$$

In this case the unit split is at the $(n^*+1)^{th}$ position from the charging side and its energy must be adjusted accordingly.

The reservoir constrained situation is shown in figure 5.6. In this case two DE units are split, one from the charging side and another from the discharging side of the storage unit and both the split units energy must be adjusted accordingly.

Note that the way the incremental charging/discharging energy is calculated is first the outages are convolved and then energy is calculated under the new ELDC. Therefore, all the DE units split from the charging side of the storage units which contain charging side outages and all the DE units split from the discharging side of the storage units which contain discharging side outages.

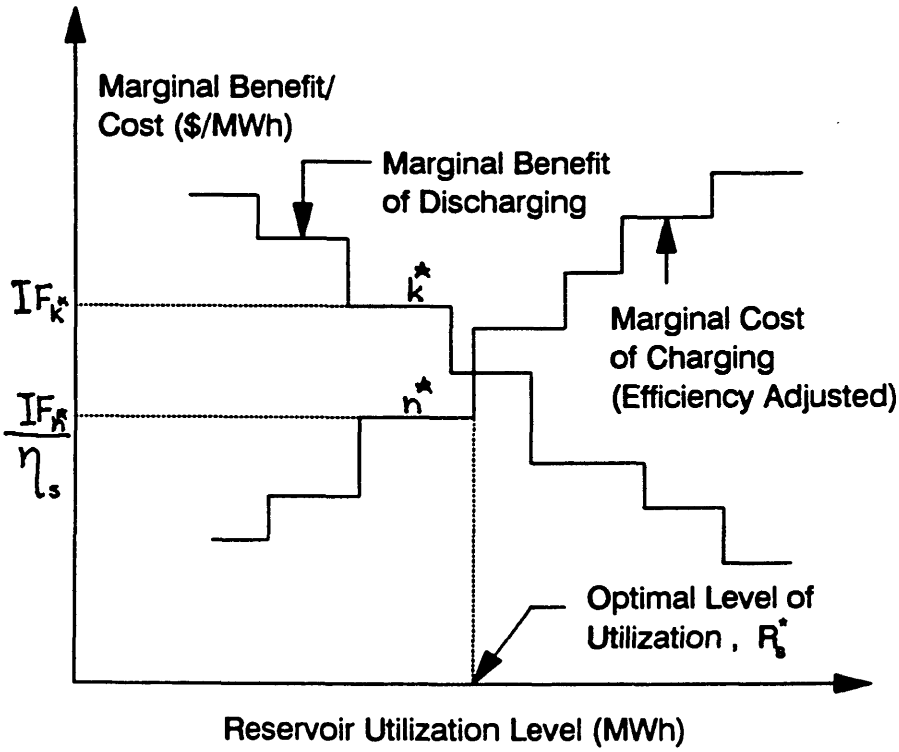


Figure 5.4 Charging constrained situation.

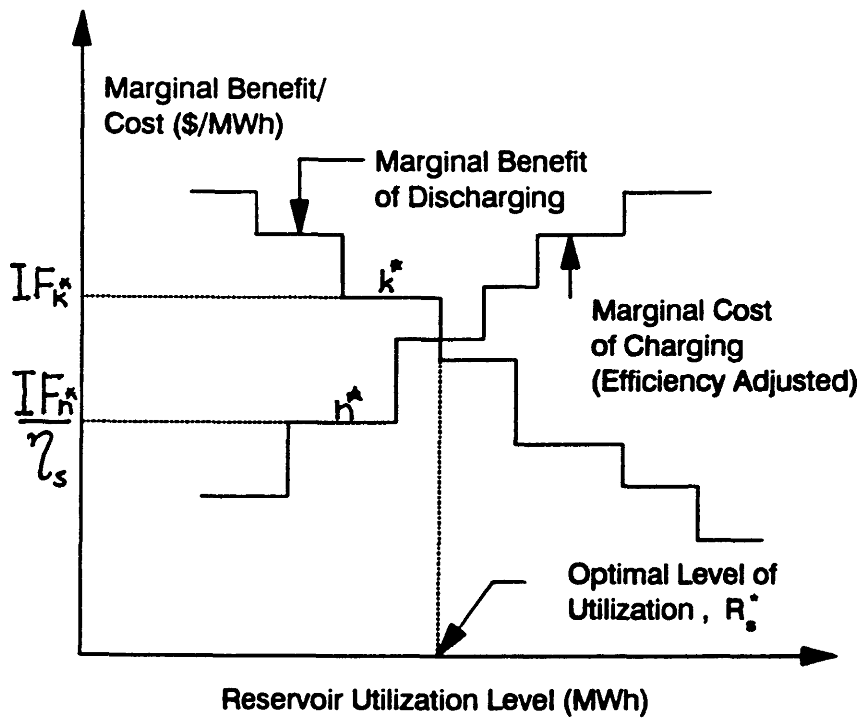


Figure 5.5 Discharging constrained situation.

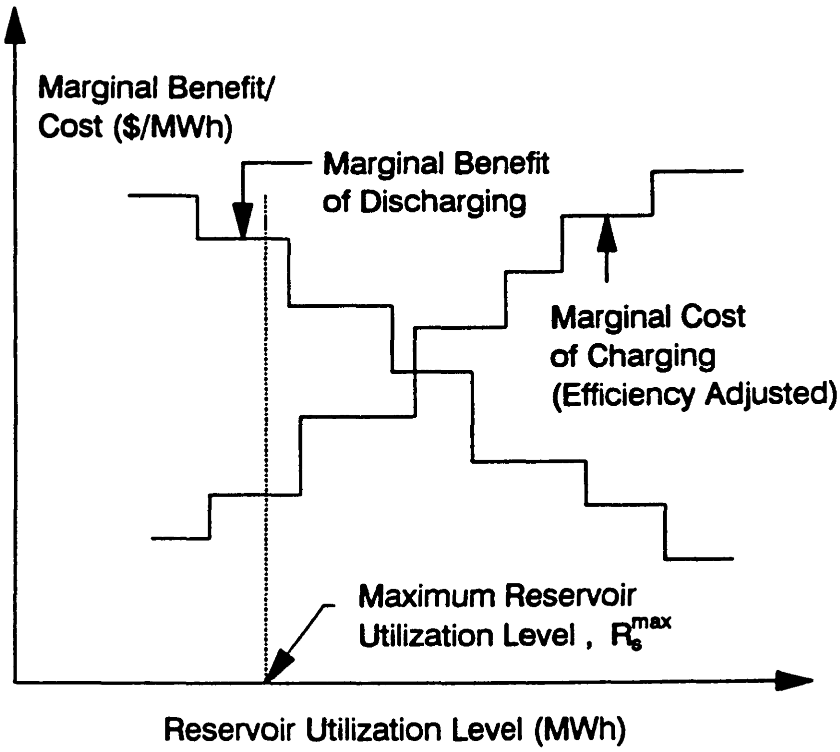


Figure 5.6 Reservoir constrained situation.

When all the storage units are optimized then the AE units are optimized.

5.1.3 AE Units Optimization

When a single AE unit is placed between two DE units, the DE unit higher in the loading order is considered split and its energy is adjusted with the AE unit. Note that unlike the DE unit that is split by the discharging side of a storage unit (which contain the outage effect of the discharging side) the DE unit split by an AE unit does not contain the outage effect of that splitting AE unit. In order to remain consistent with the criterion made for storage units, the outage of an AE unit must be convolved with the split DE unit and then its energy adjusted with the split DE unit.

When two or more AE units compete for the same or part of the same position in the loading order the technique of clustering and swapping the AE units with adjacent DE units to optimize their positions in the loading order was used in chapter 3. That technique needed record keeping of the units which were clustered and also needed deconvolution to swap the adjacent DE units. In the final algorithm developed the previous technique was abandoned and the same technique developed for off-loading DE units by the discharging side of a storage unit was used to optimize the AE units. Appendix A.3 describes the clustering and swapping technique and Appendix A.4 describes the new technique and compares them.

The AE units are considered for optimization according to their decreasing attempted operating hours. The extra load is subtracted from the DE unit by the following equation:

$$F_g'(x) = p_r F_g(x+C_r) + q_r F_g(x) \tag{5.16}$$

Similarly, for the frequency equation the extra load is subtracted from the DE unit by the following equation:

$$f_g'(x) = p_r f_g(x+C_r) + q_r f_g(x) + \frac{1}{\tau_r}\{F_g(x) - F_g(x+C_r)\} \tag{5.17}$$

where, p_r, q_r, C_r, and τ_r represents respectively the availability, forced outage rate, capacity and the mean cycle time of the AE unit r. $F_g(x)$ and $F_g'(x)$ represents respectively the ELDC of the g^{th} DE unit before and after the AE unit was convolved. $f_g(x)$ and $f_g'(x)$ represents respectively the ELFC of the g^{th} unit before and after the AE unit was convolved. $F_g'(x)$ and $f_g'(x)$ are intermediate variables and all their values should be transferred back to $F_g(x)$ and $f_g(x)$ respectively. This is because if the g^{th} unit is going to be off-loaded again by the next AE unit in the priority list it should see the modified ELDC and ELFC. The incremental potential off-loaded energy, $P_{r,g}$, can be calculated as follows:

$$P_{r,g} = E_g - E_g' = p_g T \int_{X_{g-1}}^{X_g} \{F_g(x) - F_g'(x)\} dx \tag{5.18}$$

where p_g, X_{g-1} and X_g are the availability, loading and capacity points of the g^{th} unit respectively. E_g and E_g' are the expected energies generated by the g^{th} unit before and after the unit is off-loaded by the AE unit r respectively. T is the time interval for LDC.

The frequency of starts of the g^{th} unit at the loading point X_{g-1} can be read from the new ELFC, $f_g'(X_{g-1})$.

The incremental potential off-loaded energy $P_{r,g}$ should be added to the expected energy generated by the r^{th} AE unit in the initial solution. The process of finding the incremental off-loaded energy could be continued sequentially up the curve (effective LDC) for the AE unit being considered for optimization. Now, during the process of optimization if the next unit to be off-loaded is an AE unit or the discharging side of another storage unit then a jump is required to the next DE unit up the loading order which can be off-loaded. In this way the process of optimization does not stop. Also note that there is no need to cluster the adjacent AE units. When the total expected energy generated by an AE unit (the expected energy generated plus the cumulative off-loaded energy) is more than the equivalent energy assigned to that unit than the process of finding the potential off-loading energy should be stopped and the energy of the AE unit adjusted with the last DE unit which has provided the off-loaded energy.

When all the AE units are optimized then the operating, start-up costs and the reliability indices are calculated.

5.1.4 Calculation of Costs and Reliability Indices

The optimization of storage units and AE units is finished when there is no more change in the expected energy generated by the units, following which, the operating costs of units are calculated. Similarly, by reading the transition frequency at the loading points of each unit, start-up costs of the units are calculated. Shut-down costs are not assessed separately but they can be incorporated in turbine start-up costs (see chapter 2).

The following reliability indices are found after the calculation of costs, EUE, LOLP, $\bar{f}$, $\bar{T}$ and $\bar{P}$.

5.2 CONCLUDING REMARKS

This chapter has presented a full algorithm to simulate the mixture of pumped hydro storage, assigned- and demand-energy units production costing. Firstly an initial solution is formed, secondly the storage units reservoir utilization level are optimized, thirdly the assigned-energy units are optimized and finally the start-up and operating costs are estimated. A special treatment is given to pumped storage units and the algorithm is extended from the conventional probabilistic production costing in two different dimensions:

(i) firstly, it has included the reservoir utilization levels of storage units as optimization variables and

(ii) secondly, it has included the equivalent load transition frequency information to assess the complete economic benefits of load-levelling of storage units.

For the purpose of optimal reservoir utilization level a computationally very efficient solution method is developed. The method developed is independent of the ELDC representation. A completely new technique of off-loading units is developed which does not require deconvolution. It has overcome the so-called logic and order problem of previously developed efficient non-looping method. In author's opinion, the decreasing cycle efficiency is the right criterion for ordering the storage units for carrying out the production costing and is in fact true in terms of an operational viewpoint.

For the purpose of cycling avoidance benefits the parallel frequency equation (equation 5.8) is developed for a new off-loading technique. The method developed is independent for the ELFC representation also, because there is no deconvolution involved for frequency equations as well.

The next chapter represents the results of two sample case studies to give some numeric values for pumped storage cycling avoidance benefit.

Chapter 6

Case Studies

Two sample case studies are presented in this chapter. The purposes of these case studies are:

(i) to obtain a feeling for the kind of data required in the proposed algorithm,

(ii) to highlight the application of the proposed algorithm which has been implemented with a numerical convolution based ELDC and ELFC representation, and

(iii) to draw further conclusions on pumped storage cycling avoidance benefits.

Both case studies consists of the solution of optimal reservoir utilization for only one time period.

6.1 EPRI CASE STUDY

6.1.1 Generation Data

The first study is based on a thermal system of EPRI synthetic system A (reduced version) as described in reference [63] where its extension for outage and repair rates is taken from reference [9]. The assigned-energy and pumped storage units data is supplied by the author. Demand-energy units start-up costs and cooling time constants are also supplied by the author.

Table 6.1 provides the operating costs, repair and outage rates of a demand-energy generation system. The system consists of 2,200 MW of nuclear, 6,200 MW of steam fossil-coal, 1000 MW of steam fossil-oil, and 950 MW of combustion turbines. Table 6.2 provides the turbine start-up costs, cold start-up costs and cooling time constants of demand-energy units. For each DE unit 0.05 start-up failure probability is assumed. The duty cycle of cycling or peaking DE units is considered by using four and six state models instead of two and three state models.

Table 6.3 provides the assigned-energy units data. The system consists of four AE units with total generating capacity of 225 MW.

Table 6.4 provides the pumped storage units data. The total installed capacity is 400 MW. Four units with efficiencies ranging from 80% to 70% are considered.

Both AE units and pumped storage units are modelled as two state units. Their availabilities are assumed high.

6.1.2 Load Data

A normalised chronological weekly load cycle and 25 selected load data points with percentage durations is taken from EPRI EM-285 [63]. These 25 selected points with their percentage duration, and the number of times the actual load cycle crossed these selected points in the upward direction of the load is provided in table 6.5. The frequency of crossing at every selected load point in per hour can be calculated by dividing the number of crossings at that point by the total number of hours (in this case 168 hours). The peak demand for this study is considered 8,250 MW.

Table 6.1 Demand-energy unit data for the EPRI synthetic system A with extension.

Unit Type	No. of Un-its	Unit Size (MW)	Der-ated Unit Size (MW)	Heat Rate Btu/kWh	Heat Rate at Derated Cap. Btu/kWh	Fuel Cost \$/MBtu	O&M Cost \$/MWh	Total Cap. Outage Rate Hr^{-1}	Total Cap. Repair Rate Hr^{-1}	Derated Cap. Outage Rate Hr^{-1}	Derated Cap. Repair Rate Hr^{-1}
NU-a	1	1200	275	8500	10400	0.76	1.8	1.39×10^{-3}	1.13×10^{-2}	1.59×10^{-3}	8.33×10^{-3}
NU-b	1	1000	225	8500	10400	0.76	1.8	1.39×10^{-3}	1.13×10^{-2}	1.59×10^{-3}	8.33×10^{-3}
CO-a	4	600	150	8262	10814	2.00	3.6	2.94×10^{-3}	1.54×10^{-2}	1.58×10^{-3}	4.73×10^{-3}
CO-b	3	400	100	8502	10674	2.00	3.6	1.75×10^{-3}	1.67×10^{-2}	1.38×10^{-3}	8.50×10^{-3}
CO-c	13	200	50	8806	11581	2.00	3.6	1.06×10^{-3}	1.89×10^{-2}	1.27×10^{-3}	1.30×10^{-2}
OI-a	1	400	100	8817	11148	3.75	1.8	1.75×10^{-3}	1.67×10^{-2}	1.38×10^{-3}	8.50×10^{-3}
OI-b	2	200	50	9177	12068	3.75	1.8	1.06×10^{-3}	1.89×10^{-2}	1.27×10^{-3}	1.30×10^{-2}
OI-c	4	50	25	9000	12000	4.00	1.2	4.64×10^{-4}	1.89×10^{-2}	1.14×10^{-3}	4.63×10^{-2}
CT-a	19	50	-	14000	-	4.39	3.2	6.58×10^{-3}	2.08×10^{-2}	-	-

Table 6.2 Demand-energy units start-up costs and cooling time constants for EPRI study, supplied by the author.

Unit Type	Turbine Start-up Costs \$/MW/start	Cold Start-up Cost \$/MW/start	Unit Cooling Time Constant (hrs)
NU-a&b	-	-	-
CO-a&b	10	35	12
CO-c	10	30	8
OI-a	10	35	12
OI-b&c	10	30	8
CT-a	3	20	3

Table 6.3 Assigned-Energy units data for EPRI study, supplied by the author.

Unit Type	Unit Size MW	Outage Rate Hr^{-1}	Repair Rate Hr^{-1}	Assigned Energy MWh
AE-1	25	5.00×10^{-5}	9.71×10^{-4}	4200
AE-2	50	5.00×10^{-5}	9.71×10^{-4}	7000
AE-3	50	5.00×10^{-5}	9.71×10^{-4}	7000
AE-4	100	5.00×10^{-5}	9.71×10^{-4}	10000

Table 6.4 Pumped storage units data for EPRI study, supplied by the author.

Unit Type	Unit Size MW	Cycle Efficiency	Outage Rate Hr^{-1}	Repair Rate Hr^{-1}	Initial Reservoir Utilization Level MWh	Maximum Reservoir Utilization Level MWh
PS-1	100	0.80	1.67×10^{-5}	1.54×10^{-3}	4500	6000
PS-2	100	0.78	1.67×10^{-5}	1.54×10^{-3}	3500	5000
PS-3	100	0.75	1.67×10^{-5}	1.54×10^{-3}	2500	4000
PS-4	100	0.70	1.67×10^{-5}	1.54×10^{-3}	1500	3000

Table 6.5 Load data taken from EPRI EM-285 page 4-74.

No. of Points	Load (pu)	Duration (%)	Upward Transition of Load (no. of times)
1	0.5337	1.19	1.0
2	0.5472	4.17	3.0
3	0.5688	7.74	7.0
4	0.5927	3.57	7.0
5	0.6104	5.95	7.0
6	0.6289	0.60	7.0
7	0.6488	2.38	7.0
8	0.6654	2.98	7.0
9	0.6883	2.98	7.0
10	0.7189	0.60	7.0
11	0.7361	1.19	7.0
12	0.7478	1.79	7.0
13	0.7660	4.76	8.0
14	0.7892	6.55	9.0
15	0.8081	2.38	7.0
16	0.8305	2.38	6.0
17	0.8508	4.76	7.0
18	0.8728	2.98	6.0
19	0.8907	5.95	5.0
20	0.9107	4.76	7.0
21	0.9288	12.50	10.0
22	0.9494	12.50	4.0
23	0.9654	4.17	1.0
24	0.9812	0.60	1.0
25	1.0000	0.60	0.0

6.1.3 Results of EPRI Study

For estimating the cycling avoidance benefits the program is run for two different hypothetical scenarios. Case A is a scenario in which the pumped storage units are under scheduled maintenance and therefore, the total available generating system without storage units is 10,575 MW. Case B is a scenario in which all the generating system is available with full generating capacity of 10,975 MW. Peak demand assumed is 8,250 MW for both the runs and the total energy under the LDC for one week is 1,100,082 MWh.

Fig. 6.1, shows pictorially the effective LDCs with and without the storage units in the system. The curves are the same before the knee points, i.e., the probability is 1.0, which means the base-loaded units before the knee points are not affected whether the system contains the storage units or not. The curves differ at their knee points and the area between the knees of two curves shows the extra charging energy required for storage. The middle of the curves is the same, showing that these ELDCs are unaffected and the units loaded under them will produce the same energy regardless of whether the system contains storage units or not. At the loading point of the discharging side of storage units the curves differ slightly while the tail of the curve (with storage units included) is extended due to the extra generation in the system. The area difference at the tail does not represent the total energy discharged, but shows the extra energy provided by the storage units to reduce the unserved energy.

Another useful concept of effective LFC is introduced and is parallel to the effective LDC i.e. if we plot the bits of ELFCs under which the units are loaded we will get the effective LFC. Fig. 6.2, shows this with and without the storage units in the system. Again the curves are same before the starting point, i.e., the frequency of start-up of base-loaded units loaded up to their limits - running throughout the period, is zero. The curves differ after the

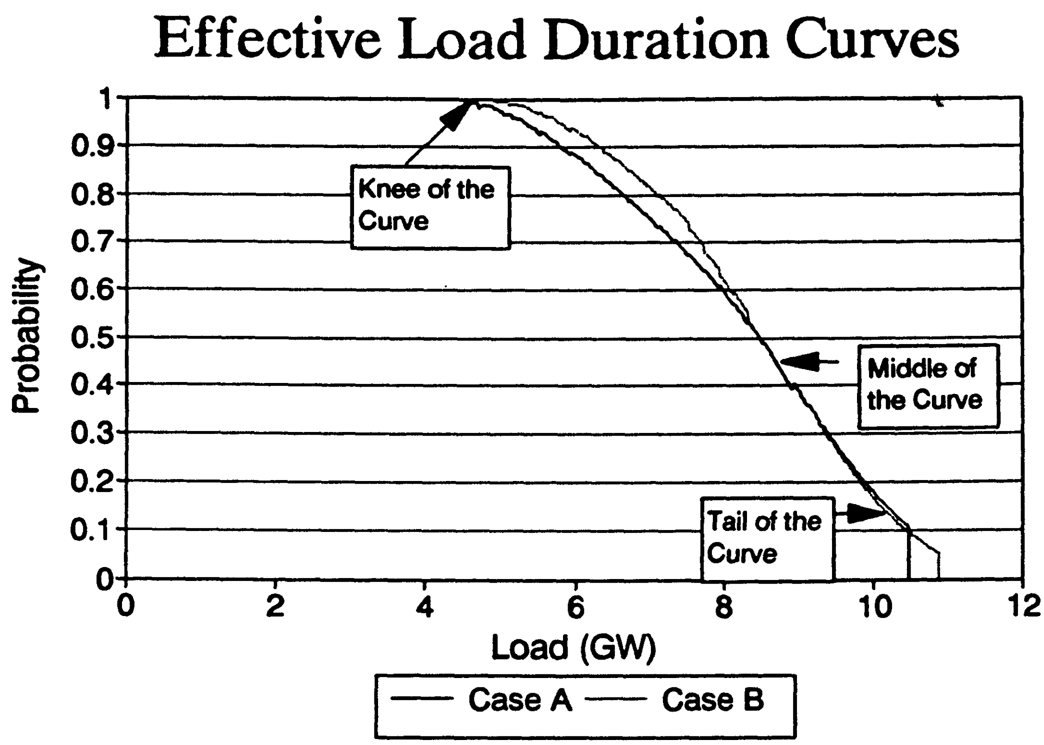


Figure 6.1 Effective load duration curves with and without storage units.

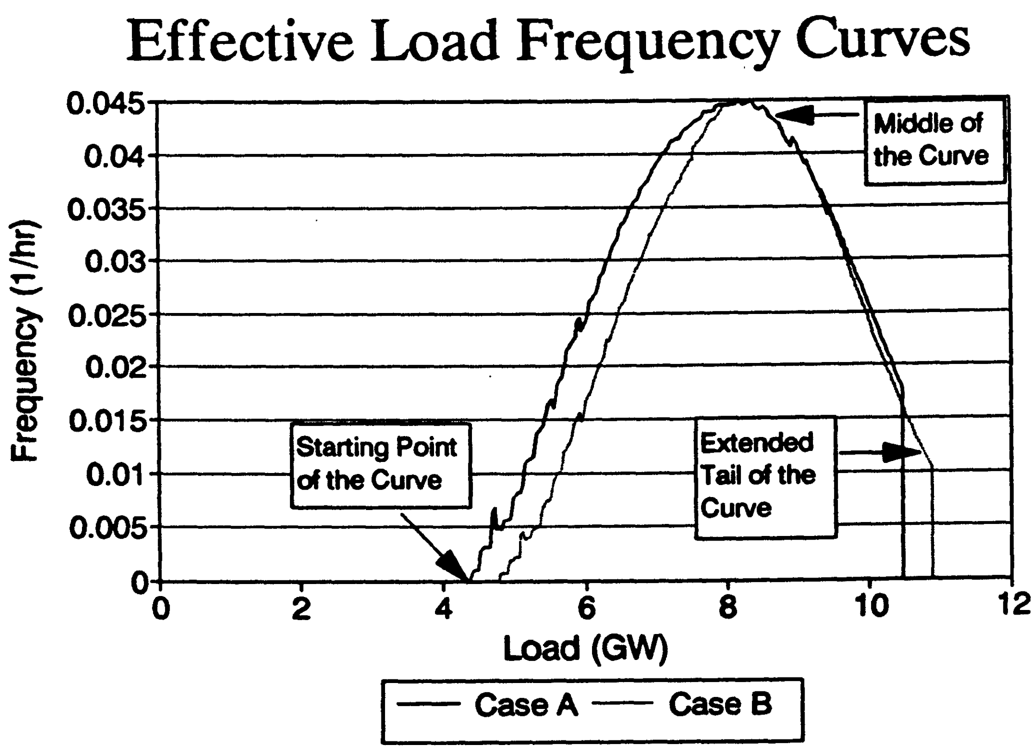


Figure 6.2 Effective load frequency curves with and without storage units.

starting point, as expected, due to charging of the storage units by base-loaded units which were not loaded up to their limits. The curve with the storage units in the system is shifted to the right compared to the curve without storage units, and shows reduced load transition frequency for the same value of load. This means that the storage unit charging has avoided the shut-down of some base-loaded thermal units and hence their start-up too. The middle of the curves are again the same. At the loading point of the discharging side of storage units the curves differ only slightly whereas the tail of the curve with storage units is extended. The discharging side of storage units at their loading positions take up the start-up positions of those units which would have been loaded had the system not contained storage units. Consequently, reduced start-ups of those units which are higher in the loading order is obtained.

Table 6.6 shows the energies and costs comparison for cases A and B, and Table 6.7 shows the initial and optimal reservoir utilization level of the storage units.

The CPU time (MicroVMS V5.4-2) for case A is 6.78 seconds and for case B is 16.77 seconds. Since the algorithm is implemented with numerical convolution the time taken also depends on the MW step size chosen for the convolution. The step size chosen for this study was 25 MW. If the ELDC and ELFC are represented analytically e.g.,[37,50], the CPU time would be a lot less, at the expense of accuracy [38]. Moreover, the idea of a fictitious AE unit can be exploited in analytical methods.

<u>Analysis.</u>

Start-up cost of generation in terms of percentage of total cost with case A is $660593/2.088\times10^{7} = 3.2\%$

Start-up cost of generation in terms of percentage of total cost with case B is $551534/2.054\times10^{7} = 2.7\%$

Difference of start-up costs between cases A&B = \$660592 - \$551534 = \$109,059 in monetary terms. This difference of start-up costs is the benefit of pumped storage units for reducing the start-up costs in case B (cycling avoidance).

Difference of total costs between cases A&B = $\$2.0883\times10^7 - \$2.0540\times10^7 = \$343,000$.

Extra energy provided by storage units in case B = unserved energy in case B - unserved energy in case A = 4,626 MWh.

Now assume that a utility operates in case A scenario, i.e., its storage units are on scheduled outage, and it has to buy energy from a neighbouring utility to meet the same reliability standard as in case B. If this extra energy is bought at the price of \$100/MWh which is the same as saying the extra energy provided by the storage units in case B is quantified at the price of 100 \$/MWh (whereas the marginal generator incremental fuel cost plus O&M cost was 64.7 \$/MWh) then the total cost benefit of load-levelling by using the storage units would be \$462,600 + \$343,000 = \$805,600.

The benefit of artificial energy exchange of storage units would then be = total load-levelling benefit minus cycling avoidance benefit = \$805,600 - \$109,059 = \$696,541.

The benefit of reduced start-up costs (cycling avoidance) in terms of percentage of total load-levelling benefit = 109059/805600 = 13.5%

The benefit of reduced start-up costs in terms of percentage of artificial energy exchange benefit = 109059/696541 = 15.7%

Table 6.6 Energies and costs for cases A & B

Case	Energy Generated (MWh)	Unserved Energy (MWh)	Energy Charged (MWh)	LOLP	$\bar{f}$	Start-up Cost($)	Fuel Cost ($)	Total Cost($)
A	1091782	8300	0	9.220×10^{-2}	1.552×10^{-2}	660592	1.7018×10^{7}	2.0883×10^{7}
B	1119685	3674	23277	4.704×10^{-2}	8.923×10^{-3}	551534	1.6735×10^{7}	2.0540×10^{7}

Table 6.7 Pumped storage units optimal reservoir utilization level for EPRI study.

Unit Type	Unit Size MW	Initial Reservoir Utilization Level MWh	Optimal Reservoir Utilization Level MWh
PS-1	100	4500	5936
PS-2	100	3500	4946
PS-3	100	2500	3957
PS-3	100	1500	2968

6.2 IEEE RTS CASE STUDY

6.2.1 Generation Data

The second study is based on a thermal system of IEEE Reliability Test System (RTS) as described in reference [30] The AE units data is also taken from IEEE RTS, however, the assigned energy values are provided by the author. Pumped storage units data is supplied by the author. Demand-energy units start-up costs and cooling time constants are also supplied by the author.

IEEE RTS was used for calculations for chapter 3 which was provided in appendix B. Table B.1 provides the operating costs, repair and outage rates of a demand-energy generation system. The system consists of 800 MW of nuclear, 1,274 MW of steam fossil-coal, 951 MW of steam fossil-oil, and 80 MW of combustion turbines. Table B.2 provides the turbine start-up costs, cold start-up costs and cooling time constants of demand-energy units. For this study start-up failure probability of DE units is assumed zero. The duty cycle of cycling or peaking DE units is considered by using a four state model instead of a two state model.

Table 6.8 provides the assigned-energy units data. The system consists of six AE units with total generating capacity of 300 MW.

Table 6.9 provides the pumped storage units data. The total pumped storage installed capacity is 200 MW. Four units with efficiencies ranging from 85% to 76% are considered.

Both AE units and pumped storage units are modelled as two state units. Their availabilities are assumed high.

6.2.2 Load Data

A winter week load cycle from IEEE RTS was chosen and the 25 selected points with their percentage duration, and the number of times the actual load cycle crossed these selected points in an upward direction is provided in table B.4. The frequency of crossing at every selected load point in per hour can be calculated by dividing the number of crossings at that point by the total number of hours (in this case 168 hours). The peak demand for this study was considered as 3,000 MW.

Table 6.8 Assigned-energy units data for IEEE RTS study.

Unit Type	Unit Size MW	Outage Rate Hr^{-1}	Repair Rate Hr^{-1}	Assigned Energy MWh
AE-1	50	5.05×10^{-4}	5.0×10^{-2}	6000
AE-2	50	5.05×10^{-4}	5.0×10^{-2}	6000
AE-3	50	5.05×10^{-4}	5.0×10^{-2}	6000
AE-4	50	5.05×10^{-4}	5.0×10^{-2}	2000
AE-5	50	5.05×10^{-4}	5.0×10^{-2}	2000
AE-6	50	5.05×10^{-4}	5.0×10^{-2}	2000

Table 6.9 Pumped storage units data for IEEE RTS study, supplied by the author.

Unit Type	Unit Size MW	Cycle Efficiency	Outage Rate Hr^{-1}	Repair Rate Hr^{-1}	Initial Reservoir Utilization Level MWh	Maximum Reservoir Utilization Level MWh
PS-1	50	0.85	1.25×10^{-3}	2.0×10^{-2}	900	2000
PS-2	50	0.80	1.25×10^{-3}	2.0×10^{-2}	500	1500
PS-3	50	0.78	1.25×10^{-3}	2.0×10^{-2}	500	1500
PS-4	50	0.76	1.25×10^{-3}	2.0×10^{-2}	300	1500

6.2.3 Results of IEEE RTS Study

Again, this time, for estimating the cycling avoidance benefit the program was run for two different scenarios.

Table 6.10 shows the energies and cost comparison for cases C and D. Case C is a scenario in which the pumped storage units are under scheduled maintenance and therefore, the total available generating system without storage unit is 3,405 MW. Case D is a scenario in which all the generating system is available with full generating capacity of 3,605 MW. Peak demand is assumed as 3,000 MW for both the runs and the total energy under the LDC for one week is 422216 MWh.

Table 6.11 shows the initial and optimal reservoir utilization of the storage units.

The CPU time (MicroVMS V5.4-2) for case C was 20.39 seconds and for case D was 37.58 seconds. The step size chosen for this study was 2 MW.

Analysis.

Start-up cost of generation in terms of percentage of total cost with case C is 200557/5392910 = 3.7%

Start-up cost of generation in terms of percentage of total cost with case D is 167613/5350632 = 3.1%

Difference of start-up costs between cases C&D = $200557 - $167613 = $32,944 in monetary terms. This difference of start-up costs is the benefit of pumped storage units for reducing the start-up costs in case D (cycling avoidance).

Difference of total costs between cases C&D = $5392910 - $5350632 = $42,278.

Extra energy provided by storage units in case D = unserved energy in case D minus unserved energy in case C = 998 MWh.

Now assume that a utility operates in case C scenario, i.e., its storage units are on scheduled outage, and it has to buy energy from a neighbouring utility to meet the same reliability standard as in case D. If this extra energy is

Table 6.10 Energies and costs for cases C & D

Case	Energy Generated (MWh)	Unserved Energy (MWh)	Energy Charged (MWh)	LOLP	$\bar{f}$	Start-up Cost($)	Fuel Cost ($)	Total Cost($)
C	420756	1460	0	5.690×10^{-2}	1.342×10^{-2}	200557	4937201	5392910
D	425628	462	3874	1.835×10^{-2}	3.407×10^{-3}	167613	4928691	5350632

Table 6.11 Pumped Storage Units optimal reservoir utilization level for IEEE study.

Unit Type	Unit Size MW	Initial Reservoir Utilization Level MWh	Optimal Reservoir Utilization Level MWh
PS-1	50	900	1056
PS-2	50	500	834
PS-3	50	500	694
PS-3	50	300	532

bought at the price of \$60/MWh which is the same as saying the extra energy provided by the storage units in case D is quantified at the price of \$60/MWh (whereas the marginal generator incremental fuel cost plus O&M cost was \$48.5/MWh) then the total cost benefit of load-levelling by using the storage unit would be \$42,278 + \$59,880 = \$102,158.

The benefit of artificial energy exchange of storage units would then be = total load-levelling benefit minus cycling avoidance benefit = \$102,158 - \$32,944 = \$69,214

The benefit of reduced start-up costs (cycling avoidance) in terms of percentage of total load-levelling benefit = 32.2%

The benefit of reduced start-up costs in terms of percentage of artificial energy exchange benefit = 47.6%

6.3 CONCLUDING REMARKS

Although some of the data presented in this chapter to carry out the production costing for the proposed algorithm is supplied by the author it is clear from the data that the practical data required to implement this algorithm for a utility is not difficult. Almost every utility has such data available and there is no extra effort needed to collect it.

The two sample case studies have shown that cycling avoidance benefits form a fair part of load-levelling benefits of pumped storage units and hence cannot be neglected for production costing studies. The pictorial representation of effective load frequency curves also helped to visualise the effect of pumped storage units on the number of start-ups on the other units in the system.

The next chapter is the general conclusion of this thesis and suggests some further extensions within the scope of the proposed algorithm. Appendix C gives some brief details of the computer program developed for the studies carried out in this chapter.

Chapter 7

Conclusions

This study has shown that, in spite of the energy losses originated by the storage cycle, the economic and operational advantage of using storage for load-levelling are:

(i) Storage units improve the overall economic performance of a power utility system. Through their use, the utilization hours of cheap base-loaded large thermal units (e.g., nuclear units) can be increased; while the utilization hours of peaking thermal units (e.g., combustion turbines) can be decreased (artificial energy exchange benefit).

(ii) Storage units facilitate the operation of a power utility system, resulting therefore in further economic improvements. For instance, must-run constraints of large base-loaded power plants can be alleviated through the use of storage units (cycling avoidance benefits).

The two sample case studies revealed the fact that the benefit from cycling avoidance is quite significant. In one study the share was 13.5% and in another study it was almost one third of the total benefit obtained from storage units load-levelling. This share of benefits depends on many factors such as the percentage of storage units in a generating system, the load cycle, the start-up costs relative to the total operating costs and the way the unserved energy in the system is costed.

Most planning studies do not include start-up costs of units and hence the load-levelling benefits of pumped storage units are only partially estimated. Clearly, the planning problem cannot include all features of system operation, nor would there be any attempt in doing so. Some effects are insignificant. Some are simply swamped by the overall uncertainties involved in future projections, but the relative importance of different features must be understood. It is usually assumed that there is no point in having planning methods significantly more accurate than the most uncertain elements in the data available. This is not correct for the following reasons:

There is a crucial distinction between bias inaccuracy and random inaccuracy. Certain modelling simplifications may randomly under- or over-estimate system costs; if the associated costs are small in comparison to overall uncertainties, that is fine. But if the miscalculation is systematic it can lead to a systematic error in resulting decisions. For example, deterministic modelling tends to ignore the frequency of "extreme" conditions, and hence underestimates the role of peaking plant or the need for transmission capacity. Irrespective of the overall uncertainties and real-world planning constraints, deterministic modelling will tend to result in a system with sub-optimal peaking or transmission capacity.

Similarly, thermal start-up costs represent a small fraction of total system costs: but if they are neglected, there is a systematic over-estimation of the benefits from very variable sources (e.g. tidal,or wind power), which may impose a heavy cycling duty. On the contrary, there is a systematic under-estimation of the benefits from storage, which is relieving the cycling duty of base-loaded units, as this study has shown. Clearly, the criteria for neglecting bias inaccuracies needs to be more severe than those for random inaccuracies.

Finally, it should be stressed that power supply is generally among the largest of industries. On the former CEGB system of UK, a saving of 1% represented over $100m/year (figures 1984 taken from reference [56]). Random inaccuracies cannot be avoided because the future is highly uncertain. But the savings offered by avoiding needless bias inaccuracies, or by using methods which can help minimise the impact of those uncertainties, may be highly significant.

7.1 ORIGINAL CONTRIBUTIONS

The major contributions of this dissertation are summarized in the following.

(a) The idea of equivalent assigned-energy [28] is formulated. The conclusion is that the assigned-energy units should be loaded in the loading order according to their equivalent assigned energy. In the author's opinion this sophisticated design factor could be used for designing the reservoir size for hydro-electric plants and storage plants and to determine their unit sizes.

(b) Clustering of more than two units competing for the same, or part of the same position, in the loading order is properly accomplished. However this concept of clustering was not further utilized in the final algorithm and the new technique developed is used.

(c) Proper assignment of energy in a multi-unit reservoir system is properly accomplished by a binomial distribution method. The under-estimation of cost benefit is small if the assigned-energy unit availabilities are high. This problem is, however, not investigated further and hence it is assumed in the development of the final algorithm that AE units and pumped storage units have individual reservoirs.

(d) Conventional probabilistic production costing [3,4] is extended to include the reservoir utilization levels of storage units as optimization variables and start-up and shut-down costs of the units are included.

(e) A computationally very efficient solution method is developed which does not stop optimization if the logic and order problem occurs.

(f) The algorithm developed is free of the way the equivalent load duration curve and equivalent load frequency curve are represented. The idea of fictitious assigned-energy unit is also presented so that if the ELDC and ELFC are represented analytically it can be exploited for computational advantage within the framework of the proposed algorithm.

(g) A novel technique of off-loading the demand-energy units is developed which does not require deconvolution. This technique is used for optimization of discharging side of storage units and assigned-energy units. It can handle the situation very efficiently when two or more assigned-energy units are competing for the same, or part of the same, position in the loading order.

(h) The proposed algorithm is computationally optimal in the sense that no further computational improvement is possible because the structure of the problem is fully exploited.

(i) The proposed method is applied to two sample case studies to highlight its applicability and evaluate the complete load-levelling benefits of pumped storage units. These studies are based on EPRI synthetic system A and IEEE reliability test system. Some of the additional data is provided by the author.

7.2 SCOPE OF APPLICABILITY

The approach used in this thesis is based on a load duration curve technique. Care should be taken in the selection of the load duration curve time span [6]. The selection of the LDC time span is relevant because the charging / discharging cycle of a storage unit is essentially a chronological cycle whereas the LDC models, however, ignore chronology. Basically the considered time span should not be very long, otherwise low-demand hours and high-demand hours of widely separated periods are traded against each other, and the economic impact of the operation of storage units tends to be overestimated.

Furthermore, the precise computation of the storage unit input parameter, maximum reservoir utilization level, is relevant. It could be used as an appropriate binding constraint for stopping the algorithm if the LDC time span is long so that the cost benefits from the pumped storage units are not over-estimated.

7.3 AREAS OF APPLICABILITY

In the heart of a generation expansion planning tool is so-called probabilistic production costing which is a model based on load duration curve technique able to simulate the operation of the system and to compute the expected cost of meeting the customer demand. The proposed algorithm presented in this thesis is computationally very efficient and more accurate within the framework of load duration curve based models because start-up and shut-down costs are included and the novel technique for off-loading, which avoids inaccurate deconvolutions, is used. Its natural area of application is therefore in the framework of generation expansion planning tools to determine the economic impact of large scale integration of storage units in a power utility system.

Strategic planning is not independent of operational planning. The higher the operating costs become, relative to capital costs, the stronger the need for coordination between strategic and operational planning. Ideally such coordination will ensure that the power system operates the way it was planned and that it is planned around the way it operates.

The algorithm is also useful for determining the likely usage of pumped storage units in operational planning and fuel budgeting context [64].

7.4 EXTENSIONS

Areas which to author's belief are grounds for fruitful further research are identified in the following.

(1) It is known that probabilistic production costing models can be included in a decomposition planning framework. We know, from the EPRI EGEAS [33] work, that both non-dispatchables and storage can be incorporated in the decomposition framework. The frequency information used in the proposed model, and the associated operational cost calculations, can be included in a decomposition approach to some extent.

(2) To formulate an expression which approximately determines the maximum reservoir utilization level for the time span of the load duration curve by using an appropriate hourly production costing model.

(3) To include spinning reserve costs. Although they appear small in comparison with total system costs, such issues become more significant in relation to storage if it is among the options in generation expansion planning.

(4) To evaluate in a quantitative fashion the importance of the statistical error, i.e., to determine

the complete load-levelling benefits of pumped storage units in greater detail by further analyzing the share of start-up and shut-down costs with respect to total operating costs, and

the sensitivity of the optimal reservoir utilization level of storage units with respect to their input parameters (chiefly availability and efficiency).

Appendix A

Off-loading Techniques

A.1 ELDC AND ELFC INDEPENDENT OF CONVOLUTION ORDER

Consider three units U1, U2, and U3; with capacities C_1, C_2, and C_3, availabilities p_1, p_2, and p_3, forced outage rates q_1, q_2, and q_3 and cycle times τ_1, τ_2, and τ_3 respectively; whose initial loading order, for ELDCs is as depicted in figure A.1a and, for ELFCs is as depicted in figure A.2a.

Now from figure A.1a:

$$F_3(x) = p_2F_2(x)+q_2F_2(x-C_2) \tag{A.1}$$

$$F_4(x) = p_3F_3(x)+q_3F_3(x-C_3) \tag{A.2}$$

Now from figure A.2a:

$$f_3(x) = p_2f_2(x)+q_2f_2(x-C_2)+\frac{1}{\tau_2}\{F_2(x-C_2)-F_2(x)\} \tag{A.3}$$

$$f_4(x) = p_3f_3(x)+q_3f_3(x-C_3)+\frac{1}{\tau_3}\{F_3(x-C_3)-F_3(x)\} \tag{A.4}$$

Then using equation A.1 in equation A.2, we get

$$
\begin{aligned}
F_4(x) &= p_3\{p_2F_2(x)+q_2F_2(x-C_2)\} + \\
&\quad q_3\{p_2F_2(x-C_3)+q_2F_2(x-C_2-C_3)\} \\
&= p_2p_3F_2(x)+p_3q_2F_2(x-C_2) + \\
&\quad p_2q_3F_2(x-C_3+q_2q_3F_2(x-C_2-C_3)
\end{aligned} \tag{A.5}
$$

Similarly, using equation A.3 in equation A.4, we get

$$
\begin{aligned}
f_4(x) &= p_3\{p_2f_2(x)+q_2f_2(x-C_2)+\frac{1}{\tau_2}[F_2(x-C_2)-F_2(x)]\} + \\
&\quad q_3\{p_2f_2(x-C_3)+q_2f_2(x-C_2-C_3) + \\
&\quad \frac{1}{\tau_2}[F_2(x-C_2-C_3)-F_2(x-C_3)]\} + \\
&\quad \frac{1}{\tau_3}[p_2F_2(x-C_3)+q_2F_2(x-C_2-C_3) - \\
&\quad p_2F_2(x)-q_2F_2(x-C_2)]
\end{aligned} \tag{A.6}
$$

$$
\begin{aligned}
&= p_2p_3f_2(x)+p_3q_2f_2(x-C_2)+p_2q_3f_2(x-C_3) + \\
&\quad q_2q_3f_2(x-C_2-C_3)+\frac{1}{\tau_2}[p_3F_2(x-C_2) + \\
&\quad q_3F_2(x-C_2-C_3)-p_3F_2(x)-q_3F_2(x-C_3)] + \\
&\quad \frac{1}{\tau_3}[p_2F_2(x-C_3)+q_2F_2(x-C_2-C_3) - \\
&\quad p_2F_2(x)-q_2F_2(x-C_2)]
\end{aligned}
$$

Alternatively, $F_4(x)$ can be sequentially generated by first adding the random forced outage effects of U3 followed by the addition of the random forced outage effects of U2 (see figure A.1b) as follows:

$$F_3'(x) = p_3F_2(x)+q_3F_2(x-C_3) \tag{A.7}$$

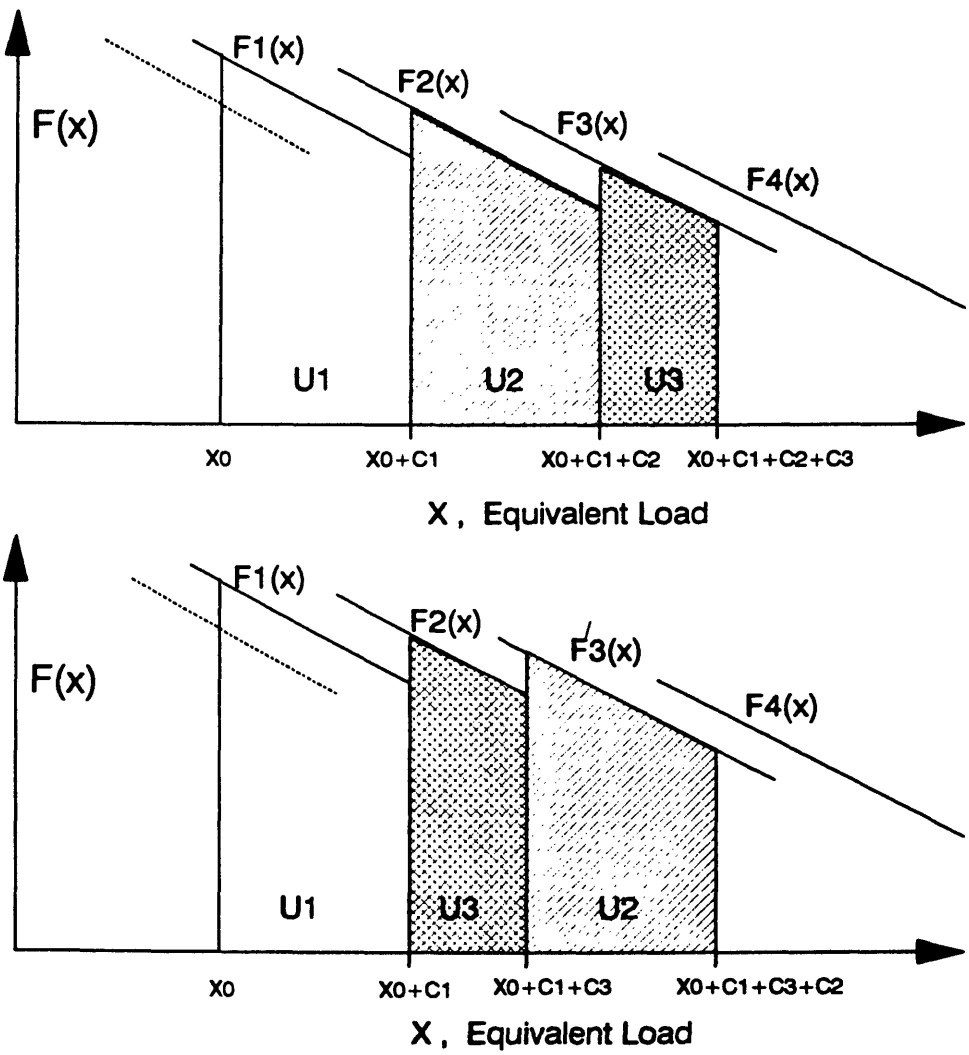
$$F_4(x) = p_2F_3'(x)+q_2F_3'(x-C_2) \tag{A.8}$$

Similarly, $f_4(x)$ can be sequentially generated by first adding the random forced outage effects of U3 followed by the addition of the random forced outage effects of U2 (see figure A.2b) as follows:

$$f_3'(x) = p_3f_2(x)+q_3f_2(x-C_3)+\frac{1}{\tau_3}\{F_2(x-C_3)-F_2(x)\} \tag{A.9}$$

$$f_4(x) = p_2f_3'(x)+q_2f_3'(x-C_2)+\frac{1}{\tau_2}\{F_3'(x-C_2)-F_3'(x)\} \tag{A.10}$$

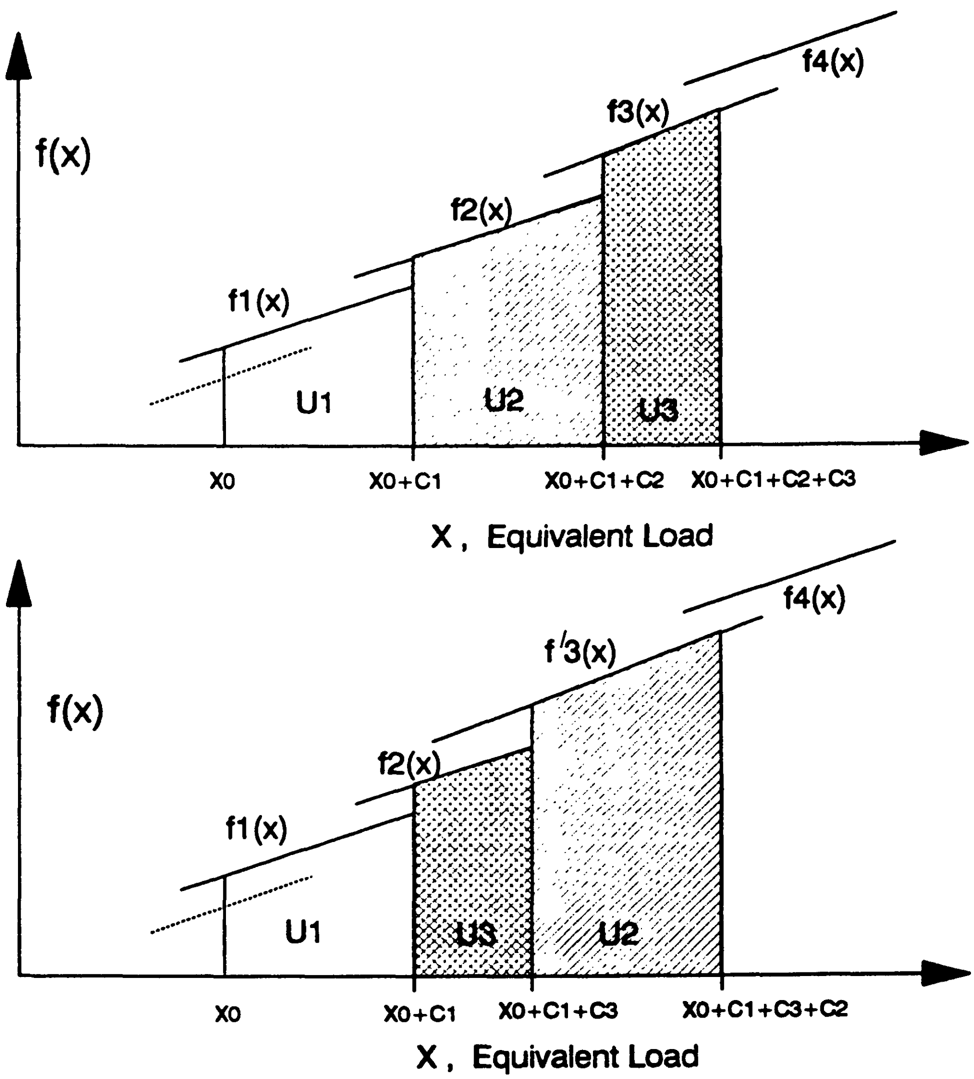
(a) $F_1(x)$ is equivalent load duration curve with all units to left of U1 convolved.
$F_2(x)$ includes convolutions of $F_1(x)$ + U1
$F_3(x)$ includes convolutions of $F_2(x)$ + U2
$F_4(x)$ includes convolutions of $F_3(x)$ + U3



(b) $F_1(x)$, $F_2(x)$ and $F_4(x)$ as above
$F'_3(x)$ includes convolution of $F_2(x)$ + U3

Figure A.1 ELDC independent of convolution order.

(a) $f_1(x)$ is equivalent load frequency curve with all units to left of U1 convolved.
$f_2(x)$ includes convolutions of $f_1(x)$ + U1
$f_3(x)$ includes convolutions of $f_2(x)$ + U2
$f_4(x)$ includes convolutions of $f_3(x)$ + U3



(b) $f_1(x)$, $f_2(x)$ and $f_4(x)$ as above
$f'_3(x)$ includes convolution of $f_2(x)$ + U3

Figure A.2 ELFC independent of convolution order.

Then using equation A.7 in equation A.8, we get

$$\begin{aligned} F_4(x) &= p_2\{p_3F_2(x)+q_3F_2(x-C_3)\} + \\ &\quad q_2\{p_3F_2(x-C_2)+q_2F_2(x-C_3-C_2)\} \\ &= p_2p_3F_2(x)+p_3q_2F_2(x-C_2) + \\ &\quad p_2q_3F_2(x-C_3+q_2q_3F_2(x-C_2-C_3) \end{aligned} \tag{A.11}$$

Similarly, using equation A.9 in equation A.10, we get

$$\begin{aligned} f_4(x) &= p_2\{p_3f_2(x)+q_3f_2(x-C_3)+\frac{1}{\tau_3}[F_2(x-C_3)-F_2(x)]\} + \\ &\quad q_2\{p_3f_2(x-C_2)+q_3f_2(x-C_3-C_2) + \\ &\quad \frac{1}{\tau_3}[F_2(x-C_3-C_2)-F_2(x-C_2)]\} + \\ &\quad \frac{1}{\tau_2}[p_3F_2(x-C_2)+q_3F_2(x-C_3-C_2) - \\ &\quad p_3F_2(x)-q_3F_2(x-C_3)] \end{aligned} \tag{A.12}$$

$$\begin{aligned} &= p_2p_3f_2(x)+p_3q_2f_2(x-C_2)+p_2q_3f_2(x-C_3) + \\ &\quad q_2q_3f_2(x-C_2-C_3)+\frac{1}{\tau_2}[p_3F_2(x-C_2) + \\ &\quad q_3F_2(x-C_2-C_3)-p_3F_2(x)-q_3F_2(x-C_3)] + \\ &\quad \frac{1}{\tau_3}[p_2F_2(x-C_3)+q_2F_2(x-C_2-C_3) - \\ &\quad p_2F_2(x)-q_2F_2(x-C_2)] \end{aligned}$$

Because equations A.5 and A.11 are the same, it follows that the equivalent load duration curves are unaffected by the order in which the effects of random forced outages of generating units are added. This is the commutative property of ELDC. Similarly as equations A.6 and A.12 are the same, it follows that the equivalent load frequency curves are unaffected by the order in which the effects of random forced outages of generating units are added. This is the commutative property of ELFC.

A.2 ENERGY INVARIANCE PROPERTY

The equivalent load duration curve does not depend on the order in which the random forced outages are convolved into the curve as proved earlier. This implies that the total energy served by any number of adjacent units in the loading order is invariant with respect to their relative positions in the loading order and is called the energy invariance property. Thus, the ELDC $F_4(x)$, which represents the load to be served by the remaining units in the loading order is unchanged by reversing the loading order positions of units U2 and U3. The invariance of $F_4(x)$ (with respect to this reversal) in conjunction with the fact that units U2 and U3 occupy adjacent loading order positions implies that the total energy delivered by both U2 and U3 is constant - regardless of their order. Thus:

$$E_2+E_3 = E_2'+E_3' \tag{A.13}$$

where E_2 and E_3 are the expected energies of units U2 and U3, respectively - when those units are positioned in the loading order as shown in figure A.1a - and E'_2 and E'_3 are the expected energies of units U2 and U3 respectively - when the loading positions are reversed as shown in figure A.2b.

This swapping of adjacent units is called off-loading and is very much desired in the case of pumped storage units and AE units optimization. For example, if unit 3 was the discharging side of a storage unit or an AE unit and initially positioned as in figure A.1a then by changing its loading position (off-loading unit 2) as in figure A.1b it would discharge more energy.

The usual method adopted for off-loading the unit, e.g. U2, is by deconvolution of the outage of unit U2, which is taking the lower position in the loading order, from the final convolution in this case $F_4(x)$. U2 is then loaded with changed loading point under $F'_3(x)$, obtained after the deconvolution of outage of U2, and finding the expected energy E'_2 with the following equation:

$$E_2' = p_2 \int_{X_0+C_1+C_3}^{X_0+C_1+C_3+C_2} F_3'(x)\,dx \tag{A.14}$$

Here p_2 is the availability, $(X_0+C_1+C_3)$ and $(X_0+C_1+C_3+C_2)$ are the loading point and the capacity point of U2 as shown in figure A.1b. The expected energy generated by U3 can then be calculated from the energy invariance property:

$$E_3' = (E_2+E_3) - E_2' \qquad (A.15)$$

Notice that expected energies E_2 and E_3 were already computed in the initial placement of the units.

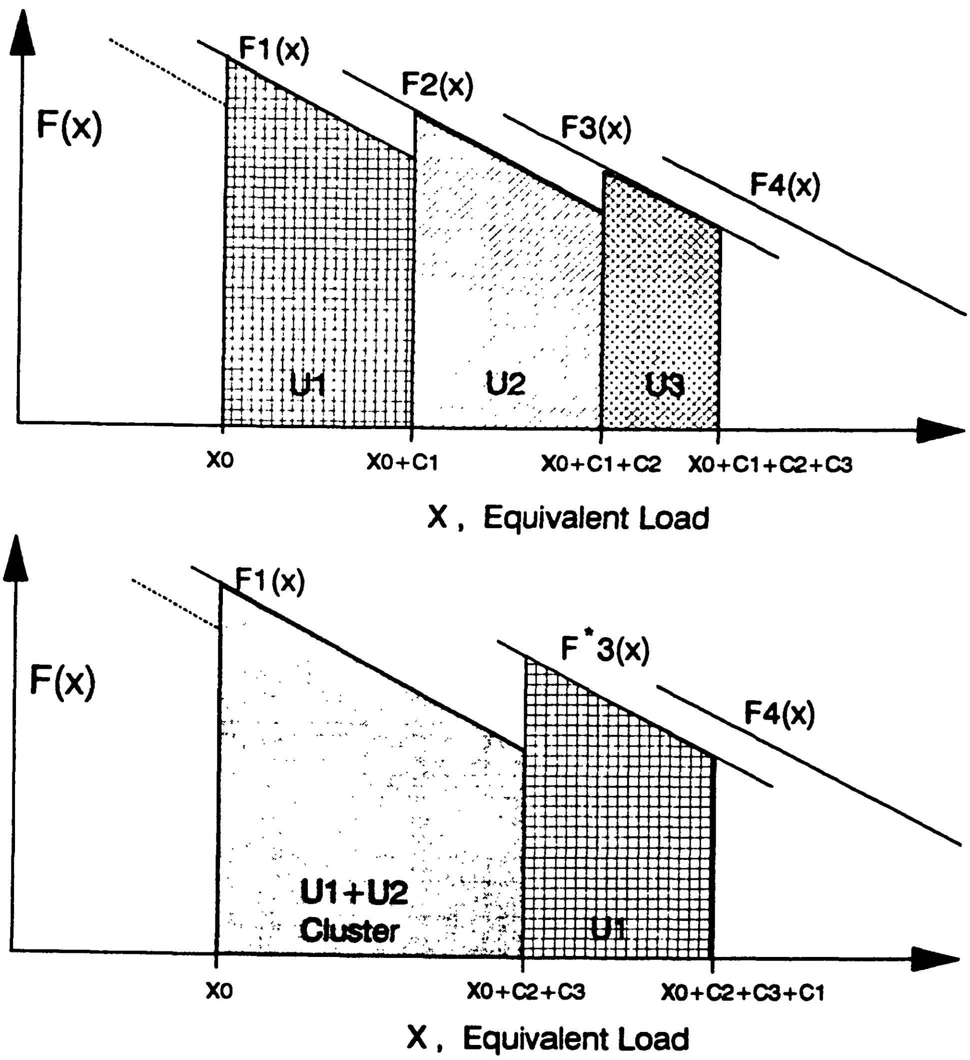
In the case of a single AE unit (the discharging side of a storage unit is also modelled as an AE unit), the indirect calculation of E'_3 shows no particular computational benefits. However, if two AE units are competing for the same or part of the same position then the advantage of using the energy invariance property becomes evident. Manhire and Jenkins proposed a clustering and swapping technique [1] to handle such a situation.

A.3 CLUSTERING AND SWAPPING TECHNIQUE

Now consider the case when two assigned energy units U2 and U3 compete for the same or part of the same position in the loading order position under the ELDC. This case is illustrated in figure A.3a. Assume that in the sequential process of positioning the AE unit U2 is correctly positioned, as shown in figure A.3a, according to the criterion for the correct placement of a single AE unit. If U2 is the discharging side of a storage unit however then assume that it is already at its optimized position. Let the energy delivered at this position be E_2.

Next assume that the energy delivered by unit U3 in figure A.3a, E_3 - whose total attempted operating hours have been precalculated to be less than or equal to the attempted operating hours of unit U2 - is less than the energy assigned to the unit. If U3 is the discharging side of a storage unit then assume that it still has to be optimized. Since U2 is correctly positioned with respect of its energy assignment, or in other words it is already at its optimized position, nothing is gained by interchanging the loading order positions of U2 and U3. However, since the ELDC is invariant with respect to convolution order, $F_1(x)$ and $F_4(x)$ in figure A.3 are unchanged by the relative loading order positions of

(a) $F_1(x)$ is equivalent load duration curve with all units to left of U1 convolved.
$F_2(x)$ includes convolutions of $F_1(x)$ + U1
$F_3(x)$ includes convolutions of $F_2(x)$ + U2
$F_4(x)$ includes convolutions of $F_3(x)$ + U3



(b) $F_1(x)$ and $F_4(x)$ as above
$F_3^*(x)$ includes convolution of $F_1(x)$ + U2 + U3

Figure A.3 Clustering and swapping.

the adjacent units: U1, U2 and U3. The desired objective is to find a position in the loading order for the two adjacent units (U2 and U3) such that they deliver their assigned energy. Such a group of AE units is designated as a cluster and treated as a single entity.

In figure A.3b, $F_3^*(x)$ is the ELDC which results when the forced outage effects of U1 are deconvolved. Then load U1 with a changed loading point under $F_3^*(x)$ obtained after the deconvolution of outage of U1, the expected energy E'_1 is found with the following equation:

$$E_1' = p_1 \int_{X_0+C_2+C_3}^{X_0+C_2+C_3+C_1} F_3^*(x)\,dx \qquad \text{(A.16)}$$

where p_1 is the availability, $(X_0+C_2+C_3)$ and $(X_0+C_2+C_3+C_1)$ are the loading point and the capacity point of U2 as shown in figure A.1b. The invariance of $F_4(x)$ with respect to the relative loading order positions of the adjacent units U1, U2 and U3 leads to the energy relationship:

$$E_1+E_2+E_3 = E_2'+E_3'+E_1' \qquad \text{(A.17)}$$

or:

$$\underbrace{(E_2'+E_3')}_{\text{(cluster energy)}} = (E_1+E_2+E_3)-E_1' \qquad \text{(A.18)}$$

Thus the single calculation of the energy delivered by the unit U1, when this unit is off-loaded by the cluster of units U2 and U3, determines the energy delivered by the cluster when the cluster off-loads the unit U1. The delivered cluster energy can then be compared with the total energy assigned to all the units of the cluster. The process is repeated until the energy delivered by the cluster exceeds its assignment.

A.4 THE NEW TECHNIQUE

For off-loading U2 we convolve the outage of U3 with the following equations:

$$F_2''(x) = p_3 F_2(x+C_3) + q_3 F_2(x) \tag{A.19}$$

$$f_2''(x) = p_3 f_2(x+C_3) + q_3 f_2(x) + \frac{1}{\tau_3}\{F_2(x) - F_2(x+C_3)\} \tag{A.20}$$

Now, compute the expected energy, E''_2, of U2 without changing its loading point under $F''_2(x)$ with the following equation:

$$E_2'' = p_2 \int_{X_0+C_1}^{X_0+C_1+C_2} F_2''(x)\,dx \tag{A.21}$$

where (X_0+C_1) and $(X_0+C_1+C_2)$ are the loading point and the capacity point of U2 as shown in figure A.1a. The expected energy E''_2 of U2 is equal to E'_2 and act as if the unit is off-loaded without changing its position.

Similarly, the frequency under $f''_2(x)$ at the loading point of unit U2 (shown in figure A.2a) is the same frequency under $f'_3(x)$ at the loading point of unit U2 in figure A.2b.

Proof: If we put equation A.19 into A.21 as follows:

$$E_2'' = p_2 \int_{X_0+C_1}^{X_0+C_1+C_2} \{p_3 F_2(x+C_3) + q_3 F_2(x)\}dx \tag{A.22}$$

and then change the argument and correspondingly change the integral limits we get equation A.23 as follows:

$$E_2'' = p_2 \int_{X_0+C_1+C_3}^{X_0+C_1+C_2+C_3} \{p_3 F_2(x) + q_3 F_2(x-C_3)\}dx \tag{A.23}$$

Now, the expression in the brackets in equation A.23 is the same as $F'_3(x)$ (equation A.7). Therefore, the equation becomes:

$$E_2'' = p_2 \int_{X_0+C_1+C_3}^{X_0+C_1+C_3+C_2} F_3'(x)\,dx = E_2' \qquad \text{(A.24)}$$

For the frequency equation proof, we know that equation A.20 is valid in the range of $X_0+C_1 \le x \le X_0+C_1+C_2$. Now had the unit U2 been swapped then the frequency equation is $f'_3(x)$, shown in figure A.2b and mathematically represented in equation A.9, and is valid in the range of $X_0+C_1+C_3 \le x \le X_0+C_1+C_3+C_2$. If we shift the right side of equation A.9 by capacity C_3, i.e. put $y=x-C_3$ then we will get equation A.25 as follows:

$$f_3'(y) = p_3 f_2(y+C_3) + q_3 f_2(y) + \frac{1}{\tau_3}\{F_2(y) - F_2(y+C_3)\} \qquad \text{(A.25)}$$

This equation is the same as equation A.20.

<u>AE Units Competing for the Same Position:</u> Now if U2 was an AE unit or the discharging side of another storage unit, we can still put the outage of unit U3 onto U1 without affecting U2 as follows:

$$F_1''(x) = p_3 F_1(x+C_3) + q_3 F_1(x) \qquad \text{(A.26)}$$

$$f_1''(x) = p_3 f_1(x+C_3) + q_3 f_1(x) + \frac{1}{\tau_3}\{F_1(x) - F_1(x+C_3)\} \qquad \text{(A.27)}$$

and the new energy for U1 can be calculated by loading U1 under $F''_1(x)$ without changing the loading point of U1 as follows:

$$E_1'' = p_1 \int_{X_0}^{X_0+C_1} F_1''(x)\,dx \qquad \text{(A.28)}$$

Then the new energy for U3 can be calculated from the energy invariance property as follows:

$$E_1+E_2+E_3 = E_1''+E_2''+E_3'' \qquad \text{(A.29)}$$

Note that E_2 and E''_2 are equal because unit U2 is not changed at all and its energy is already optimized, therefore E''_3 can be calculated as:

$$E_3'' = (E_1+E_3) - E_1'' \tag{A.30}$$

Similarly, the frequency of start of unit U1 can be estimated from $f''_1(x)$.

Note that in equations (A.26 - A.27) it is inherently assumed that unit U2 does not exist. This is in fact a logic problem and perhaps cannot be treated in a much better way. Authors like Conejo 1990 [31,32] stop optimization for the considered storage unit if during the process of optimization the next unit to be off-loaded is an AE unit or the discharging side of a storage unit which is already optimized. This problem was, however, addressed by authors Manhire and Jenkins [1] in 1982, for the case of multiple AE units competing for the same or part of the same position in the loading order and is described earlier in section A.3.

<u>Advantage of Using the New Technique:</u> In the clustering and swapping technique, unit U1 shown in figure A.3b at its swapped position contains the outage effect of units U2 & U3, because it was loaded under $F_3^*(x)$, whereas, in the new technique developed unit U1 does not contain the outage effects of unit U2, and it is not touched at all. Both the techniques take advantage of the energy invariance property to calculate the energy of unit U3. Hence the energy generated by unit U1 at its swapped position shown in figure A.3b by the clustering and swapping technique is slightly less than the new technique because U3 also contains the outage effect of unit U2. However, the energy generated by unit U3 at its swapped position in this clustering and swapping technique is slightly more than the energy generated by unit U3 in the new technique because both methods are using the energy balance equation of the energy invariance property. Thus no techniques can be argued as superior.

Nonetheless, the clustering and swapping technique involved deconvolution of DE units and record keeping of clusters. The deconvolution is an unstable phenomenon if the ELDC and

ELFC are represented numerically. On the other hand, the new technique is physically more elegant and accurate and involves no deconvolution, but acts like a peak shaving method.

Appendix B

Cost Calculations for Chapter 3

B.1 IEEE RELIABILITY TEST SYSTEM [30]

Generation Data

Table B.1 Demand-energy units data for the IEEE Reliability Test System.

Unit Type	No. of Units	Unit Size MW	Heat Rate Btu/kWh	Fuel Cost \$/MBtu	O&M Cost \$/MWh	Outage Rate Hr^{-1}	Repair Rate Hr^{-1}
NU-a	2	400	10000	0.6	0.3	9.09×10^{-4}	6.67×10^{-3}
CO-a	1	350	9500	1.2	0.7	8.7×10^{-4}	1.0×10^{-2}
CO-b	4	155	9700	1.2	0.8	1.04×10^{-3}	2.5×10^{-2}
CO-c	4	76	12000	1.2	0.9	5.1×10^{-4}	2.5×10^{-2}
OI-a	3	197	9600	2.3	0.7	1.05×10^{-3}	2.0×10^{-2}
OI-b	3	100	10000	2.3	0.8	8.33×10^{-4}	2.0×10^{-2}
OI-c	5	12	12000	2.3	0.9	3.4×10^{-4}	1.67×10^{-2}
CT-a	4	20	14500	3.0	5.0	2.22×10^{-3}	2.0×10^{-2}

Table B.2 Demand-energy units start-up Costs and cooling time constants, an extension to IEEE Reliability Test System.

Unit Type	Turbine Start-up Costs \$/MW/start	Cold Start-up Cost \$/MW/start	Unit Cooling Time Constant (hrs)
NU-a	-	-	-
CO-a	10	35	12
CO-b&c	10	30	8
OI-a	10	35	12
OI-b&c	10	30	8
CT-a	3	20	3

Table B.3 Assigned-Energy Units data supplied by the author for carrying out clustering exercises.

Unit Type	No. of Units	Unit Size MW	Outage Rate Hr^{-1}	Repair Rate Hr^{-1}	Assigned Energy MWh
AS-1	1	50	5.05×10^{-4}	5.0×10^{-2}	4000
AS-2	1	50	5.05×10^{-4}	5.0×10^{-2}	4000
AS-3	1	50	5.05×10^{-4}	5.0×10^{-2}	4000

Load Data

A winter week from the IEEE Reliability Test System is chosen for carrying out simulation. Out of 168 hours of weekly load data, the data is binned at 25 different selected load points, to make load duration curve and load frequency curve. These load points (in per units) with their corresponding durations (in percentage) and the number of times the actual chronological load crossed these 25 selected points in upward direction are given in the Table B.4 as follows:

Table B.4 Load data for IEEE RTS.

No. of Points	Load (pu)	Duration (%)	Upward Transition of Load (no. of times)
1	0.59854	5.95238	5.0
2	0.61563	5.95238	5.0
3	0.63271	5.95238	10.0
4	0.64979	1.19048	12.0
5	0.66688	3.57143	12.0
6	0.68396	4.16667	8.0
7	0.70104	1.19048	8.0
8	0.71813	0.0	8.0
9	0.73521	4.16667	8.0
10	0.75229	2.97619	8.0
11	0.76938	0.0	8.0
12	0.78646	1.19048	7.0
13	0.80354	1.19048	7.0
14	0.82063	1.19048	7.0
15	0.83771	2.97619	7.0
16	0.85479	0.0	7.0
17	0.87188	6.54762	9.0
18	0.88896	2.38095	9.0
19	0.90604	2.38095	9.0
20	0.92313	6.54762	7.0
21	0.94021	7.14286	12.0
22	0.95729	11.90476	12.0
23	0.97438	10.11905	7.0
24	0.99146	4.16667	7.0
25	1.00000	7.14286	0.0

Peak demand	2850 MW
Total number of hours in the load duration curve interval	168 hrs
Number of DE units	26
Number of AE units	3
Total Capacity	3255 MW

B.2 CLUSTERING

Table B.5 Cost calculations with and without clustering.

Clustering	Total Cost ($)	EUE (MWh)	Supplied Energy (MWh)	LOLP
Improper	5047909	1468	399606	5.63×10^{-2}
Proper	5048968	1468	399606	5.63×10^{-2}

Difference of Cost = $1,059

B.3 COMPARISON OF COST CALCULATIONS WITH AND WITHOUT EQUIVALENT ASSIGNED-ENERGY CONCEPT

B.3.1 Calculations with 0.01 FOR of unit AE-1.

Only one assigned-energy unit, AE-1, from Table B.3 is chosen with the demand-energy unit data from Table B.1 for the cost calculations. The cost and energy calculations are done with assuming the unit AE-1 is not available and then 100% available. After that calculations are weighted with its 0.01 FOR.

Table B.6 Weighted sum of costs, energies and LOLPs.

AE unit	Total Cost ($)	EUE (MWh)	Supplied Energy (MWh)	LOLP
Not Avail.	5307347	3667	397407	1.23×10^{-1}
Available	5223985	2721	398353	9.61×10^{-2}
Weighted	5224803	2730	398344	9.64×10^{-2}

Table B.7 Solution by Placing the Unit AE-1 in the Loading Order by its Assigned Energy.

Total Cost ($)	EUE (MWh)	Supplied Energy (MWh)	LOLP
5223851	2730	398344	9.64×10^{-2}

Table B.8 Solution by Placing the Unit AE-1 in the Loading Order by its Equivalent Assigned Energy.

Total Cost ($)	EUE (MWh)	Supplied Energy (MWh)	LOLP
5224803	2730	398344	9.64×10^{-2}

The total operating costs of the system and its reliabilities for placing the unit AE-1 in the loading order by its equivalent assigned energy and weighted sum are the same.

Estimated cost benefits of loading unit AE-1 in the loading order by it's assigned energy are:
5307347 - 5223851 = <u>$83,496</u>

Estimated cost benefits of loading unit AE-1 in the loading order by it's equivalent assigned energy are:
5307347 - 5224803 = <u>$82,544</u>

Over estimation of cost benefits of loading unit AE-1 in the loading order with it's assigned energy are:
83496 - 82544 = <u>$952</u>

Over estimation of cost benefits in terms of percentage of the total cost benefits calculated by placing the unit AE-1 in the loading order by it's assigned energy are: (952/83496) * 100 = <u>1.1%</u>

B.3.2 Calculations by Changing the FOR of Unit AE-1

By changing the FOR of unit AE-1 to 0.2, (which means the unit is available for 80% of the time) the total costs of operating the system with placing the unit in the loading order by it's assigned energy is $5,222,442., and by it's equivalent assigned energy is $5,240,678.

Estimated cost benefits of loading the unit AE-1 in the loading order by it's assigned energy are:
5307347 - 5222442 = <u>$84,905.</u>

Estimated cost benefits of loading the unit AE-1 in the loading order by it's equivalent assigned energy are:
5307347 - 5240678 = <u>$66,669</u>

Over estimation of cost benefits of loading the unit AE-1 in the loading order with it's assigned energy are:
84905 - 66669 = <u>$18,236</u>

Over estimation of cost benefits in terms of percentage of the total cost benefits calculated by placing the unit AE-1 in the loading order by it's assigned energy are: (18236/84905) * 100 = <u>21.5%</u>

B.4 COST COMPARISONS OF 3 AE UNITS WITH SHARED AND SEPARATE RESERVOIRS

Data of demand-energy units is same as in Table B.1 and data of assigned-energy units is also the same as in Table B.3. However, when it is assumed that the AE units share a reservoir then their total assigned energy is 12,000 MWh.

The total operating cost of the system without AE units = $5,307,347.

The operating cost of the system with shared reservoir = $5,046,245.

The cost benefits of using the AE units in a shared reservoir system = <u>$261,102.</u>

The operating cost of the system with 3 separate reservoirs of assigned energy of 4,000 MWh each = $5,048,968.

The cost benefits of using AE units in 3 separate reservoirs = <u>$258,379.</u>

The under estimation of the cost benefits by employing the algorithm of one-unit, one-reservoir system = <u>$2,723.</u>

Under estimation of cost benefits in terms of percentage = <u>1.0%</u>

Appendix C

Computational Implementation

The program was not developed with the intention for commercial usage. However a brief summary of the program is given here to facilitate those who might like to see and run the program as a potential user or a potential researcher. The computational implementation of the proposed method is denominated SUBPC, which stands for

Storage
Units
Benefits in
Production
Costing

The program is implemented in standard FORTRAN 77. It consists of seven subprograms. Subprogram Plant reads the demand-energy, assigned-energy and pumped storage unit data. Subprogram Demand reads the 25 selected load level points in per unit and correspondingly their percentage duration and number of times the load transit in upward direction. A separate program LDFC is written to create a file, with 25 selected points and their corresponding percentage duration and number of times the load crossed these selected points in upward direction, from chronological load data file. Subprogram Index and Sort taken from reference [65] are used for ordering the assigned-energy and pumped storage units data. Subprogram Ldc is used to create load duration curve and load frequency curve. Subprogram Conv is used in the main program iteratively to carry out the optimization part of storage units and assigned-energy units. Subprogram Dsimequ also used iteratively in the main program for solving simultaneous equation for calculating the forced outage rates of demand-energy units with duty cycle effect.

Input

The input data requirement are summarised in the following.

For constructing load duration and load frequency curves the data includes.

25 selected load data points in per unit,
their percentage duration, and
the number of times the chronological load crossed these selected points in upward direction of load.

Demand-energy unit data for every plant includes

name of the plant,
number of units,
derated capacity in MW,
full capacity in MW,
derated heat rate in Btu/kWh,
average incremental heat rate in Btu/kWh,
incremental fuel costs in terms of heat $/Mbtu,
variable operation & maintenance cost in $/MWh,
full outage rate in per hour,
full repair rate in per hour,
partial outage rate in per hour,
partial repair rate in per hour,
start-up failure probability,
cooling time constant in hours,
turbine start-up cost in $/MW/start, and
cold start-up cost in $/MW/start.

Assigned-energy data includes

name of the plant,
number of units,
generating capacity in MW,
incremental fuel cost (if any) in $/MWh,
outage rate in per hour,
repair rate in per hour, and
assigned energy in MWh.

Storage unit data includes

name of the plant,
generating capacity in MW,
cycle efficiency,
outage rate in per hour,
repair rate in per hour,
initial reservoir utilization level, and
maximum reservoir utilization level.

The program runs interactively and suggests the following actions when submitted to run.

Enter the peak demand.
Enter the total number of hours in a period for LDC.
Enter the MW step size.
Enter the number of demand-energy stations.
Enter the number of assigned-energy stations.
Enter the number of pumped storage stations.

After responding to the above commands the program starts running. Note that if the values given for the above commands are nonsense the program might fail to run successfully.

Output

The output report however is not very user friendly but consists of two parts:

A general part of the report provides

- total cost,
- fuel cost,
- start-up cost,
- total energy,
- supplied energy,
- unserved energy,
- charged energy,
- loss of load probability,
- average frequency of loss of load event and,
- elapsed real time and CPU time.

The second part consists of

- loading order of each unit,
- energy generated by each unit (which also give optimal level of reservoir utilization level at the loading position of discharging side of storage units),
- energy generated at derated state of each unit,
- type of unit (1=DE unit, 2=AE unit, 3=discharging side of storage unit),
- start-up frequency of each unit,
- start-up cost of each unit,
- fuel cost of each unit, and
- total cost of each unit.

SUBPC has been developed on a MicroVax II running under the operating system VMS V5.4-2.

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