A Study of Evaluation Methods Centered

On Reliability for Renewal of Aging Hydropower Plants

by

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ABSTRACT

Hydropower generation is one of the clean renewable energies which has received great attention in the power industry. Hydropower has been the leading source of renewable energy. It provides more than 86% of all electricity generated by renewable sources worldwide.

Generally, the life span of a hydropower plant is considered as 30 to 50 years. Power plants over 30 years old usually conduct a feasibility study of rehabilitation on their entire facilities including infrastructure. By age 35, the forced outage rate increases by 10 percentage points compared to the previous year. Much longer outages occur in power plants older than 20 years. Consequently, the forced outage rate increases exponentially due to these longer outages. Although these long forced outages are not frequent, their impact is immense.

If reasonable timing of rehabilitation is missed, an abrupt long-term outage could occur and additional unnecessary repairs and inefficiencies would follow. On the contrary, too early replacement might cause the waste of revenue.

The hydropower plants of Korea Water Resources Corporation (hereafter K-water) are utilized for this study. Twenty-four K-water generators comprise the population for quantifying the reliability of each equipment. A facility in a hydropower plant is a repairable system because most failures can be fixed without replacing the entire facility. The fault data of each power plant are collected, within which only forced outage faults are considered as raw data for reliability analyses. The mean cumulative repair functions (MCF) of each facility are determined with the failure data tables, using Nelson's graph method. The power law model, a popular model for a repairable system, can also be obtained to represent representative equipment and system availability. The criterion-based analysis of HydroAmp is used to provide more accurate reliability of each power plant.

Two case studies are presented to enhance the understanding of the availability of each power plant and represent economic evaluations for modernization. Also, equipment in a hydropower plant is categorized into two groups based on their reliability for determining modernization timing and their suitable replacement periods are obtained using simulation.

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NOMENCLATURE

$A(t)$	Availability
ADC	Annual depreciation cost
AFOD	Actual forced outage days per year
AIC	Annual interest cost
BIR	Benefit from increased reliability
CB	Circuit breaker
CBR	Condition-based reliability
CCIV	Complementary condition index value
CDF, $F(x)$	Cumulative distribution function
CF	Capacity factor
CI	Condition index
$F(x)$	Cumulative failure rate, cumulative distribution function
$\hat{F}(t)$	Approximate failure function
$f(x)$	Failure rate, probability density function
FOD	Forced outage days
GB	Generation benefit
$H(t)$	Cumulative hazard function
$\hat{H}$	Approximate cumulative hazard rate
$h(t)$	Hazard rate, instantaneous failure rate
HydroAMP	Hydropower Asset Management Partnership
I	Interest rate
IC	Investment cost
$M(t)$, MCF	The mean cumulative repair function
$\hat{M}(t)$	MCF estimate
MARR	Minimum attractive rate of return

MTBF	Mean time between failures
MTTF	Mean time to failure
MTTR	Mean time to repair
MUT	Mean up-time
NHPP	Nonhomogeneous Poisson process
NPV	Net present value
ODF	Annual outage day factor
$P(x)$	Probability
PDF, $f(x)$	Probability density function
$R(x)$	Reliability
RCM	Reliability-centered maintenance
RFOD	Reduced forced outage days per year
RIC	Relative interest cost
SMP	system marginal price
SY	Switchyard
λ	Intrinsic failure rate
β	Shape parameter
t_k	Failure time
$\delta_i(t_k)$	System in service at time t_k
$n_i(t_k)$	Number of failures of system i at time t_k
χ^2	Chi-square

CHAPTER 1

INTRODUCTION

1.1 Purpose

Hydropower generation is a clean renewable energy technology which has received great attention from the power industry. Hydropower has become the leading source of renewable energy. It provides more than 86% of all electricity generated by renewable sources worldwide. Other sources, including solar, geothermal, wind and biomass, account for less than 14% of renewable electricity production [1]. No fossil fuels are required to produce the electricity, and the hydrologic cycle of earth naturally replenishes the fuel supply. Therefore no pollution is released into the atmosphere and no waste that requires special containment is produced. As the need to reduce dependence on fossil fuels is not optional but indispensible, development and study on renewable energies become more active.

Hydropower is very convenient because it can respond quickly to fluctuations in load demand depending on daily usage, which is the main reason hydropower is used as peaking generators. Also it helps to maintain the stability of the grid. Hydropower is relatively inexpensive once constructed and efficient, converting over 90% energy into electricity. The best fossil fuel plants are only about 50% efficient. Nonetheless, hydropower plants can be dangerous to aquatic life and can cause other environmental concerns such as significant land use, disrupting the natural flow of rivers and impeding the natural flow of sediments.

Limitations for developing hydropower include a lack of potential sites and the tremendous infrastructure costs. The capital cost of infrastructure for hydropower is much more than other types of generation. Hydropower plants are usually not developed for a sole goal, but for the additional purposes of water storage, flood control, and irrigation.

Generally, the life span of a hydropower plant is considered as 30 to 50 years [2], [3]. Before reaching the life span, non-core facilities such as the automatic voltage regulator (AVR), governor, and cooling water pump are replaced after 20 to 30 years of operation. The forced outage rate of an individual power plant over the first 30 years may have been low [4]. Power plants over 30 years old usually conduct a feasibility study for rehabilitation on their entire facilities including infrastructure. Industry data indicate an increasing trend in power plant unreliability beginning at 20 years. By age 35, the forced outage rate increases by 10 percentage points compared to the previous year. Much longer outages occur in power plants older than 20 years [4]. Consequently, the forced outage rate increases exponentially due to these longer outages. Although these long forced outages are not frequent, their impact is immense.

It costs considerable revenue to rehabilitate or modernize hydropower plants. If opportune timing for rehabilitation is missed, an abrupt long-term outage could occur and additional unnecessary repairs and inefficiencies would follow. On the contrary, too early replacement might cause the waste of revenue. Upgrading older power plants improves power plant reliability, efficiency and capability, and lowers maintenance expenses. Also, power plant upgrading significantly reduces the probability of drastically long forced outages for older power plants by initiating preventive measures prior to this wearout phase. The challenge is determining when the best time is to implement rehabilitation. Therefore, it is worthwhile studying how to evaluate aging hydropower plants for modernization.

The operating and maintenance (O&M) records are used as fundamental data for evaluation, with which each facility could be assessed for its current status. Literature shows that reliability concepts have been adopted to evaluate the stator reliability [5], and also economic evaluation is utilized [5]. Also each of the major components could be evaluated from the viewpoint of reliability.

Using a criterion-based assessment for equipment, a more accurate reliability for each equipment and system availability will be presented and an appropriate algorithm for evaluating aging hydropower plants will be suggested. Economic evaluations with case studies and simulations for determining modernization timing will be executed for yielding a concrete indication of when appropriate modernization timing is.

1.2 Scope

Hydropower is the world's largest source of affordable renewable energy and supplies about 20 percent of world electricity [6]. There are various hydropower capacities. Small scale hydropower (< 2 MW-sized) will not be considered in this study because it is not connected to the national grid system and relatively unimportant compared to large scale hydropower. The hydropower plants of Korea Water Resources Corporation (hereafter K-water) will be utilized for this study. K-water's nine major dams are Namgang, Soyanggang, Andong, Daecheong, Chungju, Hapchen, Juam, Imha, and Youngdam Dam, which have 24 synchronous generators. Fault records of the 24 generators will be collected and filtered for only forced outage data.

In this study, only electrical and mechanical parts of hydropower plants are addressed for potential rehabilitation, not public work parts, such as the water-way tunnel, penstock and dam. There are numerous minor fault records, such as alarms, abnormal phenomenon and transient troubles, but these are insignificant and will not be considered as important fault records. Faults causing the forced outage will be mainly dealt with. While collecting and analyzing fault events, only forced outage faults will be considered as raw data for reliability. With each facility fault record, the instant hazard function can be determined. The hazard function is one of the important factors to obtain the reliability of each equipment. This study will show how to evaluate each facility based on reliability engineering. A numerical reliability, obtained by applying reliability concepts, for each equipment is essential to represent the current status of each facility.

The condition assessment methodology of HydroAMP (Hydropower Asset Management Partnership) is used to represent the current status of hydropower plant using O&M records. In this study, three typical cases of power plants are: good, mediocre and bad conditioned hydropower plants.

It is essential to consider the economic aspects when power plants are supposed to be rehabilitated. O&M and repair costs gradually increase after entering the wearout period. An abrupt failure might cause a long-term outage and require additional repair costs. Economic evaluation can be performed by calculating benefits and costs. The benefit-to-cost (B/C) ratio analysis will be used for this purpose. Economic evaluation will provide the favorable timing for replacement.

Reliability, condition assessment and economic evaluation are efficient ways to assess power plants. Combining the three evaluation methods, an algorithm for evaluating aging hydropower plants is presented.

1.3 Problem

The typical shape for failure rate curves is known as the bathtub curve as shown in Fig. 1.1. The first part, known as the early failure period, has a decreasing failure rate. The second part, known as the stable failure period, has a constant failure rate. The final part of the curve is the wearout failure period which has a rapidly increasing failure rate [7]. Likewise, hydropower plants have a similar failure rate curve. The conclusion is that power plants should be replaced before deeply entering the wearout failure period. Aged power plants will experience severe long forced outage, both hardware and personnel related repair costs and lost revenue unless timely modernization is carried out. It takes several years and considerable capital to complete a modernization project. From a contrasting point of view, if a rehabilitation project is undertaken before reaching the wearout failure period, it is not an efficient way to maintain the hydropower plant and consequently it incurs lost revenue.

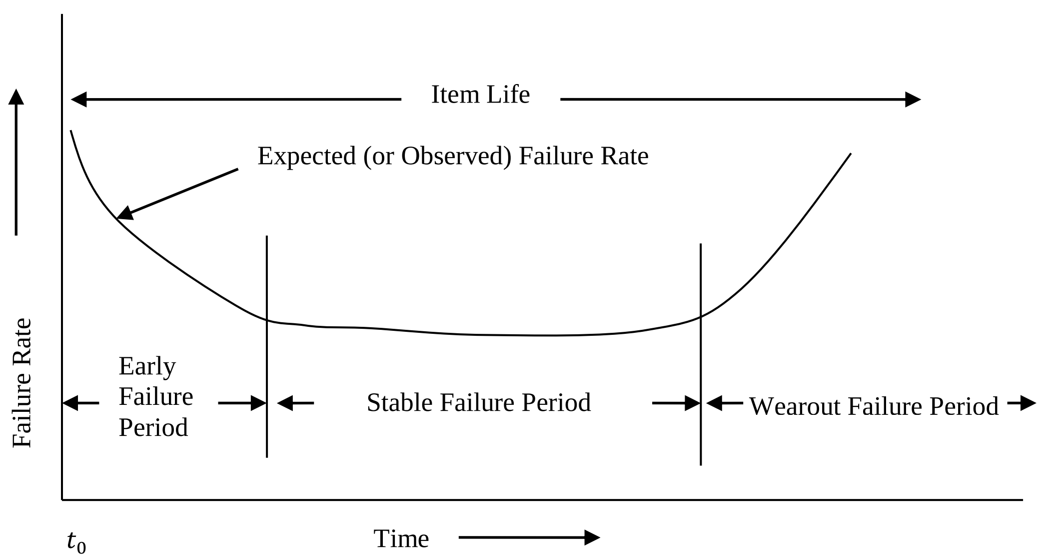

Fig. 1.1 Bathtub curve for failure rates.

It is difficult to know when a power plant reaches the wearout failure period. For that reason, rehabilitation projects are usually delayed because there have not been significant failures yet. Increasing failures and maintenance costs are often main reasons to replace equipment. It is more reasonable and scientific for hydropower plants to represent the probability of failure in the future. Reliability can be expressed by the hazard value. But, it is not easy obtain the hazard values from the manufacturers and even harder to extract those values from power plants. Hydro facilities are not high volume produced products. To obtain many same type, same capacity generators for analysis is very difficult. Also, it is essential for analysis to have fault data which may be sparse. The more power plants that are analyzed and have fault data, the more accurate the reliability data that can be produced.

The usage year and major fault records are important factors to determine the modernization project. It is insufficient to elect rehabilitation solely because of long-term usage. And also, it is not prudent to wait until there are many fault occurrences for each facility to justify modernization. The probability for a very long outage can be sharply increasing unless preventive action is taken. Although a power plant may exhibit an increase in forced outage rate with age, each major component of the power plant can have a different aging characteristic. Modernization timing is an important factor for rehabilitating of hydropower plants.

Therefore, O&M records, equipment reliability, economic evaluation, and simulation for determining of modernization timing are necessary to provide reasonable criteria for aging hydropower plants.

This thesis is organized as follows. In Chapter 2, background information related to reliability engineering is presented. Classical reliability evaluation for power plants is delivered in Chapter 3. In Chapter 4, evaluation methods centered on reliability are applied to actual fault data. Economic evaluations and determinations for modernization timing are presented in Chapter 5. Two case studies are delivered in Chapter 6 followed by conclusions and future study in Chapter 7.

CHAPTER 2

Reliability Engineering

The reliability of a hydropower plant decreases as time goes by. But it is difficult to represent the reliability of a power plant. This chapter gives background information on reliability which is a crucial to evaluate aging hydropower plants.

2.1 Reliability

Reliability is defined in this thesis as "the ability of an item to perform a required function, under given environmental and operational conditions and for a stated period of time" [8]. The term "item" is used here to denote any facility, subsystem, or system in a hydropower plant. The ability of an item to function can be expressed as a probability which represents the chances of the item working properly.

2.2 Probability Concepts

In the classical sense, the term *probability* can be thought of as the expected relative frequency of occurrence of a specific event in a very large collection of possible outcomes. There are two very useful relations often utilized in probability theory. These rules relate the occurrence of two more events. Two rules of considerable importance are now defined. The first rule states that if $P(A)$ is the probability of event A occurring and $P(B)$ is the probability of event B occurring, then the probability of events A and B occurring simultaneously, that is, intersecting, denoted $P(A \cap B)$, is

$$P(A \cap B) = P(A)P(B|A) \text{ or } P(A \cap B) = P(B)P(A|B) \tag{2.1}$$

where $P(A|B)$ is the designator for the "conditional" probability of A, given that event B has occurred. The second important probability formula relates to the situation in which either of two events, A or B, may occur. The expression for this "union" is

$$P(A \cup B) = P(A) + P(B) - P(A \cap B) \tag{2.2}$$

When events A and B are mutually exclusive or disjoint, that is both events cannot occur simultaneously, then $P(A \cap B) = 0$, and

$$P(A \cup B) = P(A) + P(B) \tag{2.3}$$

Furthermore, if both events are also exhaustive in that at least one of them must occur when an experiment is run, then

$$P(A \cup B) = P(A) + P(B) = 1 \tag{2.4}$$

Thus, in this instance event A is the *complement* of event B. Event B can be viewed as the nonoccurrence of A and designated as event $\bar{A}$. Hence, the probability of occurrence of any event is equal to one minus the probability of occurrence of its complementary events. This complement rule has important applications in reliability assessment because a component may either fail (event A) or survive (event $\bar{A}$), resulting in

$$P(\text{Failure}) = 1 - P(\text{Survival}) \tag{2.5}$$

These probability concepts are useful to express reliability concepts [7].

2.3 Reliability Concepts

2.3.1 Reliability function

Life distributions denote the theoretical population models used to describe device lifetimes. The model corresponding to the frequency distribution is the probability density function (PDF), denoted by $f(t)$, where t is time. $f(t)dx$ is the fraction of the population values occurring in the interval dt. The cumulative frequency distribution similarly corresponds to a population model called the cumulative distribution function (CDF) and denoted by $F(x)$. The CDF is related to the PDF via the following relationship

$$F(t) = \int_0^t f(t)dt \tag{2.6}$$

Pictorially, $F(t)$, in other words the *failure function*, is the area under the probability density function $f(t)$ to the left of t. This area is shown in Fig. 2.1.

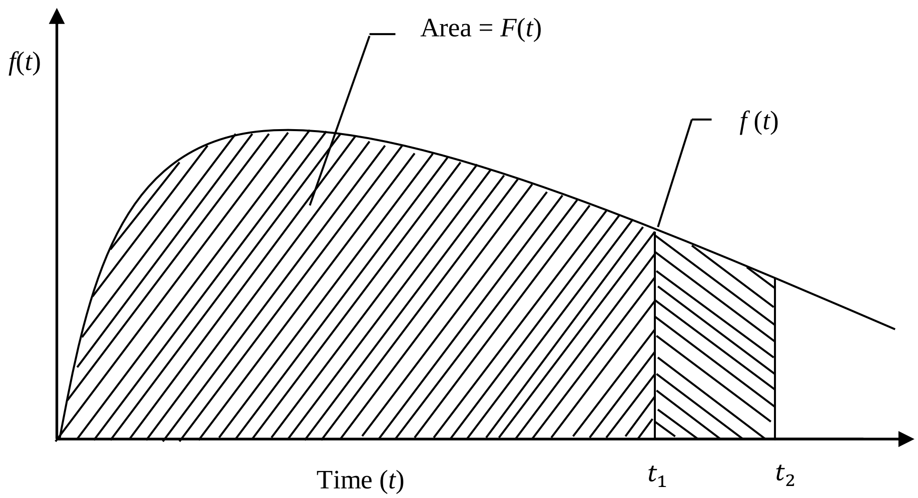

Fig. 2.1. Probability density function, $f(t)$, with corresponding failure function, $F(t)$, shown.

Since $F(t)$ is a probability, the shaded region has an area equal to the probability of a unit failure by time t. $F(t_2) - F(t_1)$ is the probability that a unit survives to time t_1 but fails before time t_2; and it is also the fraction of entire population that fails in that interval. It is often useful to focus on the unfailed units, or survivors, the reliability function (survival function) is defined using Equation (2.5)

$$R(t) = 1 - F(t) \tag{2.7}$$

The reliability function may be thought of in either of two ways: (1) the probability a random unit drawn from the population will still be operating after time t or (2) the fraction of all units in the population that will survive to at least time t [7].

2.3.2 Hazard function or failure rate

$P(B|A)$ denotes the conditional probability that event B will occur, given that A is known to have occurred. $P(B|A)$ is defined as follows

$$P(B|A) = \frac{P(B \text{ and } A \text{ both occur})}{P(A)} \tag{2.8}$$

Using this formula, the probability of failing after surviving up to time t in a small interval of time, Δt, can be calculated as follows

$$P(\text{fail in next } \Delta t | \text{survive to } t) = \frac{F(t + \Delta t) - \mathrm{F}(t)}{R(t)} \tag{2.9}$$

This equation is divided by Δt to convert it to a rate and obtain

$$\frac{F(t+\Delta t)-F(t)}{R(t)\Delta t} \tag{2.10}$$

Let Δt approach zero, the derivative of $F(t)$ can be obtained, denoted by $F'(t)$, divided by $R(t)$. Since $F'(t) = f(t)$, per Equation (2.6), the instantaneous failure rate or hazard rate $h(t)$ is derived [7] as

$$h(t) = \frac{f(t)}{R(t)} \tag{2.11}$$

2.3.3 Cumulative hazard function

In Equation (2.6), the probability density function $f(t)$ is integrated to obtain the cumulative distribution function $F(t)$. Likewise, the cumulative hazard function $H(t)$ can be obtained by integrating the hazard function $h(t)$

$$H(t) = \int_0^t h(t)dt \tag{2.12}$$

The cumulative hazard function also can be expressed by reliability

$$H(t) = -\ln R(t) \tag{2.13}$$

Reliability can be expressed by $H(t)$ using Equation (2.13) as

$$R(t) = e^{-H(t)} \tag{2.14}$$

The mean for a life distribution may be thought of as the population average or mean time to fail. In other words, a brand new unit has this expected lifetime until it fails [7]. The mean time to failure (MTTF) of an item is defined by

$$MTTF = \int_0^\infty tf(t)dt \tag{2.15}$$

2.4 Nonrepairable System

When an item is classified as nonrepairable, studying the item until the first failure occurs is sufficient. In some cases the item may be literally nonrepariable, meaning that it will be discarded by the first failure. In other cases, the item may be repaired, but what is happening with the item after the first failure is uninteresting [8]. There are quite a few probability distributions that are used to model the lifetime of a nonrepairable system. The exponential and Weibull distributions commonly used in industrial areas.

2.4.1 Exponential distribution

The exponential distribution is one of the most common and useful distribution. The probability density function, PDF, for the exponential is

$$f(t) = \lambda e^{-\lambda t} \tag{2.16}$$

Using Equations (2.6) and (2.7), the cumulative distribution function, CDF, is obtained

$$F(t) = \int_0^t f(t)dt = 1 - e^{-\lambda t} = 1 - R(t) \tag{2.17}$$

The hazard rate is obtained using Equation (2.11)

$$h(t) = \frac{f(t)}{R(t)} = \frac{\lambda e^{-\lambda t}}{e^{-\lambda t}} = \lambda \tag{2.18}$$

Also, the cumulative hazard rate, $H(t)$, is expressed with Equation (2.12)

$$H(t) = \int_0^t h(t)dt = \lambda t \tag{2.19}$$

The characteristic property of the exponential distribution is that the hazard rate is constant, which means that the instantaneous probability of having a failure is identical during the entire time period of interest. The units of λ is failures per unit time [7]. The mean time to failure is

$$\text{MTTF} = \int_0^\infty t\lambda e^{-\lambda t}dt = \frac{1}{\lambda} \tag{2.20}$$

The CDF, PDF, and hazard function are graphed when λ=2 in Fig. 2.2.

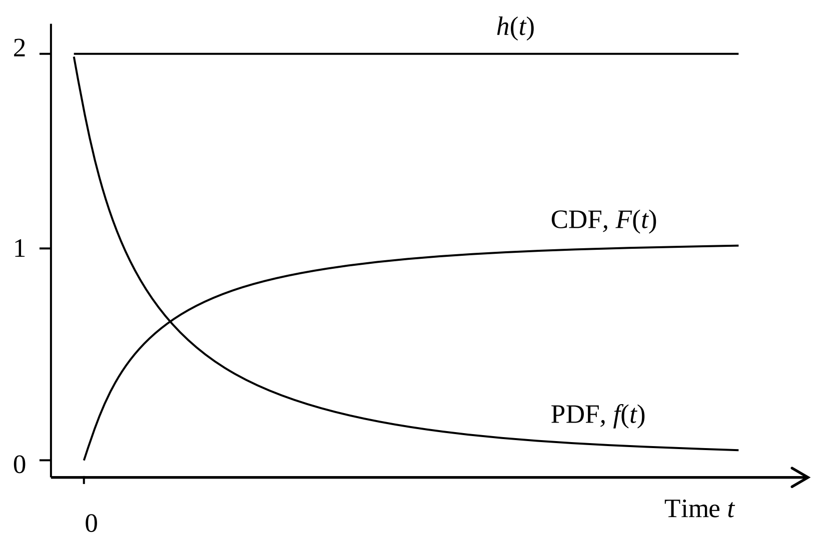

Fig. 2.2. Exponential CDF, PDF, hazard function for λ=2.

2.4.2 Weibull distribution

The hazard rate of the exponential distribution is constant as shown in Equation (2.18). In most cases, hazard rates are not constant. The Weibull distribution has proved to be a successful model for many product failure mechanisms because it is a flexible distribution with a wide variety of possible failure curve shapes. It may be necessary to have a polynomial form for the hazard rate which can be expressed as follows

$$h(t) = \lambda\beta t^{\beta-1} \tag{2.21}$$

where λ is the intrinsic failure rate, and β is the shape parameters.

The cumulative hazard rate is expressed using Equation (2.12)

$$H(t) = \int_0^t h(t)dt = \lambda t^{\beta} \tag{2.22}$$

And the failure function, CDF, is

$$F(t) = 1 - R(t) = 1 - e^{-\lambda t^{\beta}} \tag{2.23}$$

It is important to note that a distribution, which represents lifetimes of units, does not allow for more than one failure for each unit. The failure times are independent of each other. If the failure rate is increasing, then this is indicative of component wearout. For the Weibull distribution, the hazard rate is increasing for $\beta > 1$, decreasing for $\beta < 1$, and constant for $\beta = 1$.

2.4.3 Nelson-Aalen estimator

The Nelson–Aalen estimator can be used to provide a nonparametric estimate of the cumulative hazard rate function based on censored data or incomplete data. The approximate cumulative hazard rate is the sum of hazard values, which is represented as the number of failures over the number of units being tested [7]

$$\widehat{H}(t_i) = \sum_{j=1}^{i} \widehat{P}_j = \sum_{j=1}^{i} \frac{n_j - r_j}{n_j} = \sum_{j=1}^{i} \frac{d_j}{n_j} \tag{2.24}$$

where j=1, 2,… denotes the times to failure such that $j \leq i$; $\widehat{P}_j$ is the hazard value; d_j is the number of failures in the time interval (t_{j-1}, t_j); r_j is the number of items removed at the end of the interval; and n_j is number of units being tested in the interval. Using Equations (2.7) and (2.14), an approximate failure function can be obtained

$$\hat{F}(t) = 1 - \hat{R}(t) = 1 - e^{-\hat{H}(t_i)} \tag{2.25}$$

Equipment reliability or failure probability can be obtained with Nelson-Aalen estimator.

2.5 Repairable System

A repairable system is a system that, when a failure occurs, can be restored to an operating condition by some repair process other than replacement of the entire system [9]. For example, an equipment in a hydropower plant is a repairable system because most failures can be fixed without replacing the entire facility. In order to address the reliability characteristics of complex repairable systems, a process is often used instead of a distribution. The mean cumulative repair function (MCF), denoted by $M(t)$, gives the average or expected cumulative number of repairs per system at time t [7]. The most popular process model is the power law model, which can be written as

$$M(t) = at^b \tag{2.26}$$

where a and b are model parameters.

The MCF in a repairable system is similar to the cumulative hazard function in a nonrepairable system, and the intensity function is analogous to the hazard function. The power law model is widely used for its flexibility just like the Weibull which is popular in nonrepairable systems. The first failure in a repairable system follows the Weibull distribution, then each succeeding failure is governed by the power law model in the case of minimal repair. From this point of view, the power law model is an extension of the Weibull distribution.

2.5.1 Homogeneous Poisson process

Assume a repairable system is tested from the beginning and monitored until time t. During this time, a number of failures, which are random, occurred in the system. If the interarrival times for failures are independent and identically distributed with failure rate λ, this failure process is called a homogeneous Poisson process with intensity λ.

2.5.2 Nonhomogeneous Poisson process

The nonhomogeneous Poisson process (NHPP) is most widespread for modeling the number of repairs now. The advantage of using the NHPP model is that the time-between-repairs does not need to be independently and identically distributed. Consequently, NHPP may more closely approach the real world situation in many cases [10].

2.5.3 Intensity function

The system age when the system is first put into service is time 0. Under the NHPP, the first failure is governed by a distribution $F(t)$ with failure rate $h(t)$. Each succeeding failure is governed by the intensity function $\lambda(t)$ of the process. Let t be the age of the system and Δt is very small. The probability that a system of age t fails between t and $t + \Delta t$ is given by the intensity function $\lambda(t)\Delta t$. The failure intensity $\lambda(t)$ for the NHPP has the same functional form as the hazard rate governing the first system failure. Therefore, $\lambda(t) = h(t)$, where $h(t)$ is the hazard rate for the distribution function of the first system failure. If the first system failure follows the Weibull distribution, the system intensity function can be written under minimal repair as follows [7]

$$\lambda(t) = abt^{b-1} \tag{2.27}$$

The relationship between the MCF and the intensity function, which is similar to Equation (2.22), can be written

$$M(t) = \int_0^t \lambda(t)dt, \qquad \lambda(t) = \frac{dM(t)}{dt} \tag{2.28}$$

This is the power law model. It can be viewed as an extension of the Weibull distribution. If the power law model for the system uses $b = 1$, in other words, the system has a constant failure intensity $\lambda(t) = a$, then the intervals between system failures follow an exponential distribution with failure rate a [7].

2.5.4 Renewal processes

In the nonrepairable process, the working assumption is that times to failure were a truly random sample, independent and identically distributed. The failed parts are not replaced from a single population such as light and fuse lifetime tests. However, many processes need failed parts to be replaced just like automobiles, airplanes, and hydropower plants. Failed parts, which are replaced, can fail again later. If the replacements are always new parts from the same population as the original parts, it is called a renewal process. A renewal process for which the interarrival distribution is exponential is called a homogeneous Poisson process and denoted by HPP. The system intensity function is λ. The mean cumulative repair function is λt according to Equation (2.28).

2.5.5 Nonrenewal processes

If the assumptions that times between failures are independent and identically distributed are no longer valid, the processes are not renewal. Other analysis methods are necessary to deal with more general patterns of sequential repair times. In hydropower plants, small and big faults occur and failed parts are repaired or replaced. It cannot be considered as a renewal process but treated as a nonrenewal process because multicomponent systems and different types of repair actions have a slim chance to have a renewal model. The failure interarrival time of nonrenewal process is not exponential and the intensity function is not constant, therefore a nonrenewal process is not HPP. For a nonhomogeneous Poisson process (NHPP) model the time-between-repairs does not need to be independently and identically distributed. The MCF can be written with Equation (2.26), and its intensity function is Equation (2.27). There is similarity between the intensity function and the hazard rate of the Weibull distribution. But the power relation process is not based on the Weibull distribution, and procedures applicable to the analysis of Weibull data are not correct here. MLEs (maximum likelihood estimates) for the power model were developed by Crow [7]. MLEs exist for two different forms of data truncation: by failure count or by fixed time. Suppose a single system experiences n repairs at system ages t_i, i=1,2,…,n. If the data are truncated at the nth failure, the number of repairs is fixed at n, but the time t_n to the nth failure is random. For this failure truncated situation, conditioned on the system age t_n, the modified MLEs for the power model are

$$\hat{b} = \frac{n-2}{\sum_{i=1}^{n} \ln(\frac{t_n}{t_i})}, \qquad \hat{a} = \frac{n}{{t_n}^{\hat{b}}} \tag{2.29}$$

In a hydropower plant, the collected data are censored by fixed time. In the case of data censored at fixed time (consequently, the number of failures *n* by time *T* is random), conditioned on the number of repairs *n*, the time truncated modified MLEs for the power model are as follows [7],

$$\hat{b} = \frac{n-1}{\sum_{i=1}^{n} \ln(\frac{T}{t_i})}, \qquad \hat{a} = \frac{n}{T^{\hat{b}}}\,. \tag{2.30}$$

2.5.6 Nelson's graph method

Nelson's graph method can be utilized to analyze the failure data of a repairable system. This method is based on the mean cumulative repair function. Nelson's algorithm is employed to estimate the mean cumulative repair function (MCF), $M(t)$. The process of calculating the MCF is summarized in the following five steps [11]:

Step 1: Order failure times

$$t_k: failure\ time$$

Step 2: Count how many systems are in service at these times

$$\delta_i(t_k);\ \text{system in service at time } t_k,$$

where $\delta_i = 1$ (system i in service), $\delta_i = 0$ (system i not in service)

Step 3: Count how many failures

$$n_i(t_k)\text{: number of failures of system } i \text{ at time } t_k$$

$$\sum n_i(t_k)\text{: total number of failures at time } t_k$$

Step 4: Calculate the average number of failures

$$\frac{\sum n_i(t_k)}{\sum \delta_i(t_k)} = \frac{\text{sum of failures}}{\text{sum of systems}} \tag{2.31}$$

Step 5: Estimate the MCF

$$\hat{M}(t_k) = \sum_k \frac{\sum n_i(t_k)}{\sum \delta_i(t_k)} \tag{2.32}$$

The MCF is similar to the cumulative hazard function. Reliability can be obtained from the cumulative hazard function using Equation (2.14). In a similar way the reliability can be expressed by the MCF

$$R(s) = e^{-[M(t+s)-M(t)]} \tag{2.33}$$

where s is time interval [7].

If the starting time is $t = 0$, the reliability can be written as follows.

$$R(s) = e^{-M(s)} \tag{2.34}$$

2.6 Data Type, Confidence Bounds and Zero Failure

The statistical analysis of nonparametric reliability data is complicated because of the diverse forms of data. Other problems include the extent to which a calculated reliability value can be trusted after obtaining the reliability of each item and how to represent the reliability of a non-failed item.

2.6.1 Types of data

Censored Type I tests are terminated based on a designated censored period, and censored Type II tests continue until exactly designated failures occur. In the most general case, every unit under test may have a specified interval during which it might fail, or survive. These intervals and censoring times might be different for each unit. These data are called multicensored [7].

2.6.2 Confidence bounds

It is difficult to know the exact reliability value of the population until the failure data for every single unit in the population are obtained and analyzed. In real cases, the reliability should be estimated based on a sample. Different parameters for the distribution may be obtained each time, and thus slightly different reliability results. However, a range can be obtained within which these reliability values are likely to occur by employing confidence bounds. It is useful to remember that each parameter is an estimate of the true parameter. This range of plausible values is called a confidence interval. For example, the estimate $\hat{\lambda}$ = (number of failures)/(total unit test hours) is a single number or point estimate of λ, which is a rate parameter. The value $\hat{\lambda}$ does not give any measure of precision or risk. No presentation of the test results nor a calculation of $\hat{\lambda}$ is complete without including an interval around that has a high degree of confidence of enclosing the true value of λ [12].

2.6.3 Zero failure

When a test ends after time *t* with none of the *n* test units having failed, the point estimate previously defined is zero. This is not a realistic estimate, as it does not even take into account the number of units under test. An upper 100(1- α) confidence limit for λ is given by

$$\lambda_{100(1-\alpha)} = \frac{{\chi^2}_{2;100(1-\alpha)}}{2nT} = \frac{-ln\alpha}{nT} \tag{2.35}$$

where ${\chi^2}_{2;100(1-\alpha)}$ is the upper 100(1- α) percentile of the chi-square distribution with 2 degrees of freedom; α is the confidence interval; *n* is the number of tested items; and *T* is total testing time [7].

2.6.4 Chi-square goodness-of-fit test

The goodness of fit of a statistical model describes how well it fits a set of observations. The chi-square goodness of fit test decides whether sample data are consistent with a preconceived model under the null hypothesis which is that the model is adequate [7]. A confidence level such as 90% or 95% is picked for enhancing the reliability of a model. The higher confidence level means that very strong negative evidence is necessary to reject a hypothesis. The simplified steps for testing goodness of fit are as follows:

Step 1: Group the data, if necessary, into intervals as if preparing to plot a histogram.

Step 2: Based on the null hypothesis, calculate the expected number of observations in each interval.

Step 3: Calculate χ^2 statistics

$$\chi^2 \text{ Statistics} =$$

$$\sum_{i=1}^{i=n} \frac{(actual\ number\ of\ failures(i) - expected\ number\ of\ failures(i))^2}{expected\ number\ of\ failures(i)} \tag{2.36}$$

Step 4: Calculate the p-value, ${\chi^2}_{2;100(1-\alpha)}$, and then compare with α.

If a confidence level is 95%, the α-level is 0.05. The p-value, $\chi^2_{2;100(1-\alpha)}$, is calculated by the chi-square test. If the p-value is less than α, the null hypothesis, presumed to be true until statistical evidence nullifies, is rejected (i.e., that the statistical model is deemed invalid).

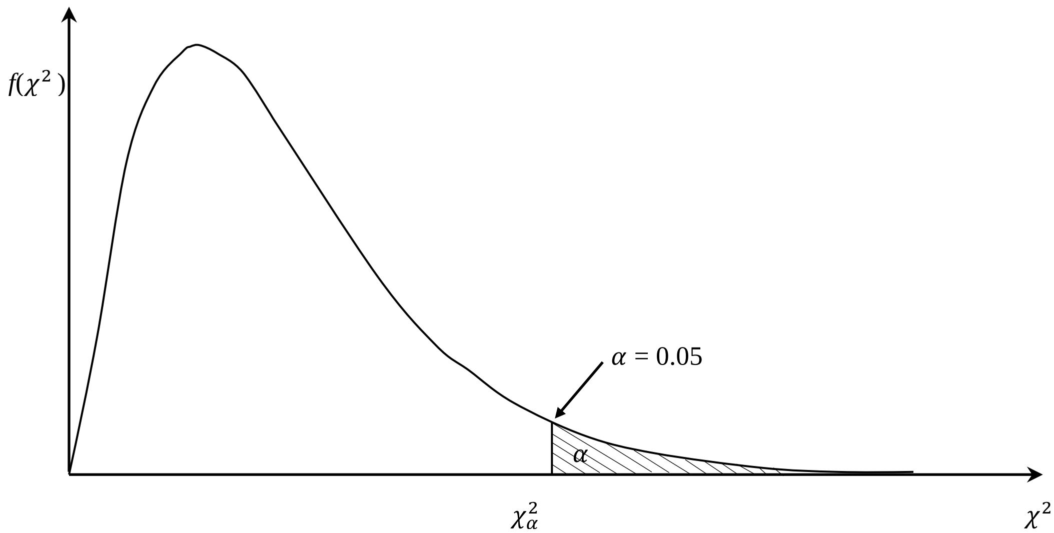

Fig. 2.3. Chi-square distribution.

CHAPTER 3

Classical Reliability Evaluation for Power Plants

3.1 Introduction

The best and most economic means of affecting the upgrade of hydropower plants have been investigated by power generation companies, research centers and consultants for better economic profits. The initial evaluation of the viability and the necessity for upgrading are not always straightforward [13]. As power plants enter the wearout period, future decisions should be decided including retirement, rehabilitation, life extension, modernization and redevelopment. *Rehabilitation* means to restore functionality of safety, reliability, maintainability, or operability of a facility [14]; and *modernization* is the improvement of level of service, and cost of service, measured by plant output and/or flexibility. *Redevelopment* is defined as "replacement of an existing plant with a new structure, units and infrastructure while maintaining their water retaining facilities" [15]. The key is to focus on those opportunities that are cost effective in improving reliability, availability, efficiency, and maintenance costs. The general conclusion from power plant retirement policies is that it is far more economical to extend the life of older power plants than to retire them [16].

In this chapter, maintenance strategies, facilities assessments and modernization are discussed. Retirement, removing the facility from service, and redevelopment, installing a new power plant with new structure, are not addressed by in this thesis.

3.2 Maintenance

Maintenance is defined by the International Electrotechnical Commission (IEC) as "the combinations of all technical and corresponding administrative actions, including supervision actions, intended to retain an entity in, or restore it to, a state in which it can perform its required function" [7]. Availability is defined as "the ability of an item (under combined aspects is reliability, maintainability, and maintenance support) to perform its required function at a stated instant of time or over a stated period of time" [7] and can represent the status of maintenance. The main reliability measure for a maintained item is the availability, $A(t)$. The availability at time t is

$$A(t) = P(\text{item is functioning at time } t) \tag{3.1}$$

The average availability A_{av} denotes the mean time that the item is functioning. For an item that is repaired to "as good as new" condition every time it fails, the average availability is [7]

$$A_{av} = \frac{MTTF}{MTTF + MTTR} \tag{3.2}$$

where MTTR is the mean time to repair. The total mean downtime, MDT, is the average time that the item is in a nonfunctioning state. The MDT, which includes time to detect and diagnose the failure, logistic time, and time to test and startup the item, is usually significantly longer than the MTTR. When a new item, which failed, is put into operation again, it is considered to be "as good as new". The mean up-time, MUT, of the item is equal to mean time to failure, MTTF. The mean time between failures, MTBF, is the sum of the MDT and the MUT. The time concepts of a repairable item are represented in Fig. 3.1.

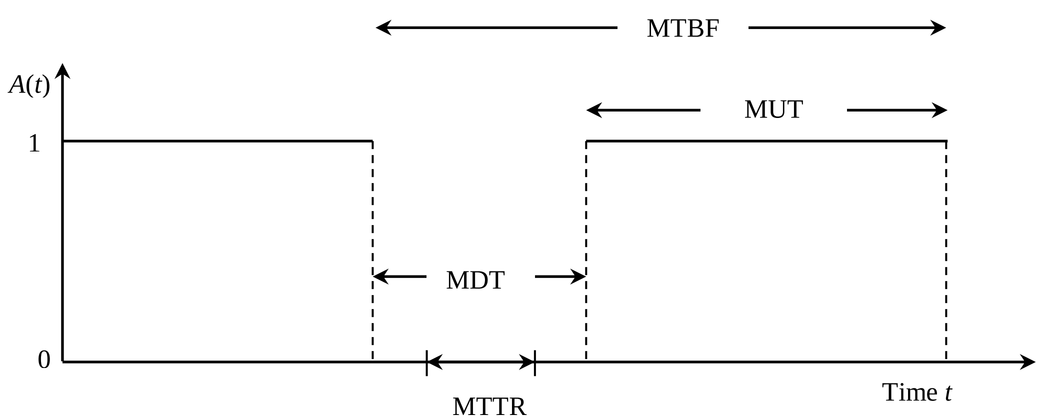

Fig. 3.1. Average "behavior" of a repairable item and main time concepts [7].

The purpose of maintenance is to extend equipment lifetime or at least the mean time to the next failure. Effective maintenance policies can reduce many undesirable faults and the frequency of service interruptions. Maintenance directly affects component and system reliability. If little and inappropriate maintenance is done, this may cause many costly failures and unreliable system performance. On the other hand too much maintenance may improve the reliability of a system but maintenance costs will rapidly increase. It is necessary to obtain a balanced expenditure for maintenance. Maintenance is just one of the tools for ensuring satisfactory component and system reliability. In fact, maintenance is becoming an important part of what is often called asset management [17].

3.3 Asset Management

The oldest replacement schemes of asset management are the age replacement and bulk replacement policies. In the first, a component is replaced at a certain age or when it fails, whichever comes first. In the second, all devices in a given class are replaced at predetermined intervals, or when they fail. Newer replacement schemes are often based on probabilistic models and can be quite complex. A classification of the various maintenance approaches is presented in Fig. 3.2.

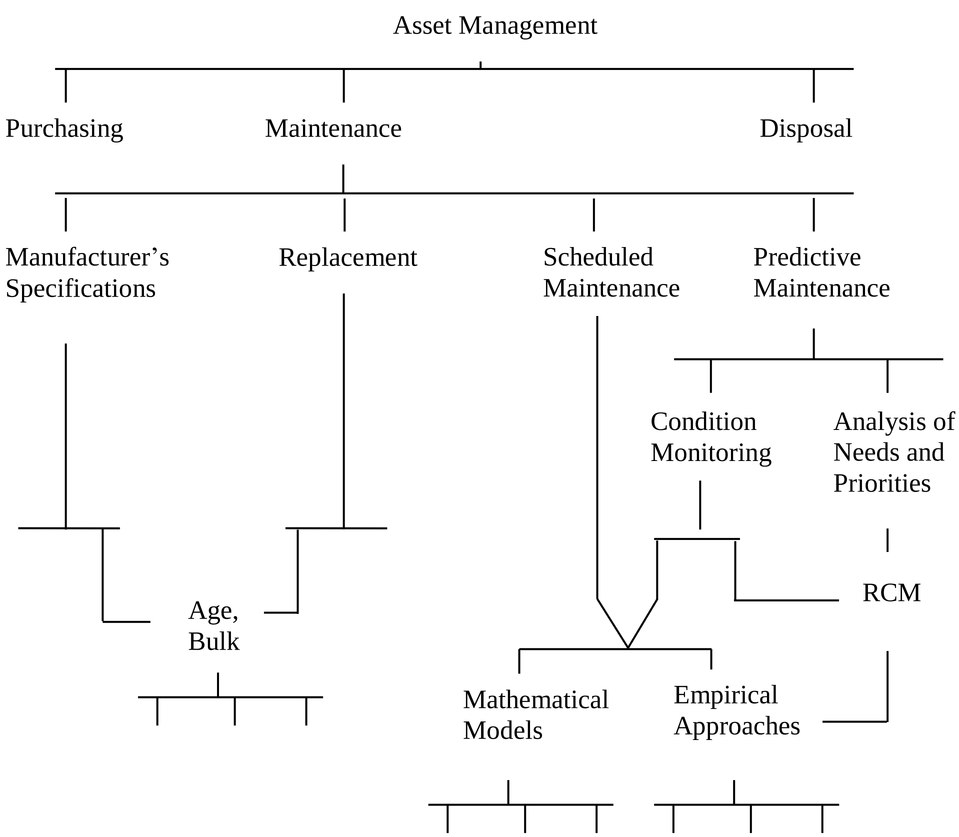

Fig. 3.2. Overview of maintenance approaches [17].

The predictive maintenance routines include a group of programs named Reliability-Centered Maintenance, commonly abbreviated as RCM. Its application requires experience and judgment at every turn. Besides, it can take a long time before enough data are collected for making such judgments. It is necessary to evaluate the current status of equipment for maintenance. A criterion based analysis is one of the methods to evaluate the current status of equipment and systems [17].

3.4 Criterion Based Analysis

Old and deteriorating hydropower plants pose considerable risk to have failures in their equipment and may result in low generation unit availability. It is essential for assuring the continued viability and cost-effectiveness of existing hydropower assets to invest in replacing, repairing, and refurbishing hydroelectric generation and auxiliary equipment. The plan for capital investments in a hydropower plant should consider many factors, some of which are contrary to one another, which must be balanced [18].

One asset management method is suggested by HydroAMP. The four organizations, Bureau of Reclamation, Hydro-Quebec, U.S. Army Corps of Engineers, and Bonneville Power Administration, involved in the "Hydropower Asset Management Partnership (HydroAMP) joined together to create a framework to streamline and improve the evaluation of the condition of hydroelectric equipment and facilities in order to support asset management and risk-based resource allocation" [18]. HydroAMP organizations developed condition assessment guides for key hydropower plant components, dividing them into two classes. "The first equipment class includes major power components, such as circuit breakers, excitation systems, generators, governors, transformers, and turbines. The second class consists of auxiliary components, including batteries, compressed air systems, cranes, emergency closure gates and valves, and surge arresters. A two-tiered approach for assessing hydropower equipment condition was developed" [18]. Tier 1, the first equipment class of the assessment process, relies on normal and routine tests and inspection results of operation and maintenance (O&M) activities. To obtain a Condition Index (CI), test results should be combined with equipment age, O&M history, and other relevant condition indicators. The second phase of the condition assessment, or Tier 2, utilizes non-routine tests and inspections to refine the CI based on the Tier 1 assessment. Tier 2 tests often require specialized expertise or instrumentation, depending on the problem or issue being investigated. In this thesis, only Tier 1, which can be easily obtained and available for assessing current equipment, is utilized for evaluating K-water hydropower facilities with each equipment reliability, which is obtained by fault data analyses, to provide a more suitable reliability for the hydropower plants.

3.5 Evaluation for Power Plants

Power utility companies have investigated how to maximize the benefits from their investments by extending the life of their power plant and/or modernization. Upgrading and life extension would only be executed in the case of a cost effective plan with comparisons to other alternatives. Before implementing the modernization of a power plant, unit selection should be decided in addition to what extent these units are economically justified in being upgraded [16].

3.5.1 Power plant performance trends

Two key points for modernization are: (1) restoration of power plant performance to “as-new” conditions and (2) enhancement of power plant performance with new technology features. The steam power plant forced outage rate increases with plant age as illustrated in Fig. 3.3. “The plant forced outage rate for units in the 50 MW to 100 MW size range was analyzed from 15 years of North American Electric Reliability Council data. From an age of 20 years to 40 years, the forced outage rate of power plants increases 7 percentage points” [16].

The forced outage rate of turbine-generators is very low up to age 20. But after 25 years it increases rapidly. The maintenance repair cost of older units generally increases with age. Failure of major components also requires longer time and greater cost to repair or replace [16].

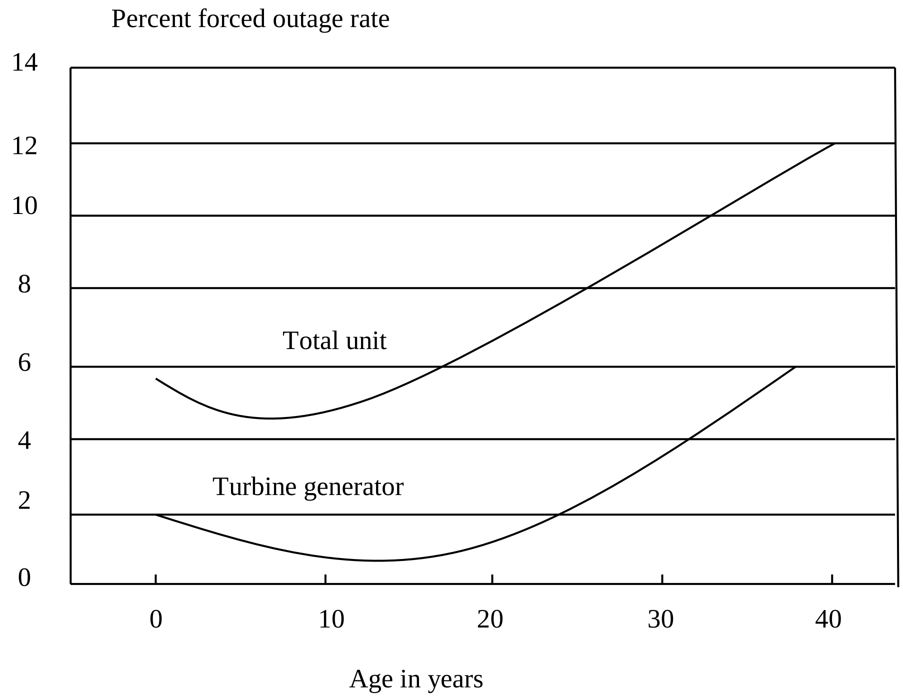

Fig. 3.3. Steam plant forced outage rate trend [16].

3.5.2 New technology

Francis turbines were invented in the early 1800s and are now widely used in hydropower plants. The peak efficiency of the Francis turbine was approximately 82% at that time. The efficiency of Francis turbines has increased dramatically over the years with advanced design and up to 95% efficiency. Efficiency increase in Francis turbines is represented in Fig. 3.4. The efficiency of Propeller and Kaplan turbines has also increased over the years.

The potential efficiency gain (from tests or graphs such as Fig. 3.3), based on the size and age of the unit, is presented in Table 3.1. If the conditions of a given power plant agree with the table, this indicates the potential efficiency increase and the necessity of modernization.

Table 3.1. Efficiency gain from turbine replacement [3].

Unit size	Efficiency gain from turbine replacement that indicates feasibility	Age Indicator that indicates feasibility
< 10 MW	> 5%	> 60 years
10-50 MW	3-4%	> 45 years
50-100 MW	2-3%	> 30 years
> 100 MW	2%	> 30 years

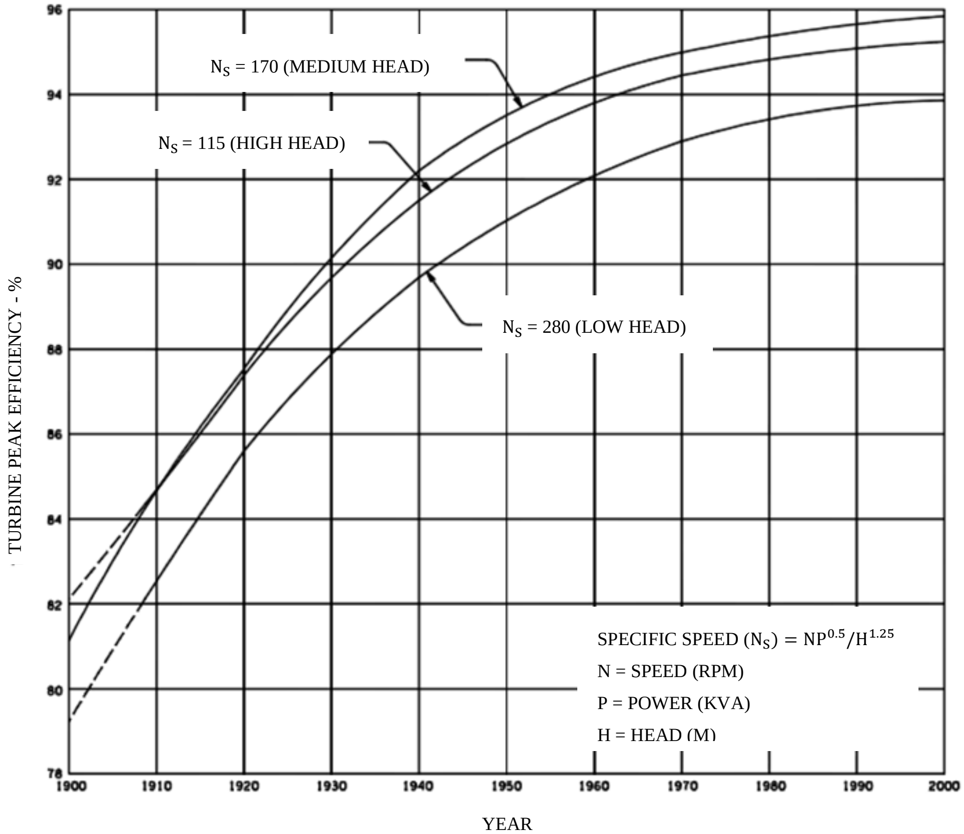

Fig. 3.4. Francis turbine efficiency trends [3].

The HydroVision 98 benchmarking survey indicates significant improvements in capacities and efficiencies resulting from turbine and generator modernization, as shown in Table 3.2.

Table 3.2 Hydro life extension modernization [19].

	Percentage of Projects with Reported Increases	% Increase Average	% Increase Range
Turbine Capacity	42	23.8	1-230
Generator Capacity	29	20.1	1-67
Turbine Efficiency	22	6.1	3-15
Generator Efficiency	3	1.5	1-2

3.5.3 Life of hydropower plant

Typical life expectancies of mechanical parts, turbine, gates, and valves in a hydropower plant are presented in Table 3.3, which can assist engineers in determining an approximate remaining life for individual equipment with conditions and performance assessment.

Table 3.3. Life of hydropower plant systems [3].

Plant Systems	Economic Life (years)	Considerations which Affect Component Life
Turbines Francis, Propeller Kaplan Pelton Pump-turbines	 50 30-40 40-50 25-33	Safety of operation, leakage, cavitation damage, erosion, corrosion, cracks, decreased efficiency, technology level used in design
Other Mechanical Installations Gates, butterfly valves, special valves, cranes, auxiliary mechanical equipment	25-50	Quality of material, condition, safety of operation, quality of design, design stresses

3.6 Economic Evaluation

It is well known that as a power plant enters a wearout failure period, it is likely to have many failures, for which an outage will be much longer and severe than the stable failure period shown in Fig. 1.1. Also, with replacing, upgrading, and modernization, deteriorated viability and reliability can be recovered, and economic benefits and stable power supply can be obtained. The capital investment is decided by what equipment and the extent to which units are replaced and upgraded considering replacement costs, interest rates, O&M cost, and modernization benefits, which include increased capacity and future power revenues. An economic evaluation will determine when the best time is for executing the modernization of a power plant. Modernization will improve the plant heat rate, operating flexibility, efficiency, reliability and reduce O&M costs. The key is to focus on cost effectively improving reliability, availability, efficiency, and maintenance costs. The economic analysis focuses on two segments: (1) the performance characteristics of the existing component and (2) the performance characteristics of the upgraded component. The performance characteristics of the existing component are failure modes, probabilities and their consequences. Failure modes are distinct mechanisms of potential failure over the evaluation period. The failure probability represents the chance of component failure in each failure mode over the evaluation period. A failure consequence is expressed as outage time, efficiency loss, and repair costs of a component in each failure mode. The component failure probability can be determined based upon inspections of components, review of the operating history and failures of similar components in other power plants [16]. In other words, the component failure probability can be obtained with criterion based analyses of items and equipment reliability. The economic worth values are shown in Fig. 3.5.

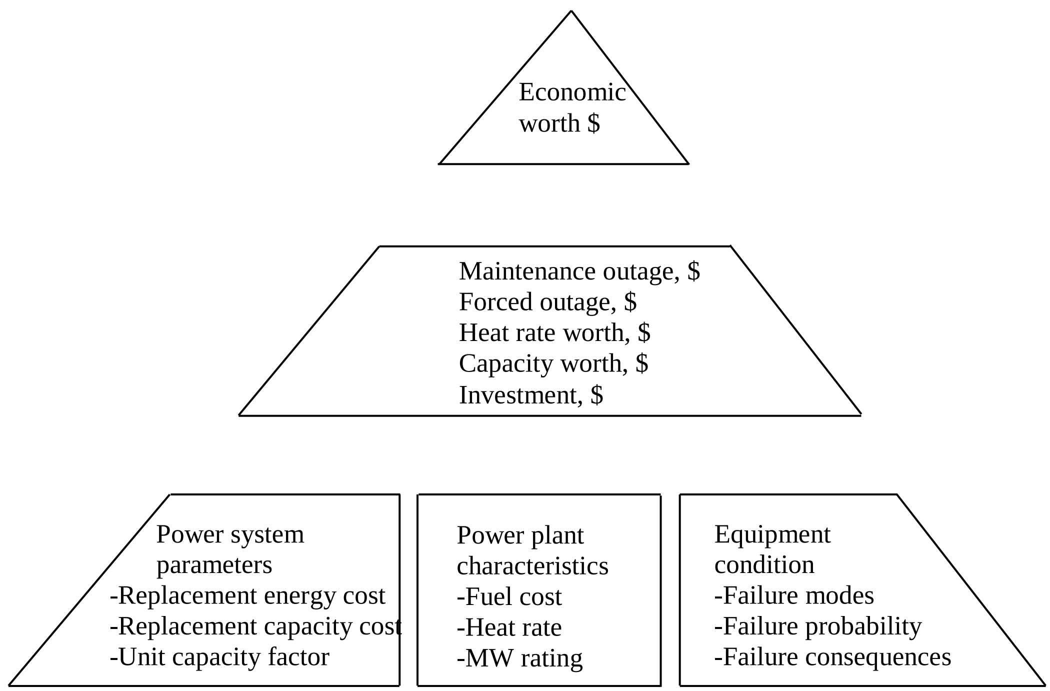

Fig. 3.5. Computation of economic worth values [16].

3.6.1 Economic equivalence

In modernization projects, power companies invest a lot of revenue for modernization during the first several years of the projects. But benefits will be returned over the lifetime of the power plants. It is necessary to compare various cash flows. Calculations for determining the economic effect of one or more cash flows are based on the concept of economic equivalence. “Economic equivalence exists between cash flows that have the same economic effect and could therefore be traded for one another" [20]. The present time is commonly used to compare the value of alternative cash flow, which is called the present value of the cash flows, or some point in the future, which represents their future value. Two relationships are denoted as follows. The present value (*P*) is converted to the future value (*F*) with

$$F = P(1 + i)^N \tag{3.3}$$

where *I* is the interest rate, and *N* is the number of periods [20].

3.6.2 Net present value analysis

Companies use financial assessments of various ideas and modernization projects. One of the most widely used techniques for comparing the financial benefits of long term projects is net present value (NPV) analysis. The NPV analysis is a technique of estimating future net cash flow in terms of the present value of money [21]. The interest rate is often referred to as either a required rate of return or minimum attractive rate of return (MARR). The MARR changes over the life of a project. But a single rate of interest is used in calculating the NPV. The net cash flow is denoted as [20]

$$\text{Net cash flow} = \text{cash inflow} - \text{cash outflow} \tag{3.4}$$

3.6.3 Benefit to cost ratios

A popular method for deciding upon the economic justification of a public project is to compute the benefit to cost (B/C) ratio. Let *B* and *C* be the present values of benefits and costs defined, respectively, as

$$B = \sum_{n=0}^{N} b_n(1 + i)^{-n} \tag{3.5}$$

$$C = \sum_{n=0}^{N} c_n(1 + i)^{-n} \tag{3.6}$$

where b_n= benefit at the end of period *n*, $b_n \geq 0$; c_n= expense at the end of period *n*, $c_n \geq 0$; *N* = project life.

The B/C ratio is therefore

$$BC(i) = \frac{B}{C} \tag{3.7}$$

If the ratio is 1, the equivalent benefits and the equivalent cost are equal. This represents the minimum justification for projects.

3.6.4 Investment payback analysis

Investment payback analysis evaluates the number of years of cumulative annual benefits required to equal (payback) the investment cost [16]. If a company makes an investment decision solely on the basis of the payback period, it considers only those projects with a payback period shorter than the maximum acceptable payback period [20]. Fig. 3.6 presents the results of an example. The investment payback is five years in this example.

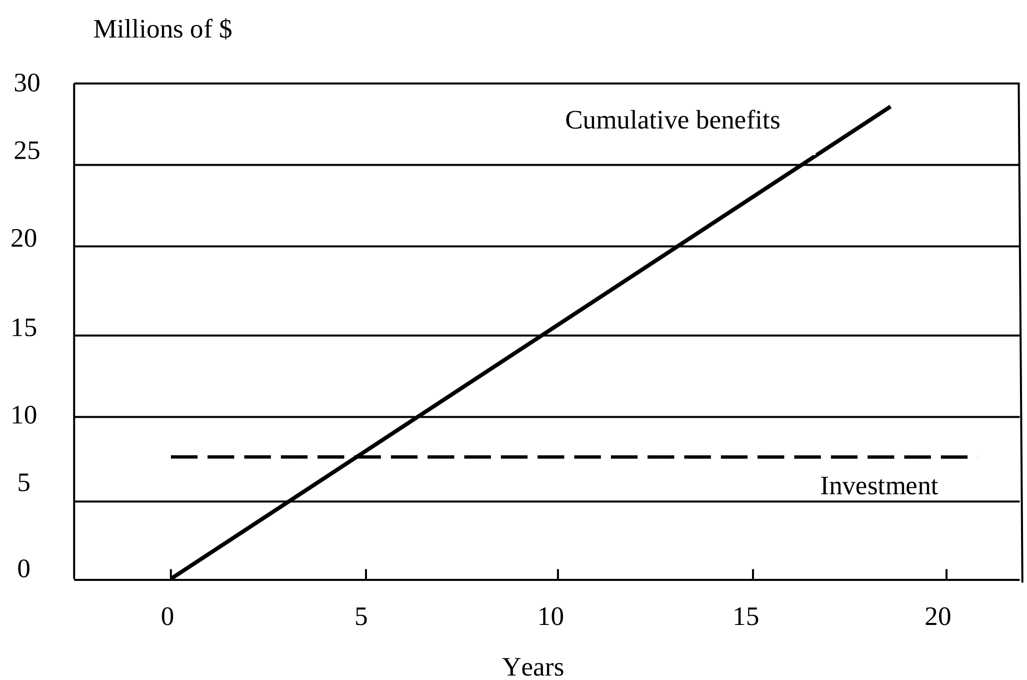

Fig. 3.6. Investment payback hydropower plant rotor example.

CHAPTER 4

EVALUATION METHODS CENTERED ON RELIABILITY

4.1 Methodology

A power plant and its equipment deteriorate and their physical condition becomes worse with operating age because of wear from use, failures in service, inadequacy in performance, and obsolescence. To what extent can equipment in a power plant be trusted as time goes by? One method is to calculate the reliability of equipment. It is not a simple task to quantify the reliability of equipment and the entire hydropower plant. It may not be possible to obtain each reliability datum from manufacturers, who seldom want to reveal and provide these data.

In this investigation a stochastic measure is utilized to obtain the reliability of equipment and the entire hydropower plants. Twenty-four K-water generators comprise the population for quantifying the reliability of each equipment. The fault data of each power plant are collected, within which only forced outage faults are considered as raw data for reliability assessment. Other transient faults and faults not causing outages are disregarded. The representative reliability, which is obtained by the fault analysis of the 24 generators, is used to denote the extent a general facility depicts a particular plant's reliability throughout its operation years. The representative reliability is addressing not the reliability of each equipment and power plant but the representative reliability of all 24 generators. The criterion-based analysis of HydroAmp is a good complement for providing more accurate availability of each power plant. With results of each criterion-based analysis, the representative reliability can be modified to more accurately denote the condition of each power plant.

In this chapter, evaluation methods for aging hydropower plants are described using equipment reliability, system availability and a criterion-based assessment. Economic evaluations and determinations for modernization timing are discussed in Chapter 5.

4.2 Reliability Algorithm

The important facilities in a hydropower plant are stator, rotor, turbine, main transformer, excitation system, governor, main circuit breaker (CB), and switchyard CB. With Nelson's graph method, described in Section 2.5.6, the MCF of each facility can be obtained. The reliability of each facility is obtained with Equation (2.34). The calculated reliability is the representative reliability of the 24 generators. Therefore, it is necessary to use a complementary method to obtain a more accurate reliability for each power plant. Condition values of each facility can be obtained considering equipment usage age and the criterion-based analysis of HydroAmp's Tier 1 values.

Tier 1 values can be acquired by test and inspection results that are normally obtained during routine operation and maintenance (O&M) activities. Data sources of Tier 1 are physical inspection, equipment age, number of operations, O&M history, and relevant condition indicators. The condition index is scored on a 0 to 10 numerical scale. A higher number means better condition. Tier 2 utilizes non-routine tests and inspections to refine the condition index obtained during the Tier 1 assessment. Tier 2 tests often require specialized expertise or instrumentation and require an outage for performing tests to investigate problems [18]. In this thesis, only the Tier 1 method, which can be easily obtained with routine O&M, is utilized for representing equipment reliability. Needless to say, if the Tier 2 method is utilized, the results of the condition assessment should be more accurate. The reliability algorithm developed here is shown in Fig. 4.1.

The reliability, obtained by Nelson's graph method, is the representative reliability of 24 generators. It is desirable for the reliability of each power plant to incorporate the condition value of each facility as calculated by the Tier 1 assessment. The condition index (CI) of equipment, using a 0 to 10 numerical scale, results in the ratings as shown in Table 4.1.

Table 4.1. Condition index ratings of equipment

Condition index (CI)	Rating
$7 \leq CI \leq 10$	Good
$3 \leq CI < 7$	Fair
$0 \leq CI < 3$	Poor

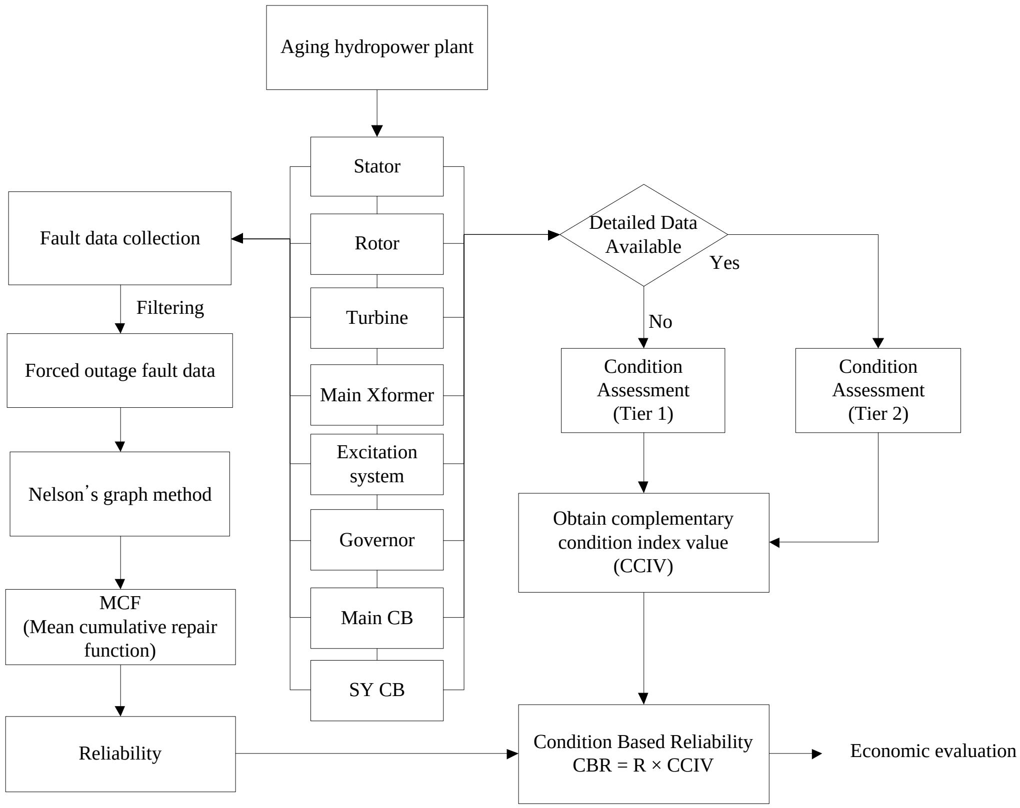

Fig. 4.1. Reliability algorithm.

Equipment assessments, except circuit breakers, have an age based score. Circuit breaker assessment is based on the number of operations. The age scoring table for one of the assessed items, specifically rotor windings, is presented in Table. 4.2.

Table 4.2. Rotor winding age scoring

Age	Rotor condition indicator score
Under 40 years	3
40 to 50 years	2
50 to 60 years	1
Over 60 years	0

Table 4.3 presents the condition index of a rotor winding if it is exclusively assessed by rotor winding age. An age condition index can be obtained from the usage age of a rotor winding using

a fitting graph. The graph for age condition index of a rotor is presented in Fig. 4.2. The condition index of a rotor winding starts with 10 until 40 years and declines to a condition index of 7 after 50 years of usage. The condition index for other equipment is found in Appendix A.

Table 4.3. Condition index based on a rotor age exclusively

Age	Condition index
Under 40 years	10
50 years	7
60 years	3

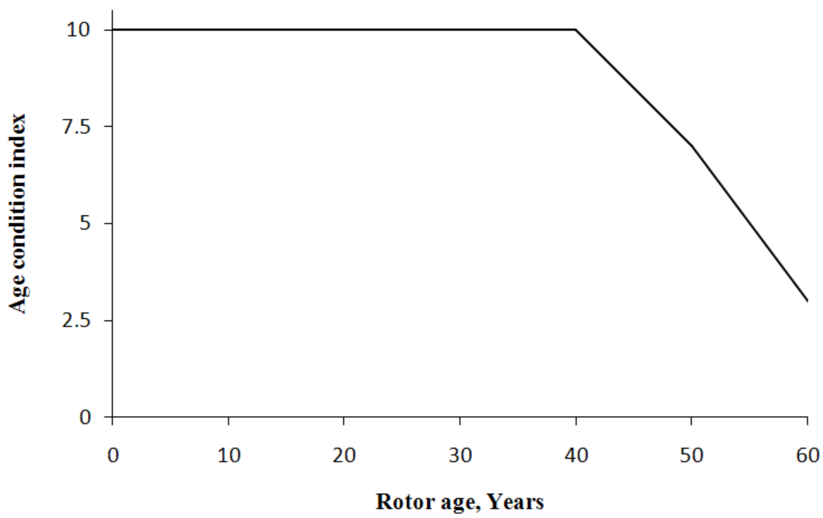

Fig. 4.2. Rotor age condition index value vs. years.

After obtaining the age condition index, the rotor condition index value can be obtained to represent its condition with the Tier 1 assessment. The complementary condition index value (CCIV) is introduced in this thesis and is defined as

$$\mathrm{CCIV} = \frac{\text{Condition index value}}{\text{Age condition index value}} \tag{4.1}$$

The complementary condition index value is utilized to calculate condition-based reliability (CBR) which is defined in this thesis as

$$\mathrm{CBR} = \text{Reliability} \times \mathrm{CCIV} \tag{4.2}$$

The condition-based reliability of other equipment is obtained in a similar way.

4.3 Equipment Reliability

In hydropower plants there are many facilities, including generators, turbines, auxiliaries, spillways, cranes, and gate facilities. Major facilities used for reliability calculations in a hydropower plant are generators (rotor and stator), turbines, excitation systems, governors, transformers, and circuit breakers. The circuit breaker can be divided into the main circuit breaker (main CB) and the switchyard circuit breaker (SY CB), the main CB operates at every unit start and stop, and the SY CB operates when maintenance and powerline changes are needed. Therefore, the SY CB has fewer operation times than the main CB.

The commercial operation starting dates of the 24 specimen generators were different, and the manufacturers of those generators are not all the same. For a stochastic analysis, it is assumed that the commercial operation years of the power plants and the manufacturers of facilities are identical. When a fault happened, failed equipment was partially replaced with spare parts or repaired until the complete replacement of equipment. Therefore, hydropower facilities can be regarded as a repairable system. The replaced facilities are also included as additional specimens for obtaining equipment reliability. Table 4.4, ordered by commercial operation dates, lists the replaced years of equipment for each power plant. The eleven power plants are named as *A*, *B*, *C*, . . . , *J* for convenience. A singular year in a cell in Table 4.4 represents two units being replaced in that year. If two years are shown, then each year represents one unit of being replaced in each year.

Fault data, treated as repairable data, of 24 generators of K-water are collected and filtered for only forced outage data. Some power plant facilities do not have component failures or the same observation time. Each failure data table, representing how many failures per year of each facility, is obtained based on the forced outage data, which is called multicensored data. The mean cumulative repair functions (MCF) of each facility can be achieved with the failure-data tables, using Nelson’s graph method. The power law model, a popular model for a repairable system, can also be obtained using Equations (2.26) and (2.30). After fitting power law parameters a and b, the reliability of each facility can be calculated with Equation (2.34).

Table 4.4. Dates of replaced equipment in hydropower plants.

Power plant	I	J	A	D	B	C	E	F	H	G
Commercial Operation	1969	1973	1976	1980	1985	1985	1987	1989	1991	1992
Rotor		1991 1993								
Stator		1991 1994								
Excitation System	1998	1991 1995	2001	2003	2006	2007				2010
Governor	1998	1996 2000	2010	2006	2007	2007				2008
Main Transformer	1998			2003 2007						
Main Circuit Breaker	1998	1998 1996	2000	2006	2003 2003 2004 2005	2000	2006	2008 2009	2007 2004	
Switchyard Circuit Breaker	1998	1994 1998	1998							
Turbine		1996 2000								

Appendix B contains detailed tables with the fault data for all 24 generators. Units are denoted as numbers and replaced items are suffixed with "*R*" representing replacement. The following subsections summarize the results of analyzing the fault data from Appendix B.

4.3.1 Stator

The stators have three fault points among 24 generators, which means the stator is one of the most reliable facilities in hydropower plants. The power function line fit for the stator is obtained using software, "Weibull ++" [22], and is redrawn with Excel for better viewing. The MCF of the stator is presented in Fig. 4.3. The confidence level of the stator reliability is 95%, in other words the α-level is 0.05. The result of the chi-square goodness-of-fit is that the p-value of 0.605 is greater than α, therefore the null hypothesis, presumed to be true until statistical evidence nullifies, is accepted.

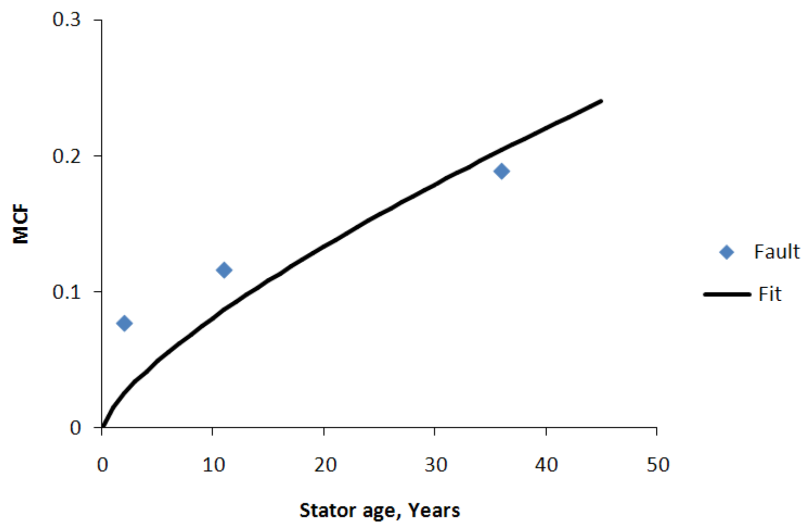

Fig. 4.3. The MCF of the stator.

4.3.2 Rotor

The rotors have only one fault. Therefore, the maximum likelihood estimate (MLE) function of Weibull ++ is used to obtain a fitting graph of the rotor shown in Fig. 4.4. A mathematical expression of MLE is known as likelihood function which maximizes the sample likelihood. The sample data have no fault before 36 years, therefore the MLE fit is zero until 25 years, and then the chance of having a fault increases rapidly because of only one fault datum. If there were at least one additional fault datum, the fitting graph would be linear and increase stably.

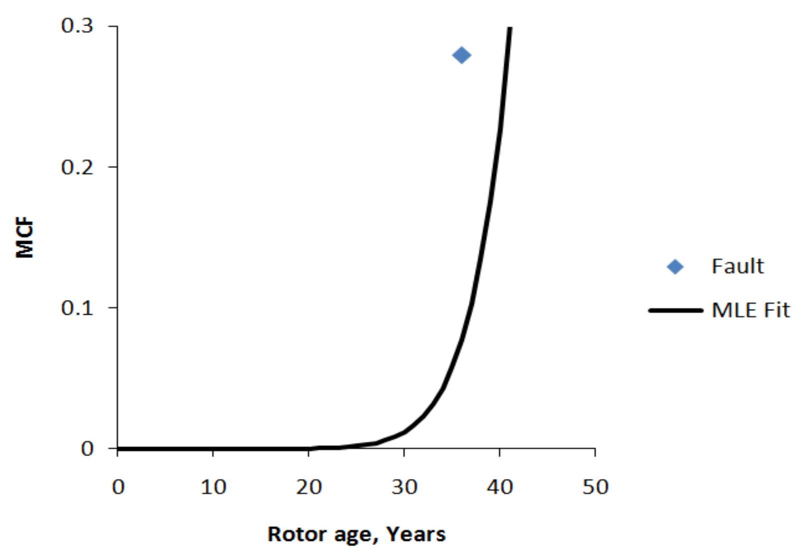

Fig. 4.4. The MCF of the rotor.

4.3.3 Turbine

The turbines have four forced outage faults which is relatively few. The fitting graph, presented in Fig. 4.5, shows that the MCF increases rapidly after 20 years of usage, but the value of the MCF is not high. Except for the rotor, all MCF line fits are based on the power law model given in Equation (2.26).

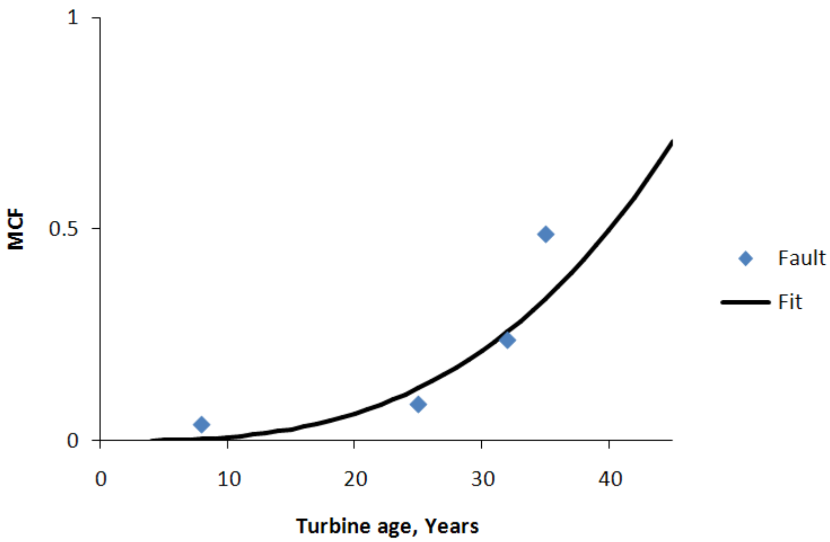

Fig. 4.5. The MCF of the turbine.

4.3.4 Transformer

Transformers are relatively stable equipment in hydropower plants. The MCF of the transformer is shown in Fig. 4.6. The fault event plot of the transformer is provided in Fig. 4.7. Power plant D has relatively many faults; therefore, it had early transformer replacements. Power plant D has an abnormally large number of transformer faults as shown in Fig. 4.7. It is reasonable to represent the transformer MCF and reliability without the power plant D fault data. The transformer MCF without the plant D fault data is presented in Fig. 4.8.

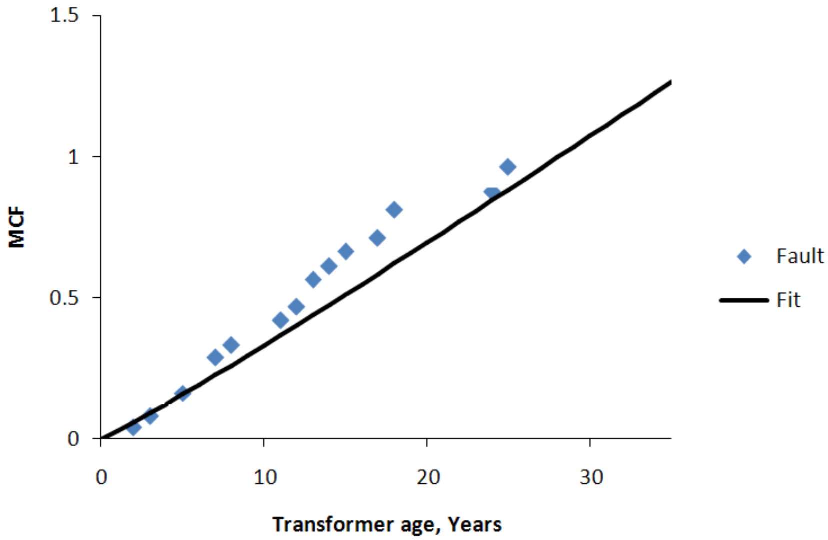

Fig. 4.6. The MCF of the transformer.

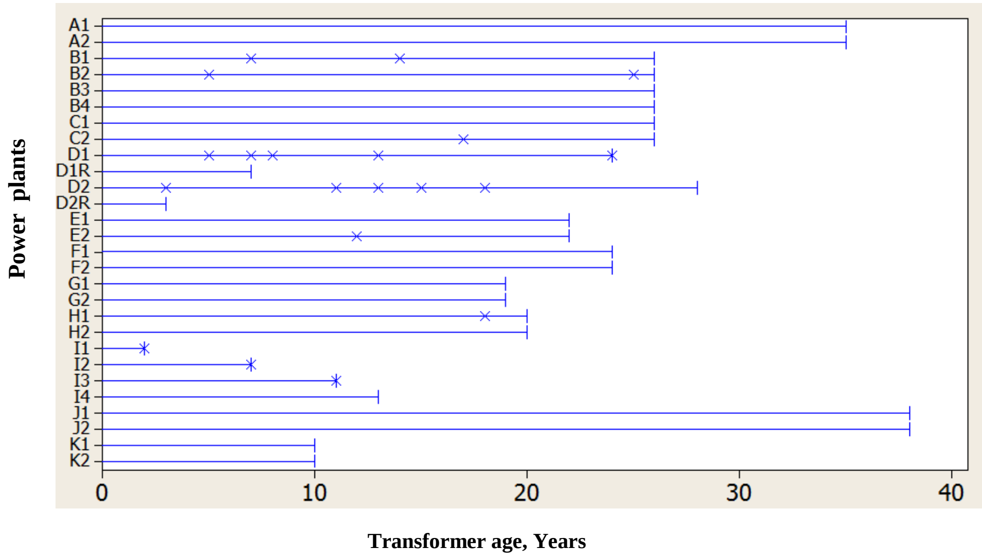

Fig. 4.7. The fault event plot of the transformers.

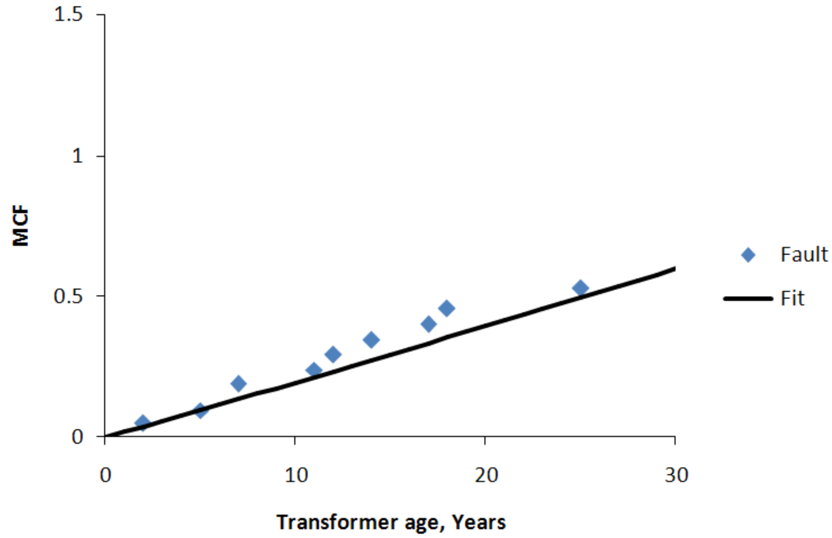

Fig. 4.8. The MCF of the transformer without power plant D fault data.

4.3.5 Excitation system

The excitation system controls the voltage and reactive power of a generator by adjusting the magnetic field current. The faults of the excitation systems are relatively condensed in early and wearout failure periods. The fitting graph is shown in Fig. 4.9.

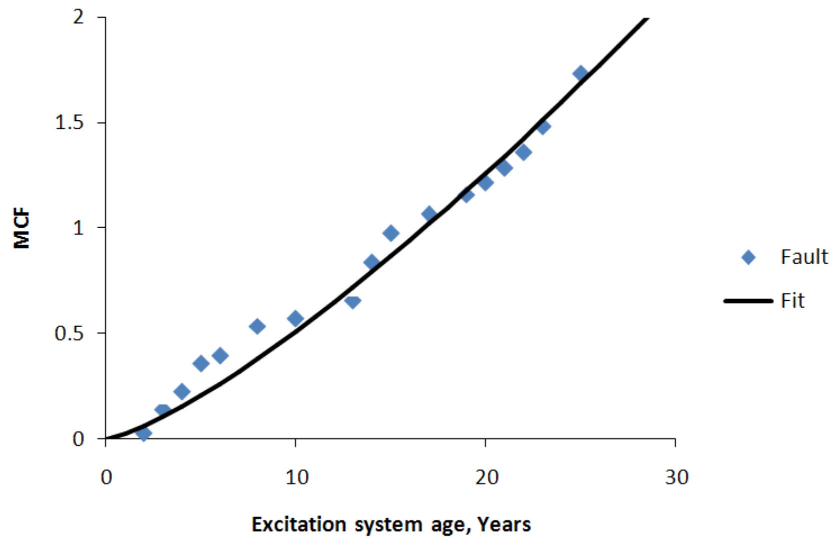

Fig. 4.9. The MCF of the excitation system.

4.3.6 Governor

The governor controls the speed and output of a turbine-generator. The MCF, shown in Fig. 4.10, increases sharply after 20 years of usage. The governors have relatively many faults compared with the stators and rotors.

4.3.7 Main circuit breaker

The K-water hydropower plants are operated as peak generators or frequency controllers because they can change their output quickly to follow the fluctuating power demand. Therefore, generators in these hydropower plants start and stop several times daily. Hence the main circuit breakers operate frequently and have many failures compared with switchyard circuit breakers. The main CBs have relatively many faults compared with other equipment. The MCF of the main CB is illustrated in Fig. 4.11.

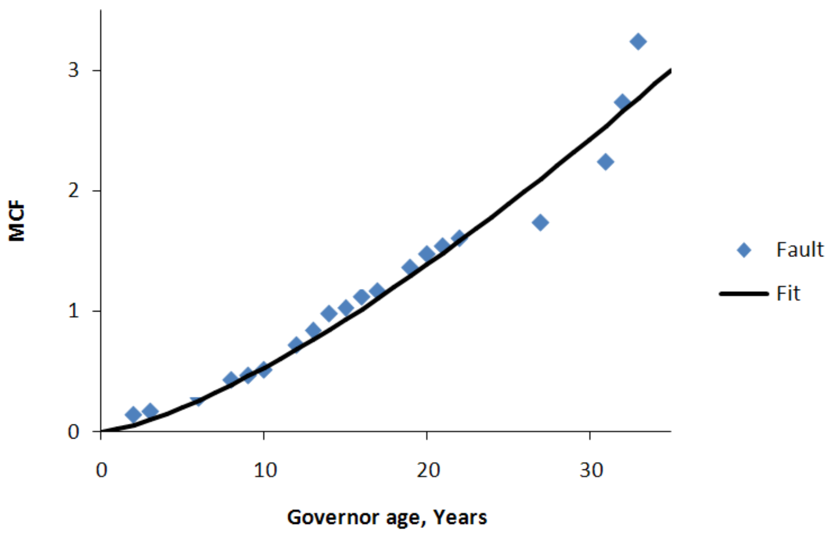

Fig. 4.10. The MCF of the governor.

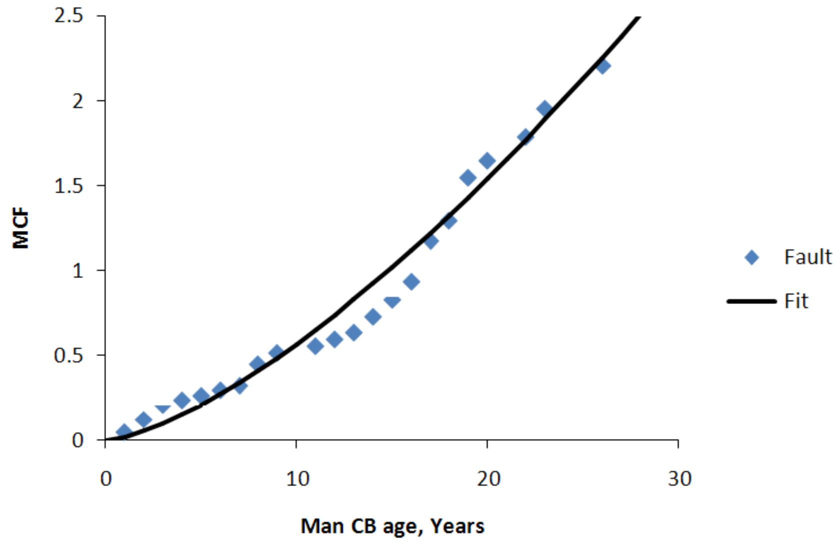

Fig. 4.11. The MCF of the main CB.

4.3.8 Switchyard circuit breaker

Switchyard circuit breakers do not operate frequently. Therefore, the faults of the SY CB is fewer than the main CBs, and also the MCF of the SY CB is less, and the reliability of the SY CB is more stable than the main CB. The MCF of the SY CB is provided in Fig. 4.12.

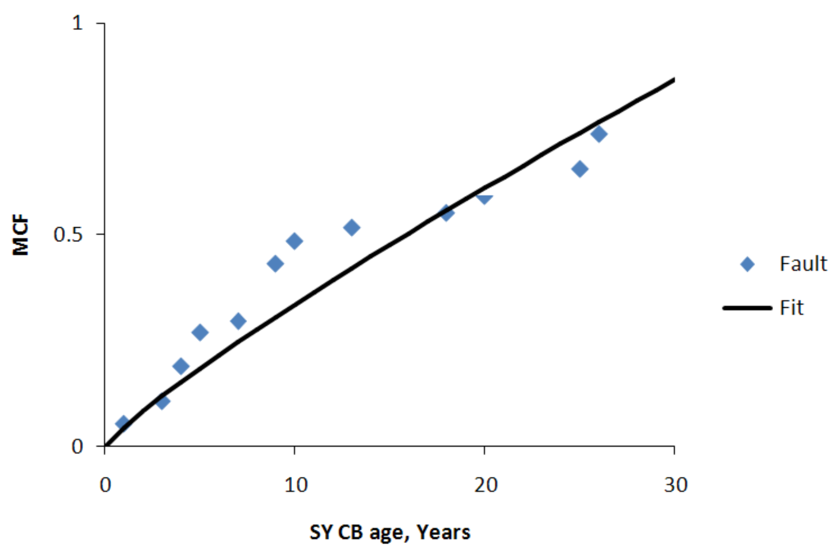

Fig. 4.12. The MCF of the SY CB.

4.4 Reliability Comparison

The MCFs of each facility were presented in the previous section, but a comparison between facilities has not yet been provided. As the MCFs of each facility are obtained, the equipment reliability can be calculated using Equation (2.34). Fig. 4.13 compares the reliability of the eight equipment categories.

Stators, rotors, and turbines have relatively high reliability than the other facilities. Governors, excitation systems, and main CBs have the least reliability, which explains the reason that many power plants have replaced these equipment earlier than other facilities in Table 4.2. The SY CB has higher reliability than the transformer with the transformer faults of power plant D. The transformer faults of power plant D are abnormally high. It is more reasonable to construct a reliability comparison graph without the transformer faults of power plant D. The graph is given in Fig. 4.14.

After excluding abnormal fault data, the reliability of the transformer is higher than the reliability of SY CB. The transformer reliability is utilized hereafter without the transformer fault data of power plant D.

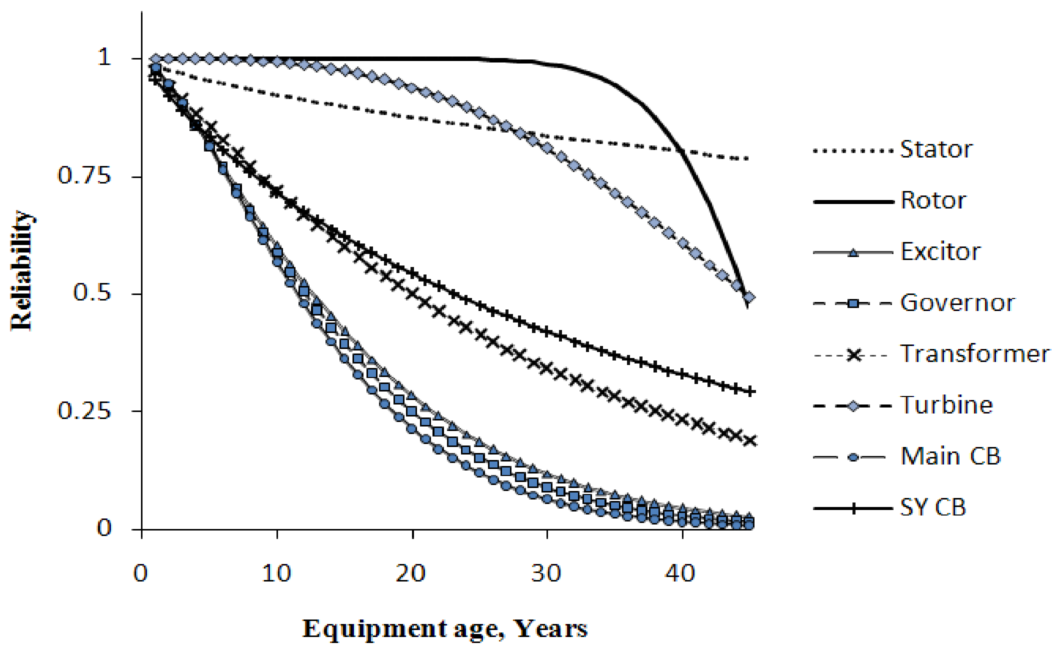

Fig. 4.13. Reliability comparisons.

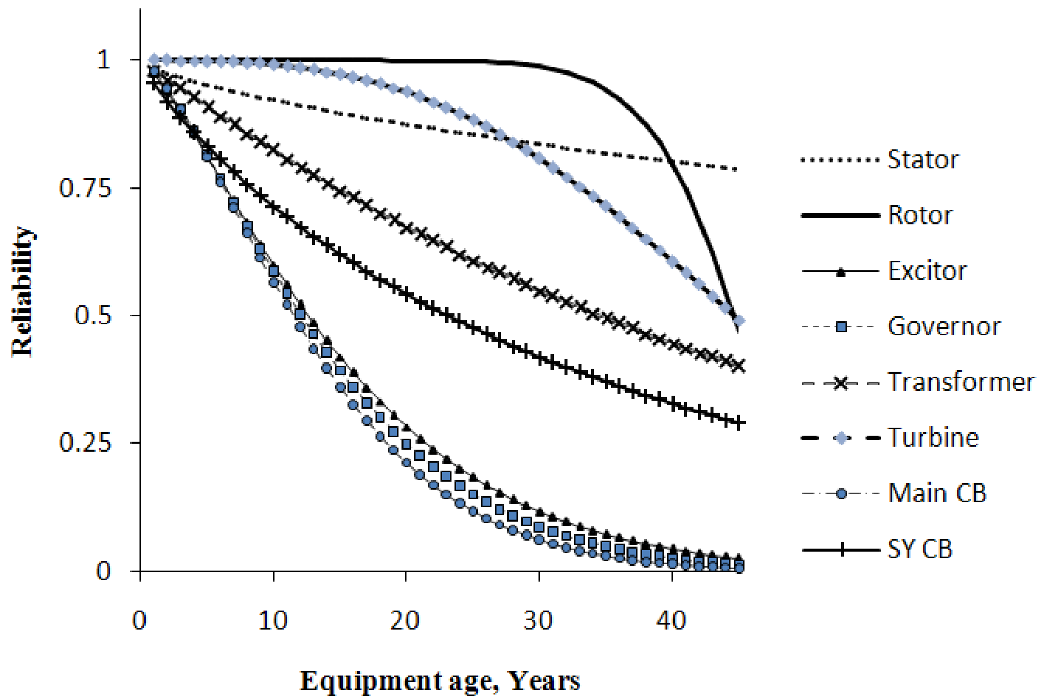

Fig. 4.14. Reliability comparisons without the transformer fault data of power plant D.

4.5 System Availability

The typical hydropower plant of K-water, whose block diagram is shown in Fig. 4.15, has two turbine-generator units. The reliability of each unit in a power plant is the main focus on this study. The simplified block diagram is necessary to represent each unit and their major components. The simplified block diagram of a hydropower-plant unit is presented Fig. 4.16.

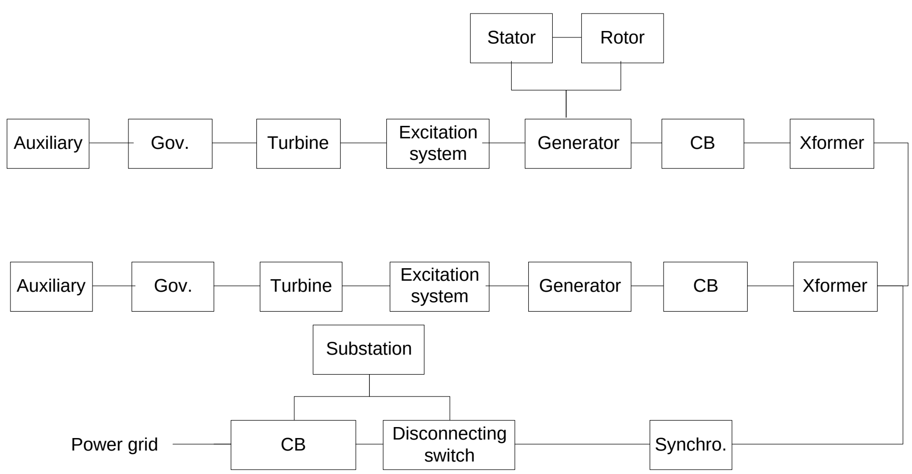

Fig. 4.15. Block diagram of a typical K-water hydropower plant.

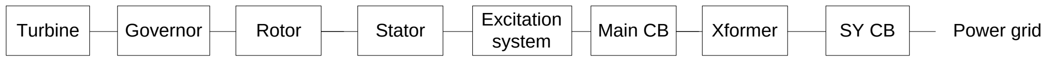

Fig. 4.16. The simplified block diagram of a hydropower plant unit.

The reliability of each facility has already been obtained. Therefore, the overall system reliability and availability can be computed using Equations (3.1) and (3.2). The system reliability is dramatically decreased if the importance of each equipment is identical, but actually the importance of each equipment is not the same. If an important equipment has a fault, a longer outage is expected than for other less important equipment, which means a longer MTTR. Therefore, a weight for each component is necessary for representing the system availability. Weight values of each facility are shown in Table 4.5, based on HydroAmp "Component Weights" [18].

Table 4.5. Component weights

Component	Weight
Stator	0.15
Rotor	0.15
Transformer	0.25
Turbine	0.2
Governor	0.1
Exciter	0.1
Main CB	0.025
Switchyard CB	0.025
Sum	1

Each facility reliability is multiplied by each weight. The overall weighted system availability is

$$System\ avilability = \sum R_i \omega_i \tag{4.3}$$

where R_i and ω_i are the equipment reliability and weight, respectively. This approach was applied only to system availability not the economic analyses and not the final analysis in Chapter 6.

The system availability would be "1" if all of the facilities are in perfect condition. The system availability graph without any replacement is presented in Fig. 4. 17. This availability is less than 0.6 after 30 years of usage. In actual cases, hydropower plants have replaced main CBs, excitation systems, and governors before overall modernization. It is assumed that main CBs are replaced every 15 years and excitation systems and governors are replaced every 20 years. Fig. 4.18 represents the system availability with the replacements of main CBs, excitation systems, and governors at those intervals. This system availability is over 0.7 until 30 years of usage in this case. Even though excitation systems and governors are replaced at 40 years, the system availability is less than 0.5 after 45 years of usage, which means that a hydropower plant will have more frequent forced outage faults, which might be more severe than the stable failure period. Therefore, the modernization of a hydropower plant should be considered before the power plant reaches 35 years of operation. The next chapter seeks to better define the most favorable timing for modernization.

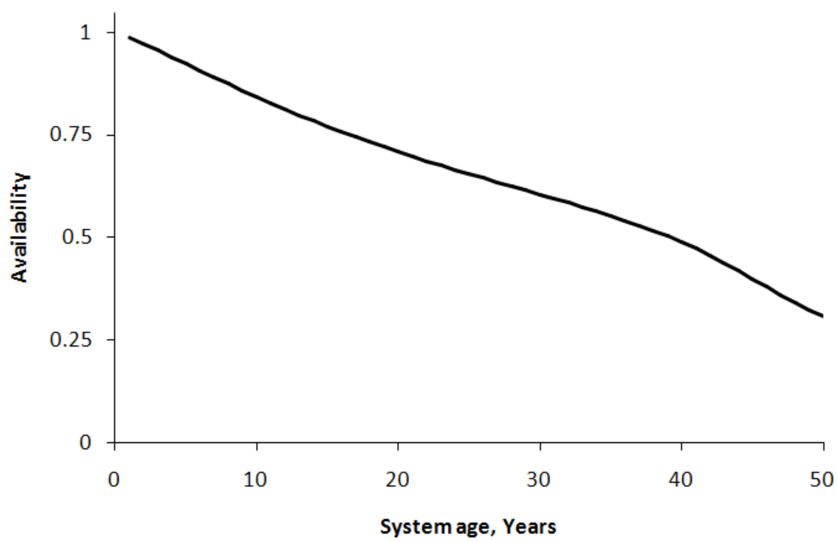

Fig. 4.17. System availability without replacement.

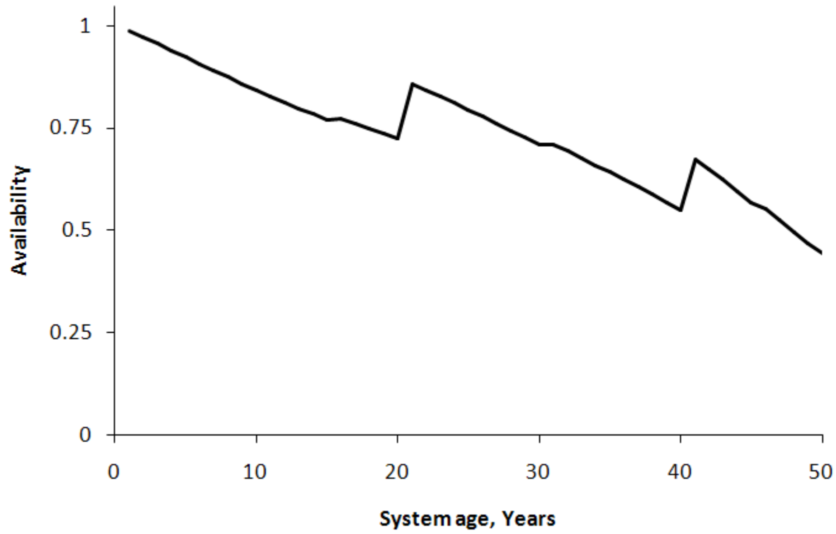

Fig. 4.18. System availability with replacement.

CHAPTER 5

Economic Evaluations and Determinations for Modernization Timing

5.1 Introduction

As it ages a power plant experiences many failures and spends more revenue on maintenance. A generation unit is entirely replaced at the earliest after 30 years of usage, during which time the technology for manufacturing equipment has improved. Developing technology which increases capacity and efficiency of a turbine-generator should be considered when an aging power plant is a candidate for modernization.

It is necessary to clarify the benefits and costs from the modernization of aging hydropower plants. The benefits and costs would vary based on consultants, countries, and power market systems. In this study benefits are calculated based on power revenues from power markets - in other words, the profits are decided by the System Marginal Price (SMP) of the power market in South Korea. The feasibility study of the Nagang modernization (2008) from K-water [23] and the renovation of Chuncheon hydropower plant (2009) from Korea Hydro & Nuclear Power Company (KHNP) are referenced for modernization costs [24]. The total investment costs are categorized into replacement costs, operation costs, depreciation costs, interest costs, and lost revenues during construction, whereas the benefits from modernization are power revenues and reliability increases. The replacement cost of an entire generation unit is a huge amount.

It is necessary to evaluate a modernization project for a hydropower plant from an economic perspective. Benefit-to-cost (B/C) ratios and investment payback analyses are mainly used for economic evaluations. Determinations for modernization timing to maximize benefits with minimized costs are studied after economic evaluations. The original cost data from K-water were provided using Korean currency, the won, therefore all Korean currency data are converted to U.S. dollar with an exchange rate of 1 dollar equals 1000 won.

5.2 Algorithm for an Economic Evaluation

It is worthwhile to review the possibility of a capacity and efficiency increase of a turbine-generator attained during a modernization project. The algorithm of an economic evaluation, developed based on the Namgang feasibility study [23], is presented Fig. 5.1, which is used for computing three different B/C ratios in this study.

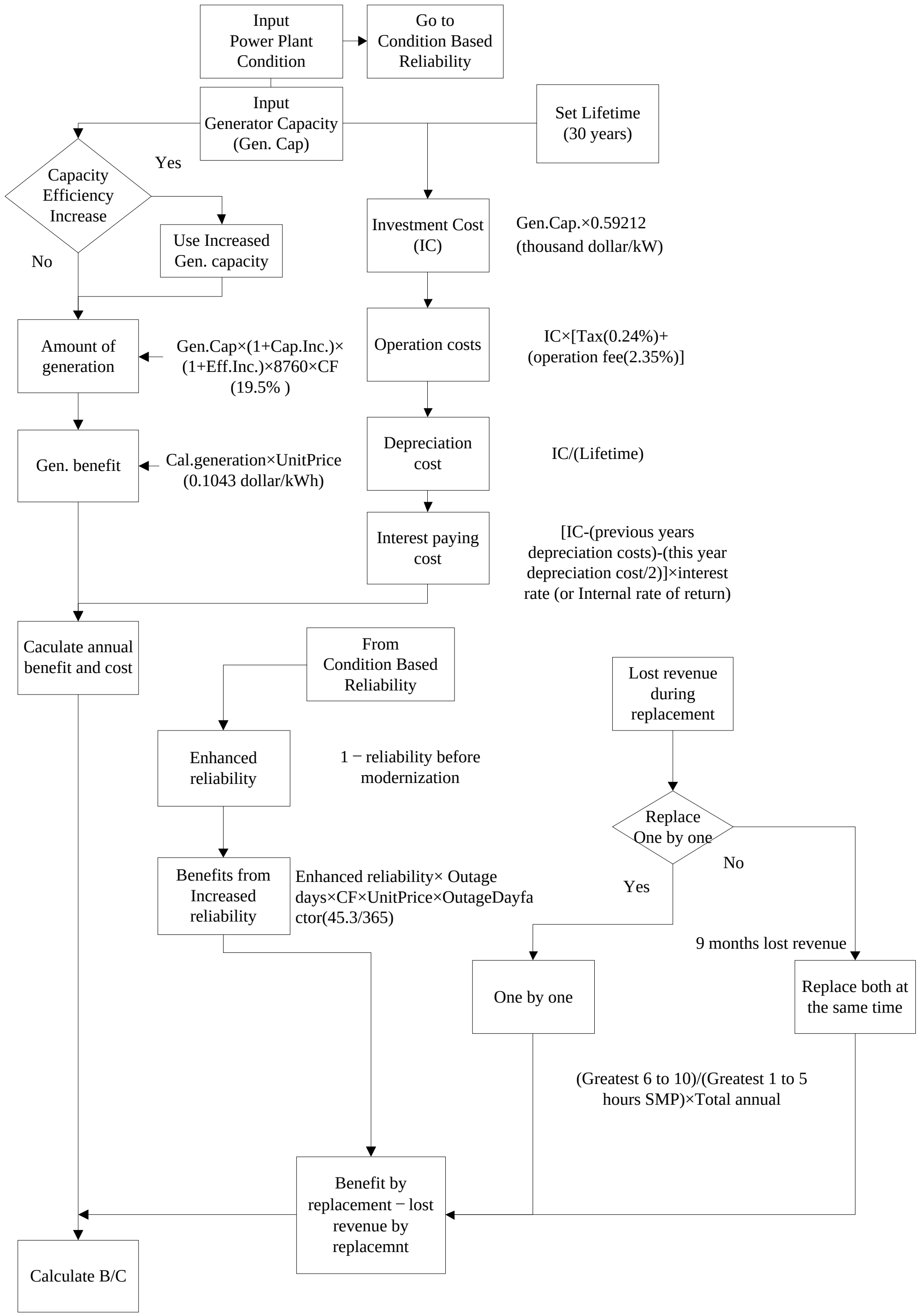

Fig. 5.1. Algorithm of an economic evaluation.

The B/C ratio can be calculated with the benefits and the costs. The increased reliability benefits from modernization and the costs from lost revenues during replacement, developed in this study, also should be considered.

5.3 Benefits

The benefits from modernization in a hydropower plant are expressed as capacity and efficiency increase, enhanced reliability, and power revenue.

5.3.1 Power revenues

Hydropower plants, which do not generally operate all day long, usually run as peaking units, which have low capacity factors. The capacity factor (CF) is defined as the ratio of the actual energy output of a power plant produced during some period over its output that could have been produced at full nameplate capacity the entire time. The 5-year average capacity factors for 5 major power plants in K-water are presented in Table 5.1. The overall average capacity factor (19.5%) is utilized for calculating power revenue in this study.

Table 5.1. Five-year average capacity factors for K-water [25]

Hydropower plant	A	B	D	E	J	Average
Capacity factor	12.9%	20.9%	18.4%	15.8%	29.3%	19.5%

Generators receive the system marginal price (SMP) of Korea power markets when providing power. Power revenues are decided by the SMP. The SMP, dollars/kWh, of the 5 major power plants in K-water is compiled in Table 5.2, which shows that the SMP increases annually. It is reasonable to utilize the most recent average SMP of 2009 as a unit price, 0.1043 dollars/kWh, not the average of 5 years.

The generation benefit (GB) per year is calculated with the following equation

$$\mathrm{GB} = \text{generation capacity (kW)} \times \mathrm{CF} \times \text{unit price} \times 8760\ \mathrm{hr/yr} \qquad (5.1)$$

Table 5.2. System marginal price of the 5 major dams in K-water [25]

[dollar/kWh]

Plant	A	B	D	E	J
Year	Unit Price	Unit Price	Unit Price	Unit Price	Unit Price
2005	0.136	0.051	0.078	0.076	0.062
2006	0.083	0.080	0.080	0.083	0.082
2007	0.083	0.080	0.080	0.083	0.082
2008	0.094	0.090	0.089	0.093	0.092
2009	0.107	0.101	0.101	0.107	0.105
The average for 2009 is 0.1043 dollar/kWh (1 dollar = 1,000 won).					

5.3.2 Benefit from increased reliability

The equipment reliability after modernization becomes ideally perfect and is denoted as "1". The chance of having failures, the failure function, is dramatically reduced. In other words, potential lost revenues from forced outages owing to generation failures are decreased by enhanced reliability, which is one of benefits from modernization. The forced outage days of the equipment increase as it ages. Much longer outages occur in power plants older than 20 years, as shown in Fig. 5.2.

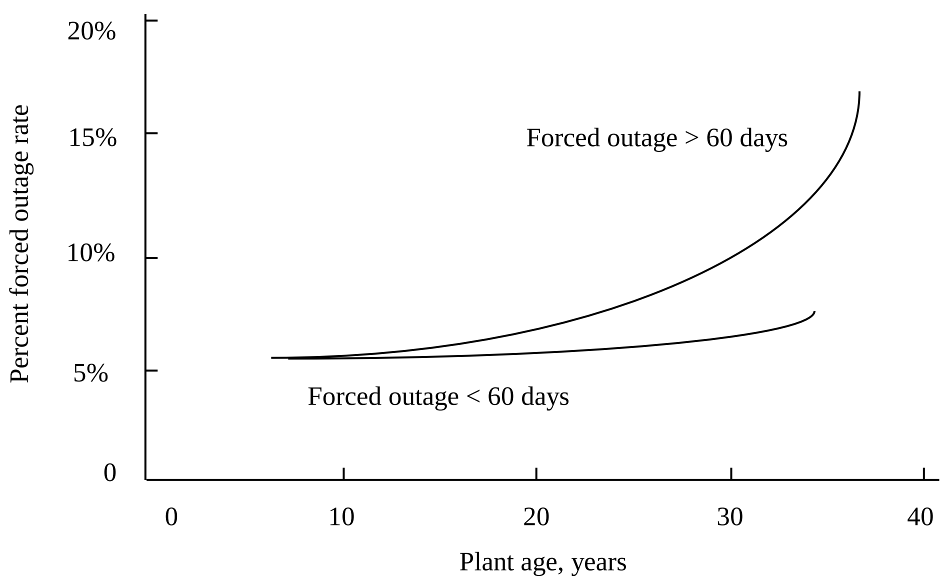

Fig. 5.2. Forced outage rate increase in later life [1].

Some forced outage lengths of equipment for K-water are illustrated in Table 5.3. Forced outage days are different according to equipment type and the seriousness of the fault.

Table 5.3. Forced outage days of equipment

Equipment	Fault	Forced outage (days)	Power plant
Rotor	Spoke jaw	50	D
Stator	Stator burnout	120	I
Turbine	Runner hub	21	A
Main Xformer	Tap changer	30	A
SY CB	Contactor	7	B
Excitation system	Thyristor	14	A
Governor	Proportional valve	14	G
Main CB	Contactor	7	E

Even though one generator, which has a failure, cannot operate, the other generator unit could accommodate the average daily load of two generators because of the low capacity factor. However, to account for 24-hour a day operation during the rainy season, an annual outage day factor (ODF) is defined as

$$ODF = \frac{Number\ of\ 24\text{-}hour\ generation\ days}{365} \tag{5.2}$$

The reduced forced outage days per year (RFOD) is the product of the forced outage days (FOD) and the increased reliability, in this study, defined as

$$RFOD = FOD \times (1 - reliability) \tag{5.3}$$

The actual forced outage days per year (AFOD) is obtained by multiplication of RFOD and ODF

$$AFOD = RFOD\ \times ODF \tag{5.4}$$

The benefit from increased reliability (BIR) is calculated using Equation (5.1)

$$BIR = generation\ capacity\ (kW) \times CF\ \times\ unit\ price \times AFOD\ \times 24hr/day \tag{5.5}$$

5.3.3 Capacity and efficiency increase

With advancements in technology, the turbine-generator efficiency is increased after modernization. The comprehensive increased efficiency of turbine-generators over time is above

7% according to Table 3.2. In this study, an efficiency increase of 5% is utilized as a conservative estimate.

The existing structures, such as penstock, spiral casing, and draft tubing, are not replaced during modernization. Hence, the water flow to a turbine remains the same. Capacity increase will be limited without changing structures, but it is possible to increase capacity by 5% within the marginal limits of the structures. The capacity factor of the hydropower plants in K-water is below 0.5, but in rainy seasons, from July to September, the hydropower plants often operate continuously with full power generation for several days. If a hydropower plant had a larger capacity, it could earn more revenue in rainy seasons. On the other hand, installing a bigger capacity unit requires more investment. Depending on the number of continuous operation days during the rainy season and the costs of capacity increase in a hydropower plant, the benefit of capacity increase will be decided. Table 5.4 presents the average number of 24-hour generation days per year for each plant over the last 6 years.

Table 5.4. Average of 24-hour generation days per year over 6 years

Year / Plant	2005	2006	2007	2008	2009	2010	Average days for 6 years
A	0	16	0	0	0	0	2.7
B	21	37	24	5	11	8	17.7
D	48	32	22	0	12	24	23.0
E	0	18	0	1	0	7	4.3
G	3	23	9	0	4	0	6.5
H	58	62	71	16	32	71	51.7
I	57	76	77	29	34	141	69.0
J	0	38	18	1	44	0	16.8
K	275	220	254	184	169	196	216.3
Average days of all power plants							45.3

Power plants C and F are the secondary power plants located downstream of power plants B and G. That is the reason power plants C and F are omitted from the table. Power plant K, which is a river-diversion dam, was constructed for supplying water continuously to downstream of other regions. Therefore at least one generator operates throughout the year. Power plant K controls power output for regulating the amount of water supplied to the downstream. The average 24-hour generation days of power plant K are not full power generation. Capacity increase evaluation for each power plant is performed considering 24-hour generation days and installation cost for increased capacity.

5.4 Costs

Modernization costs differ among power companies and countries. The total costs for modernization are investment cost, operation cost, depreciation cost, and interest cost. The investment cost, a necessary cost to replace an aging hydropower plant, is taken from the feasibility study of Nagang modernization (2008) from K-water [23] and the renovation of Chuncheon hydropower plant (2009) from KHNP [24].

5.4.1 Investment cost

The Namgang feasibility study presents the unit investment cost as 811.718 dollar/kW based on estimated prices of Namgang hydropower and Shihwa tidalpower plants. The actual contract amount of Chuncheon renovation was 372.522 dollar/kW. The two investments costs are significantly different because one is based on an estimation and the other is the actual contract cost. The average of the two, 592.12 dollar/kW, is used for the unit investment cost in this study.

5.4.2 Operation, depreciation, and interest cost

Operation cost, the necessary cost to run a power plant, is from the Namgang feasibility study, which utilized 2.35% of an investment cost (IC), and tax and insurance costs are 0.42% of the IC as the average cost for K-water.

The value of replaced equipment decreases over time. The annual depreciation cost is calculated by the investment cost over the lifetime of a hydropower plant. In this study, the lifetime is 30 years and interest rate is 6.5% cited by the Namgang feasibility study. The annual depreciation cost (ADC) is roughly defined as

$$ADC = \frac{Investment\ cost}{Lifetime\ of\ a\ hydropower\ plant} \tag{5.6}$$

The modernization of a hydropower plant demands huge investment cost, which is mostly from commercial banks. The annual interest cost (AIC) is simply calculated as follows

$$AIC = (IC - total\ depecication\ cost\ which\ was\ paid\ previous) \times interest\ rate \quad (5.7)$$

5.4.3 Lost revenues during replacement

A typical hydropower plant in K-water has two generation units as shown in Table 4.4 except power plant B, which has four generation units. The modernization can be carried out unit by unit or at the same time. In the Chuncheon renovation, two generation units were replaced one after another over two years. During these two years, one generator could compensate for the generation of the other unit because of the low capacity factor except during the rainy season. Lost revenues for unit-by-unit replacement is less than replacement of two units at the same time. The operable generator must also run during non-peak time to compensate for the other unit during replacement, which means less lucrative than peak-time generation. Also in the rainy season a power plant will lose 50% of power revenues because of modernization of the off-line unit. If the installation term is out of the rainy season, lost revenues are not considerable. If an operable generator has some faults during installation of the other unit, neither unit is available to operate, which causes no power revenue for that period. The replacement term of the Chuncheon renovation was the 9 months outside of the rainy season, October to June, for each unit. The average K-water capacity factor of 19.5% equates to approximately 5 hours per day. The capacity factor of an operable generator is doubled to 39% during installment, and it should operate 10 hours per day. The lost revenue during a modernization is calculated considering revenue loss from non-peak time operation and estimated forced outage days per year and is defined as follows

$$Lost\ revenue\ during\ modernization$$
$$= \frac{Greatest\ 6th\ to\ 10th\ hours\ of\ average\ SMP}{Greatest\ 1st\ to\ 5th\ hours\ of\ average\ SMP} \times \frac{365 - forced\ outage\ days\ per\ year}{365}$$
$$\times Total\ annual\ revenue \quad (5.8)$$

The average SMP ratio, greatest 6th to 10th over greatest 1st to 5th SMP, of each month in 2010 is shown in Table 5.5.

Table 5.5. Average SMP ratio in 2010

Month	1	2	3	4	5	6	10	11	12	Average
SMP ratio	0.77	0.78	0.80	0.82	0.89	0.85	0.88	0.89	0.84	0.83

If two units are replaced during the same period, there is no operable generator during installation. The lost revenues for two units replaced during the same period are calculated from the product of the installation period, denoted per year, and the annual power revenues.

5.5 B/C Calculation

It is controversial to include all power revenues as benefits after a modernization since the plant would likely produce revenue even without modernization. Three ways of computing B/C ratios for economic evaluations in hydropower plants are suggested in this study. The first technique is presently used by K-water in the feasibility study of the Namgang modernization [23] whereas the other two are developed as part of this thesis research including the increased reliability benefit.

1. The first method, *total power revenue*, includes all power revenues of existing and increased capacity including efficiency and reliability increases as its benefits. Costs are calculated using depreciation cost, operation cost, and interest cost as shown in Fig. 5.1. Even though the reliability of a power plant is poor and modernization of a power plant is not executed, the power plant still earns power revenues for the time being regardless of modernization.

2. The benefits of the second approach, *conservative power revenue*, includes only power revenues of capacity and efficiency increases with enhanced reliability. Costs are calculated with depreciation cost and interest cost, omitting operation cost, which should be spent regardless of replacement. The operation cost is apparently different between before and after modernization because of maintenance costs. This method is the most conservative calculation.

3. The third method is *conservative power revenue considering definite replacement*. Even though the modernization of a hydropower plant is not implemented immediately, the replacement should be executed in the near future. The power revenue is same as the conservative power revenue. The

costs are lost revenue and the interest cost of the sum of the depreciation costs and the investment interest costs, hereafter termed relative interest cost, RIC, which should be paid if modernization is implemented earlier than the definite replacement time. The relative interest cost depends totally on the definite replacement time. The total amount of previous depreciation and investment interest costs should be added to calculate the interest cost of each year. Therefore, the relative interest cost is greater if setting a definite replacement time later. The operation cost should be spent regardless of modernization.

The three cases of B/C ratios are summarized in Table 5.6. The Matlab programs created to make these calculations are provided in Appendix C.

Table 5.6. Three ways of computing B/C ratios

	Benefits	Costs
Total power revenue	Existing capacity power revenue Increasing capacity power revenue Efficiency increasing revenue Enhanced reliability revenue	Depreciation cost Operation cost Investment interest cost Lost revenue
Conservative power revenue	Increasing capacity power revenue Efficiency increasing revenue Enhanced reliability revenue	Depreciation cost Investment interest cost Lost revenue
Definite replacement power revenue	Increasing capacity power revenue Efficiency increasing revenue Enhanced reliability revenue	Relative interest cost Lost revenue

5.6 Determination of Modernization Timing

When a project is under consideration for modernization, many aspects, such as environmental, safety and economic, are analyzed and discussed for maximizing benefits and minimizing costs. The economic aspect is the key factor for deciding whether to modernize. The modernization of a hydropower plant can be assessed with the B/C ratio used for justifying the project. It is well known that operation and maintenance costs increase and plant reliability decreases over usage time. Long-term outage and considerable lost revenue could happen if appropriate timing of a modernization were missed. On the other hand the waste of revenue accompanies a hasty modernization. It is worth studying when the opportune time is to carry out modernization. The three parameters, reliability, time, and B/C ratio, are utilized to optimize the modernization of aging hydropower plants. If the cost for not being modernized is not considered, it is more beneficial for a hydropower plant to be used as long as possible. The annual cost for not being modernized increases and is the same as the enhanced reliability benefits, which increase annually because equipment reliability decreases as it ages.

CHAPTER 6

CASE STUDIES

Eleven power plants are used to calculate the representative reliability of equipment. The oldest power plant I had its feasibility study for modernization and the next oldest power plant J has already replaced the generator and turbine. Power plants A and D are utilized for case studies in this chapter. The usage year age of power plant A is 35 years, and power plant D is 31 years.

6.1 Power Plant A

6.1.1 Reliability

Power plant A is 35 years old, some of whose equipment have already been replaced. In Chapter 4, the representative equipment reliability is obtained over the usage year. The parameters of the MCF, equipment usage year, and equipment reliability based on usage year are presented in Table 6.1. The SY CB, excitation system, governor, and main CB were each replaced once before as shown in Table 4.4.

Table 6.1. Power plant A reliability and parameters

Equipment	*a*	*b*	Usage year	Reliability
Rotor	1.04E-17	10.20	35	0.94
Stator	0.0153	0.72	35	0.82
Turbine	9.0264E-06	2.96	35	0.71
Transformer	0.0180	1.03	35	0.50
SY CB	0.0459	0.86	13	0.67
Excitation sys.	0.0254	1.30	10	0.60
Governor	0.0222	1.38	1	0.98
Main CB	0.0204	1.44	11	0.52

6.1.2 Condition assessment

The age condition index (CI) is obtained only from the usage year except for circuit breakers, which are assessed by operation times. The CI, which is from HydroAMP Tier 1 assessment, is obtained from employees of power plant A as part of this research. With Equations (4.1) and (4.2), the CCIV and condition-based reliability (CBR) are found. Age CI, CI, CCIV, and CBR are shown in Table 6.2.

Table 6.2. CI data and CBR of power plant A

Equipment	Age CI	CI	CCIV	CBR
Rotor	10.0	10.0	1.0	0.94
Stator	9.0	9.2	1.0	0.84
Turbine	6.9	8.0	1.2	0.83
Transformer	8.7	9.5	1.1	0.54
SY CB	8.0	8.0	1.0	0.66
Excitation	10.0	9.0	0.9	0.54
Governor	10.0	10.0	1.0	0.98
Main CB	8.0	8.0	1.0	0.52

The historical system availability of power plant A is presented in Fig. 6.1. The system availability at 35 years, in other words, the current availability is 0.75. The SY CB, main CB, excitation system and governor of power plant A were replaced at the system age of 22, 24, 25 and 34 years, respectively. At these points the system availability increased. The present system age is 35 years old. If no other significant replacement is carried out, the system availability is expected to decrease as shown in Fig. 6.1.

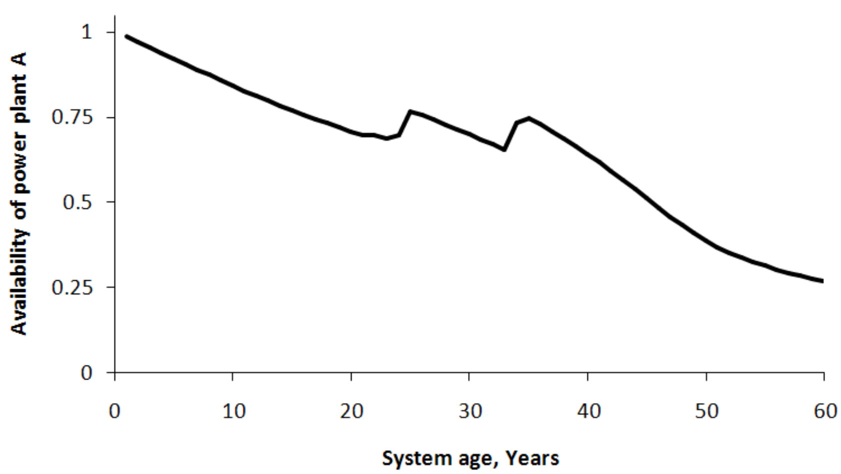

Fig. 6.1. System availability of power plant A.

6.1.3 Reliability benefit

The forced outage days (FOD) of equipment were reported in Table 5.3. The reduced forced outage days per year (RFOD) is calculated with Equation (5.3) and the actual reduced forced outage days (AFOD), which affects generation revenue loss, is computed with Equation (5.4). The actual outage reduced days are 6.5 and their benefits, calculated with Equation (5.5), are 285 thousand dollars per year, which are presented in Table 6.3

Table 6.3. Benefits from increased reliability of power plant A

Equipment	FOD	RFOD	AFOD	Benefits (thousand dollars)
Rotor	50	2.8	0.35	15.4
Stator	120	19.6	2.43	106.9
Turbine	21	3.6	0.45	19.6
Transformer	30	13.7	1.70	74.9
SY CB	7	2.4	0.30	13.1
Excitation sys.	14	6.4	0.80	35.1
Governor	14	0.3	0.04	1.7
Main CB	7	3.3	0.42	18.3
Total	263	52.3	6.5	285.0

6.1.4 Total power revenue economic evaluation

Power revenue includes existing capacity and increased capacity, and efficiency increase. Lost revenue is subtracted from power revenue. Operation, depreciation, and interest costs are included as part of the costs. The first five years of benefits and costs using the total power revenue evaluation are presented in Table 6.4.

Table 6.4. Total power revenue economic evaluation of power plant A

thousand dollars

	Year	1	2	3	4	5
Benefit	Power revenue	6,654	8,839	17,678	17,678	17,678
	Reliability benefit		143	285	285	285
Costs	Operation Cost	1,449	1,449	1,449	1,449	1,449
	Depreciation cost		933	1,865	1,865	1,865
	Interest Cost	1,819	3,607	3,516	3,395	3,273
Benefits current value		6,248	7,919	14,871	13,963	13,111
Costs current value		3,068	5,280	5,654	5,215	4,808

The power revenue in the first year is less than the second year because the first year power revenue does not include capacity and efficiency increases. The modernization term is two years. Two units with increased capacity will run from the third year of the beginning of modernization. Reliability benefits come from the second year of modernization after replacing one unit. Benefits from increased reliability are expressed in Table 6.4. Depreciation cost, calculated by Equation (5.6), starts the second year and the cost of the first year is half that of the following years because of unit-by-unit replacement. Interest cost is calculated using Equation (5.7). The current value of the B/C ratio of total power revenue is 3.033 over a 30 year lifetime extension, and the investment payback is 6.61 years.

6.1.5 Conservative power revenue economic evaluation

Even if power plant A does not undergo modernization, it still earns power revenues for the time being regardless of modernization. In this evaluation, power revenue is only from capacity, efficiency, and reliability increases, therefore the power revenue of Table 6.5 is dramatically reduced in comparison with Table 6.4, which shows the first five years of benefits and costs using the conservative power revenue method. The first year of modernization does not have any benefit because of unit-by-unit replacement. The benefits from modernization occur from the second year of modernization onward. Operation cost should be paid regardless of modernization; hence, operation cost is excluded in costs of this evaluation. The B/C ratio of conservative power revenue is 0.251 over a 30 year lifetime extension.

Table 6.5. Conservative power revenue economic evaluation of power plant A

thousand dollars

	Year	1	2	3	4	5
Benefit	Power revenue	-	421	842	842	842
	Reliability benefit	-	143	285	285	285
Costs	Depreciation cost	-	933	1,865	1,865	1,865
	Interest Cost	1,819	3,607	3,516	3,395	3,273
Benefits current value		-	497	933	876	822
Costs current value		1,708	4,002	4,455	4,089	3,751

6.1.6 Definite replacement economic evaluation

The benefits of the definite replacement economic evaluation are same as the conservative power revenue calculation. Costs are the interest rate of depreciation cost and investment interest cost because depreciation cost and investment interest cost should be paid in the near future when power plant A starts its modernization. The relative interest cost increases annually because the total amount of previous depreciation and investment interest costs should be added to calculate the interest cost of each year, therefore the relative interest cost increases annually. The justification of this economic evaluation depends on a comparison of modernization timing. If a comparison of modernization timing is later, the B/C ratio is below 1. If modernization is executed within 5 years for power plant A, the B/C ratio is over 1, but after 5 years, the B/C ratio is below 1, which means power plant A can be used more than 5 years. This is because hasty replacement causes the waste of revenue since power plant A can be used for more years and the interest rate of the depreciation cost and the investment interest cost increase annually. The B/C ratios with respect to a comparison of modernization timing are presented in Table 6.6.

Table 6.6. Definite replacement economic evaluation of power plant A

thousand dollars

	Year	1	2	3	4	5
Benefit	Power revenue	-	421	842	842	842
	Reliability benefit	-	143	285	285	285
Costs	IC of depreciation cost	-	61	182	303	424
	IC of investment interest Cost	118	353	581	802	1,015
Benefits current value		-	497	933	876	822
Costs current value		111	364	632	859	1050
B/C		-	1.045	1.2914	1.17	1.03

6.1.7 Conclusion for power plant A

Power plant A had relatively good system availability until age 10 as shown in Fig. 6.1. The system availability of power plant A was below 0.8 from 10 to 20 years. In this period the forced outages increased so that the SY CB, main CB, excitation system, and governor were replaced after 20 years of usage. Therefore, the system availability was around 0.7 from 20 to 35 years. The current system age is 35 years old. The system availability rapidly decreases after 35 years compared to prior years. The system availability will be under 0.6 after 40 years of usage, which implies many system failures with long-term forced outage days.

The total power revenue economic evaluation shows that it is worthwhile to execute the modernization of power plant A. However, power plant A earns power revenues for the time being regardless of modernization. The conservative power revenue economic evaluation is done to justify the modernization of power plant A. The B/C ratio of the conservative power revenue is 0.251, which does not justify the modernization. An aging power plant should be replaced in the near future. The definite replacement of economic evaluation assumes the possible replacement year. Based on this assumption, the results show that it is worthwhile if the modernization is carried out within 5 years of the assumed replacement year.

The graph of the three different B/C ratios versus system age (replacement age) is provided in Fig. 6.2. The total and conservative B/C ratios slightly increase as power plant A ages because the enhanced reliability benefit, which is the only changing variable in these simulations, increases.

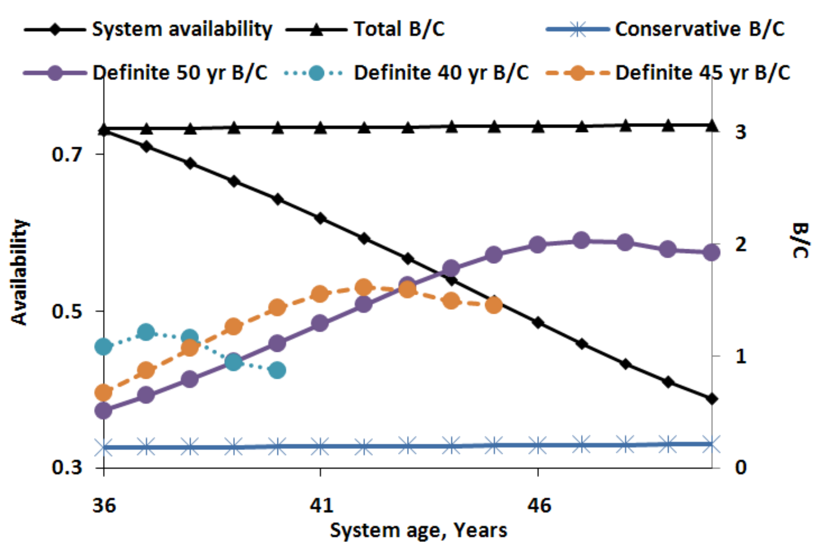

Fig. 6.2. Three different B/C ratios for power plant A versus system age.

The definite replacement economic evaluation sets a definite replacement year, within which an aging hydropower plant must be replaced. B/C ratios until the set definite replacement year are calculated. The three cases of the definite B/C ratios, which use ages 40, 45, and 50 as the definite replacement years, convey that the peak B/C years of the three cases are 3 years before the specific (definite) replacement years because capacity and efficiency increased benefits outweigh relative interest cost for last 3 years before a definite replacement year.

The total and conservative B/C ratios do not show when the best time for modernization is even if the both B/C ratios slightly increase. The definite B/C ratios present that a higher B/C ratio is acquired from setting the definite replacement year later. It is well known that more benefits from a current system can be obtained as a new investment time is delayed only if no forced outage fault occurs. Hence, the best replacement year is inconclusive. Therefore, one more case study, power plant D, is presented in the next section for determining a suitable replacement time and ensuring that the total power revenue approach is in fact inappropriate since this is the method presently employed at K-water.

6.2 Power Plant D

6.2.1 Reliability

The parameters of the mean cumulative function (MCF), equipment usage year, and equipment reliability based on usage years of power plant D, which is 31 years old, are presented in Table 6.7. The transformer, excitation system, governor, and main CB were each replaced once before as shown in Table 4.4. The reliability of power plant D, shown in Table 6.7, is the representative reliability determined in Chapter 4.

Table 6.7. Power plant D reliability and parameters

Equipment	*a*	*b*	Usage year	Reliability
Rotor	1.04E-17	10.20	31	0.98
Stator	0.0153	0.72	31	0.83
Turbine	9.0264E-06	2.96	31	0.79
Transformer	0.0180	1.03	6	0.89
SY CB	0.0459	0.86	31	0.41
Excitation sys.	0.0254	1.30	8	0.68
Governor	0.0222	1.38	5	0.81
Main CB	0.0204	1.44	5	0.81

6.2.2 Condition assessment

The CI, which is from HydroAMP Tier 1 assessment, is obtained from employees of power plant D. In the same way as power plant A, the age CI, CI, CCIV, and condition-based reliability (CBR) are calculated and shown in Table 6.8 for power plant D.

Table 6.8. CI data and CBR of power plant D

Equipment	Age CI	CI	CCIV	CBR
Rotor	10	10.0	1.0	0.98
Stator	9.7	9.2	0.9	0.79
Turbine	7.8	8.0	1.0	0.81
Transformer	10	10.0	1.0	0.89
SY CB	10	8.6	0.9	0.35
Excitation	10	10.0	1.0	0.68
Governor	10	10.0	1.0	0.81
Main CB	10	10.0	1.0	0.81

Replacement times of the two transformers were different. An average of the two transformers is utilized for calculating the system availability of power plant D. The excitation system, transformer, main CB, and governor of power plant D were replaced at the system age of 23, 25, 26 and 26 years, respectively. The system availability of power plant D is presented in Fig.

6.3. The system is 31 years old, so the current availability, is 0.83, which is 0.08 higher than the 0.75 of 35 year old power plant A. Equipment replacement was executed from 23 to 26 years of usage. System availability increased from 0.69 to 0.92 during this period. The system availability is projected below 0.5 after 45 years of usage.

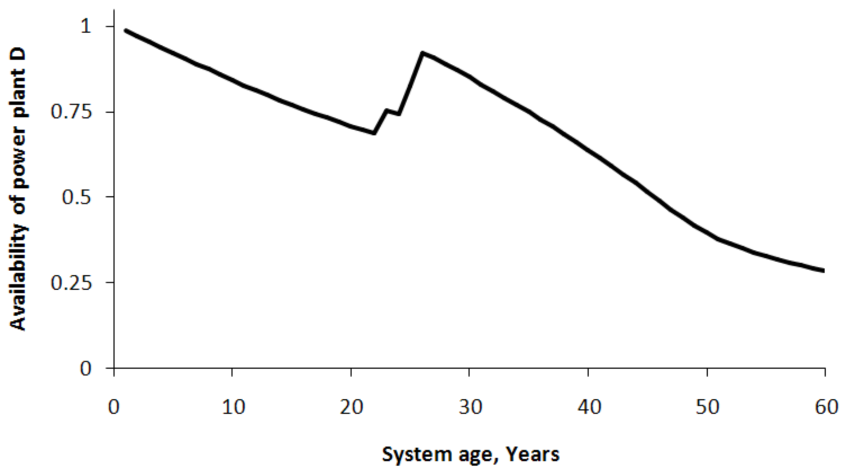

Fig. 6.3. System availability of power plant D.

6.2.3 Reliability benefit

The reliability benefits of power plant A were calculated earlier in this chapter. In a similar way, the forced outage days (FOD), reduced forced outage days per year (RFOD), actual reduced forced outage days (AFOD), and benefits of power plant D are calculated and presented in Table 6.9.

Table 6.9. Benefits from increased reliability of power plant D

Equipment	FOD	RFOD	AFOD	Benefits (thousand dollar)
Rotor	50	0.9	0.1	4.8
Stator	120	25.2	3.1	137.2
Turbine	21	4.0	0.5	21.6
Transformer	30	3.2	0.4	17.6
SY CB	7	4.5	0.6	24.7
Excitation sys.	14	4.4	0.6	24.2
Governor	14	2.6	0.3	14.1
Main CB	7	1.3	0.2	7.2
Total	263	46.1	5.7	251.5

6.2.4 Total power revenue economic evaluation

The total power revenue economic evaluation is carried out in the same manner as power plant A. Benefits of power plant D include power revenue and reliability benefits. Costs are operation, depreciation, and interest cost. Input data for economic evaluation are presented in Table 6.10. The first five years of benefits and costs for total power revenue evaluation are presented in Table 6.11.

Table 6.10. Input data for economic evaluation

Item	Value
Capacity	90 (45×2) MW
Capacity increase	5%
Efficiency increase	5%
CF	19.5%
Lifetime	30 years
Unit Price	$ 0.1043/kWh
Unit Replacement Cost	$ 592.12/kW
Tax	0.24%
Operation Cost	2.35%
Interest rate	6.5%
Construction term	2 years

Table 6.11. Total power revenue economic evaluation of power plant D

thousand dollars

	Year	1	2	3	4	5
Benefit	Power revenue	6,654	8,839	17,678	17,678	17,678
	Reliability benefit	-	126	252	252	252
Costs	Operation Cost	1,449	1,449	1,449	1,449	1,449
	Depreciation cost	-	933	1865	1865	1865
	Interest Cost	1,819	3,607	3,516	3,395	3,273
Benefits current value		6,248	7,904	14,843	13,937	13,087
Costs current value		3,068	5,280	5,654	5,215	4,808

The explanations for the calculation of each item are same as power plant A. The B/C ratio of the total power revenue method for power plant D is 3.027 over a 30 year lifetime extension, and the investment payback is 6.87 years. There is not much difference in the economic evaluation of power plants A and D because they have same capacity and they have almost the same parameters to compute the B/C ratio. The difference between the two B/C ratios comes from reliability increased benefits. Power plant D is younger than power plant A, which will have better reliability increased benefits, therefore the B/C ratio of power plant A is slightly higher, 0.006, and, the investment payback is shorter, by 0.26 year, than power plant D because power plant A has more increased reliability benefits with replacement.

6.2.5 Conservative power revenue economic evaluation

The economic evaluation using the conservative power revenue approach is performed in the same manner as power plant A. Table 6.12 shows the five years of benefits and costs using the conservative power revenue method. The B/C ratio of the conservative power revenue is 0.244 over a 30 year lifetime extension. This B/C ratio is less than power plant A because the reliability benefit is less than that of power plant A.

Table 6.12. Conservative power revenue economic evaluation of power plant D

thousand dollars

	Year	1	2	3	4	5
Benefit	Power revenue	-	421	842	842	842
	Reliability benefit	-	126	252	252	252
Costs	Depreciation cost	-	933	1865	1865	1865
	Interest Cost	1819	3607	3516	3395	3273
Benefits current value		-	482	905	850	798
Costs current value		1,708	4,002	4,455	4,089	3,751

6.2.6 Definite replacement economic evaluation

The costs for the definite replacement economic evaluation are lost revenue and the relative interest cost because depreciation cost and investment interest cost should be paid in the near future but it depends on when power plant D starts its modernization. This evaluation is carried out in the same way of that for power plant A. The justification of this economic evaluation depends on a comparison of the modernization year. Table 6.13 shows that if a definite replacement time is within 5 years, the B/C ratio is above 1. If a definite replacement time is after 5 years from now, the B/C ratio will be below 1 (not shown), which means that early replacement causes a waste of revenue.

Table 6.13. Definite replacement economic evaluation of power plant D

thousand dollars

	Year	1	2	3	4	5
Benefit	Power revenue	-	421	842	842	842
	Reliability benefit	-	126	252	252	252
Costs	IC of depreciation cost	-	61	182	303	424
	IC of investment interest Cost	118	353	581	802	1015
Benefits current value		0	482	905	850	798
Costs current value		111	364	632	859	1050
B/C		-	1.083	1.338	1.215	1.075

6.2.7 Conclusion for power plant D

The system availability of power plant D decreased to 0.69 after 22 years of usage as shown in Fig. 6.3. With the replacement of the transformer, excitation system, governor, and main CB, the system availability of power plant D increased up to 0.92 at age 26. After that, the system availability decreased. The current system age is 31 years old and its reliability is 0.83. It is expected that the system availability will drop below 0.5 after 45 years of usage, which implies many system failures with long-term forced outage days. If existing capacity is included in benefits, the B/C ratio is greater than 1. The total power revenue economic evaluation, which includes existing capacity as a power revenue benefit, shows that it is worthwhile to execute the modernization of power plant D, but this evaluation does not justify the modernization of power plant D, because the B/C ratio of total power revenue economic evaluation is above 1 at all times in this evaluation. The total power revenue economic evaluation is worthwhile to represent how lucrative a modernization project is, but it does not specify the timing. A modernization project will be justified if the B/C ratio of the conservative power revenue economic evaluation is over 1. The B/C ratio of the conservative power revenue for power plant D is 0.244, which does not justify the modernization. It is worthwhile to replace power plant D based on the definite replacement economic evaluation if it is replaced within 5 years. After 5 years later (i.e., at age 36), the system availability of power plant D will be 0.7287, which presents relatively stable system availability. The graph of the three different B/C ratios for power plant D versus system age (replacement age) is provided in Fig. 6.4.

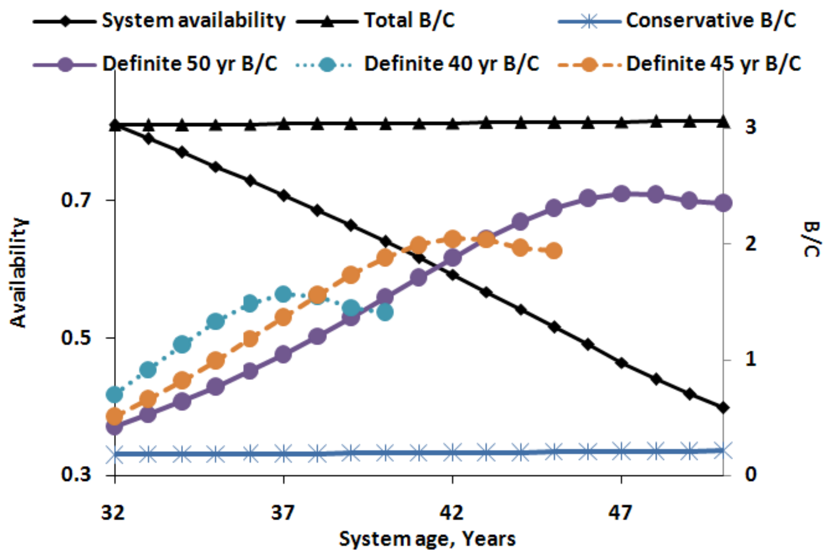

Fig. 6.4. Three different B/C ratios for power plant D versus system age.

The total and conservative B/C ratios slightly increase as power plant D ages, which is the same as power plant A. The total and conservative B/C evaluations do not justify the modernization of power plant A or D. Three cases of the definite B/C ratios, which are 40, 45, and 50 definite replacement years, are computed for determining a suitable replacement time. The definite B/C ratios for power plant D present that a higher B/C ratio is acquired from setting a definite replacement year later while the system availability decreases, which is the same as for power plant A.

With the two case studies, the system availabilities of the two power plants are obtained using condition-based reliability. Three different economic evaluations and system availability are computed for obtaining the best time for replacement. However, the graphs of total and conservative B/C ratios over system age for the two power plants are almost flat while the system availabilities of the two power plants decrease. Also, the definite B/C ratios of the two power plants imply that by setting a definite replacement year later, a higher B/C ratio is acquired; meanwhile the system availabilities decreases below 0.5. Therefore, the three different B/C ratios do not give a concrete idea of when the best time for replacement is. It remains necessary to determine suitable modernization timing for equipment in a hydropower plant.

6.3 Determination of Modernization Timing

Economic evaluations of power plant A and D were executed in Sections 6.1 and 6.2, which did not yield suitable timing for modernization. Economic and reliability aspects are two major factors to determine replacement timing for equipment. If equipment are replaced individually, a plant would have multiple outage times. That is why power companies plan to replace equipment, auxiliaries, and cables at the same time to minimize the outage duration when major equipment such as stator, rotor, and turbine should be replaced. Group replacement is more economical than individual replacement by reducing multiple installation outages. Equipment in a hydropower plant is divided here into two groups based on their reliability and replacement period for calculation of modernization timing. Group 1 includes the rotor, stator, turbine and transformer, which are the 4 most reliable equipment, and group 2 is the SY CB, excitation, governor, and main CB, which are the 4 least reliable equipment.

6.3.1 Reliability group 1 and group 2

The representative reliability of the 24 generators in K-water is presented in Fig. 4.14. The parameters of groups 1 and 2 for reliability are calculated by the average of each group parameter except the *b* parameter of group 1, which is calculated as the average of stator, turbine, and transformer without rotor because the rotor *a* value is very small and *b* is too big in comparison with other equipment parameters. The reliability parameters of groups 1 and 2 are presented in Table 6.14. Reliability curves of groups 1 and 2 are shown with equipment reliability in Fig. 6.5, which illustrates that the reliability graphs of groups 1 and 2 accurately represent the average of items in each group.

Table 6.14. The reliability parameters of groups 1 and 2

Group 1			Group 2		
Equipment	*a*	*b*	Equipment	*a*	*b*
Rotor	1.04E-17	10.1996	SY CB	0.0459	0.8643
Stator	0.0153	0.7235	Excitation	0.0254	1.3036
Turbine	9.03E-06	2.9603	Governor	0.0222	1.3803
Transformer	0.018	1.0297	Main CB	0.0204	1.4440
Average	0.0083	1.1783	Average	0.0284	1.2480

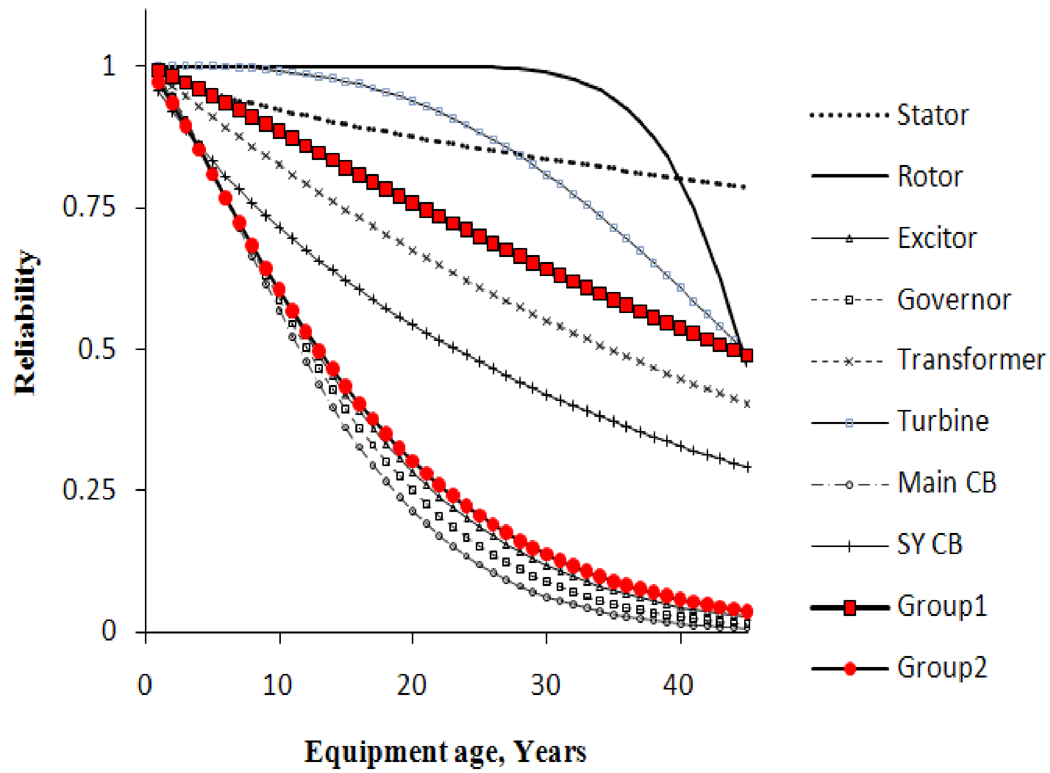

Fig. 6.5. Reliability graphs of groups 1 and 2.

6.3.2 Outages days based on reliability

The forced outage days of each equipment increase as it ages as shown in Fig. 5.2. It is reasonable that equipment should be totally replaced when its reliability reaches to zero. The installation time for equipment with zero reliability is the same as a normal installation term if all parts are prepared for replacement, if not, additional days are necessary for making a contract, manufacturing, inspecting and shipping, which should be executed urgently to minimize lost revenue. Normal and urgent replacement terms are presented in Table 6.15. The average replacement term for each group is used for computing outage days as reliability changes.

Table 6.15. Normal and urgent replacement terms

days

Group 1			Group 2		
Equipment	Normal	Urgent	Equipment	Normal	Urgent
Rotor	60	210	SY CB	15	60
Stator	180	210	Excitation	30	150
Turbine	60	210	Governor	30	150
Transformer	30	210	Main CB	15	60
Average	120		Average	56.25	

The outage length is calculated with change of reliability as follows

$$\text{Outage days} = (1 - \text{equipment reliability}) \times \text{average replacement days} \qquad (6.1)$$

The graphs of reliability and outage days versus usage year for group 1 and group 2 are shown in Figs. 6.6 and 6.7, respectively.

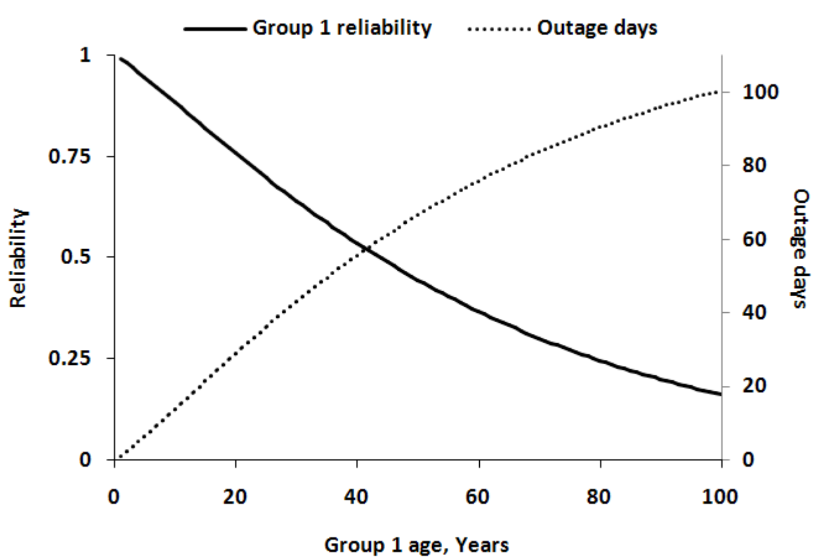

Fig. 6.6. Reliability and outage days versus usage year for group 1.

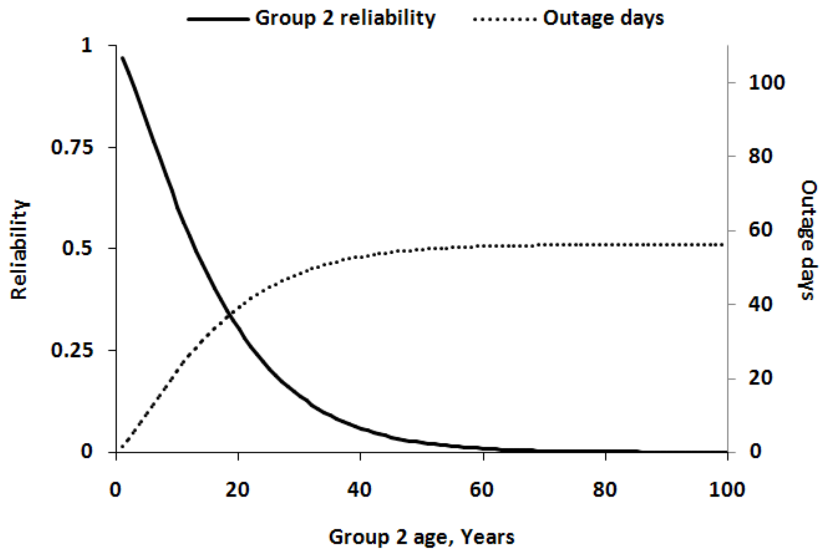

Fig. 6.7. Reliability and outage days versus usage year for group 2.

6.3.3 The determination of group 2 replacement

In the simulation of this subsection, the group 1 equipment is not replaced and the replacement period of group 2 varies from 10 to 30 years. The repair cost is 0.8% of investment cost, which is from K-water's reliability evaluation algorithm for electric power equipment [26]. The generation and capacity increased benefits are not included in benefits. The only benefit of replacing group 2 is the reliability increased benefit. The benefit and costs of replacing group 2 are shown in Table 6.16 and the simulation parameters are presented in Table 6.17.

Table 6.16. The benefit and costs of replacing group 2

Benefits	Increased reliability benefit for group 2
Costs	Repair cost for group 2 Lost revenue for replacement Replacement Cost

Table 6.17. Simulation parameters for group 2 replacement

Item	Value
Capacity	90 (45×2) MW
CF	19.5%
Unit Price	$ 0.1043/kWh
Repair cost	0.8%
Interest rate	6.5%
Starting year	1
Termination year	100
Start period of group 2	10
End period of group 2	300

The simulation results for various replacement periods for group 2 is presented in Fig. 6.8. The benefit minus cost, net benefit, increases as the replacement period becomes longer.

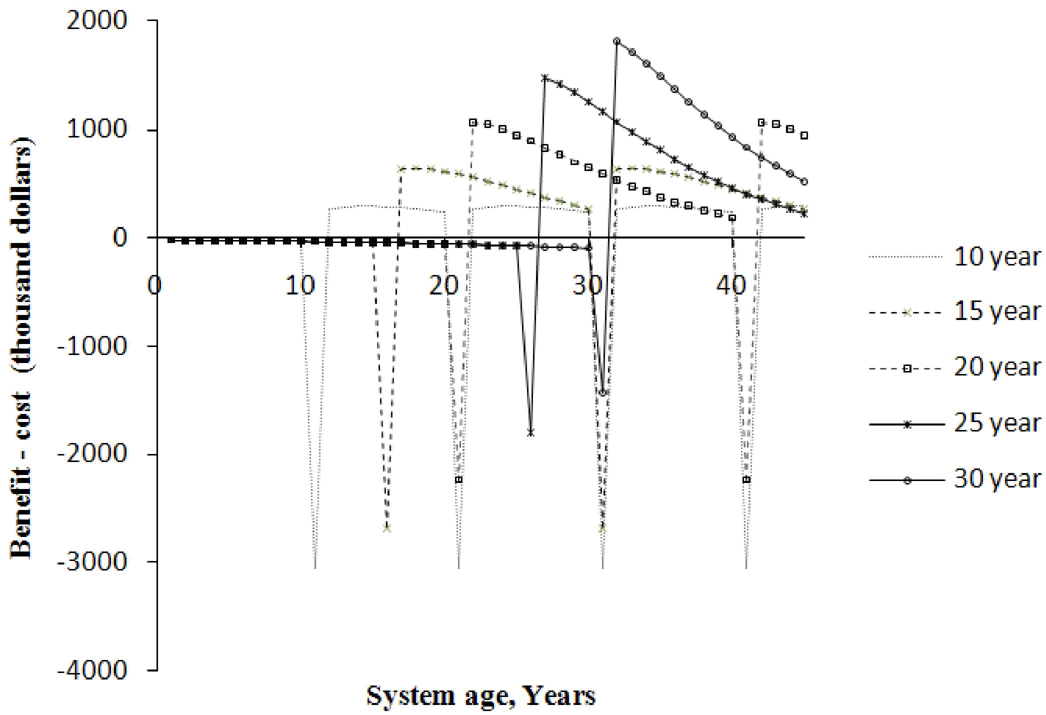

Fig. 6.8. Benefit minus cost with group 2 replacement period.

The replacement costs of group 2 should be paid during the year in which the replacement occurs. The large negative drops in net benefit curves mainly originate from the replacement costs of group 2. Each replacement occurrence causes a negative net benefit canyon. The positive parts of the net benefit graphs are mostly from the increased reliability benefits. Therefore, the maximum values of the net benefit graphs are greater for longer replacement periods. This results from the fact that the reliability increased benefit is greater as the replacement period is lengthened.

It is necessary to compute the total sum of the net benefits for each replacement period for better understanding. Sums of net benefit and group 2 reliability versus replacement period are presented in Fig. 6.9. It appears that sums of benefit minus cost begin to saturate at the age of 22 while the reliability of group 2 decreases as it ages. The minimum reliability of group 2 is 0.3 if group 2 is replaced on a 20 year period. Considering reliability and sums of benefit minus cost versus replacement period, it appears that age 20 to 23 years is the best time to replace equipment of group 2.

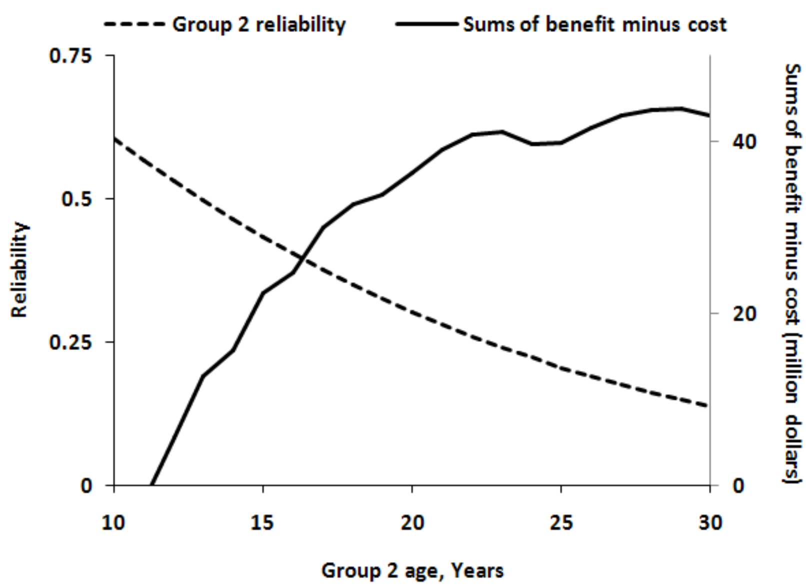

Fig. 6.9. Sums of net benefit versus group 2 replacement period.

6.3.4 Group 1 replacement determination

In this simulation, the group 2 replacement period is fixed at 20 years based on the results from the prior subsection. The group 1 replacement period is varied from 30 to 55 years. The benefits and costs of replacing group 1 are shown in Table 6.18 and the simulation parameters are presented in Table 6.19.

Table 6.18. The benefit and costs of replacing group 1

Benefits	Generation revenue Increased capacity and efficiency revenue Increased reliability benefit for group 1
Costs	Repair cost for group 1 Lost revenue for replacement Replacement Cost

Table 6.19. Simulation parameters for group 1 replacement

Item	Value
Capacity	90 (45×2) MW
CF	19.5%
Unit Price	$ 0.1043/kWh
Repair cost	0.8%
Interest rate	6.5%
Starting year	1
Termination year	100
Group 2 replacement period	20 yr
Start period of group 1	30
End period of group 1	55

The simulation result for various replacement periods for group 1 is presented in Fig. 6.10. It is difficult to ascertain whether the benefit minus cost, net benefit, increases or decreases as the replacement period is longer because generation revenue is much greater than increased reliability benefit for group 1. It is necessary to compute the total sums of net benefit for each replacement period for better understanding. Fig. 6.11 illustrates sums of net benefit versus replacement period of group 1 along with reliability. Normalized sums of net benefit are presented based on the sums of net benefit for a 55 year replacement interval. The sums of net benefit increases as the replacement period is greater and saturates at a replacement of approximately 40 years while group 1 reliability decreases. The minimum reliability of group 1 is 0.53 if group 1 is replaced on a 40 year period. Considering reliability and sums of benefit minus cost versus replacement period, it appears that between 40 to 45 years is the best time to replace equipment of group 1.

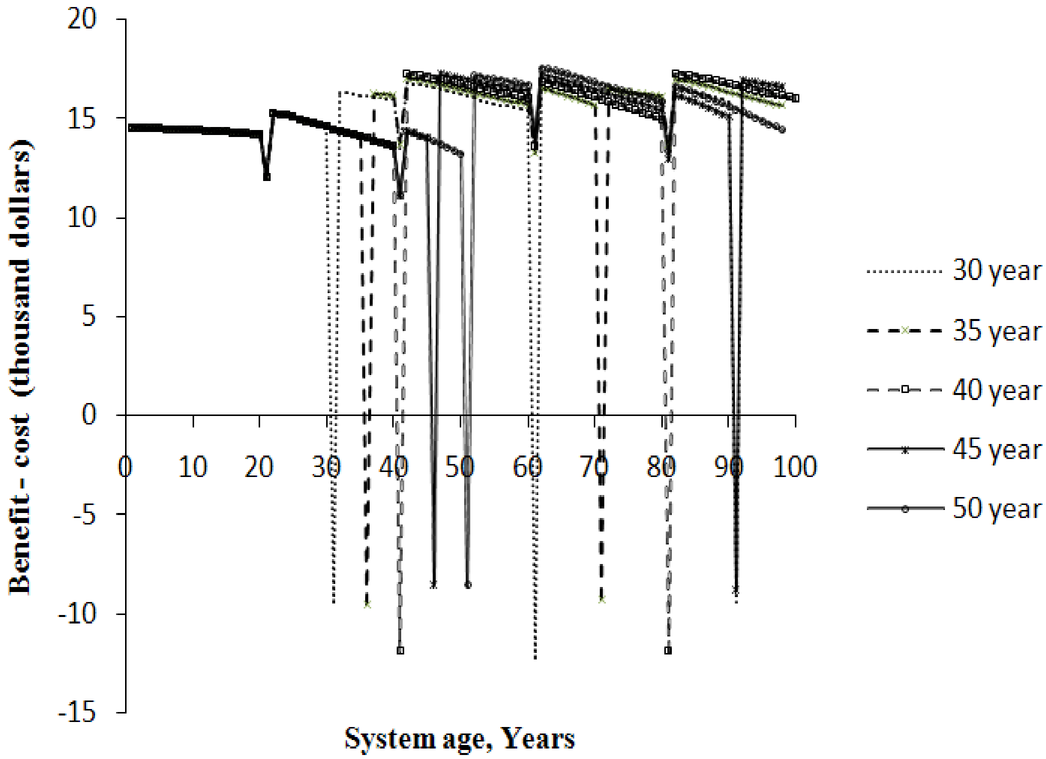

Fig. 6.10. Benefit minus cost with group 1 replacement period.

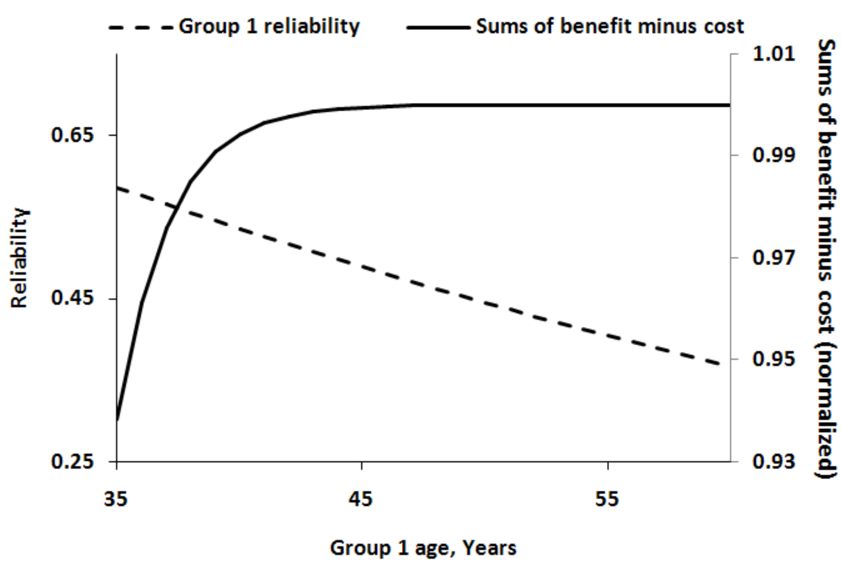

Fig. 6.11. Normalized sums of net benefit versus group 1 replacement period.

The group 1 result of 40 to 45 years is fortuitous since it is double the 20 to 23 year period of group 2 and therefore would permit simultaneously replacement of group 2 equipment with those in group 1.

CHAPTER 7

CONCLUSIONS AND FUTURE STUDY

7.1 Conclusions

It is generally understood that equipment deteriorates and its reliability decreases as it ages. In this study, the existing hydropower structures, such as penstock, spiral casing, and draft tubing, are not considered for computing equipment reliability. Major equipment for calculating reliability of a hydropower plant are rotor, stator, turbine, transformer, SY CB, excitation system, governor, main CB as shown in Fig. 4.15.

Twenty-four K-water synchronous generators and associated equipment are selected to represent equipment reliability and system availability. Fault data for the 24 generators are collected and filtered for only forced outage data. Using reliability concepts, equipment reliability is obtained in Chapter 4 and the equipment reliability is presented graphically in Fig. 4.13.

The three most reliable facilities in a hydropower plant are the rotor, stator, and turbine. The reliability of the rotor and stator, which are the most reliable facilities in a hydropower plant, is above 0.75 until 40 years of usage. Turbine reliability is below 0.75 after 34 years of usage. The second most reliable category is the transformer and SY CB, which do not operate frequently in comparison with the Main CB. The third category is the excitation system, governor, and main CB. The reliability of the excitation system and governor are below 0.5 after 13 years of usage, and the reliability of the main CB becomes 0.5 at the age of 11, which explains the reason these three facilities are replaced the most and have many forced outage faults. These equipment reliabilities provide representative reliability of the 24 generators.

The criterion-based analysis of HydroAmp is adopted to provide a more accurate reliability for each power plant, and “component weights” are also used for computing system availability of a hydropower plant. System availability decreases as it ages until equipment replacement. Two case studies find that system availability increases with the replacement of less reliable excitation system, governor, main CB, SY CB, and transformer as shown in Figs. 6.1 and 6.3. These two graphs present how the system availability of the two power plants changes as they age.

Based on system availability, three ways of computing B/C ratios were investigated for economic evaluations in hydropower plants. Because the *total power revenue economic evaluation* includes existing capacity as its power revenue benefit, the B/C ratio of this evaluation is above 1 at all times. The benefits of the *conservative power revenue economic evaluation* are only from capacity, efficiency, and reliability increases, therefore the power revenue is dramatically reduced in comparison with total power revenue economic evaluation. The third economic evaluation, the *definite replacement economic evaluation*, regards cost as relative interest cost (the interest cost of the sum of the depreciation costs and the investment interest costs) because depreciation cost and investment interest cost should be paid in the near future until an aging power plant starts its modernization

Two case studies show that the trend of total and conservative B/C ratios over replacement age for two power plants slightly increase but are almost constant as the two power plants age while system availability decreases as shown in Figs. 6.2 and 6.4. The definite B/C ratios of the two case studies find that a higher B/C ratio is acquired by setting a definite replacement a year later while the system reliabilities decrease. It is well known that more benefit from a current system can be obtained as a new investment time is delayed only if no forced outage fault occurs. Therefore, the three different B/C ratios do not yield a concrete indication of when suitable modernization timing is and they do not justify the modernization of hydropower plants.

Grouping equipment replacement is more economical than replacing individual components since the number and length of installation outages are minimized. Therefore, equipment in a hydropower plant is divided into two groups based on their reliability for calculation convenience of modernization timing. The rotor, stator, turbine and transformer, forming group 1, are the 4 most reliable equipment, and the SY CB, excitation system, governor, and main CB, composing group 2, are the 4 least reliable equipment.

The forced outage days of each equipment increase as it ages as shown in Fig. 5.2. Therefore, reliability and outage days versus usage year for group 1 and group 2 are graphically shown in Figs. 6.6 and 6.7, respectively. In a simulation, the replacement period for group 2 is varied from

10 to 30 years without group 1 replacement, and then in a second simulation the group 1 replacement period is varied from 30 to 55 years with a fixed group 2 replacement period of 20 years based on group 2 simulation result. Considering reliability and sums of benefit minus cost versus replacement period, it appears that 20 to 23 years are best time to replace equipment of group 2 and 40 to 45 years are best time to replace equipment of group 1.

In this study, only HydroAmp Tier 1, which is based on normal and routine tests and inspection results from operation and maintenance (O&M) activities, is used for calculating condition based reliability (CBR) for convenience. More accurate reliability is obtained if Tier 2, which utilizes non-routine tests and inspections performed by specialized expertise or instrumentation, is used for computing the CCIV to represent the CBR.

With the representative reliability of equipment, a general idea of how much a system can be trusted is presented, also the economical replacement period for equipment is determined. More accurate reliability with Tier 2 condition-based assessment should provide a more definitive indication of equipment residual lifetime. Considering each power plant availability and the economical replacement periods of groups 1 and 2, the appropriate modernization time for each power plant can be achieved.

7.2 Future Study

Twenty-four generators are utilized for computing equipment reliability and system availability. These data can be used as representative reliabilities of the plant equipment. However, there is only one fault for the rotor, and the stator has just three fault points, neither of which are sufficient to accurately represent the reliability. Reliability calculations are based on statistics. The obtained reliability is not for an individual power plant but representative of all 24 generators. Therefore, the criterion-based assessment of Tier 1 is used for obtaining more accurate reliability of each power plant. If Tier 2 condition based assessment of each power plant and more generators are utilized, a more accurate reliability will be obtained

In economic evaluations, the increased reliability benefit is added to the benefits calculation, but O&M cost is regarded as the same over the lifetime for calculation convenience. Actually the

O&M cost is different after modernization and also increases annually. In a future study, evaluation of aging hydropower plants should be executed with more generators considering O&M cost increase, Tier 2 condition based assessment, corporate image benefits and costs so that a more accurate decision can be achieved.

Finally, two reliability groups were used to categorize the eight equipment types. Referring to Fig. 6.5, it may be useful to expand the number of reliability groups from two to three with group 1 consisting of the rotor, stator, and turbine, and group 2 comprised of transformer and SY CB, and group 3 composed of excitation system, governor, and main CB.

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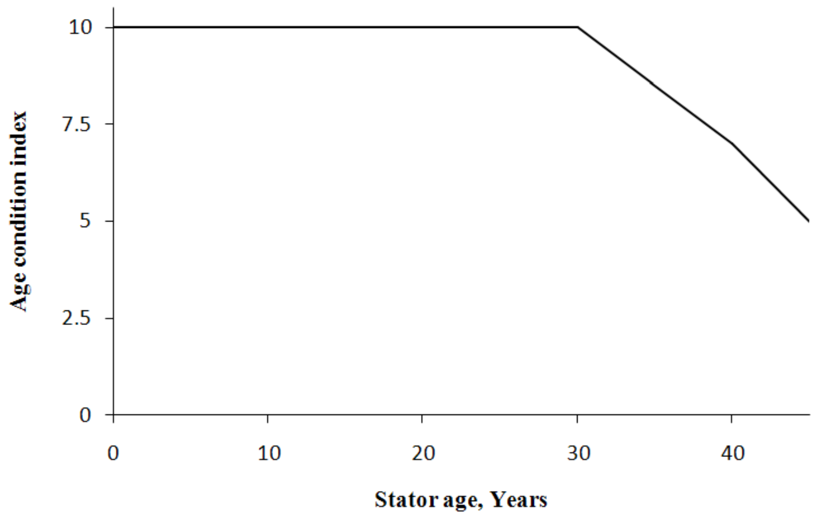
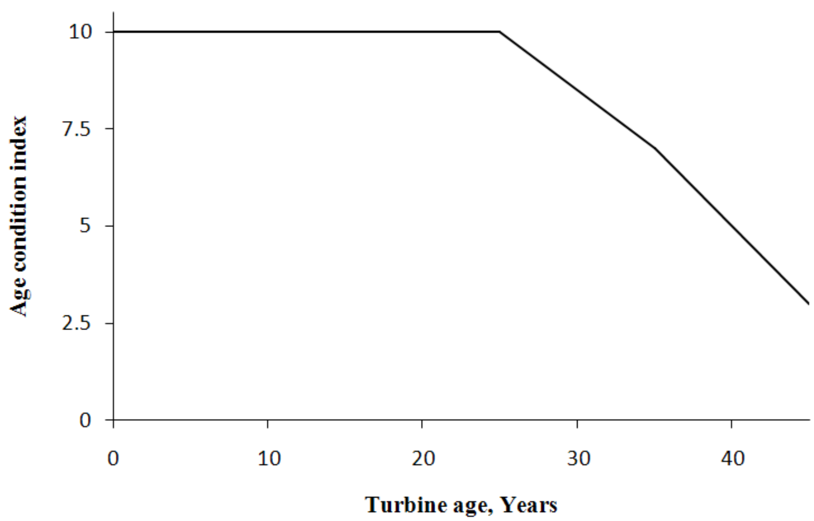
APPENDIX A

AGE CONDITION INDEX GRAPHS FOR EQUIPMENT

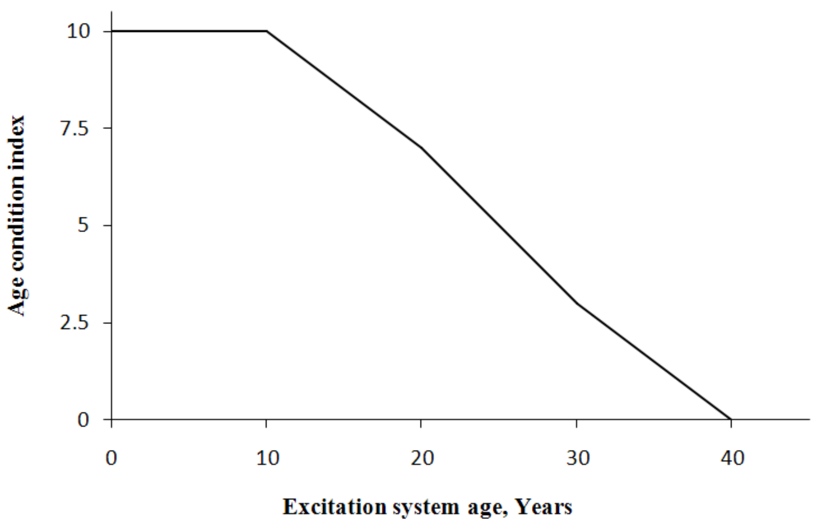


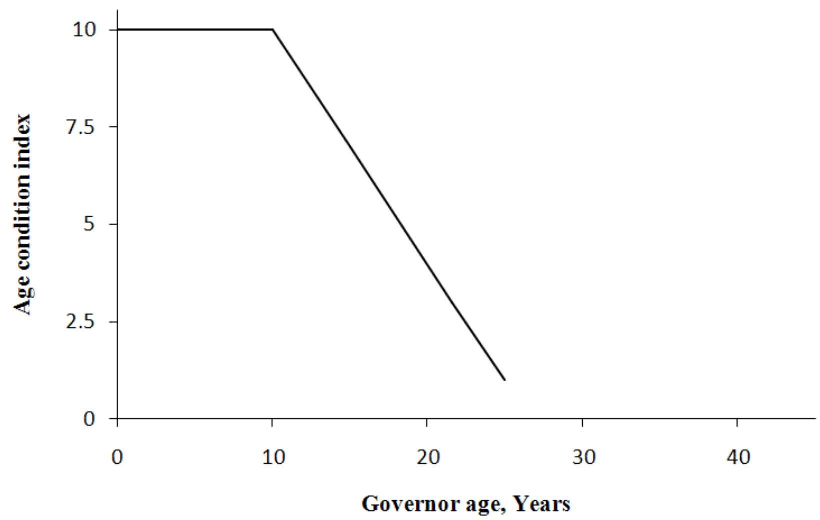
10
7.5
5
2.5
0
0
10
20
30
40
Age condition index
Stator age, Years

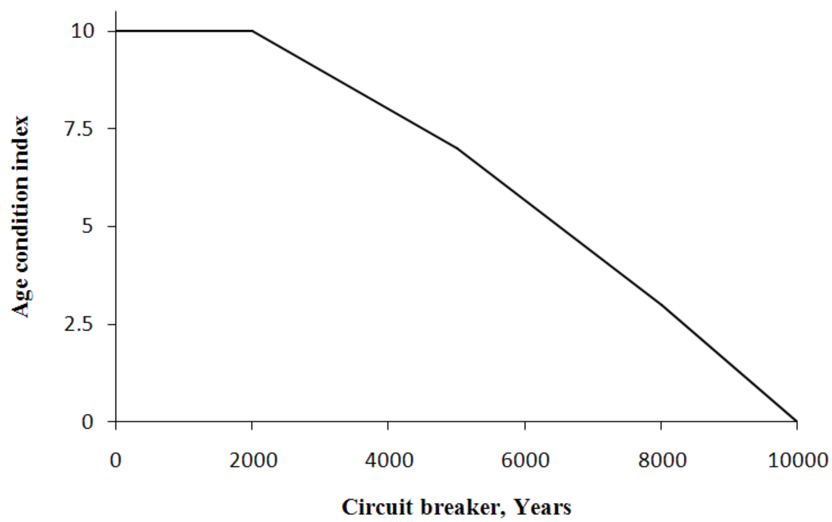


10
7.5
5
2.5
0
0
10
20
30
40
Age condition index
Turbine age, Years


10
7.5
5
2.5
0
0
10
20
30
40
50
60
Age condition index
Transformer age, Years


10
7.5
5
2.5
0
0
10
20
30
40
Age condition index
Excitation system age, Years


10
7.5
5
2.5
0
Age condition index
0
10
20
30
40
Governor age, Years


10
7.5
5
2.5
0
Age condition index
0
2000
4000
6000
8000
10000
Circuit breaker, Years

APPENDIX B

EQUIPMENT FAULT DATA TABLE

Rotor fault data table for 24 generators																										
Lapsed year	I1	I2	J1	J2	J1R	J2R	A1	A2	D1	D2	B1	B2	B3	B4	C1	C2	E1	E2	F1	F2	H1	H2	G1	G2	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
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17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
18	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
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25	0	0		0			0	0	0	0	0	0	0	0	0	0										
26	0	0					0	0	0	0	0	0	0	0	0	0										
27	0	0					0	0	0	0																
28	0	0					0	0	0	0																
29	0	0					0	0	0	0																
30	0	0					0	0	0	0																
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32	0	0					0	0																		
33	0	0					0	0																		
34	0	0					0	0																		
35	0	0					0	0																		
36	0	0																								
37	0	0																								
38	0	0																								
39	0	0																								
40	0	0																								
41	0	0																								
42	0	0																								

Stator fault data table for 24 generators

Lapsed year	I1	I2	J1	J2	J1R	J2R	A1	A2	D1	D2	B1	B2	B3	B4	C1	C2	E1	E2	F1	F2	H1	H2	G1	G2	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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35	0	0					0	0																		
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37	0	0																								
38	0	0																								
39	0	0																								
40	0	0																								
41	0	0																								
42	0	0																								

Turbine fault data table for 24 generators

Lapsed year	I1	I2	J1	J2	J1R	J2R	A1	A2	D1	D2	B1	B2	B3	B4	C1	C2	E1	E2	F1	F2	H1	H2	G1	G2	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
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9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
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15	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
16	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
17	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
18	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
19	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
20	0	0		0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
21	0	0		0			0	0	0	0	0	0	0	0	0	0	0	0	0	0						
22	0	0					0	0	0	0	0	0	0	0	0	0	0	0	0	0						
23	0	0					0	0	0	0	0	0	0	0	0	0			0	0						
24	0	0					0	0	0	0	0	0	0	0	0	0			0	0						
25	0	0					1	0	0	0	0	0	0	0	0	0										
26	0	0					0	0	0	0	0	0	0	0	0	0										
27	0	0					0	0	0	0																
28	0	0					0	0	0	0																
29	0	0					0	0	0	0																
30	0	0					0	0	0	0																
31	0	0					0	0	0	0																
32	1	0					0	0																		
33	0	0					0	0																		
34	0	0					0	0																		
35	0	1					0	0																		
36	0	0																								
37	0	0																								
38	0	0																								
39	0	0																								
40	0	0																								
41	0	0																								
42	0	0																								

Transformer fault data table for 24 generators																									
Lapsed year	I1	J1	J2	A1	A2	D1	D2	D1R	D2R	B1	B2	B3	B4	C1	C2	E1	E2	F1	F2	H1	H2	G1	G2	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	1	0	0		0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	1	0	0	0	0	1	0	0		1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	1	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	1	0	0	0	0	0	1			0	0	0	0	0	0	0	0	0	0	0	0	0	0		
12	0	0	0	0	0	0	0			0	0	0	0	0	0	0	2	0	0	0	0	0	0		
13	0	0	0	0	0	1	1			0	0	0	0	0	0	0	0	0	0	0	0	0	0		
14		0	0	0	0	0	0			1	0	0	0	0	0	0	0	0	0	0	0	0	0		
15		0	0	0	0	0	1			0	0	0	0	0	0	0	0	0	0	0	0	0	0		
16		0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0		
17		0	0	0	0	0	0			0	0	0	0	0	1	0	0	0	0	0	0	0	0		
18		0	0	0	0	0	1			0	0	0	0	0	0	0	0	0	0	1	0	0	0		
19		0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0	0	0		
20		0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0				
21		0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0						
22		0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0						
23		0	0	0	0	0	0			0	0	0	0	0	0			0	0						
24		0	0	0	0	1	0			0	0	0	0	0	0			0	0						
25		0	0	0	0		0			0	1	0	0	0	0										
26		0	0	0	0		0			0	0	0	0	0	0										
27		0	0	0	0		0																		
28		0	0	0	0		0																		
29		0	0	0	0																				
30		0	0	0	0																				
31		0	0	0	0																				
32		0	0	0	0																				
33		0	0	0	0																				
34		0	0	0	0																				
35		0	0	0	0																				
36		0	0																						
37		0	0																						
38		0	0																						
39																									
40																									
41																									
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Transformer fault data table for 10 power plant without power plant D																					
Lapsed year	I1	J1	J2	A1	A2	B1	B2	B3	B4	C1	C2	E1	E2	F1	F2	H1	H2	G1	G2	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
11	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
12	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	0	0	0	0		
13	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
14		0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0		
15		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
16		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
17		0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0		
18		0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0		
19		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		
20		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
21		0	0	0	0	0	0	0	0	0	0	0	0	0	0						
22		0	0	0	0	0	0	0	0	0	0	0	0	0	0						
23		0	0	0	0	0	0	0	0	0	0			0	0						
24		0	0	0	0	0	0	0	0	0	0			0	0						
25		0	0	0	0	0	1	0	0	0	0										
26		0	0	0	0	0	0	0	0	0	0										
27		0	0	0	0																
28		0	0	0	0																
29		0	0	0	0																
30		0	0	0	0																
31		0	0	0	0																
32		0	0	0	0																
33		0	0	0	0																
34		0	0	0	0																
35		0	0	0	0																
36		0	0																		
37		0	0																		
38		0	0																		
39																					
40																					
41																					
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Switchyard circuit breaker fault data table for 11 power plants																																					
Lapsed year	I	J1	J2	J1R	J2R	J3	J4	J5	J6	A	AR	D1	D2	B1	B2	B3	B4	B5	B6	C1	C2	E1	E2	E3	E4	F	H1	H2	H3	H4	H5	G1	G2	K1	K2	K3	K4
1	0	1	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
4	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
5	0	0	1	0	0	0	0	0	0	0	0	0	0	1	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
7	o	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
9	1	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0				
12	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
13	0	0	0			0	0	1	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
14		0	0			0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
15		0	0			0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
16		0	0			0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
17		0	0			0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
18		0	0			0	0			0		0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
19		o	o			o	o			0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0				
20		0	0			0	0			0		0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0							
21		0	0			0	0			0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0											
22		0	0							0		0	0	0	0	0	0	0	0	0	0	0	0	0	0	0											
23		0	0							0		0	0	0	0	0	0	0	0	0	0					0											
24		0	0									0	0	0	0	0	0	0	0	0	0					0											
25		0	1									0	0	0	0	0	0	0	0	0	0																
26		1	0									0	0	0	0	0	0	0	0	0	0																
27												0	0																								
28												0	0																								
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Excitation system fault data table for 24 generators

Lapsed year	I1	I2	J1	J2	J1R	J2R	A1	A2	A1R	A2R	D1	D2	D1R	D2R	B1	B2	B3	B4	B1R	B2R	B3R	B4R	C1	C2	C1R	C2R	E1	E2	F1	F2	H1	H2	G1	G2	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1
4	0	0	0	0	0	0	1	0	1	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	0	1					0	0			0	0	0	0	0	0	0	0	0	1
6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					0	0			0	0	0	0	0	0	0	0	0	0
7	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0					0	0			0	0	0	0	0	0	0	0	0	0
8	0	1	1	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	1	0	1	0
9	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0	0	0
10	0	0	1	0	0	0	0	0			0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0	0	0
11	0	0	0	0	0	0	0	0			0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0		
12	0	0	0	0	0	0	0	0			0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0		
13	0	0	0	1	0	0	0	0			0	0			1	0	1	0					0	0			0	0	0	0	0	0	0	0		
14			1	0	0	0	0	0			0	0			1	1	1	0					0	0			0	0	0	0	0	0	0	0		
15			0	0	1	0	0	0			0	0			1	0	0	0					0	0			0	1	0	0	0	0	0	0		
16			0	0	0	0	0	0			0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0		
17			0	0	0	0	0	0			0	0			0	1	0	0					0	1			0	0	0	0	0	0	0	0		
18			0	0	0	0	0	0			0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0		
19				0	0		0	0			0	0			0	0	0	0					1	1			0	0	0	0	0	0	0	0		
20				0	0		0	0			1	0			0	0	0	0					0	0			0	0	0	0	0	0				
21							0	0			0	0			0	1	0	0					0	0			0	0	0	0						
22							0	0			0	1			1	0	0	0					0	0			0	0	0	0						
23							1	0			0	0											0	0					0	0						
24							0	0			0	0																	0	0						
25							0	1																												
26							0	0																												
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Governor fault data table for 24 generators																																				
Lapsed year	I1	I2	J1	J2	J1R	J2R	A1	A2	D1	D2	D1R	D2R	B1	B2	B3	B4	B1R	B2R	B3R	B4R	C1	C2	C1R	C2R	E1	E2	F1	F2	H1	H2	G1	G2	G1R	G2R	K1	K2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
2	1	1	0	0	0	0	0	0	0	0	0	1	1	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0					0	0			0	0	0	0	0	0	0	0			0	0
5	0	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0			0	0
6	1	0	0	0	0	1	0	0	0	0			0	0	0	0					0	1			0	0	0	0	0	0	0	0			0	0
7	0	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0			0	0
8	0	0	0	0	0	1	0	0	0	0			0	0	0	0					0	0			0	1	0	0	1	0	0	0			1	0
9	0	0	0	0	0	0	0	0	0	0			1	0	0	0					0	0			0	0	0	0	0	0	0	0			0	0
10	0	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	1	0			0	0
11	0	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0				
12	0	0	0	0	0		0	0	0	0			0	0	0	0					0	0			1	0	0	1	1	1	0	1				
13	0	0	0	1	0		0	0	0	0			0	0	0	0					0	0			0	1	0	0	0	0	1	0				
14			0	0	0		0	0	0	0			0	0	0	0					0	0			0	0	0	0	1	1	0	1				
15			1	0			0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0				
16			0	1			0	0	0	0			0	0	0	0					0	0			0	1	0	0	0	0	0	0				
17			0	0			0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	1	0	0				
18			0	0			0	0	0	0			0	0	0	0					0	0			0	0	0	0	0	0	0	0				
19			0	0			0	0	0	0			1	1	1	1					0	0			0	0	0	0	0	0	0	0				
20			1	0			0	0	0	0			0	0	0	0					0	0			0	0	1	0	0	0						
21			0	0			0	0	0	0			0	0	0	0					0	1			0	0	0	0								
22			0	0			0	0	0	0			0	1	0	0					0	0			0	0	0	0								
23			0	0			0	0	0	0			0	0	0	0					0	0					0	0								
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Main circuit breaker data table for 24 generators																																										
Lapsed year	I 1	I 2	J 1	J 2	J1 R	J2 R	A 1	A 2	A1 R	A2 R	D 1	D 2	D1 R	D2 R	B 1	B 2	B 3	B 4	B1 R	B2 R	B3 R	B4 R	C 1	C 2	C1 R	C2 R	E 1	E 2	E1 R	E2 R	F 1	F 2	F1 R	F2 R	H 1	H 2	H1 R	H2 R	G 1	G 2	K 1	K 2
1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0
2	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0	0	0	0	0	0	0	0	0	0	0	0
3	0	0	0	0	0	0	0	1	0	0	0	0	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	1	0	0	0	0	0
5	0	0	0	0	0	0	0	0	0	0	0	0			0	2	0	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0	0	0	0	0	0	0	0	0
6	0	0	0	0	1	0	0	0	0	0	0	0			0	0	0	0	0	0	0		0	0	0	0	0	0			0	0			0	0	0	0	0	0	0	0
7	o	0	0	0	0	1	0	0	0	0	0	0			0	0	0	0	0	0			0	0	0	0	0	0			0	0			0	0		0	0	0	0	0
8	0	o	0	0	0	1	0	0	0	0	1	0			0	0	0	0					0	0	0	0	0	0			0	0			0	1		0	0	0	1	0
9	1	0	0	0	0	0	0	0	0	0	0	0			0	0	0	0					0	0	0	0	1	0			0	0			0	0		0	0	0	0	0
10	0	0	0	0	0	0	0	0	0	2	0	0			0	0	0	0					0	0	0	0	0	0			0	0			0	0			0	0	0	0
11	0	0	0	0	1	0	0	0			0	0			0	0	0	0					0	0			0	0			0	0			0	0			0	0		
12	0	0	0	0	0	0	0	0			0	0			0	0	0	0					0	0			0	1			0	0			0	0			0	0		
13	0	0	0	0	0	0	0	0			0	0			0	1	0	0					0	0			0	0			0	0			0	0			0	0		
14			1	0		0	0	0			0	0			0	0	0	0					1	0			0	0			0	0			0	0			0	0		
15			0	1		0	0	0			0	0			1	0	0	0					0	0			0	0			0	0			0				0	0		
16			0	0			1	0			0	0			0	0	0	0					0	0			0	0			0	0			0				0	1		
17			0	0			0	0			0	0			1	2	0	0									1	0			0	0			1				0	0		
18			0	0			0	0			0	0			0	0	1	0									0	1			0	0							0	0		
19			0	1			0	0			0	0			0	0	0	0									1	0			1	2							0	0		
20			1	0			0	0			0	0					0	0									0	0														
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APPENDIX C

SIMULATION PROGRAMS

Conservative power revenue considering definite replacement with 50 year definite replacement for power plant A

```
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%  B/C calculation until definite replacement time  %%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%--------------------------------------------------------------------------
% Description
%
% Using economic evaluation of "conservative power revenue considering
% definite replacement", reliability and B/C is calculated until definite
% replacement time. Power plant A system age is 35 years old, and definite
% replacement year is 50 year.
%
%--------------------------------------------------------------------------
% Language:       Matlab R2009b
% Author:         Ogeuk Kwon
% Reference:      MS thesis
% Date:           March. 2011
%--------------------------------------------------------------------------

clear,clc
LifeTime=30;% book value of equipment
GenCap=90;% Two unit total capacity (100MW)
CF=0.195;% capacity factor
UnitPrice=0.1043;% dollar/kWh
UnitRpsCost=0.59212;% thousand dollar/kW
Tax=0.0024;% 0.24% of replacement cost
OperFee=0.0235;% 0.235% of replacement cost
IntRate=0.065;% Interest Rate
ConstTerms=2;% Constructing terms
CorpTaxRate=0.2750

% Step 1 Benefits calculation

    CapInc=0.05; %Capacity Increase
    EffIncrease=0.05;% Efficiency calculation

    % 1.1 Annual capacity increase calculation not total power revenue
    GenCal=GenCap*(CapInc)*(1+EffIncrease)*8760*CF; %Annual generation (MWH)
    % 1year=8760h,% Benefit during one year
    % BnfGen=GenCal*UnitPrice
    % MWH*thousand won/kWh=unit [million won] and [thousand dollar]

    BnfGen=[];%Generation benefit
    for i=1:1% Generationg benefit of first year calculation
        BnfGenTemp=0; % There is no benefit in first year because one unit
        % is replacing and the other unit does not have increased capacity
    % 0.83 is (6th~10th hours greatest SMP) over (1th~5th hours greatest SMP)
        BnfGen=[BnfGen;BnfGenTemp];
    end
    for i=2:2% Generation benefit of second year calculation
        BnfGenTemp=GenCal*UnitPrice*(1/2);
      % Modernization of one unit is completed while other unit is replacing
        BnfGen=[BnfGen;BnfGenTemp];
    end
    for i=3:60
         % Generation benefit from third year to equipment lifeTime
        BnfGenTemp=GenCal*UnitPrice;
        BnfGen=[BnfGen;BnfGenTemp];% thousand dollar
    end
    BnfGen;

% Step 2 Conventional costs calculation
```

```
    % 2.1 Replacement cost
    RplCost=GenCap*(1+CapInc)*UnitRpsCost*1000; % Replacement cost
    % [million won] or [thousand dollar]
    AnnualRplCost=[];% Declare Annual replacement cost matrix
    for i=1:2% Replacement cost is consumed first two years
        RplCostTemp=RplCost*0.5;
        AnnualRplCost=[AnnualRplCost;RplCostTemp];
    end

    for i=3:LifeTime+ConstTerms
        RplCostTemp=0;
        AnnualRplCost=[AnnualRplCost;RplCostTemp];
    end
    AnnualRplCost;

    % 2.2 Depreciation cost
    DeprCost=RplCost/LifeTime; %DeprCost: Depreciation Cost
    % unit [million won] and [thousand dollar]
    AnnualDeprCost=[];% Declare annual depreciating cost matrix
    for i=1:1
        DeprCostTemp=0;
        AnnualDeprCost=[AnnualDeprCost;DeprCostTemp];
    end
    for i=2:2
        DeprCostTemp=DeprCost*0.5;
        AnnualDeprCost=[AnnualDeprCost;DeprCostTemp];
    end

    for i=3:60
         DeprCostTemp=DeprCost;
        AnnualDeprCost=[AnnualDeprCost;DeprCostTemp];
    end

    AnnualDeprCost;

    % 2.3 Interest cost
    % initializing variables
    AnnualIntPayCost=[];% initialize interest pay cost
    AcmDeprCost=[];%AcmDeprCost: Accumulated Depreciation Cost
    % unit [million won] and [thousand dollar]

    % Interest cost calculation

    for i=1:1
        IntPayCostTemp=RplCost/2*IntRate;
        AnnualIntPayCost=[AnnualIntPayCost;IntPayCostTemp];
        AcmDeprCost=[AcmDeprCost;AnnualDeprCost(i,1)];% accumulative Depreciation
Cost
    end

    for i=2:60
    IntPayCostTemp=(RplCost-sum(AcmDeprCost)-AnnualDeprCost(i,1)/2)*IntRate;
    %IntPayCostTemp is temporary "interest payment cost"
     % (AnnualDeprCost(i,1)/2) means the middle of year of depreciating cost
    AnnualIntPayCost=[AnnualIntPayCost;IntPayCostTemp];
    AcmDeprCost=[AcmDeprCost;AnnualDeprCost(i,1)];% accumulative Depreciation Cost
    end
    AnnualIntPayCost;


    % 2.4 Lost revenue cost during replacement
    LostRevenue=[];% Initialize lost revenue matrix
    for i=1:2
    LostRevenueTemp=(GenCap*8760*CF*UnitPrice)*(1-0.83)*2 %0.83 is SMP average of
```

```
    % 6~10 hours over 1~5 hours highest SMP
    LostRevenue=[LostRevenue,LostRevenueTemp];
    end
    for i=3:LifeTime+2
     LostRevenueTemp=0;
     LostRevenue=[LostRevenue,LostRevenueTemp];
    end

% Step 3 Increased reliability calculation
    % 3.1 Calcualte current reliability

    a=[1.03789E-17, 0.0153, 9.0264E-06, 0.018,  0.0459, 0.0254, 0.0222,...
        0.0204];% a (lamda) parameter of Mean function
    b=[10.1996,     0.7235, 2.9603,     1.0297, 0.8643, 1.3036, 1.3803,...
        1.44408];% b (beta) parameter of Mean function
    % Rotor, Stator, Turbine,   Xformer,SY CB,  Excitor,Governor,Main CB]

    Age_CI=[10;   9; 6.9; 8.7; 8;   10;  10;   8]
    % Rotor,   Stator, Turbine,   Xformer,SY CB, Excitor,Governor,Main CB]
    CI=    [10.0; 9.2; 8.0; 9.5; 8.0; 9.0; 10.0; 8.0 ]
    CCIV=CI./Age_CI
    WeightOfEquipment=[0.15; 0.15; 0.2; 0.25; 0.025; 0.1; 0.1; 0.025];
      % weighted values for equipment
    x=[1:60]% Initialize x-axis values
    Reliability=[];% initialize reliability matrix
    BenefitsIncreasedReliability=[]
    % initialize benefit increased reliability matrix
    IntPayCostOfDepreInvestIntcost=[]% Declare matrix
    % Interest cost of sum of depreciation cost and investment interest
    % cost (hereafter "relative interest cost")
        CumsumAnnualDeprCost=cumsum(AnnualDeprCost);
        %cumulative annual depreciation cost
        CumsumAnnualIntPayCost=cumsum(AnnualIntPayCost);
        %cumulative annual interest cost
             BC=[]
    ReliabilityIncreaRevenue=[];
    BminusC=[];
    UsageYear=35;% Usage year of a power plant
    ExpRplYear=50;% Expected replacement year
    for Year=UsageYear:ExpRplYear
        % reliability calculation from usage year to definite replacement
        % year

        for i=1:4 % % Rotor, Stator, Turbine,   Xformer reliability calculation
            Reliability_temp=exp(-(a(1,i)*Year^b(1,i)));
            Reliability(Year,i)=Reliability_temp*CCIV(i,1)
        end

        for i=5:5% SY CB reliability calculation

            Reliability_temp=exp(-(a(1,i)*(Year-22)^b(1,i)));
            Reliability(Year,i)=Reliability_temp*CCIV(i,1)
        end

        for i=6:6% Excitor reliability calculation

            Reliability_temp=exp(-(a(1,i)*(Year-25)^b(1,i)));
            Reliability(Year,i)=Reliability_temp*CCIV(i,1)
        end
        for i=7:7% Excitor reliability calculation
            Reliability_temp=exp(-(a(1,i)*(Year-34)^b(1,i)));
            Reliability(Year,i)=Reliability_temp*CCIV(i,1)
        end
       for i=8:8% Main CB reliability calculation
```

```
            Reliability_temp=exp(-(a(1,i)*(Year-24)^b(1,i)));
            Reliability(Year,i)=Reliability_temp*CCIV(i,1)
        end
        Reliability;

        System_Reliability=Reliability*WeightOfEquipment
        % System reliability calculation

        % Increased reliability benefits

        rotorOutageDays=50;
        statorOutageDays=120;
        turbineOutageDays=21;
        xformerOutageDays=30;
        sY_CBOutageDays=7;
        excitorOutageDays=14;
        governorOutageDays=14;
        main_CBOutageDays=7;

        ODF=45.3/365 %outageDayfactor 45.3/365
        % Actual outage data calculation
        RotorOutageDays=(1-Reliability(Year,1))*rotorOutageDays;
        % Actual RotorOutageDays
        StatorOutageDays=(1-Reliability(Year,2))*statorOutageDays;
        % Actual statorOutageDays
        TurbineOutageDays=(1-Reliability(Year,3))*turbineOutageDays;
        % Actual turbineOutageDays
        XformerOutageDays=(1-Reliability(Year,4))*xformerOutageDays;
        % Actual xformerOutageDays
        SY_CBOutageDays=(1-Reliability(Year,5))*sY_CBOutageDays;
        % Actual SY_CBOutageDays
        ExcitorOutageDays=(1-Reliability(Year,6))*excitorOutageDays;
        % Actual ExcitorOutageDays
        GovernorOutageDays=(1-Reliability(Year,7))*governorOutageDays;
        % Actual GovernorOutageDays
        Main_CBOutageDays=(1-Reliability(Year,8))*main_CBOutageDays;
        % Actual GovernorOutageDays

        % Calculate increased reliability benefit
        BenefitsIncreasedReliabilityTemp=GenCap*(RotorOutageDays+...
        StatorOutageDays+TurbineOutageDays+XformerOutageDays+SY_CBOutageDays...
        +ExcitorOutageDays+GovernorOutageDays+Main_CBOutageDays)*...
        24*CF*UnitPrice*ODF; %outageDayfactor 45.3/365

       BenefitsIncreasedReliability=[BenefitsIncreasedReliability;...
       BenefitsIncreasedReliabilityTemp]
   end

 BenefitsIncreasedReliability;
 System_Reliability=Reliability*WeightOfEquipment

% Step 4  calculate Interest cost of sum of depreciation cost and ...
% investment interest cost and increase reliability benefit

 for i=1:1% first year no reliability power revenue
     ReliabilityIncreaRevenueTemp=0;
     % Benefit calculation (reliability increase + capacity
     % and efficiency increase)
     ReliabilityIncreaRevenue=[ReliabilityIncreaRevenue;...
     ReliabilityIncreaRevenueTemp];% Accumulate benefit
                        % [million won] or [thousand dollar]

      IntPayCostOfDepreInvestIntcostTemp=(CumsumAnnualDeprCost...
          (ExpRplYear-UsageYear+1-i)+CumsumAnnualIntPayCost(ExpRplYear...
```

```
            -UsageYear+1-i))*IntRate; % interest of interest rate
        IntPayCostOfDepreInvestIntcost=[IntPayCostOfDepreInvestIntcost;...
            IntPayCostOfDepreInvestIntcostTemp];
  end
  for i=2:2
      % second year half reliability power revenue because of one
      % unit replacement
      ReliabilityIncreaRevenueTemp=BenefitsIncreasedReliability(i,1)*0.5;
        % Benefit calculation (reliability increase + capacity and
        % efficiency increase)
       ReliabilityIncreaRevenue=[ReliabilityIncreaRevenue;...
           ReliabilityIncreaRevenueTemp];% Accumulate benefit
                         % [million won] or [thousand dollar]

       IntPayCostOfDepreInvestIntcostTemp=(CumsumAnnualDeprCost(ExpRplYear-...
       UsageYear+1-i)+CumsumAnnualIntPayCost(ExpRplYear-UsageYear+1-i))*IntRate;


       % interest of interest rate
       IntPayCostOfDepreInvestIntcost=[IntPayCostOfDepreInvestIntcost;...
       IntPayCostOfDepreInvestIntcostTemp];
  end

  for i=3:ExpRplYear-UsageYear

        ReliabilityIncreaRevenueTemp=BenefitsIncreasedReliability(i,1);
        % Benefit calculation (reliability increase + capacity and efficiency in-
crease)
        ReliabilityIncreaRevenue=[ReliabilityIncreaRevenue;...
        ReliabilityIncreaRevenueTemp];% Accumulate benefit
                     % [million won] or [thousand dollar]

        IntPayCostOfDepreInvestIntcostTemp=(CumsumAnnualDeprCost...
        (ExpRplYear-UsageYear+1-i)+CumsumAnnualIntPayCost(ExpRplYear-...
        UsageYear+1-i))*IntRate; % interest of interest rate
        IntPayCostOfDepreInvestIntcost=[IntPayCostOfDepreInvestIntcost;...
        IntPayCostOfDepreInvestIntcostTemp];

  end
       ReliabilityIncreaRevenue;
       IntPayCostOfDepreInvestIntcost;

% Step 5 B/C calculation
  % Initialize matrix
  SumReliabilityIncreaRevenue=[]
  % Sum of reliability increased revenue
  SumIntPayCostOfDepreInvestIntcost=[]
  % Accumulative sum of Interest cost of sum of depreciation cost and ...

  Benefit=[]
  Cost=[]

  for i=1:1% Usage year+1 year benefit cost calculation
      benefit1=0% saving relative interest cost is zero
      % benefit1 is saving relative interest cost
      benefit2=sum(ReliabilityIncreaRevenue(1:ExpRplYear-UsageYear+1-i))...
        +sum(BnfGen(1:ExpRplYear-UsageYear+1-i))
      % benefit2 is reliability increased benefit + generation benefit

      BenefitTemp=benefit1+benefit2
      Benefit=[Benefit;BenefitTemp]

      % cost
      cost1=0
```

```
    % cost1 is reliability increased benefit because modernization is not
    % implemented
    cost2=sum(IntPayCostOfDepreInvestIntcost(1:ExpRplYear-UsageYear+1-i))
    % cost2 is reliability increased benefit + generation benefit
    CostTemp=cost1+cost2
    Cost=[Cost;CostTemp]
    BbyC=BenefitTemp/CostTemp
           BC=[BC;BbyC]

end

for i=2:ExpRplYear-UsageYear
        benefit1=sum(IntPayCostOfDepreInvestIntcost(1:i-1))
        % benefit1 is saving relative interest cost

        benefit2=sum(ReliabilityIncreaRevenue(1:ExpRplYear-UsageYear+1-i...
            ))+sum(BnfGen(1:ExpRplYear-UsageYear+1-i))
       % benefit2 is reliability increased benefit + generation benefit
        BenefitTemp=benefit1+benefit2
        Benefit=[Benefit;BenefitTemp]

    % cost

    cost1=sum(ReliabilityIncreaRevenue(ExpRplYear-UsageYear+2-i:...
        ExpRplYear-UsageYear))+sum(BnfGen(ExpRplYear-UsageYear+2-i:...
        ExpRplYear-UsageYear))
    % cost1 is reliability increased benefit because modernization is not
    % implemented
    cost2=sum(IntPayCostOfDepreInvestIntcost(i:ExpRplYear-UsageYear))
    % cost2 is reliability increased benefit + generation benefit
    CostTemp=cost1+cost2
    Cost=[Cost;CostTemp]
    BbyC=BenefitTemp/CostTemp
           BC=[BC;BbyC]
end
Benefit
Cost
BC

x=UsageYear+1:ExpRplYear
[AX,H1,H2]=plotyy(x,System_Reliability(UsageYear+1:ExpRplYear),x,BC)
  xlabel('System age, Year')
  title('Reliability and B/C versus year')
  set(get(AX(1),'Ylabel'),'String','System reliability')
  set(get(AX(2),'Ylabel'),'String','B/C')

 % End
%-----------------------------------------------------------------------
```

Determination for equipment replacement

```
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%%%%%%%%%%%%%%%  Determination for Group1 replacement period  %%%%%%%%%%%%%
%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%%
%--------------------------------------------------------------------------
% Description
%
% Group 1 is rotor, stator, turbine and transformer, which are
% 4 greatest reliable equipment. The best replacement period for group 2 is
% simulated with 20 year replacement period of group 2.
%
%--------------------------------------------------------------------------
% Language:       Matlab R2009b
% Author:         Ogeuk Kwon
% Reference:      MS thesis
% Date:           March. 2011
%--------------------------------------------------------------------------
% Step 1. Input data and initialize matrices
clear,clc
Lifetime=30;
GenCap=90;% Two unit total capacity (100MW)
CF=0.195;% capacity factor
UnitPrice=0.1043;% dollar/kWh
LifeTime=30;
UnitRpsCost=0.59212;% thousand dollar/kW
Tax=0.0024;% 0.24% of replacement cost
OperFee=0.0235;% 0.235% of replacement cost
IntRate=0.05;% Interest Rate
ConstTerms=2;% Construction terms
CorpTaxRate=0.2750;
RepairCost=0.008;
StartingYear=1;% Usage year of a power plant
TerminationYear=500;% Expected replacement year
CapInc=0.05; %Capacity Increase
EffIncrease=0.05;% Efficiency calculation
OutageDayFactor=45.3/365; %outageDayfactor 45.3/365

% Parameters for equipment
a=[1.03789E-17, 0.0153, 9.0264E-06, 0.018,  0.0459, 0.0254, 0.0222,...
    0.0204];% a (lamda) parameter of Mean function
b=[10.1996,     0.7235, 2.9603,     1.0297, 0.8643, 1.3036, 1.3803,...
    1.44408];% b (beta) parameter of Mean function
% Rotor,   Stator,       Turbine,   Xformer,SY CB,  Excitor,Governor,Main CB]

% Installing costs for equipment thousand dollars or million won
PriceForRotor=5000;
PriceForStator=5000;
PriceForTurbine=10000;
PriceFortransformer=4000;
PriceForSYCB=400;
PriceForExcitationSystem=1000;
PriceForGovernor=1000;
PriceForMainCB=400;

% Replacement days for equipment
ReplacementDaysForRotor=60;
ReplacementDaysForStator=180;
ReplacementDaysForTurbine=60;
ReplacementDaysFortransformer=30;
ReplacementDaysForSYCB=15;
ReplacementDaysForExcitationSystem=30;
ReplacementDaysForGovernor=30;
ReplacementDaysForMainCB=15;
```

```
 % Initialize matrices
WeightOfEquipment=[0.15; 0.15; 0.2; 0.25; 0.025; 0.1; 0.1; 0.025];
x=(StartingYear:TerminationYear);
Reliability=[];% initialize stator reliability
BenefitsIncreasedReliability=[];
BenefitsIncreasedReliabilityGroup1=[];
BenefitsIncreasedReliabilityGroup2=[];
IntPayCostOfDepreInvestIntcost=[];
BC=[];
ReliabilityIncreaRevenue=[];
BminusC=[];
SumBenefitMinusCost=[];
Group2_ReplacementYear=20;
Group1_ReplacementYearStart=30;
Group1_ReplacementYearEnd=55;

% Group1 reliability
a_Group1=0.0083272566;
% a is Lambda average of rotor, stator, turbine, and transformer
b_Group1=1.178375;
% b is Beta % average of stator, turbine, and transformer except rotor
R_Group1=[];% initialize Group 1 reliability
Year=[];
% Group2 reliability
a_Group2=0.028475; % a is Lambda
b_Group2=1.24807; % b is Beta
R_Group2=[];% initialize Group 2 reliability
% Group1 outage days
OutageDayGroup1=[];
OutageDayGroup1Max=120;
% Group2 outage days
OutageDayGroup2=[];
OutageDayGroup2Max=56.25;

% Step 2. Find suitable group 1 replacement period varying replacement period
% Do the group 1 replacement period loop with 20 year replacement of group 2
for Group1_ReplacementYear=Group1_ReplacementYearStart:Group1_ReplacementYearEnd

% Reliability Group 1
    for i=StartingYear:TerminationYear% Set loop time
    R_temp=exp(-(a_Group1*i^b_Group1));% Calculate group 1 reliability
    R_Group1=[R_Group1;R_temp];% Accumulate group 1 reliability
    end
    R_Group1;
% Reliability Group 2
    for i=StartingYear:TerminationYear
    R_temp=exp(-(a_Group2*i^b_Group2));% Calculate group 2 reliability
    R_Group2=[R_Group2;R_temp];% Accumulate group 2 reliability
    end
    R_Group2;

% Group 1 outage days calculation based on reliability
    for i=StartingYear:TerminationYear
    OutageDayGroup1Temp=(1-R_Group1(i,1))*OutageDayGroup1Max
    OutageDayGroup1=[OutageDayGroup1;OutageDayGroup1Temp];% Accumulate
    end

% Group 2 outage days calculation based on reliability
    for i=StartingYear:TerminationYear
    OutageDayGroup2Temp=(1-R_Group2(i,1))*OutageDayGroup2Max
    OutageDayGroup2=[OutageDayGroup2;OutageDayGroup2Temp];
    end
```

```
% 2.1. Benefits
% 2.1.1 Annual power revenue
 GenerationBenefit=[];
 for Year=StartingYear:TerminationYear
        GenCal=GenCap*8760*CF; %Annual generation (MWH)
            % 1year=8760h,% Benefit during one year
        GenerationBenefitTemp=GenCal*UnitPrice;
        GenerationBenefit=[GenerationBenefit;GenerationBenefitTemp];
        % thousand dollar
 end

% 2.1.2 Annual increased power revenue
 IncreasedGenerationBenefit=[];
 for Year=StartingYear:TerminationYear
     % If present year is less than replacement year, no benefit
     if Year <= Group1_ReplacementYear
        IncreasedGenerationBenefitTemp=0;
        IncreasedGenerationBenefit=[IncreasedGenerationBenefit;...
            IncreasedGenerationBenefitTemp];% thousand dollar

     else
        GenCal=GenCap*(CapInc)*(1+EffIncrease)*8760*CF;
        %Annual generation (MWH)
            % 1year=8760h,% Benfit during one year
        IncreasedGenerationBenefitTemp=GenCal*UnitPrice;
        IncreasedGenerationBenefit=[IncreasedGenerationBenefit;...
            IncreasedGenerationBenefitTemp];% thousand dollar
     end
 end
 IncreasedGenerationBenefit;

 % 2.1.3 Annual increased reliability benefit
    ReliabilityLapseYearGroup1=0;
    ReliabilityLapseYearGroup2=0;
    Group1_TurnTime=0
    Group2_TurnTime=0
    rotorOutageDays=50;
    statorOutageDays=120;
    turbineOutageDays=21;
    xformerOutageDays=30;
    sY_CBOutageDays=7;
    excitorOutageDays=14;
    governorOutageDays=14;
    main_CBOutageDays=7;
    OutageDayFactor=45.3/365 %outageDayfactor 45.3/365

for Year=StartingYear:TerminationYear
 % If present year is less than group 1 replacement year, no benefit
 if Year <= Group1_ReplacementYear
    BenefitsIncreasedReliabilityGroup1Temp=0;
    BenefitsIncreasedReliabilityGroup1=[BenefitsIncreasedReliabilityGroup1;...
    BenefitsIncreasedReliabilityGroup1Temp]
% If present year is 1 year greater than every times of replacement year
 elseif   (Year==1*Group1_ReplacementYear+1) | (Year==2*Group1_ReplacementYear+1)...
      | (Year==3*Group1_ReplacementYear+1) | (Year==4*Group1_ReplacementYear+1)...
      |(Year==5*Group1_ReplacementYear+1) | (Year==6*Group1_ReplacementYear+1)...
      | (Year==7*Group1_ReplacementYear+1)...
      | (Year==8*Group1_ReplacementYear+1)| (Year==9*Group1_ReplacementYear+1)|...
      (Year==10*Group1_ReplacementYear+1)

    ReliabilityLapseYearGroup1=0
    OneUnitSavedOutageDayGroup1=(1-R_Group1(Year-Group1_TurnTime...
        *Group1_ReplacementYear,1))...
        *(1-R_Group1(Year-Group1_TurnTime*Group1_ReplacementYear,1))...
```

```
        *OutageDayGroup1Max
    BothUnitSavedOutageDayGroup1=(1-R_Group1(Year-Group1_TurnTime*...
        Group1_ReplacementYear,1))...
    *(1-R_Group1(Year-Group1_TurnTime*Group1_ReplacementYear,1))*...
      (1-R_Group1(Year-Group1_TurnTime*Group1_ReplacementYear,1))*...
    OutageDayGroup1Max
    BenefitsIncreasedReliabilityGroup1Temp=GenCap*...
        (OneUnitSavedOutageDayGroup1)*24*CF*UnitPrice*OutageDayFactor...;
        %outageDayfactor 45.3/365
             +GenCap*(BothUnitSavedOutageDayGroup1)*24*CF*UnitPrice
             % When both units calculating, except "OutageDayFactor"
    BenefitsIncreasedReliabilityGroup1=[BenefitsIncreasedReliabilityGroup1...
        ;BenefitsIncreasedReliabilityGroup1Temp]
    Group1_TurnTime=Group1_TurnTime+1
 else
    ReliabilityLapseYearGroup1=ReliabilityLapseYearGroup1+1
    OneUnitSavedOutageDayGroup1=(R_Group1(ReliabilityLapseYearGroup1,1)...
        -R_Group1(Year-(Group1_TurnTime-1)*Group1_ReplacementYear,1))...
        *(1-R_Group1(Year-(Group1_TurnTime-1)*Group1_ReplacementYear,1))...
        *OutageDayGroup1Max % Outage days are reversely proportional to reliabil-
ity
     BothUnitSavedOutageDayGroup1=(R_Group1(ReliabilityLapseYearGroup1,1)...
         -R_Group1(Year-(Group1_TurnTime-1)*Group1_ReplacementYear,1))*...
    (R_Group1(ReliabilityLapseYearGroup1,1)-R_Group1(Year-(Group1_TurnTime-1)...
    *Group1_ReplacementYear,1))*...
    (1-R_Group1(Year-(Group1_TurnTime-1)*Group1_ReplacementYear,1))...
      *OutageDayGroup1Max

    BenefitsIncreasedReliabilityGroup1Temp=GenCap*(OneUnitSavedOutageDayGroup1)...
        *24*CF*UnitPrice*OutageDayFactor...; %outageDayfactor 45.3/365
     +GenCap*(BothUnitSavedOutageDayGroup1)*24*CF*UnitPrice
    % When both units calculating, except "OutageDayFactor"
    BenefitsIncreasedReliabilityGroup1=[BenefitsIncreasedReliabilityGroup1;...
        BenefitsIncreasedReliabilityGroup1Temp]
 end
% If present year is less than group 2 replacement year, no benefit
  if Year <= Group2_ReplacementYear
    BenefitsIncreasedReliabilityGroup2Temp=0;
    BenefitsIncreasedReliabilityGroup2=[BenefitsIncreasedReliabilityGroup2...
        ;BenefitsIncreasedReliabilityGroup2Temp]
 elseif  (Year==1*Group2_ReplacementYear+1) | (Year==2*Group2_ReplacementYear+1)...
      | (Year==3*Group2_ReplacementYear+1) | (Year==4*Group2_ReplacementYear+1)...
      |(Year==5*Group2_ReplacementYear+1) | (Year==6*Group2_ReplacementYear+1)...
      | (Year==7*Group2_ReplacementYear+1)| (Year==8*Group2_ReplacementYear+1)...
      | (Year==9*Group2_ReplacementYear+1)| (Year==10*Group2_ReplacementYear+1)

    ReliabilityLapseYearGroup2=0
    OneUnitSavedOutageDayGroup2=(1-R_Group2(Year-Group2_TurnTime*...
        Group2_ReplacementYear,1))...
        *(1-R_Group2(Year-Group2_TurnTime*Group2_ReplacementYear,1))...
        *OutageDayGroup2Max
    BothUnitSavedOutageDayGroup2=(1-R_Group2(Year-Group2_TurnTime*...
        Group2_ReplacementYear,1))...
    *(1-R_Group2(Year-Group2_TurnTime*Group2_ReplacementYear,1))*...
    (1-R_Group2(Year-Group2_TurnTime*Group2_ReplacementYear,1))*...
    OutageDayGroup2Max
    BenefitsIncreasedReliabilityGroup2Temp=GenCap*(OneUnitSavedOutageDayGroup2)...
        *24*CF*UnitPrice*OutageDayFactor...; %outageDayfactor 45.3/365
     +GenCap*(BothUnitSavedOutageDayGroup2)*24*CF*UnitPrice
    % When both units calculating, except "OutageDayFactor"
    BenefitsIncreasedReliabilityGroup2=[BenefitsIncreasedReliabilityGroup2;...
        BenefitsIncreasedReliabilityGroup2Temp]
    Group2_TurnTime=Group2_TurnTime+1
 else
```

```
    ReliabilityLapseYearGroup2=ReliabilityLapseYearGroup2+1


    OneUnitSavedOutageDayGroup2=(R_Group2(ReliabilityLapseYearGroup2,1)...
        -R_Group2(Year-(Group2_TurnTime-1)*Group2_ReplacementYear,1))...
        *(1-R_Group2(Year-(Group2_TurnTime-1)*Group2_ReplacementYear,1))...
        *OutageDayGroup2Max % Outage days are reversely proportional to reliabil-
ity
     BothUnitSavedOutageDayGroup2=(R_Group2(ReliabilityLapseYearGroup2,1)...
         -R_Group2(Year-(Group2_TurnTime-1)*Group2_ReplacementYear,1))*...
    (R_Group2(ReliabilityLapseYearGroup2,1)-R_Group2(Year-(Group2_TurnTime-1)...
    *Group2_ReplacementYear,1))*...
    (1-R_Group2(Year-(Group2_TurnTime-1)*Group2_ReplacementYear,1))*...
    OutageDayGroup2Max

    BenefitsIncreasedReliabilityGroup2Temp=GenCap*(OneUnitSavedOutageDayGroup2)...
        *24*CF*UnitPrice*OutageDayFactor...; %outageDayfactor 45.3/365
         +GenCap*(BothUnitSavedOutageDayGroup2)*24*CF*UnitPrice
     % When both units calculating, except "OutageDayFactor"

    BenefitsIncreasedReliabilityGroup2=[BenefitsIncreasedReliabilityGroup2...
        ;BenefitsIncreasedReliabilityGroup2Temp]
  end

  BenefitsIncreasedReliability=[BenefitsIncreasedReliability;...
  BenefitsIncreasedReliabilityGroup1Temp+BenefitsIncreasedReliabilityGroup2Temp]
end

 % 2.2 Costs
 % 2.2.1 Operation cost
 OperationCost=[];
 for Year=StartingYear:TerminationYear
        OperationCostTemp=(GenCap*OperFee*UnitRpsCost*1000);
        OperationCost=[OperationCost;OperationCostTemp];% thousand dollar
 end

 % 2.2 Repair cost
 RepairCostGroup1=[]
 RepairCostGroup2=[]
 Group1_TurnTime=0;
 Group2_TurnTime=0;

 for Year=StartingYear:TerminationYear

    if (Year==1*Group1_ReplacementYear+1) | (Year==2*Group1_ReplacementYear+1)...
      | (Year==3*Group1_ReplacementYear+1) | (Year==4*Group1_ReplacementYear+1)...
      |(Year==5*Group1_ReplacementYear+1) | (Year==6*Group1_ReplacementYear+1)...
      | (Year==7*Group1_ReplacementYear+1)| (Year==8*Group1_ReplacementYear+1)...
      | (Year==9*Group1_ReplacementYear+1)| (Year==10*Group1_ReplacementYear+1)


    RepairCostGroup1_Temp=((PriceForRotor+PriceForStator+PriceForTurbine+...
    +PriceFortransformer)*(RepairCost)*(1+IntRate)^1);
    RepairCostGroup1=[RepairCostGroup1;RepairCostGroup1_Temp]
    Group1_TurnTime=Group1_TurnTime+1
    else
      RepairCostGroup1_Temp=((PriceForRotor+PriceForStator+PriceForTurbine+...
        +PriceFortransformer)*(RepairCost))*(1+IntRate)^(Year-...
        Group1_TurnTime*Group1_ReplacementYear);
     RepairCostGroup1=[RepairCostGroup1;RepairCostGroup1_Temp]

    end
```

```
    if (Year==1*Group2_ReplacementYear+1) | (Year==2*Group2_ReplacementYear+1)...
      | (Year==3*Group2_ReplacementYear+1) | (Year==4*Group2_ReplacementYear+1)...
      |(Year==5*Group2_ReplacementYear+1) | (Year==6*Group2_ReplacementYear+1)...
      | (Year==7*Group2_ReplacementYear+1)| (Year==8*Group2_ReplacementYear+1)...
      | (Year==9*Group2_ReplacementYear+1)| (Year==10*Group2_ReplacementYear+1)

     RepairCostGroup2_Temp=((PriceForSYCB+PriceForExcitationSystem+...
         PriceForGovernor+PriceForMainCB)*(RepairCost))*(1+IntRate)^1;
     RepairCostGroup2=[RepairCostGroup2;RepairCostGroup2_Temp]
     Group2_TurnTime=Group2_TurnTime+1
    else

     RepairCostGroup2_Temp=((PriceForSYCB+PriceForExcitationSystem+...
     PriceForGovernor+PriceForMainCB)*(RepairCost))*(1+IntRate)^...
     (Year-Group2_TurnTime*Group2_ReplacementYear);
     RepairCostGroup2=[RepairCostGroup2;RepairCostGroup2_Temp]

    end
 end

       RepairCostSum=RepairCostGroup1+RepairCostGroup2;% thousand dollar

% 2.2.3 Construction lost revenue

        ConstructionLostRevenueGroup1=[];
        ConstructionLostRevenueGroup2=[];
 for Year=StartingYear:TerminationYear


    if (Year==1*Group1_ReplacementYear+1) | (Year==2*Group1_ReplacementYear+1)...
      | (Year==3*Group1_ReplacementYear+1) | (Year==4*Group1_ReplacementYear+1)...
      |(Year==5*Group1_ReplacementYear+1) | (Year==6*Group1_ReplacementYear+1)...
      | (Year==7*Group1_ReplacementYear+1)| (Year==8*Group1_ReplacementYear+1)...
      | (Year==9*Group1_ReplacementYear+1)| (Year==10*Group1_ReplacementYear+1)

       ConstructionLostRevenueGroup1Temp=GenCap*8760*CF*UnitPrice*...
       (ReplacementDaysForRotor+ReplacementDaysForStator+...
        ReplacementDaysForTurbine+ReplacementDaysFortransformer)/365*...
        OutageDayFactor;

    else
      ConstructionLostRevenueGroup1Temp=0

    end
      ConstructionLostRevenueGroup1=[ConstructionLostRevenueGroup1;...
          ConstructionLostRevenueGroup1Temp];

     if (Year==1*Group2_ReplacementYear+1) | (Year==2*Group2_ReplacementYear+1)...
      | (Year==3*Group2_ReplacementYear+1) | (Year==4*Group2_ReplacementYear+1)...
      |(Year==5*Group2_ReplacementYear+1) | (Year==6*Group2_ReplacementYear+1)...
      | (Year==7*Group2_ReplacementYear+1)| (Year==8*Group2_ReplacementYear+1)...
      | (Year==9*Group2_ReplacementYear+1)| (Year==10*Group2_ReplacementYear+1)
     ConstructionLostRevenueGroup2Temp=GenCap*8760*CF*UnitPrice*...
         (ReplacementDaysForSYCB+ReplacementDaysForExcitationSystem+...
         ReplacementDaysForGovernor+ReplacementDaysForMainCB)/365*OutageDayFactor;
    else
    ConstructionLostRevenueGroup2Temp=0
    end
     ConstructionLostRevenueGroup2=[ConstructionLostRevenueGroup2;...
         ConstructionLostRevenueGroup2Temp];
 end
        ConstructionLostRevenue=ConstructionLostRevenueGroup1+...
            ConstructionLostRevenueGroup2
```

```
% 2.2.4 Construction cost

     ConstructionCostRevenue=[];
     ConstructionCostRevenueGroup1=[];
     ConstructionCostRevenueGroup2=[];
for Year=StartingYear:TerminationYear


    if (Year==1*Group1_ReplacementYear+1) | (Year==2*Group1_ReplacementYear+1)...
     | (Year==3*Group1_ReplacementYear+1) | (Year==4*Group1_ReplacementYear+1)...
     |(Year==5*Group1_ReplacementYear+1) | (Year==6*Group1_ReplacementYear+1)...
     | (Year==7*Group1_ReplacementYear+1)| (Year==8*Group1_ReplacementYear+1)...
     | (Year==9*Group1_ReplacementYear+1)| (Year==10*Group1_ReplacementYear+1)

          ConstructionCostRevenueGroup1Temp=(PriceForRotor+PriceForStator+...
              PriceForTurbine+PriceFortransformer);
   else
         ConstructionCostRevenueGroup1Temp=0;

    end
           ConstructionCostRevenueGroup1=[ConstructionCostRevenueGroup1;...
               ConstructionCostRevenueGroup1Temp];

    if (Year==1*Group2_ReplacementYear+1) | (Year==2*Group2_ReplacementYear+1)...
     | (Year==3*Group2_ReplacementYear+1) | (Year==4*Group2_ReplacementYear+1)...
     |(Year==5*Group2_ReplacementYear+1) | (Year==6*Group2_ReplacementYear+1)...
     | (Year==7*Group2_ReplacementYear+1)| (Year==8*Group2_ReplacementYear+1)...
     | (Year==9*Group2_ReplacementYear+1)| (Year==10*Group2_ReplacementYear+1)
    ConstructionCostRevenueGroup2Temp=(PriceForSYCB+PriceForExcitationSystem+...
        PriceForGovernor+PriceForMainCB);
   else
   ConstructionCostRevenueGroup2Temp=0;
   end
      ConstructionCostRevenueGroup2=[ConstructionCostRevenueGroup2;...
          ConstructionCostRevenueGroup2Temp];

end

             ConstructionCostRevenue=ConstructionCostRevenueGroup1+...
             ConstructionCostRevenueGroup2

% 2.3. BC calculation
% 2.3.1 Benefit calculation
        SumOfBenefit=[]
        SumOfCost=[]

   for Year=StartingYear:TerminationYear
       SumOfBenefitTemp=GenerationBenefit(Year,1)+...
       IncreasedGenerationBenefit(Year,1)+BenefitsIncreasedReliability(Year,1)
       SumOfBenefit=[SumOfBenefit;SumOfBenefitTemp];
   end

 % 2.3.2 Cost calculation
   for Year=StartingYear:TerminationYear
       SumOfCostTemp=OperationCost(Year,1)+RepairCostSum(Year,1)+...
           ConstructionLostRevenue(Year,1)+ConstructionCostRevenue(Year,1)
       SumOfCost=[SumOfCost;SumOfCostTemp];
   end

 % 2.3.3 Benefit-Cost
   for Year=StartingYear:TerminationYear
       BenefitMinusCost(Year,Group1_ReplacementYear-29)=SumOfBenefit(Year,1)...
           -SumOfCost(Year,1)
   end
```

```
% 2.3.4 Sum of "Benefit-Cost"
SumBenefitMinusCost=[SumBenefitMinusCost;sum(BenefitMinusCost...
    (:,Group1_ReplacementYear-29))]

% Reset the vectors which were used to store next data
Reliability=[];
GenerationBenefit=[];
IncreasedGenerationBenefit=[];
BenefitsIncreasedReliability=[];
OperationCost=[];
RepairCostGroup1=[];
RepairCostGroup2=[];
RepairCostSum=[];
ConstructionLostRevenue=[];
ConstructionCostRevenue=[];
SumOfBenefit=[];
SumOfCost=[];
BenefitMinusCostTemp=[];
Group1_TurnTime=0;
Group2_TurnTime=0;
end

% 3. Plotting
% Plot Benefit minus cost versus power plant usage year
plot(x,BenefitMinusCost(:,1),x,BenefitMinusCost(:,2),x,BenefitMinusCost...
  (:,3),x,BenefitMinusCost(:,4),x,BenefitMinusCost(:,5),...
   x,BenefitMinusCost(:,6),x,BenefitMinusCost(:,7),x,BenefitMinusCost...
   (:,8),x,BenefitMinusCost(:,9),x,BenefitMinusCost(:,10),...
   x,BenefitMinusCost(:,11),x,BenefitMinusCost(:,12),x,BenefitMinusCost...
   (:,13),x,BenefitMinusCost(:,14),x,BenefitMinusCost(:,15),...
   x,BenefitMinusCost(:,16),x,BenefitMinusCost(:,17),x,BenefitMinusCost...
   (:,18),x,BenefitMinusCost(:,19),x,BenefitMinusCost(:,20),...
   x,BenefitMinusCost(:,21))

% Plot sum of "benefit mimus cost" versus "group 1 replacement range"
       x2=Group1_ReplacementYearStart:Group1_ReplacementYearEnd;
       % set range of "Group1_ReplacementYear"
       plot(x2,SumBenefitMinusCost)
        xlabel('Replacement period of Group1 (Year)')
        ylabel('Sum of Benefit minus Cost')
% End
%--------------------------------------------------------------------------
```