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ECONOMIC AND SYSTEM RELIABILITY CONSIDERATIONS FOR ACHIEVING AN EXTENDED OPERATING CYCLE FOR LIGHT WATER REACTORS

by

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ABSTRACT

The economic performance of a nuclear power plant can be improved by increasing the plant capacity factor. However, the current short refueling cycle lengths, usually 12 to 18 months, limit the capacity factor that can be achieved. Extending the refueling cycle length should be considered as a strategy to obtain higher capacity factor. A project concerned with the feasibility of extending the refueling interval to 48 months is currently in progress at MIT. This thesis will be a part of this project.

This thesis has two major parts. The first part is an economic analysis. The purpose of the economic analysis is to study the economic feasibility of operating cycle extension, and to set a reasonable goal for the capacity factor of the plant and its individual systems which is required to make a 48-month operating cycle length economically attractive. In the economic analysis, the potential benefits and costs of operating cycle extension are identified. The major benefit of cycle extension is the additional electricity generation because of the higher plant capacity factor. Besides this, benefits can be gained from reduced number of outages. The dominant cost of operating cycle extension is the extra fuel cost because of the required higher fuel enrichment and lower fuel burnup. A economic model for operating cycle extension is developed to evaluate the net benefit of operating cycle extension. As the extreme boundaries, the annual extra cost is considered as constant and linearly changing with the extended cycle length.

In the economic analysis, the changes in the net benefit due to different extended cycle lengths, changes in total outage length and different current cycle lengths are studied; the sensitivities of net benefit to the total extra costs and the electricity price are also studied. All these sensitivity studies are carried out based upon both constant and linear annual extra cost models. Since some required surveillance whose interval is shorter than 48 months may not be extended, a mid-cycle planned outage for surveillance only may be necessary. The effects of the mid-cycle outage on the plant capacity factor and net benefit of refueling cycle extension will be studied.

The second part of this thesis is a study for improving the reliability and capacity factor of nuclear plant systems. To make the extension of refueling cycle length to 48 months profitable, the unplanned outage rate must be limited below a certain level. This requirement for unplanned outage rate is set based upon the results of the economic analysis. The intentions of the reliability and capacity factor analyses are to identify the individual component performance regimes of a PWR system which are necessary for achieving the required levels of power plant reliability, to formulate the basic strategies for obtaining high capacity factor for PWR systems, and to develop a framework for analyzing the economically-important system performance.

The feedwater supply system of a PWR, the Seabrook Nuclear Power Station is chosen as an example. To aid in understanding the system's working principle, a system description is included in this thesis. By using a Markov model, the feedwater supply system reliability is thoroughly investigated. The studies include a reliability analysis and a capacity factor analysis. The reliability analysis identifies the key components of the condensate and feedwater system based upon plant-specific data. The capacity factor analysis studies whether the strategy of providing redundancy in the key components is necessarily a good strategy for improving the capacity factor of an economically-important system, even though we already know that it is a good strategy for improving the reliability of a safety-important system. The capacity factor analysis also studies the sensitivity of system capacity factor to the individual system component failure rates and repair rates. The component performance regimes is thus obtained from these sensitivity analyses. In addition, the effects of common cause failures, human errors, and component wearout upon the system capacity factor is also investigated in the capacity factor analysis. Based upon the results of these analyses, the strategies for obtaining high system capacity factor are proposed.

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Chapter 1 INTRODUCTION

1.1 Impetus

Nuclear power has been facing more and more competition since the former monopolized utility market was opened to independent power producers (IPP). The competition from the coal and gas power forces the nuclear industry to focus on strategies that will improve its economic performance and make it attractive compared with other major electric power producing options. Only by pursuing these strategies may the nuclear industry be able to survive in the short term and grow in the long term.

Conventional power plants have economic advantages over nuclear plants, such as lower construction costs and interest payment, fewer safety requirements and thus lower operation and maintenance costs, low decommissioning costs, and relatively less staff levels. But nuclear plants have an obvious advantage over the conventional plants in their much lower fuel costs. The contribution to the cost per unit electricity from some costs, such as fuel costs, is almost constant; but the contributions from some other costs, such as investment and staff costs, which are basically constant in the total amount, will decease if the amount of generated electricity increases. Therefore, the time that the nuclear plant is on-line should be pursued as much as possible because the more time that the nuclear plant is on-line, the less generating cost per unit electricity, and the more the disadvantages of nuclear power can be offset by its low fuel costs.

The economic performance of nuclear power plants is usually measured in terms of capacity factor. Capacity factor is defined as the ratio of the amount of electricity produced over a given time period to the amount of electricity that could have been produced if the plant had always been operated at full capacity for the same time period. Since a nuclear plant is generally operated at full capacity when on-line, the capacity factor is approximately determined by the ratio of on-line time to the sum of on-line and off-line time for a given time period. The off-line time, called outage time, consists of two parts, planned outage and unplanned outage. The planned outage is usually scheduled over a certain time period for reactor refueling, component maintenance and other surveillance activities. Unplanned outage, sometimes called forced outage, is usually caused by system malfunctions or human errors. Any strategy to improve the plant capacity factor has to reduce the length of planned outage and/or unplanned outage over a given time period.

An unplanned outage is the unanticipated plant shutdown or power reduction due to component failures or/and operator errors. It can be reduced by optimizing the design, enhancing the component performance, shortening the repair times, and reducing the human error rates. The unplanned outage rate should be minimized, because the unplanned shutdown of a nuclear plant is not only a economic loss, but may also have a negative impact on the plant operational safety.

The length of planned outage over a given period can be reduced by reducing the total length of each outage or by extending the time interval between two planned outages, thus effectively reducing the planned outage length over the given time period. Both approaches are currently practiced by the industry. Some European countries, such as Finland and Switzerland, are operating their nuclear plants with short planned outages. In Finland, the plants are operating on a one-year refueling cycle, with alternating ten and fifteen day planned outages. In the US, the nuclear industry is also striving to reduce the planned outage length. However, equal effort is also focused on extending the operating cycle length. The reasons are as follows:

- Historically, the US nuclear industry has had long outage lengths with the average values being about sixty-five days for PWRs and a little longer for BWRs, although the best plant has been as short as twenty-two days. This is the basis for concluding that margin exists for improvement of plant capacity factor through either extension of operating cycle length or reduction of planned outage length.
- The capacity factor of a plant with a longer operating cycle is higher than that of a plant with a shorter operating cycle. As illustrated in Table 1.1, if the planned outage length is sixty days, assuming no forced outages, the maximum capacity factor that can be achieved in a plant with 48-month cycle is 95.9%. This is much higher than that of a twelve-month cycle plant, which is only 83.6%.

Cycle Length	Maximum Capacity Factor
12 Months	83.6%
18 Months	89.0%
24 Months	91.8%
48 Months	95.9%

Table 1.1 Maximum Capacity Factor For Variable Operating Cycle Length

- Doubling the cycle length is effectively equal to reducing the outage length by half. It may prove more difficult to reduce the outage length than to extend the cycle length in order to achieve the same capacity factor enhancement; especially when the outage length is already relatively short.

- Extending the cycle length will reduce the total number of refueling outages within a given time interval. Elimination of the expensive refueling outages can save a utility tens of millions dollars.

The US nuclear industry increasingly realizes the potential economic gains from the extension of operating cycles. However, as shown in Table 1.1, the current industry practice of moving from 12- and 18-month cycles to 24 month cycles may be too modest for sizable economic gains. It is logical to raise the questions: Are there even greater economic benefits available by extending the cycle length to the order of 48 months? And, if the answer to the first question is yes, how can these benefits be obtained? In order to answer these questions, a project concerned with the feasibility of extending the operating cycle to 48 months is underway at MIT. This thesis is a part of the work of this project.

1.2 Forty-eight Month Operating Cycle Project

In order to make the extension of the operating cycle to 48 months economically profitable, a comprehensive strategy for obtaining a 48-month operating cycle must be developed. Such a strategy should address the following areas:

- Core Design Issues: A fuel core needs to be designed that is capable of continuous operation for 48 months. For practicality, its dimensions, geometry, and thermal-hydraulic characteristics should fit the current operating plant envelope, and its fuel burnup and poison concentrations should be maintained at or below the licensing limits.

- Required Reliability and Availability Performance: The forced outage rate must be limited in order to make a 48 month operating cycle economically profitable. Otherwise, the benefit gained from the longer cycle will be negated by the increased forced outage rate. A strategy for attaining the required plant levels of reliability and availability must be formulated.
- Surveillance Requirements: The surveillance activities include all required maintenance and testing. These activities must be made consistent with a 48-month cycle through one of three ways: extending the surveillance interval to at least 48 months, changing the surveillance from off-line to on-line, or eliminating unnecessary surveillances[1].

1.3 Thesis Objectives

There will be extra costs for a plant with 48-month operating cycle. These costs need to be offset by the economic gains of the longer cycle operation. The economic gains come mainly from the additional generated electricity due to the increased plant capacity factor. However, the plant forced outage rate has to be limited. Otherwise, the enhancement of the plant capacity factor through the longer cycle will be canceled by the increased forced outage rate. In order to understand how to make the extended operating cycle economically attractive, the following objectives are developed in this thesis:

[1] T. Moore, J. Maurer, R. McHenry and N.E. Todreas, "Surveillance Strategy for a Four-Year Operating Cycle in Commercial Nuclear Reactors," MIT-ANP-TR-036, June 1996.

- Investigate the economic feasibility of extending the operating cycle length; set up a reasonable goal for the capacity factor of the plant and its individual systems that makes the extension of the operating cycle length to 48 months economically favorable.
- Identify the individual component performance regimes that are necessary for achieving the required levels of power plant reliability; formulate the basic principles for obtaining high capacity factors for economically-important systems; develop a framework for analyzing the economically-important system performance.

1.3.1 Economic Considerations

In order to achieve the first objective, an economic analysis is done. This economic analysis is described in Chapters two through five.

The economic penalty of an operating cycle extension comes mainly from the higher fuel cost because a 48-month cycle core requires higher performance fuel, such as, higher enrichment, higher quality of cladding, higher enrichment of burnable poisons. Lower burnup may also be required. Additionally, a transition cost is necessary. The economic gains through longer cycle operation come mainly from more generated electricity and fewer number of outages within a given time period. All these economic factors, both benefit and cost, are identified in Chapter two. The model to analyze the economic feasibility of extending operating cycle length is presented in Chapter three. The impacts of the economic factors on the economics of the operating cycle extension are investigated in Chapter four. In term of maximum allowed outage days, Chapter four also establishes the required goal for the plant capacity factor for the extension of operating cycle length to 48 months to be profitable.

Since some required surveillances whose interval is currently shorter than 48 months may not be extendible[2], a mid-cycle planned outage for surveillance only may be necessary. The effects of the mid-cycle outage on the plant capacity factor and net benefit of refueling cycle extension are also studied in Chapter four.

The results and conclusions of economic analysis are summarized in the end of Chapter four. According to the analysis results, it can be concluded that extension of the operating cycle length to 48 months is economically feasible if the refueling outage length and the unplanned outage rate can be limited within a certain level.

1.3.2 Reliability and Availability Considerations

To achieve the second objective, a system reliability and capacity factor analysis is done as described in Chapters five to nine. In the reliability and capacity factor analysis, the feedwater supply system at Seabrook Nuclear Power Station (SNSP), a typical Westinghouse type PWR, is examined. The reason for choosing a feedwater supply system as an example is that the feedwater supply system has a significant impact on the plant capacity factor and safety.

To help to understand how the feedwater supply system performs its functions, a description of the system is included in Chapter five of this thesis. The methodology to evaluate the system reliability and capacity factor is developed in Chapter six. Chapter six describes the methods to

[2] T. Moore, J. Maurer, R. McHenry and N.E. Todreas, "Surveillance Strategy for a Four-Year Operating Cycle in Commercial Nuclear Reactors," MIT-ANP-TR-036, June 1996.

- Estimate the reliability of a component or its availability if the component is repairable;
- Process the operational history record into needed failure and repair rates;
- Simplify the system to a degree which can be analyzed yet still captures the essential nature of problem;
- Understand the consequences for the system of each component's malfunction;
- Determine which system power capacity level corresponds to each combination of component failures;
- Calculate the probability of the system being in each of the possible power capacity levels.

The reliability and capacity factor analyses for a PWR feedwater supply system are presented in Chapter seven. In this chapter, the key components of the feedwater supply system are identified based upon the plant-specific data. It is studied whether the strategy of providing redundancy in the key components is necessarily a good strategy for improving the capacity factor of an economically-important system, even though it is already known that it is a good strategy for improving the reliability of a safety-important system. The capacity factor analysis also studies the sensitivity of system capacity factor to the individual system component failure rates and repair rates. The component performance regimes are obtained from these sensitivity analyses. In addition, the effects of common cause failures, human errors, and component wearout upon the system capacity factor are also investigated in the capacity factor analysis. Based upon the results of these analyses, the basic principles for obtaining high system capacity factor are identified in Chapter eight.

The conclusions of this thesis are summarized in Chapter nine, and some consideration about the future work are also presented in Chapter nine.

1.4 Terminology

Some important terms used in this thesis need to be clarified here.

Reliability: The "reliability" R(t) of a component (or a system), which performance is measured, is the probability that the component (or system) will operate successfully over the time interval from 0 to t.

Availability: The "availability" A(t) of a component (or a system), which performance is measured, is the probability that the component (or system) is operating successfully at time t. If repair of the component is impossible, the availability A(t) must be equal to reliability R(t). If repair is possible, then $R(t) \leq A(t)$.

Capacity: The "capacity" of a system is the designed maximum ability of system to perform the system function. The system may be running under full capacity or partial capacity corresponding to different output of the system.

Capacity Function: The "capacity function" C(t) of a system, which performance is measured, is the output of system at time t as the fraction of the full capacity, representing the system performance at time t.

Capacity Factor: The "capacity factor" CF(t) of a system, which performance is measured, is the ratio of the average output (capacity function C(t)) of the system over the time interval [0,t] to the full capacity of the system.

The capacity factor is a commonly used index to measure system performance.

Chapter 2 ECONOMIC FACTORS OF OPERATING CYCLE EXTENSION

Comparing with current industrial practice, there are economic benefits and penalties associated with the extension of the operating cycle length. In order to study the economic feasibility of operating cycle length extension, all these economic factors need to be identified. This chapter will describe the benefits and costs due to the extension of operating cycle length.

2.1 Benefits of Operating Cycle Extension

2.1.1 Introduction

There are many benefits which accrue to utilities that choose to extend plant cycle length. In some cases, they can be translated into direct revenue gains. In other instances, the benefits in the operation and maintenance (O&M) of the plant and the benefits to the environment are more difficult to quantify in monetary terms. All of these factors are addressed in this section.

The greatest benefit of extending fuel cycle lengths is the increase of the plant capacity factor, and thus the generation of more electricity. This term can be easily translated into monetary form if the cost of buying replacement electricity and the selling price of electricity are known. In addition to the benefit of increased electricity generation, there are also significant advantages to the environment and possibly to the O&M costs of plants.

2.1.2 Increased Generation of Electricity

If the total outage length of a nuclear plant, including forced outages and planned outages, can be maintained unchanged or even lower, a longer operating cycle results in a smaller ratio of outage time to cycle length, i.e., a higher capacity factor. The number of Effective Full Power Days (EFPDs) per year of plant operation is increased. The saving of replacement energy cost due to the increased EFPDs can be calculated if the monetary value of the dispatch of a KwHr of electricity to the grid is known. For example, the gross saving realized per EFPD for a 1150 MWe plant is $\$2.76 \times 10^7 * E$, where E is the rate of replacement energy cost in terms of \$/KwHr. The benefit of the increased amount of generated electricity varies with the different replacement energy prices of different regions. In the US, the average replacement energy cost is about 2.5 cents per KwHr. Therefore, the saving of replacement energy cost for each EFPD is about 0.7 million dollars.

2.1.3 Operation and Maintenance Benefits

O&M benefits are more difficult to quantify. However, the following factors can be significant:

- Expensive outage costs are reduced due to the fewer number of outages needed over the same time period. Normally during outages, most utilities pay considerable overtime to plant staff while hiring a large number of contract workers and outside services to complete all required jobs. By reducing the number of outages, the overtime, contract labor and service costs are proportionately reduced. There will also be a reduction in the materials and supplies consumed during outages. This reduction of outage expenses could be as much as 15 million dollars per outage.

- More reliable components require fewer surveillances, tests, calibrations, and repairs. Consequently, less manpower is required to run the plant. The reduced labor cost is sizable. However, to achieve higher reliability, investments in hardware innovations and different management styles may be required. The investments will be listed in the second part of this chapter, as a cost of extending fuel cycle length.
- To achieve longer cycle length, new techniques are employed to make components more reliable. Thus, the costs of repair and replacement can be reduced since more reliable components require fewer repairs and replacements. This reduction may be tremendous.
- Fewer refuelings also reduce the probability of damage to equipment as a result of maintenance done during the outage. When the reactor vessel head is removed, there is the possibility of some inadvertent damage to the fuel or core internals. The thermal cycles imposed on other plant equipment can cause problems with seals, valve packing, and even structures. Most equipment performs better when it runs continuously than when subject to cycling.
- The time spent on outage planning may be reduced, since the number of outages is reduced.
- More reliable operation may result in a longer plant life. There is an obvious benefit if plant life can be extended since the initial investment required in nuclear power plants is so large.

2.1.4 Benefit to Environment and Plant Personnel

The potential benefit to the environment and plant personnel is most difficult to express in monetary terms. These impacts, however, are also important advantages resulting from the extension of fuel cycle length.

For example, the personnel radiation exposure is reduced because of the reduced amount of time spent by plant personnel in handling fuel and performing maintenance on primary systems during outage periods.

2.2 Extra Costs of Operating Cycle Extension

2.2.1 Introduction

There are costs inherent in extending plant cycle lengths. Most of them are one time expenses as initial investments for technical innovations or development of techniques to extend the cycle length of operating plants. However, the extra fuel cost is incurred over the entire subsequent operation period.

Extra fuel cost is the most significant cost in plant cycle extension. In addition, the transition cost may also be significant depending on the rate of premature replacement of old assemblies, even though it is a one time expense. These factors can be translated into monetary terms directly. Other additional expenses, such as management expense, however, are more difficult to determine. All of these costs will be addressed in this section.

2.2.2 Extra Fuel Cost

A longer-life core will utilize higher enrichment fuel. The higher enrichment requirement increases the cost. Also, depending on core design, the fuel burnup may have to be reduced so that more fuel is needed to produce the same amount of power. Besides, additional fuel is needed for the added plant on-line days. Preliminary estimates suggested that the extra fuel cost is about 1.5 mills/KwHr, i.e., about 13 million dollars per year for a 1150 Mw plant being extended to a 48 month cycle from the current 18 month cycle with an 87% capacity factor.[1] More recent results, of work still in progress, suggest that even including reuse of peripheral assemblies, the cost could reach $27 million per year[2].

2.2.3 Transition Cost

Transition cost is defined as the one time cost of shifting a currently operating plant to a longer cycle length. It includes:

- Initial investment to design the new core;
- Costs of labor and materials to replace the old core;
- Cost of prematurely disposing of the old core.

(Note: the factors presented above refer only to the added incremental cost compared to "business as usual" cost associated with these factors.)

- Any investment in advanced technology applied to improve component availability, extend surveillance intervals, and perform on-line maintenance. For example, the

[1] "A Strategy For Extending Cycle Length To Improve Pressurized Water Reactor Capacity Factor", A.F.A. Ayoub and M.J. Driscoll, MIT-ANP-TR-032, May, 1995
[2] reference.

investment in a robotics system to facilitate on-line testing of steam generators falls into this category.

- To reduce the repair time of failed components thus increasing the availability of components, more spare components may be required. There will be a cost to maintain this increased inventory.

2.2.4 Management Cost

More efficient management is required to achieve higher system/component availability and, ultimately, a higher plant capacity factor. Initial investment in upgrading management techniques and tools, such as advanced management software, may be required.

Also, extra on-site and off-site education and training may be required for plant workers to master the new technique. The investment in training facilities and costs of human resources need to be considered.

2.2.5 Other Costs

- Interest due to new investments;
- Taxes on the increased electrical output.

Chapter 3 CALCULATION OF THE NET BENEFITS OF OPERATING CYCLE LENGTH EXTENSION

3.1 Introduction

Benefits and costs of extending plant cycle lengths have been mentioned above. Subtracting the costs from the benefits will yield the net benefit of extending the plant cycle length.

As illustrated in Figure 4.1, the benefits generally change in direct proportion to capacity factor increase. The costs, however, may resemble an exponential-like function. Starting from a low capacity factor state, a small investment in innovations may result in a large increase in capacity factor, but if the current capacity factor is already relatively high, even a small increase in capacity factor requires a much larger investment. Thus, there

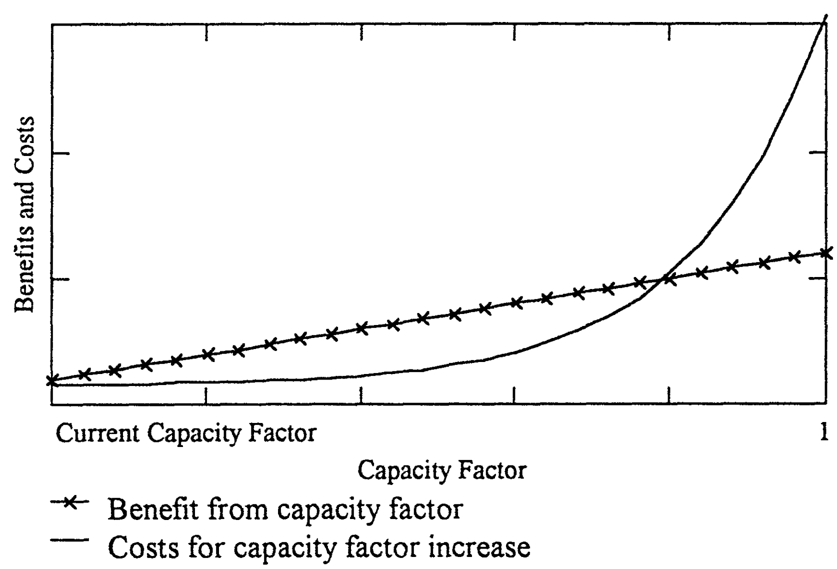


Figure 3.1 Benefits and Costs Trends Associated with Capacity Factor Increase

may be an upper limit to the capacity factors that power plants could achieve. Significant research will be required to determine the true shape of the curve of cost increase with capacity factor.

As a starting point, this chapter will try to quantify the economic factors of nuclear plant operating cycle length extension in term of the present monetary value. Therefore, the net benefits of such an extension can be calculated. In this chapter, the net benefits will be estimated in term of the annual net income. The effect of discount rate (i.e., the future monetary value) will not be considered at this point.

To simplify the analysis and still be able to ascertain the nature of the problem, only the extra fuel cost, the saving from replacement energy cost and the saving from the elimination of outages are considered in the following analysis, since they are the dominant economic factors of the operating cycle extension project.

3.2 Modeling The Extra Costs

The extra costs of the operating cycle extension mainly come from the increased fuel cost. For a plant operating at a relatively low capacity factor, the annual extra cost increases when the plant operating cycle length is extended. The longer the cycle is extended, the higher the extra cost. This is because the extra fuel cost is increased when the operating cycle is extended, even though the initial investments in some necessary innovations may be the same for variable extended cycle lengths.

The extra fuel cost is mostly due to the required higher enrichment and depends on the number of fuel batches. If the fuel batch fraction is linearized between 2.67 for an 18-

month cycle, which is the current industrial practice, and 1 for the 48-month cycle, which is the design goal of this project, the extra fuel cost is roughly linearly proportional to the extended cycle length.[1]

This thesis will bracket the extra fuel cost using two extreme cases: 1) Constant annual extra fuel cost, 2) Linearly increased extra fuel cost. In the constant extra fuel cost model, the extra fuel cost is treated as 20 million dollars per year, regardless of the operating cycle length extension. In the linear cost model, the extra fuel cost is treated as zero for the current cycle, linearly increasing to 20 million dollars for the 48-month cycle. It must be emphasized that the benchmark value of 20 million dollars per year is still a rough preliminary estimate. These two models can be mathematically formulated as:

1) Constant Cost Model:

$$C = M \tag{3-1}$$

2) Linear Cost Model:

$$C = \frac{T_e - T_0}{1460 - T_0} * M \tag{3.-2}$$

where C is the annual extra fuel cost, T_0 is the current cycle length in days, T_e is the extended cycle length in days, M is the annual extra fuel cost if the cycle is extended to 48 months (1460 days). As mentioned above, the value of M is assumed to be 20 million dollars in this thesis.

The two extra fuel cost models are the extreme boundaries of the actual extra fuel cost, at least in terms of functional behavior, if not absolute magnitude. The constant cost

[1] Christopher S. Handwerk, "Economic Analysis of Implementing a Four Year Extended Operating Cycle in Existing PWR's." August 1996.

model represents the most pessimistic case and the linear cost model, which is based on the linearized batch fraction assumption, represents the most optimistic case. The actual economics of operating cycle length extension will be between the results of the analyses based on these two models. Even though more study is required to determine the precise relation between the extra fuel cost and the extended cycle length and to establish a more accurate number for the extra fuel cost, the present results based on these models are still able to give us valuable information about the economic feasibility of operating cycle extension.

3.3 Modeling The Benefits

The benefits of the operating cycle extension mostly come from the additional generated electricity and the saving from the elimination of outages. The benefit from the additional generated electricity is basically the saving for the replacement energy cost, which is proportional to plant capacity factor increase. The saving from eliminating each single outage can be taken as a constant.

If a plant, currently operated in a cycle length of T_0 with a total outage length of O_0, is modified to operate in a cycle length of T_e with a total outage length of O_e, the increase ΔCP of plant capacity factor will be

$$\Delta CP = \frac{O_e}{T_e} - \frac{O_0}{T_0}. \tag{3-3}$$

If the replace energy cost is R million dollars per EFPD, the annual saving B_1 from the additional generated electricity will be:

$$B_1 = \Delta CP * R * 365 = (\frac{O_e}{T_e} - \frac{O_0}{T_0}) * R * 365 \tag{3-4}$$

Assume that the cost for an outage is E million dollars, i.e., the saving from the elimination of one outage is E million dollars. If the plant cycle length is extended from current T_0 days to T_e days, the effective annual saving B_2 from the elimination of outage is given by

$$B_2 = (\frac{365}{T_0} - \frac{365}{T_e}) * E . \tag{3-5}$$

In this thesis, the value of E will be taken as 15 million dollars. This number is an average value of current industrial experience.

3.4 Net Benefit of Operating Cycle Extension

Subtracting the extra cost from the benefits will yield the net benefit of operating cycle extension. i.e.,

$$NB = B_1 + B_2 - C \tag{3-6}$$

Combining equations (3-1) to (3-5), the net benefit NB can be formulated as:

1) Constant extra fuel cost model:

$$NB = (\frac{O_e}{T_e} - \frac{O_0}{T_0}) * R * 365 + (\frac{1}{T_0} - \frac{1}{T_e}) * E - M \tag{3-7}$$

2) Linear extra fuel cost model:

$$NB = (\frac{O_e}{T_e} - \frac{O_0}{T_0}) * R * 365 + (\frac{1}{T_0} - \frac{1}{T_e}) * E - \frac{T_e - T_0}{1460 - T_0} * M \tag{3-8}$$

In this thesis, the economic feasibility of the operating cycle extension project is analyzed for both the constant cost and linear cost models.

To simplify the analysis without changing the nature of the problem, assume that the total number of outage days, which includes planned outages and unplanned outages, in an extended cycle is the same as in a current plant cycle. Some may argue that there would be more forced outages for a plant running on a longer cycle. This may be true. However, one of the goals of this research is to develop a methodology for applying advanced technology to improve the availability of components, thus reducing plant forced outages as much as possible. On the other hand, refueling outages are more easily kept at the same length, and even shortened, by better refueling outage management and by maximizing the percentage of maintenance which is performed on-line. Thus the goal of keeping total outage length unchanged is achievable.

The cost to improve component availability has the same trend as that to increase plant capacity factor. Improvement of component availability over a certain value will incur an unrecoverable cost. Work done by the MIT research group suggests that there are probably a number of components for which surveillance interval extension is not prudent because of the excessive cost. Based on this consideration, the mid-cycle outage concept is introduced. The plant plans to shut down between two refueling outages for a short time to conduct essential preventive maintenance and surveillance testing for components with poor performance history. This mid-cycle outage still realizes the benefit of not removing the reactor vessel head.

The net benefits of extending plant cycle length without a mid-cycle outage and with a mid-cycle outage are both calculated in this thesis. All these analyses are to investigate the economic feasibility of extending the operating cycle length under the basic conditions and goals as follows:

- Extra fuel cost: 1) 20 million dollars per year regardless the extended cycle length; 2) linear increase with the extended cycle length, from zero on current cycle length to 20 million dollars per year for a 48 month cycle length;
- Replacement Energy Cost: 2.5 cent/KwHr, i.e., $0.7 million/EFPD for a 1150 MW plant;
- Saving from elimination of outages: 15 million dollars per outage.

And the basic goal of the project is to achieve a 48-month operating cycle with 30 days refueling outage and maximum 43 days forced outage (3% unplanned outage rate) during one cycle.

Chapter 4 RESULTS AND CONCLUSIONS OF ECONOMIC ANALYSIS

4.1 Introduction

The results of the economic analysis are presented in this chapter. Different extended cycle lengths, different total outage lengths, and different current operating cycle length, will yield different economic favorability. So do the total extra costs and replacement energy cost. All these effects on the economic feasibility of operating cycle extension will be studied first without considering the effect of mid-cycle outage.

The effects of a mid-cycle outage on the plant capacity factor and economics are then studied. Based on the analysis, the maximum allowed mid-cycle outage length can be obtained. The study considering a mid-cycle outage is only for a plant with an extended cycle length of 48 months, since for shorter cycle length extensions, a mid-cycle outage may be not necessary.

Every study in this chapter includes cases based on the constant extra cost and the linear extra cost models. As discussed in Chapter three, the results based on these two models represent the extreme boundaries of the possible economic trends for operating cycle extension.

4.2 Net Benefits of Extending Plant Cycle Length Without Considering a Mid-Cycle Outage

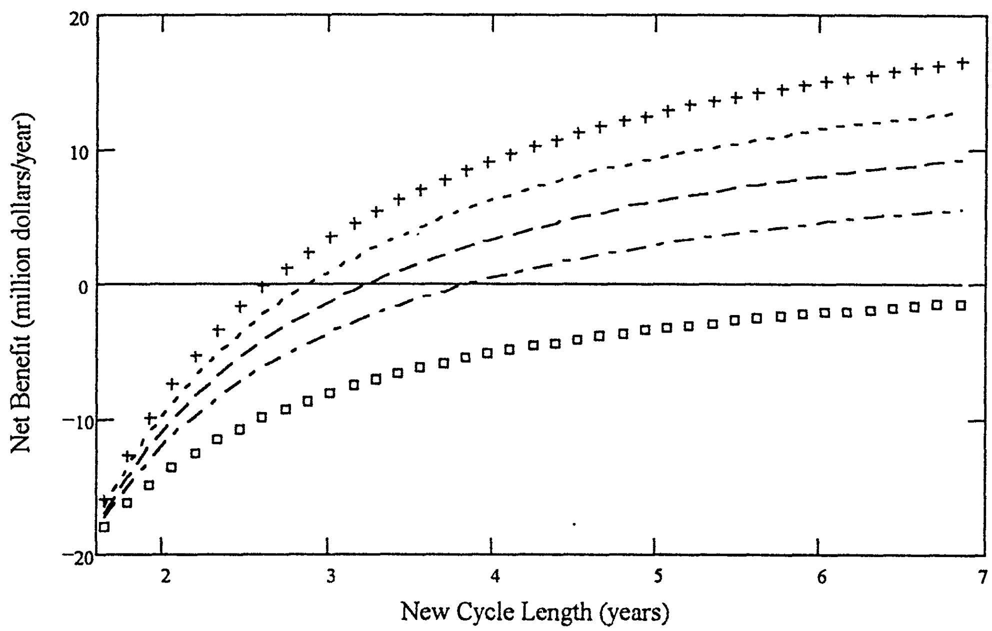
In this section, some comparisons of net benefits as affected by different factors are presented. The effects of extended plant cycle length, total outage length, current operation cycle length, total extra cost and the replacement energy cost will be discussed.

4.2.1 Effects of Extended Plant Cycle Length

A. Constant Extra Cost Model

If the extra cost is assumed to be constant, for a plant currently on an 18 month cycle, the net benefit of an extended fuel cycle as a function of the cycle length and outage length is shown in Figure 4.1. In this figure, the replacement electricity cost per EFPD is taken as 0.7 million dollars, i.e. 2.5 cents per KwHr for a 1150 MW plant, which is a typical electricity replacement price. The total added cost (mostly from extra fuel cost) is taken as 20 million dollars per year, and saving from elimination of outages is $15 million per outage.

It is found that the longer the cycle is extended, the greater the net benefit gained. If the total outage length is longer, the effect is more significant. The line with the symbol "+" represents a plant with an 80 day outage, which is a typical value for current US practice. This line shows a sizable net benefit from extending the cycle length to 4 years even though there is negative net benefit for extending cycle length to 2 years. The MIT research group has been told by some utility representatives that there was little motivation to drive current 12 or 18 month cycles to 24 month cycles because there was no real economic benefit. Figure 4.1 suggests that a two year cycle extension is too modest to get economic benefits, while a more ambitious goal of four year cycles could lead to significant benefits (under a constant scenario).



+++ 80 days outage
-- 70 days outage
— - 60 days outage
— - 50 days outage
□□□ 30 days outage
— zero net benefit line

Figure 4.1 Net Benefit v/s Cycle Length For Various Outage Lengths
(Constant Extra Cost, Current Cycle Length: 18 Months)

B. Linear Extra Cost Model

If the extra cost is considered as linearly changing with the extended cycle length, the net benefit of the operating cycle length extension is shown in Figure 4.2. For a plant with total outage length of 80 days, its optimal cycle length is about three years. The shorter the plant total outage length, the shorter the optimal cycle length. For a plant with current total outage longer than 50 days, extending the operating cycle length to four years is still economically profitable if the total outage length is maintained at 50 days.

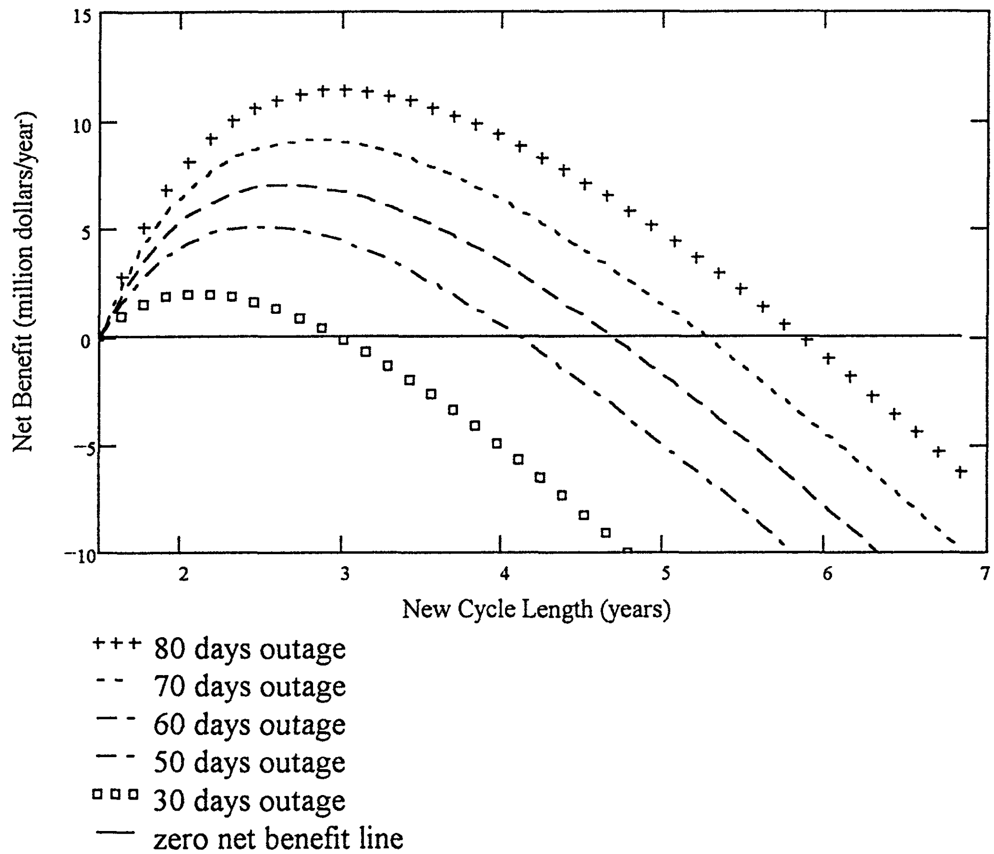


Figure 4.2 Net Benefit v/s Cycle Length For Various Outage Lengths
(Linear Extra Cost, Current Cycle Length: 18 Months)

4.2.2 Effects of Total Outage Length

A. Constant Extra Cost Model

As described in Chapter three, the total outage length in an extended cycle is assumed to remain the same as the current total outage length in a current cycle. Figure 4.3 shows the relationship of the total outage length to the net benefit of extending the cycle length. It is found that the extension of the operating cycle length is more economically profitable if the total outage length is longer. As shown in the figure, an extension to a four year cycle can yield a net benefit even though the current total outage is very short, while an extension to two years can achieve a benefit only if the current outage length is relatively long.

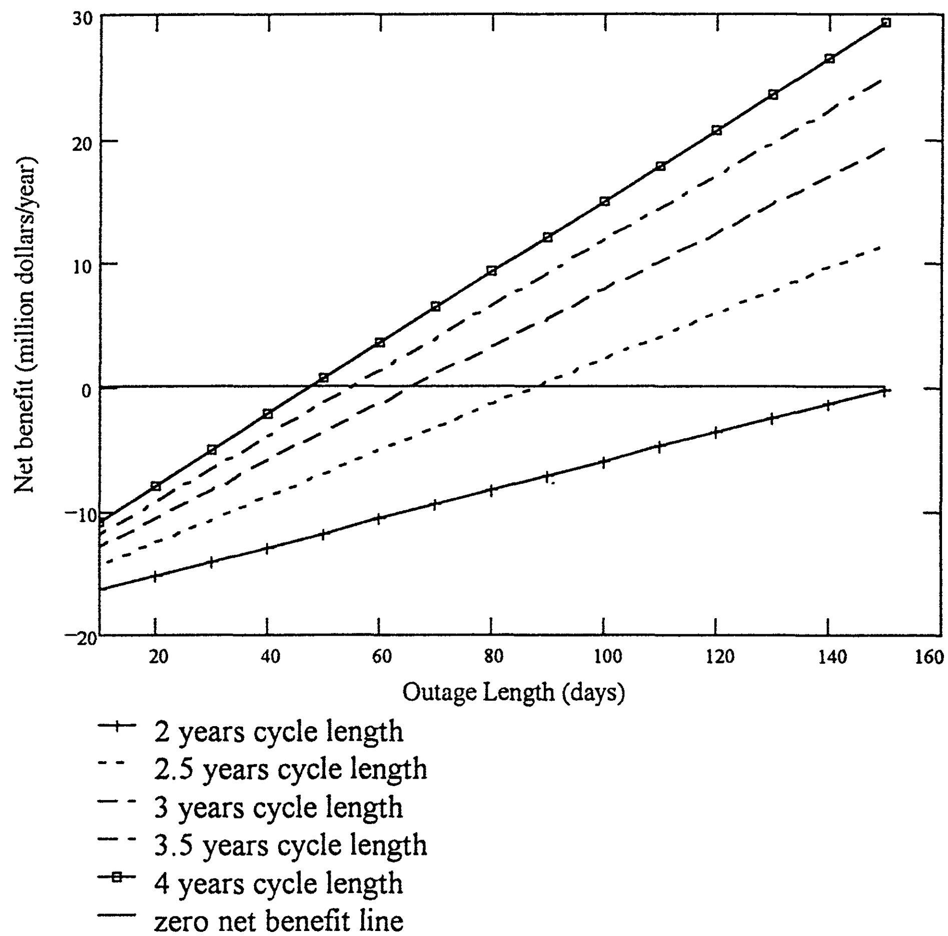


Figure 4.3 Net Benefit v/s Outage Length For Various Cycle Lengths
(Constant Extra Cost, Current Cycle Length: 18 Months)

B. Linear Extra Cost Model

The effect of the total outage length using the linear extra cost model is shown in Figure 4.4. The results based on the linear extra cost assumption are in contrast to the results based on the constant extra cost model. To make the operating cycle extension profitable, the shorter total outage length requires shorter extended cycle length. However, if the total outage is longer than 70 days, the short cycle length extension to two years is no longer the most economically favorable, and if the total outage is very

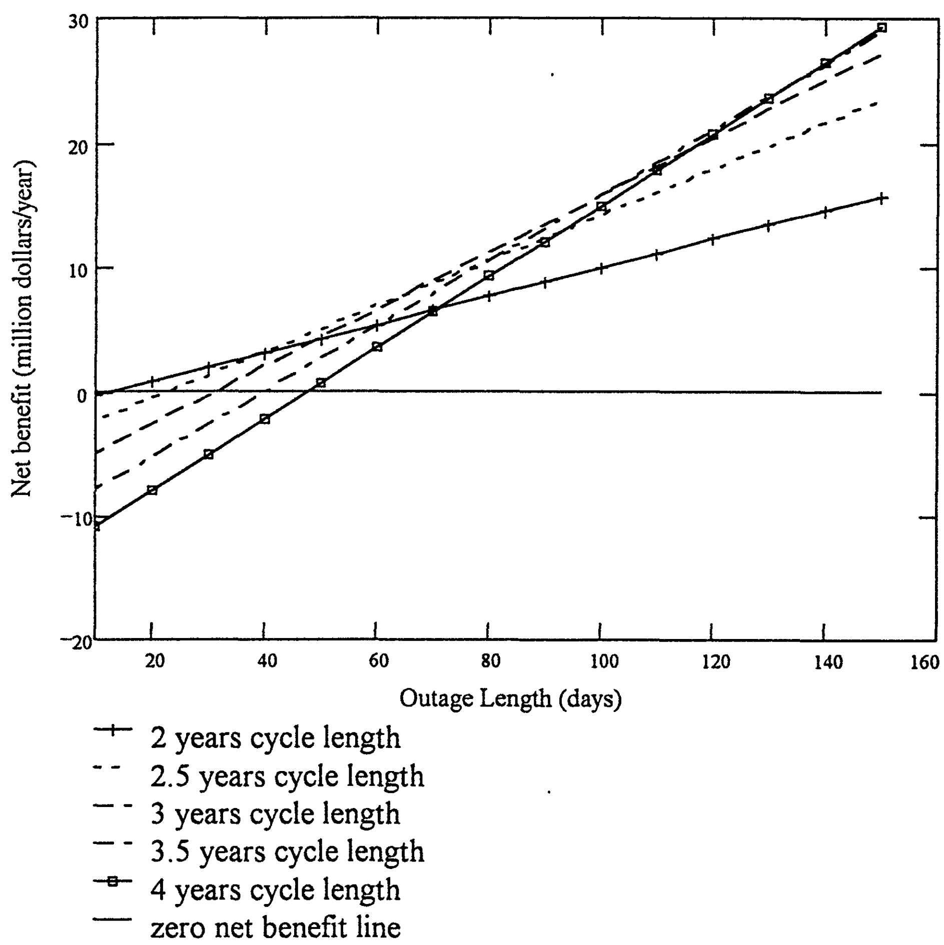


Figure 4.4 Net Benefit v/s Outage Length For Various Cycle Lengths (Linear Extra Cost, Current Cycle Length: 18 Months)

long, such as longer than 120 days, the longer extended cycle length shows more economic favorability.

4.2.3 Effects of Current Operation Cycle Length

A. Constant Extra Cost Model

Figure 4.5 represents plants currently with 12 month cycles and the same parameters as those in section 4.2.1 ($0.69 million/EFPD of replacement energy cost, $15 million/outage of saving, and $20 million/year of extra cost). In Figure 4.5, a more

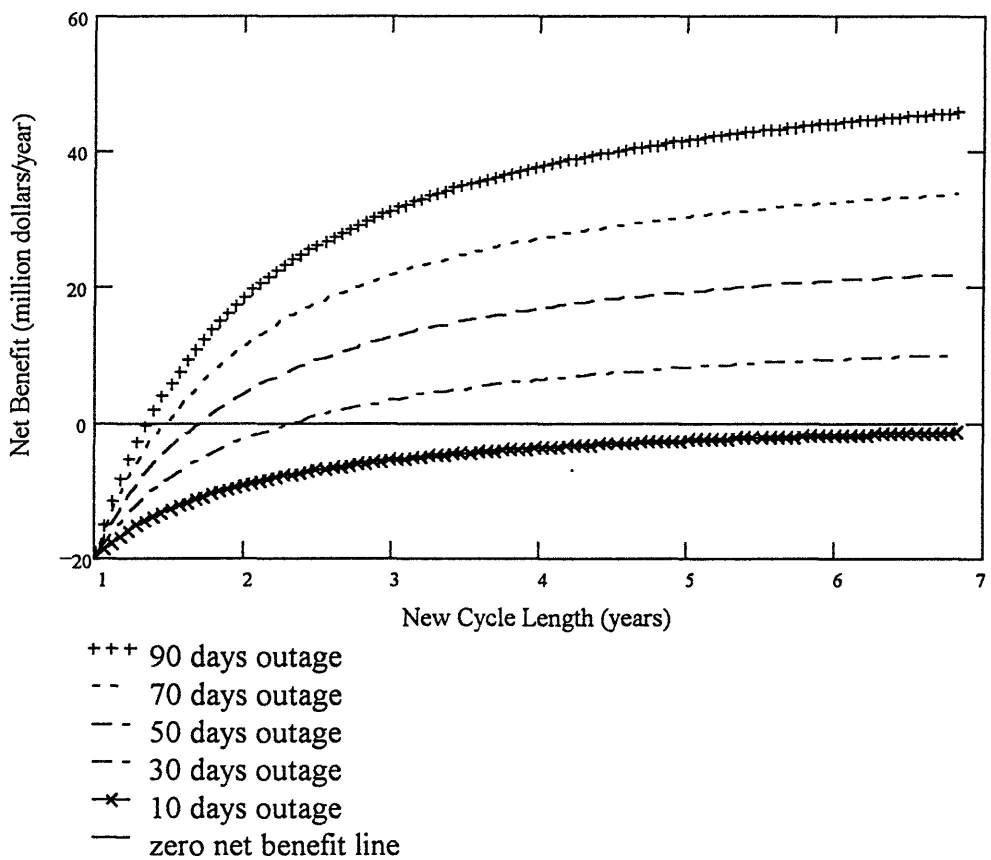


Figure 4.5 Net Benefit v/s Cycle Length For Various Outage Lengths
(Constant Extra Cost, Current Cycle Length: 12 Months)

significant effect of extension of cycle length is shown. For plants with 12 month cycles, extending the cycles to four years can be profitable even if the total outages which can be achieved are as short as 10 days. This is an interesting point for those utilities inclined to remain in a 12 month cycle and put their efforts into driving the outage length shorter.

B. Linear Extra Cost Model

Using the linear extra cost model, the net benefit of extending the operating cycle length of a plant which is currently operated on a 12-month cycle is shown in Figure 4.6. Comparing with the economics of a plant with 18 month cycle, extending the operating

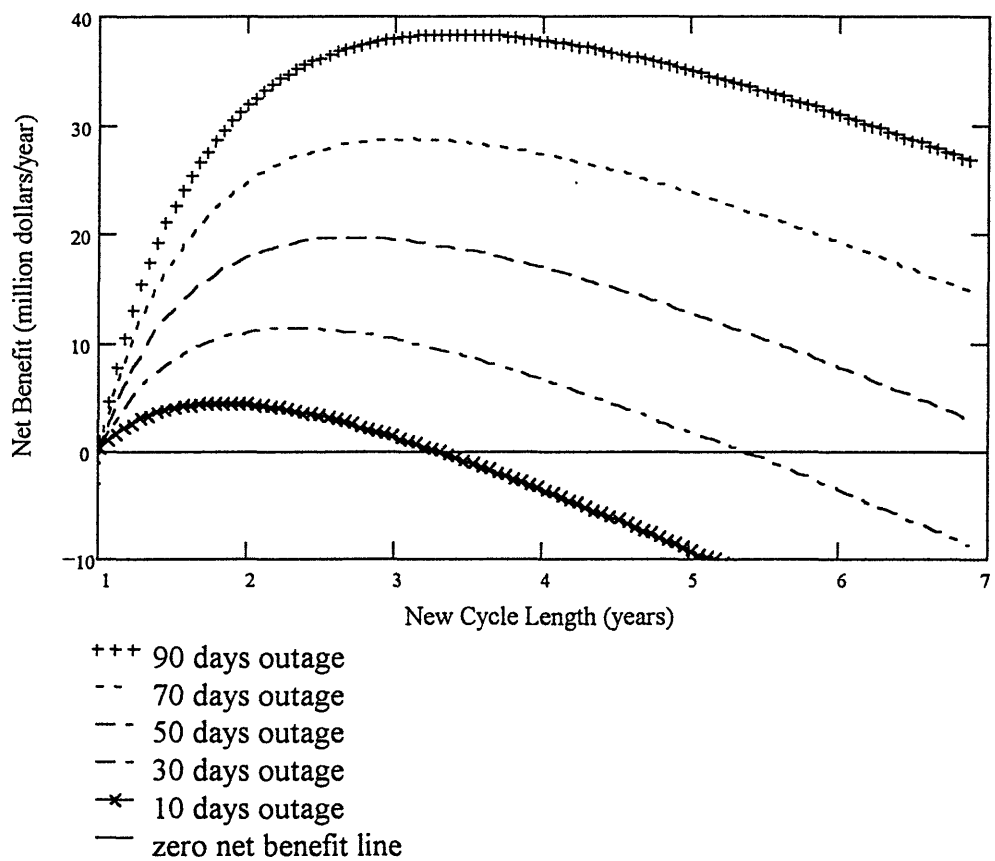


Figure 4.6 Net Benefit v/s Cycle Length For Various Outage Lengths
(Linear Extra Cost, Current Cycle Length: 12 Months)

cycle length of a plant on a 12-month cycle shows stronger favorability. The optimal cycle lengths are longer, and almost four years if the total outage is 90 days.

4.2.4 Effects of Total Extra Costs

A. Constant Extra Cost Model

If the total extra cost of extending the fuel cycle length to four years is more than the assumed 20 million dollars per year, cycle extension may be still attractive. Figure 4.7 shows the net benefit of extending the operating cycle length of a current 18-month cycle plant assuming the total extra cost of extending the plant cycle to four years is 25 million

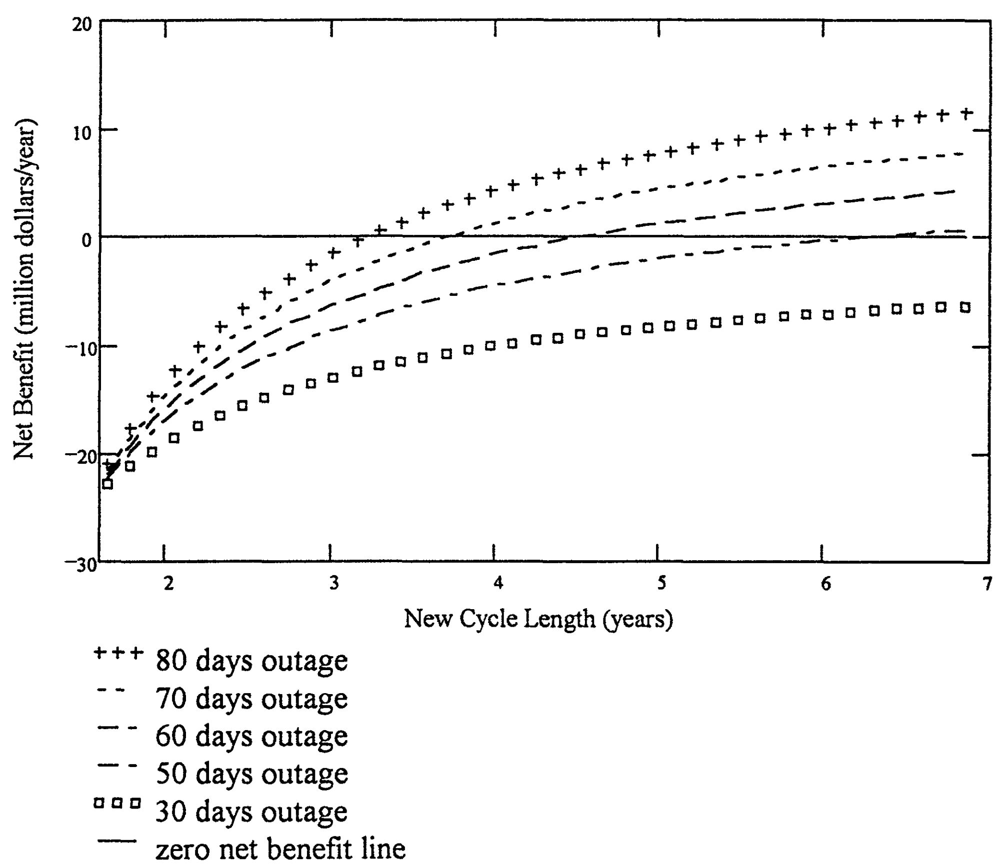


Figure 4.7 Net Benefit v/s Cycle Length
(Constant Extra Cost, Current Cycle length: 18 months,
Total Added Cost: $ 25 Million/year)

dollars per year. It is found in Figure 4.7 that there is still a net benefit for extending cycle length to four years.

Figure 4.8 also shows the effect of different total extra cost for extending the operating cycle length of a plant with a 70-day total outage per cycle from 18 months to 48 months. Net benefit decreases while total extra cost goes up. But the longer the cycle,

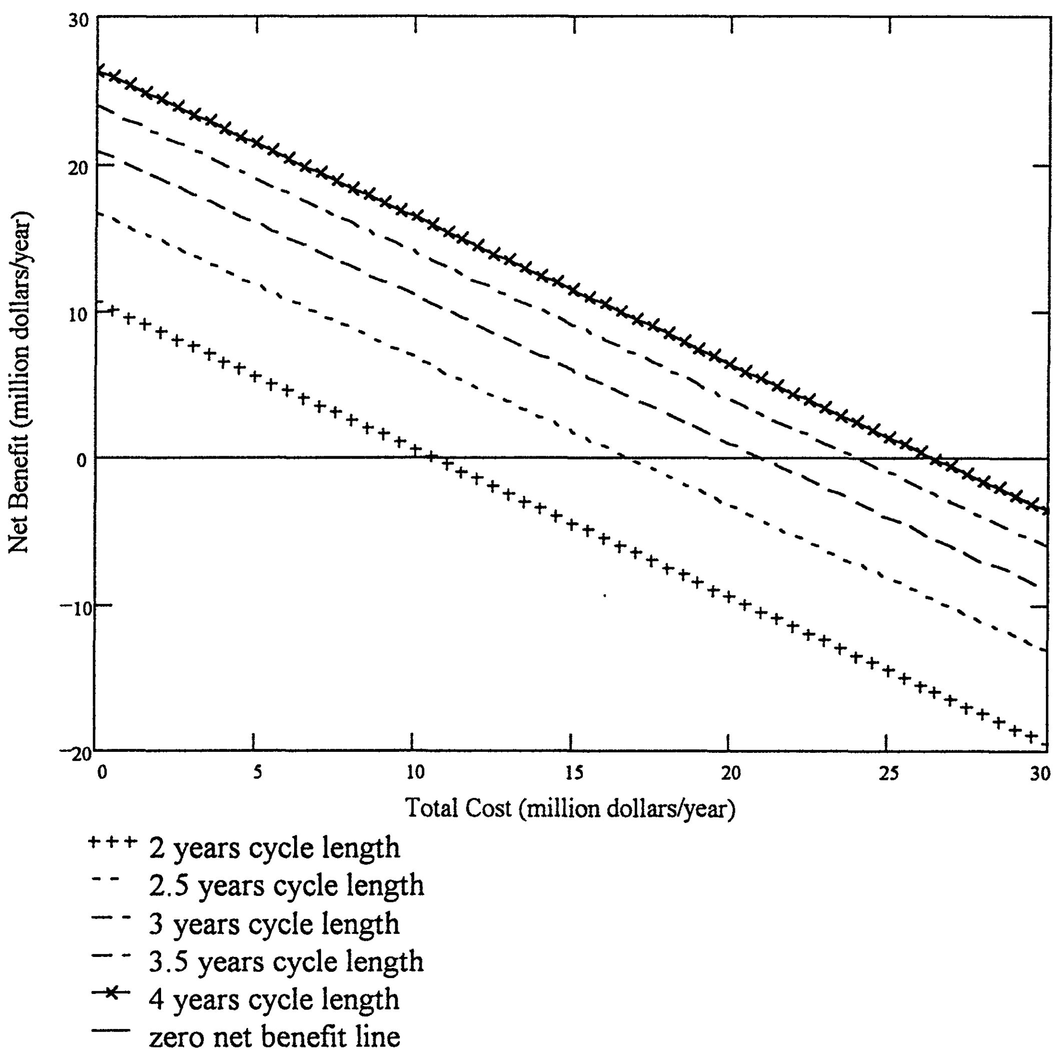


Figure 4.8 Effect of Total Cost For Various Cycle Lengths
(Constant Extra Cost, Current Cycle Length: 18 months,
Total outage length: 70 days)

the more the expense which can be tolerated. If the cycle length is extended to four years, an extra cost of 27 million dollars per year can be offset.

B. Linear Extra Cost Model

Using the linear extra cost model, the net benefit for various extended cycle length is shown in Figure 4.9 assuming that the extra cost is 25 million dollars for extending the cycle length from the current 18 months to 48 months. As shown in the figure, if the total outage is longer than 65 days, extending the cycle length to four years still can achieve a positive net benefit, even though the optimal cycle lengths are less than three years.

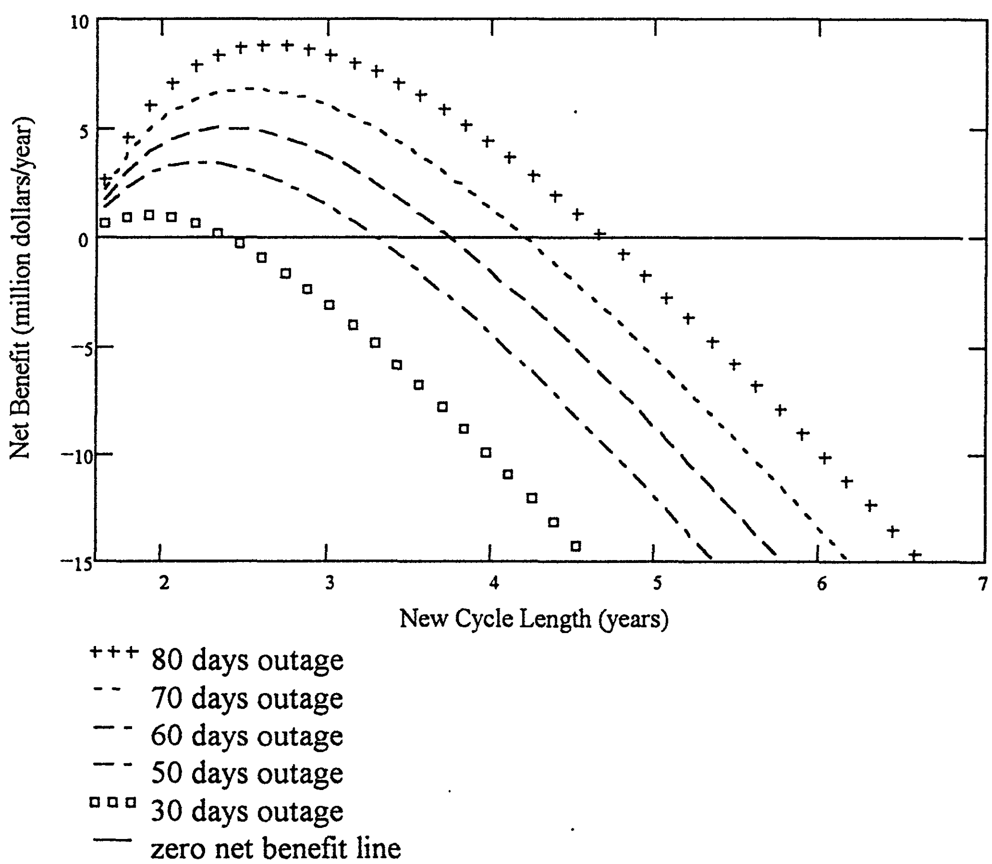


Figure 4.9 Net Benefit v/s Cycle Length
(Linear Extra Cost, Current Cycle length: 18 months,
Total Added Cost: $ 25 Million/year)

Comparing with Figure 4.2, in which the extra cost for extending the cycle to 48 months is 20 million dollars, it can be concluded that the economics of the cycle length extension is sensitive to the extra cost.

This conclusion can be supported by the results shown in Figure 4.10. Figure 4.10 shows how the net benefits change with the nominal extra cost for extending the cycle to

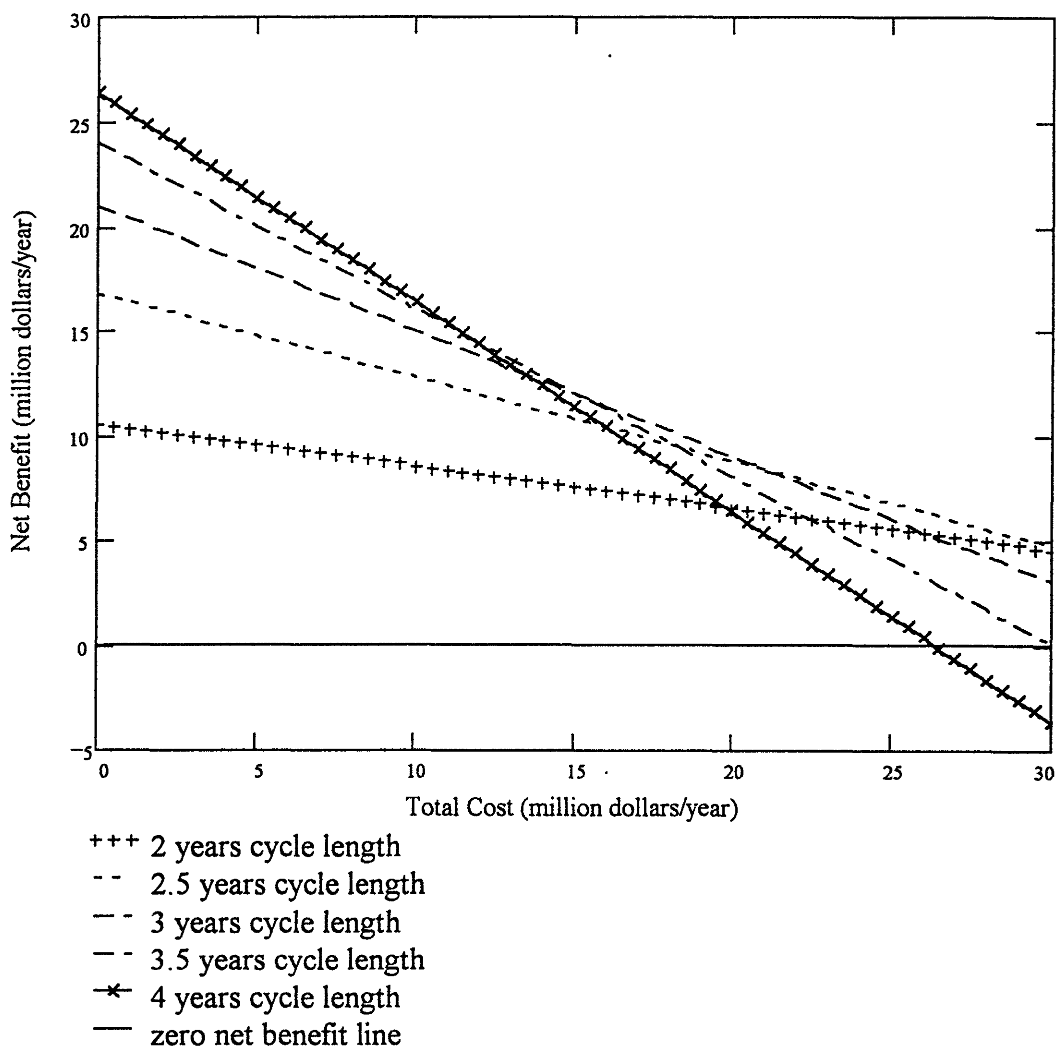


Figure 4.10 Effect of Total Cost For Various Cycle Lengths
(Linear Extra Cost, Current Cycle Length: 18 months,
Total outage length: 70 days)

four years. It is found that the net benefit of the operating cycle length extension is sensitive to this nominal value and the sensitivity increases if the cycle length is extended longer.

4.2.5 Effects of Replacement Energy Cost

The effects of replacement energy cost per EFPD on net benefit are shown in Figure 4.11. Net benefit is sensitive to the replacement energy cost per EFPD. The benefit mostly comes from the additional generated electricity. So a small change in the price of electricity will yield a large change in the net benefit. This point is interesting because the price of electricity is region-dependent. That means that the net benefit of extending plant

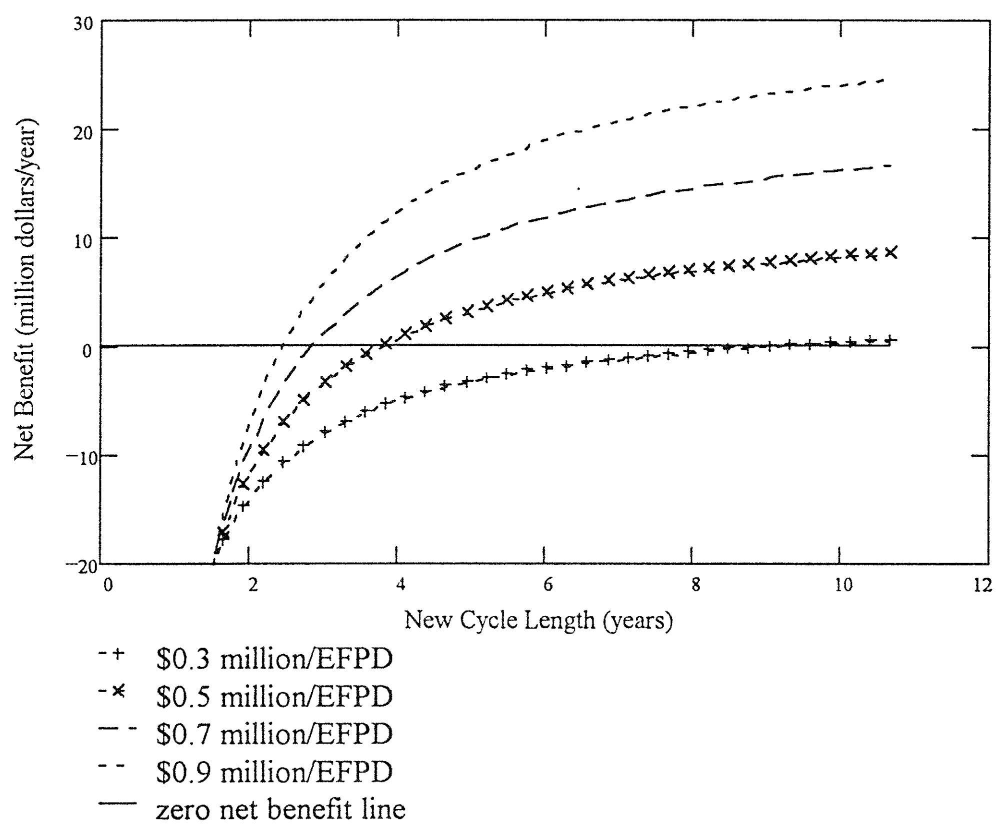


Figure 4.11 Effect of Replacement Energy Cost per EFPD
(Constant Extra Cost, Current Cycle Length: 18 months, Outage length: 70 days)

cycle length has a regional dependency. Figure 4.11 also shows that there will be no benefit if the replace energy cost is too small, as in the case of $0.3 million per EFPD, equal to about 1 cent per KwHr for a 1150 MW plant.

B. Linear Extra Cost Model

Using the linear extra cost model, the sensitivity of net benefit to the replacement energy cost is shown in Figure 4.12. It is also found that there will be little net benefit if the replacement energy cost is too small. In order to establish the economic feasibility of operating cycle length extension, an accurate value for the replacement energy cost must be obtained.

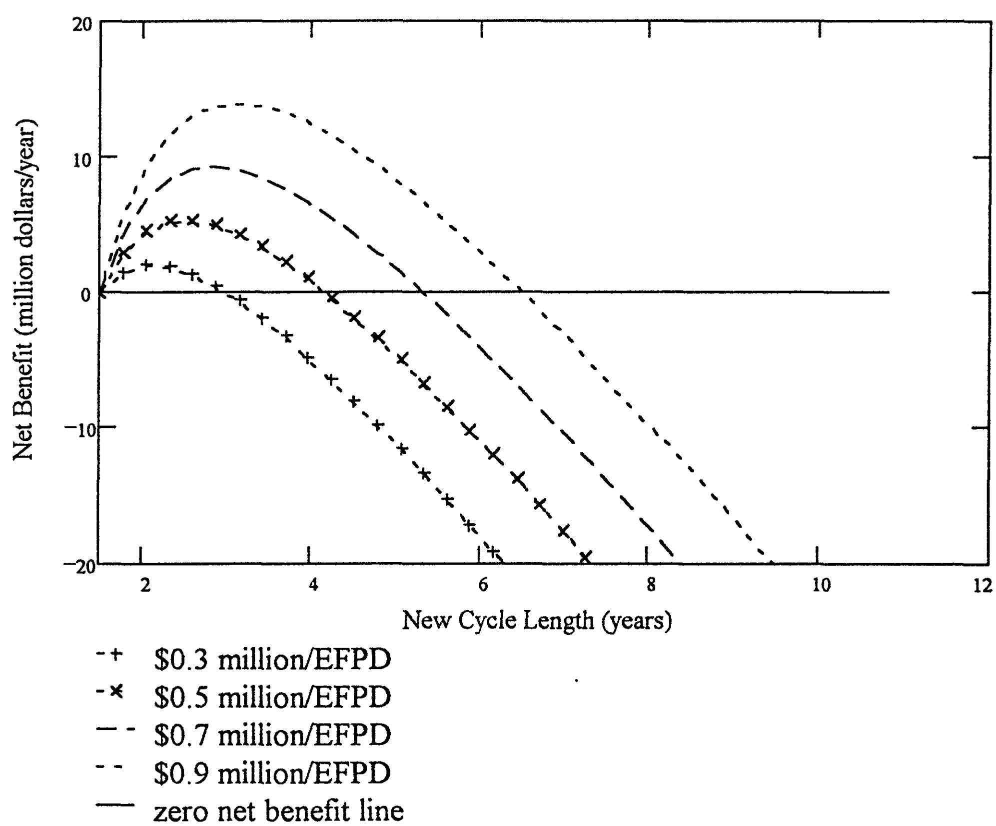


Figure 4.12 Effect of Replacement Energy Cost per EFPD
(Linear Extra Cost, Current Cycle Length: 18 months, Outage length: 70 days)

4.3 Effects of Mid-Cycle Outage

The outage length considered in section 4.2 is the total outage length. For a more detailed analysis, outage days can be broken into three categories: Refueling outage, Unplanned (Forced) outage, and Mid-cycle outage. The effects of these three categories of outages on plant capacity factor and net economic benefit will be discussed in this section.

4.3.1 Effects on Plant Capacity Factor

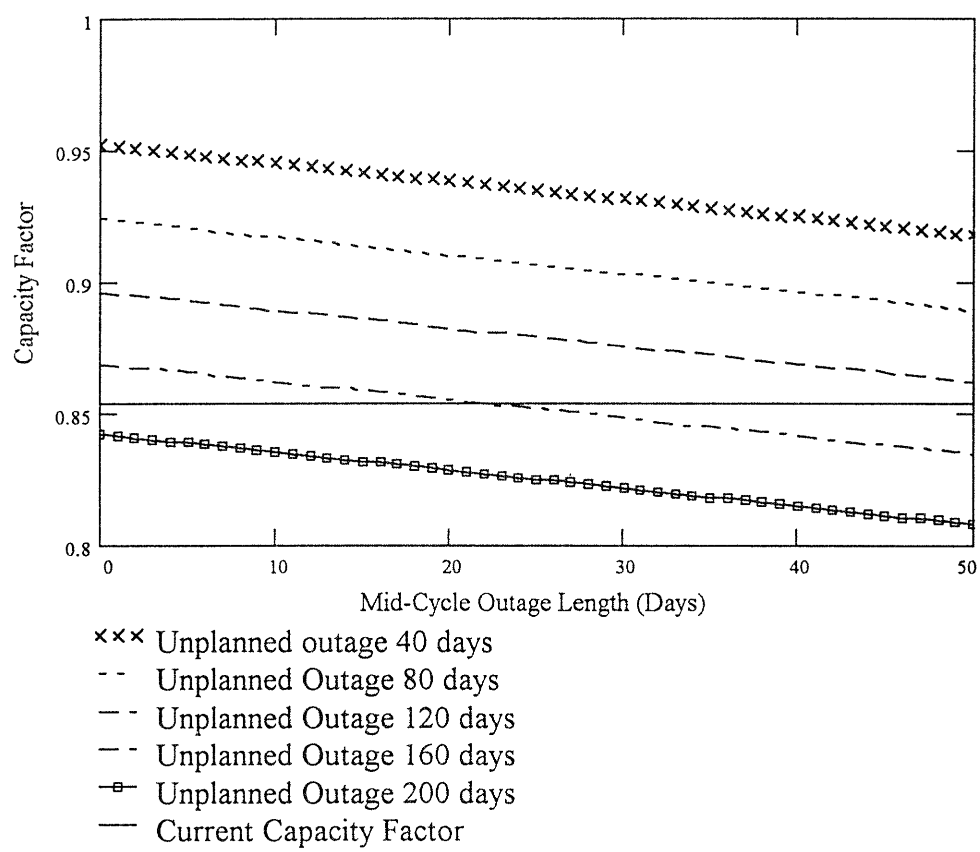


Figure 4.13 Effect on Capacity Factor of Mid-Cycle Outage
For Various Unplanned Outage Lengths
(Refueling Outage: 30 days, Current total outage: 80 days,
Current cycle length: 18 months, Extended cycle length: 48 months)

Figure 4.13 shows the effect of mid-cycle outage lengths on plant capacity factor, for a range of unplanned outage lengths. The refueling length is fixed at 30 days per cycle and the cycle length is assumed to have been extended to four years. Compared with the current 18 month cycle with a 80 day total outage, a four year cycle with a mid-cycle outage up to 50 days in length is competitive in terms of plant capacity factor even though the unplanned outage is as high as 120 days. However, only comparing to the current state in terms of capacity factor is not sufficient, because it doesn't take into account the

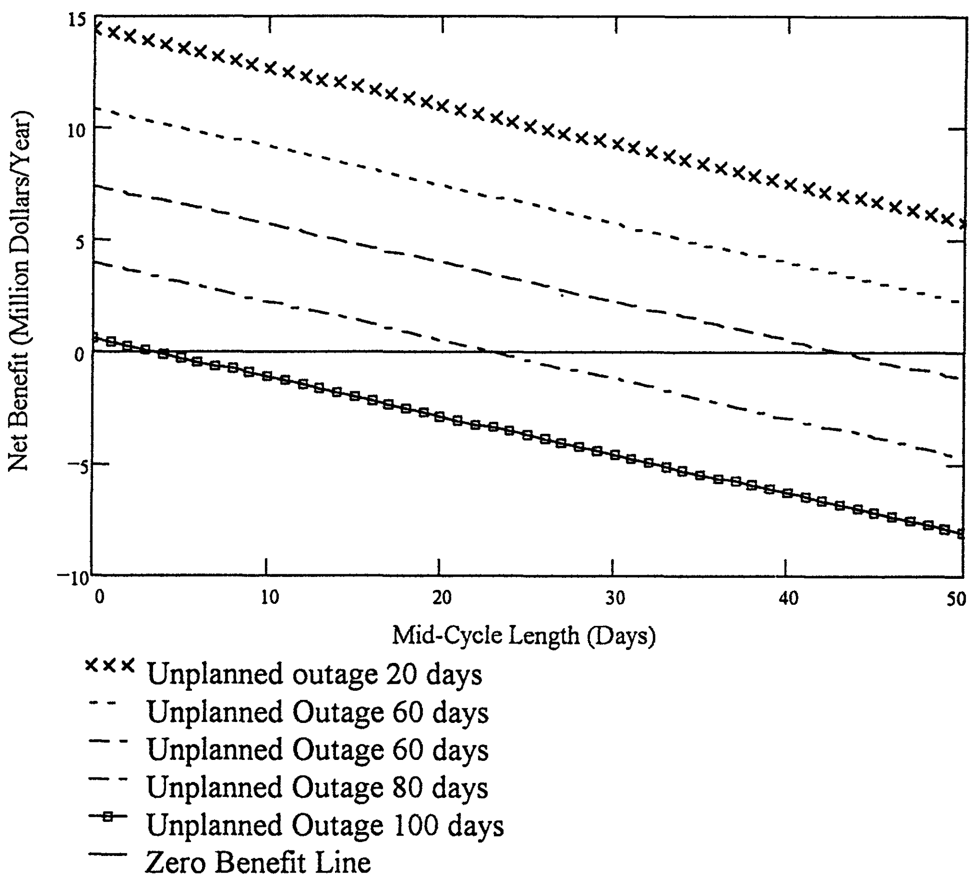


Figure 4.14 Effect on Net Benefit of Mid-Cycle Outage Length
For Various Unplanned Outage Lengths
(Refueling Outage: 30 days, Current total outage: 80 days,
Current cycle length: 18 months, Extended cycle length: 48 months)

economic penalty associated with the operating cycle length extension.

4.3.2 Effects on Net Benefit

Assuming the replacement energy cost is $0.69 million/EFPD, cost for one outage is $ 15 million, and the extra cost for extending the cycle length to 48 months is $ 20 million, the net benefit of extending cycle length to four years is shown in Figure 4.14. Generally, if the mid-cycle outage is kept to less than 20 days, extension of the cycle length is still economically attractive. Of course, excessive unplanned outages will negate the effort to shorten mid-cycle outage and refueling outage.

4.4 Conclusions of Economic Analysis

Based on the previous analyses, it can be concluded that:

- The major part of the benefits come from the additional electricity produced and the saving from the elimination of expensive outages.
- Higher costs will be required for operating cycle length extension. The extra fuel expense is the predominant cost of operating cycle length extension.
- Extension of cycle length has a more significant effect on current 12 month cycle plants than on current 18 month cycle plants.
- The economics of extending the operating cycle length is sensitive to the extra cost model, i.e., the appointment between costs which are insensitive to, and those proportional to, the length of cycle extension. An accurate extra cost model must be developed including consideration of the time value of money.

- The economics of extending the operating cycle length is sensitive to the value of the extra cost, i.e., the magnitude of the cost ????.
- The net benefit is sensitive to the replacement energy cost per EFPD. For areas with high replacement energy cost, extending the cycle length is more attractive.
- If the electricity rate is 2.5 cents per KwHr, i.e., 0.69 million dollars per EFPD for a 1150 MW plant, and the extra cost of extending cycle length from 18 months to 48 months is 20 million dollars a year, extension to four year cycles with 30 days refueling outage will allow a 20 day mid-cycle outage plus 80 days of unplanned outages per cycle and still break even. If the unplanned outage length is reduced, a longer mid-cycle outage is allowed.

Chapter 5. THE FEEDWATER SUPPLY SYSTEM OF A TYPICAL PWR[1]

5.1 General System Description

The Seabrook Nuclear Power Station (SNPS) is chosen as a study example. The SNPS is a 4-loop 1194 MWe Pressurized Water Reactor (PWR) designed by Westinghouse Electric Co. There are three systems related to the steam generator feedwater supply in this unit.

1) The main condenser and condensate system provides a heat sink for exhaust steam from the main turbine and steam generator feed pump (SGFP) turbine and transport condensate from the condenser hotwells to the SGFPs. Additionally, it also

- Preheats the condensate from the main condenser temperature to the SGFP suction temperature;
- Supplies gland seal water to the condensate pumps, SGFPs, heater drain pumps, hotwell isolation valves, and condensate pump suction valves;
- Supplies heater drain pump tempering water.

2) The feedwater system automatically maintains the proper steam generator water inventory during power generating operations. Additional functions of the system are that it:

- Provides final preheat to feedwater;

[1] The system description is based on Seabrook Station Detailed Systems Texts: "Main Condenser and Condensate System," "Feedwater System" and "Heater Drain and Vent System."

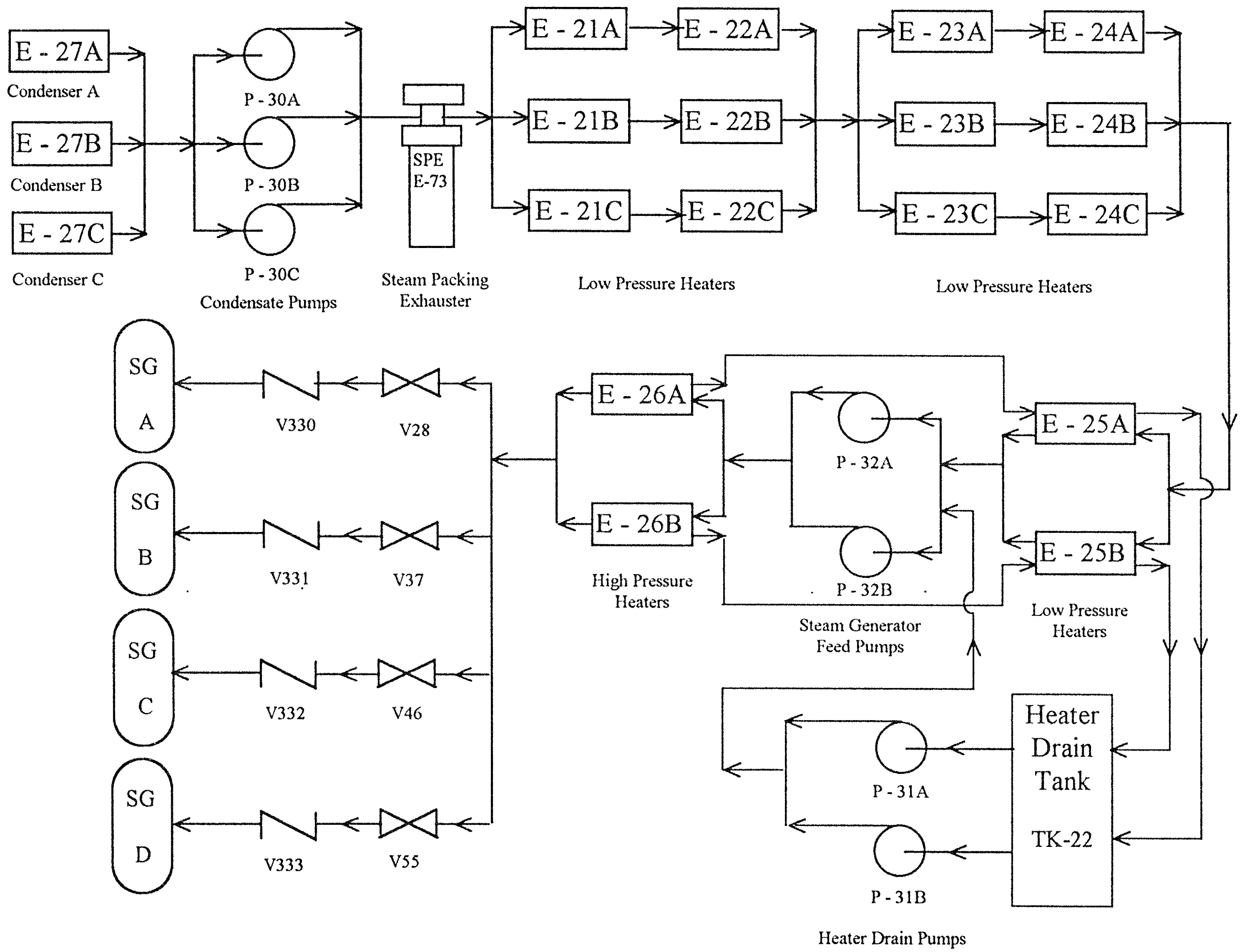


Figure 5.1 A Schematic of Feedwater Supply Systems

- Ensures proper steam generator water inventory during plant startup and shutdown operations;
- Provides steam generator recirculation and wet lay-up capabilities.

3) The heater drain and vent system improves the overall efficiency of the secondary plant. It provides almost 30% of total water flow to the common suction of SGFPs.

A schematic with the major components of the three systems is shown in Figure 5.1. The exhaust steam is condensed in condensers and condensate is pumped from the condenser hotwells through the steam packing exhauster and five stages of low pressure heaters into the common suction of the SGFPs. When the condensate water reaches the SGFP, it becomes feedwater. The feedwater is supplied to the steam generator through the high pressure feedwater heater at the proper temperatures and flow rates as determined by unit load. The condensate system supplies about 70% of the total feedwater flow. The heater drain system collects the water in the bottom of the heater shell when the extraction steam is condensed as it passes over the heaters tubes, and pumps the water into the SGFP common suction line via the heater drain pumps. The heater drain system supplies the remaining 30% of the total feedwater flow.

5.2 Condenser and Condensate System

A schematic diagram of the condenser and condensate system is shown on Figure 5.2. The condenser and condensate system consists of the following major components:

- main condenser and its air evacuation system (one)
- hotwells (three)

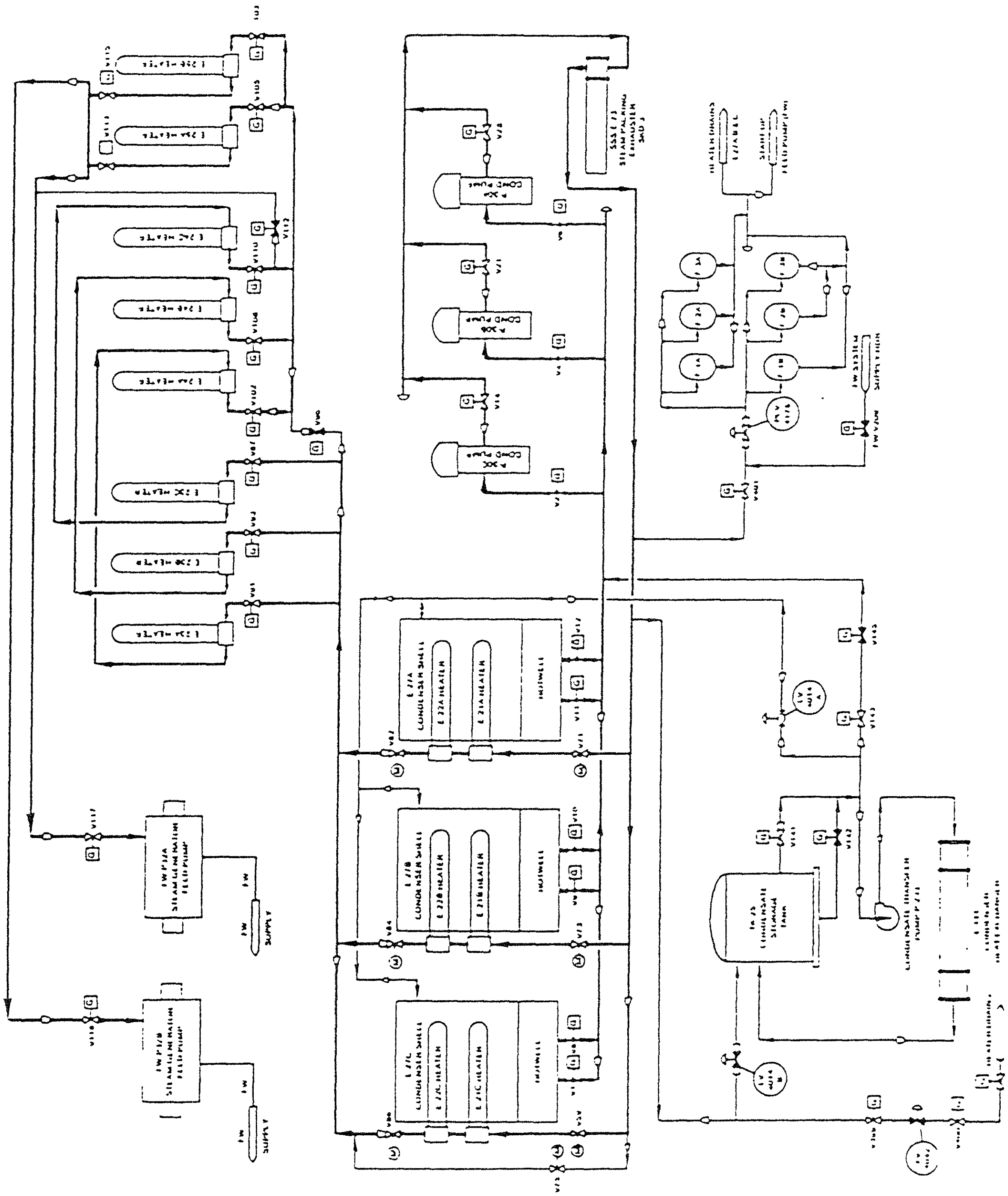


Figure 5.2 A Schematic of Condenser and Condensate System

- condensate pumps (three),
- low pressure heaters (fourteen),
- condensate storage tank (one)
- condensate storage tank transfer pump (one).

The main condenser and air evacuation system is located directly beneath the low pressure sections of main turbine. The main condenser consists of three identical, separate surface condensers, which are designated CO-E-27A, CO-E-27B and CO-E-27C. Its condensing surface is sufficient to limit the turbine backpressure to no more than 2.8 inches HgA during full load operation. It also has the capability to condense turbine bypass flows up to 40% of the full load main steam flow without exceeding the turbine exhaust pressure (5 inches HgA) and corresponding temperature limitations.

The main condenser utilizes the circulating water flowing through its tubes to condense the turbines exhaust steam into water droplets. As the steam is condensed, entrained air and other noncondensible gases are released. The air and noncondensible gases are undesirable because of the inefficient heat transfer properties of these gases. In order to remove these gases, the condenser tube arrangement forms lanes to route the gases to special air removal sections of the condenser. In these air removal areas, the gases are drawn into two air removal pipes by external, mechanical vacuum pumps and expelled to the atmosphere.

The condensate system is part of the closed loop steam-water cycle. It is designed to deliver approximately 1370 kg/sec (about 10.9×10^6 lb./hr) of condensate flow to the suction side of SGFPs under unit full-load conditions. The condensate system is also designed to maintain and supply makeup water to the system from the condensate storage tank (CST).

The low pressure turbine exhaust steam is condensed by circulating water flowing through the condenser tubes. The condensate collects in the hotwell of each condenser, which is capable of holding 83.3 m^3 (22,000 gallons) of condensate when filled to the normal water level.

A 1.22-m (48-inch) main suction header directs condensate from the hotwells to the three condensate pumps. The condensate pumps are 50% capacity, six-stage, vertical, centrifugal pumps. During normal operation, two of the condensate pumps are in operation while the third pump is in standby. With two pumps in operation, the condensate system supplies 70% of the required condensate to the SGFPs. The remain 30% is supplied by heater drain pumps.

The condensate pump discharge header is routed to the steam packing exhauster. The steam packing exhauster is used to condense gland sealing steam from the main turbine and the SGFP turbines.

Flow from the condensate pump discharge header is next routed through the low pressure heaters. The heaters utilize the thermal energy from extraction steam and the cascaded heater drain flow to heat the condensate in order to increase plant efficiency. Each heater comprises a stage of feedwater heating. The condensate flows through the tube side of the heaters. The condensate temperature increases as the condensate passes through each successive heater stage.

The first group of low pressure heaters consists of three parallel sets of heaters, two heaters per set. The heaters (E-21A and E-22A, E-21B and E-22B, E-21C and E-22C) are mounted horizontally in the necks of the main condenser shells and two heaters in each condenser shell. The condensate flows through the E-21 and E-22 heaters to a common discharge header at the outlet of each E-22 heater.

The second group of low pressure heaters also consists of three parallel sets of heaters, two heaters per set, designated as E-23A and E-24A, E-23B and E-24B, and E-23C and E-24C. The discharge header of the E-22 heaters is routed to the common inlet header of the E-23 heaters. The condensate flows through each set of E-23 and E-24 heaters to a common discharge header connected to the outlet of each E-24 heater.

Heaters E-25A and E-25B make up the final stage of the low pressure heaters. They are connected in parallel to the common discharge header from the E-24 heaters. The discharge of heaters E-25A and E-25B is connected to a common header which is connected to the suctions of SGFPs P-32A and P-32B. Two connections from the heater drain pumps are made at the common discharge header of heaters E-25A and E-25B.

5.3 Feedwater System

A schematic diagram of the feedwater system is shown on Figure 5.3. The major components of the feedwater system include the following:

- steam generator feed pumps (two)
- high pressure feedwater heaters (two)
- main feed block valves (four)

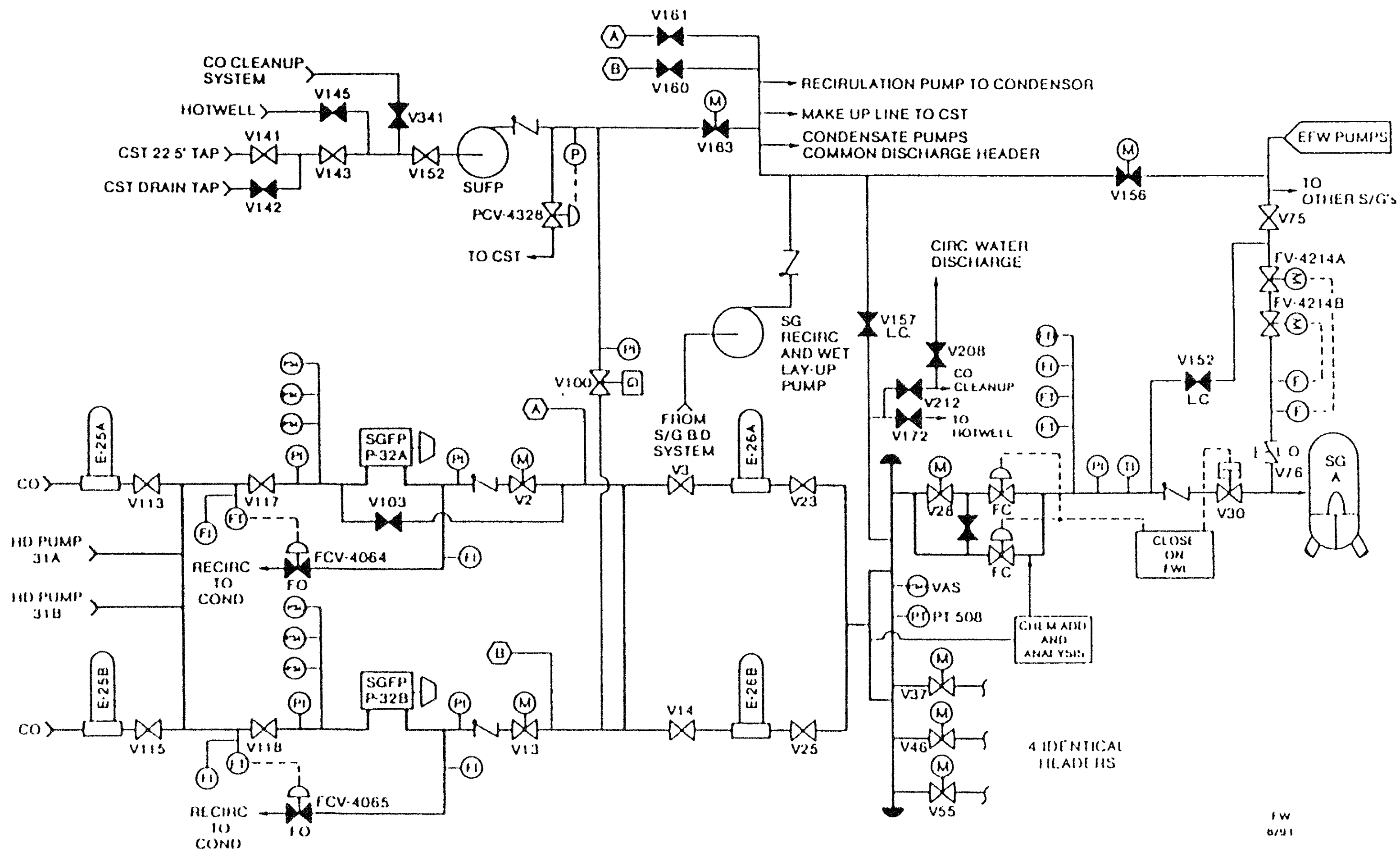


Figure 5.3 A Schematic of Feedwater System

- main feedwater regulating valves (four)
- bypass feed regulating valves (four)
- feedwater isolation valves (four)
- startup feed pump (one)
- steam generator recirculation and wet lay-up pump (one)

The feedwater system is designed to deliver 228 °C (443 °F) feedwater to each steam generator at a rate of 2140 kg/sec (1.7×10^7 lb./hr) with the turbine control valves wide open. In addition, the feedwater system is designed to maintain the proper water level in each steam generator under steady-state and transient conditions.

Feedwater is supplied to each SGFP through identical suction inlet headers. Each suction inlet contains a gear-operated isolation valve, a flow sensing element, and pressure transmitting instruments. Each SGFP discharges to its discharge header through a motor-operated isolation valve (V2 and V13) controlled from the main control board.

The two SGFPs are horizontally mounted, variable speed, centrifugal pumps. Each pump is capable of 60% of the full power flow and is driven by an associated steam turbine. The pump speed is regulated by the turbine control system.

Each SGFP turbine is a multistage, dual-inlet steam turbine. It is designed to be powered by both high and low pressure steam and tested with auxiliary steam. From no load to approximately 40% of the full plant load, the turbine is driven by high pressure steam through the high pressure steam stop and control valve. Above 40% of the full plant load, the SGFP turbine is powered by low pressure crossaround reheat steam.

The discharge of the SGFP proceeds to the high pressure feedwater heaters for the last preheat prior to entering the steam generators. Feedwater flows through the tubes of each high pressure heater (E26A and E26B), and steam flows through the shell side of the heaters.

The outlet of each high pressure heater discharges to a common header. From this header the feedwater flow is evenly distributed to each steam generator through four supply headers. The individual supply headers are identical. Each supply header contains the following: (1) a motor-operated main feed block valve; (2) a flow control valve and bypass; (3) two flow transmitters; (4) a flow element; (5) a check valve; (6) a electrohydraulic feedwater isolation valve.

The motor-driven isolation valve is a normally open gate valve (V28). The air-operated main feedwater regulating valve (MFRV) modulates feedwater flow to the steam generator when the plant load is greater than approximately 15% of full power. A normally closed bypass feed regulating valve bypasses the MFRV during low flow conditions. When plant load is less than 15% of full power, the bypass feed regulating valve is placed in operation to maintain proper steam generator water level.

The feedwater flow rate varies greatly between 15% and 100% of full plant load. In order to meet the required low rate, the MFRV would have to modulate the flow over its full range. Operation in this manner produces a damaging high differential pressure across the valve disc during low flow conditions. A variable speed SGFP which modulates the flow eliminates this problem, protecting the control valve internals from excessive wear.

Downstream of the MFRV and bypass valves is a local flow indicator. This flow indicator is of the sonic probe type. A flow sensing venturi is also located downstream of the flow control and bypass valves. Two flow transmitters on the venturi provide dual flow indications for each supply header.

A check valve is located in each supply header in order to prevent reverse blowdown of a steam generator in the event of a feedwater header rupture.

When the plant load is below 3% of full power, the feedwater flow requirements are met with the startup feed pump. This pump is also used as a backup source of feedwater for both the SGFPs and the emergency feedwater (EFW) pumps.

The steam generator recirculation and wet lay-up pump recirculates water through the steam generators when they are in the wet lay-up condition in order to prevent chemical stratification, and also to provide a way to drain a steam generator to the condensate storage tank or condenser hotwells.

5.4 Heater Drain System

A schematic diagram of the heater drain system is shown on Figure 5.4. The heater drain system consists of the following major components:

- feedwater heaters (six sets)
- heater drain tank (one)
- heater drain pumps (two)

In order to increase unit efficiency, steam is extracted from various stages in each turbine and directed to a number of feedwater heaters. The feedwater heaters utilize the extraction steam to preheat the condensate and feedwater prior to its entry into the steam

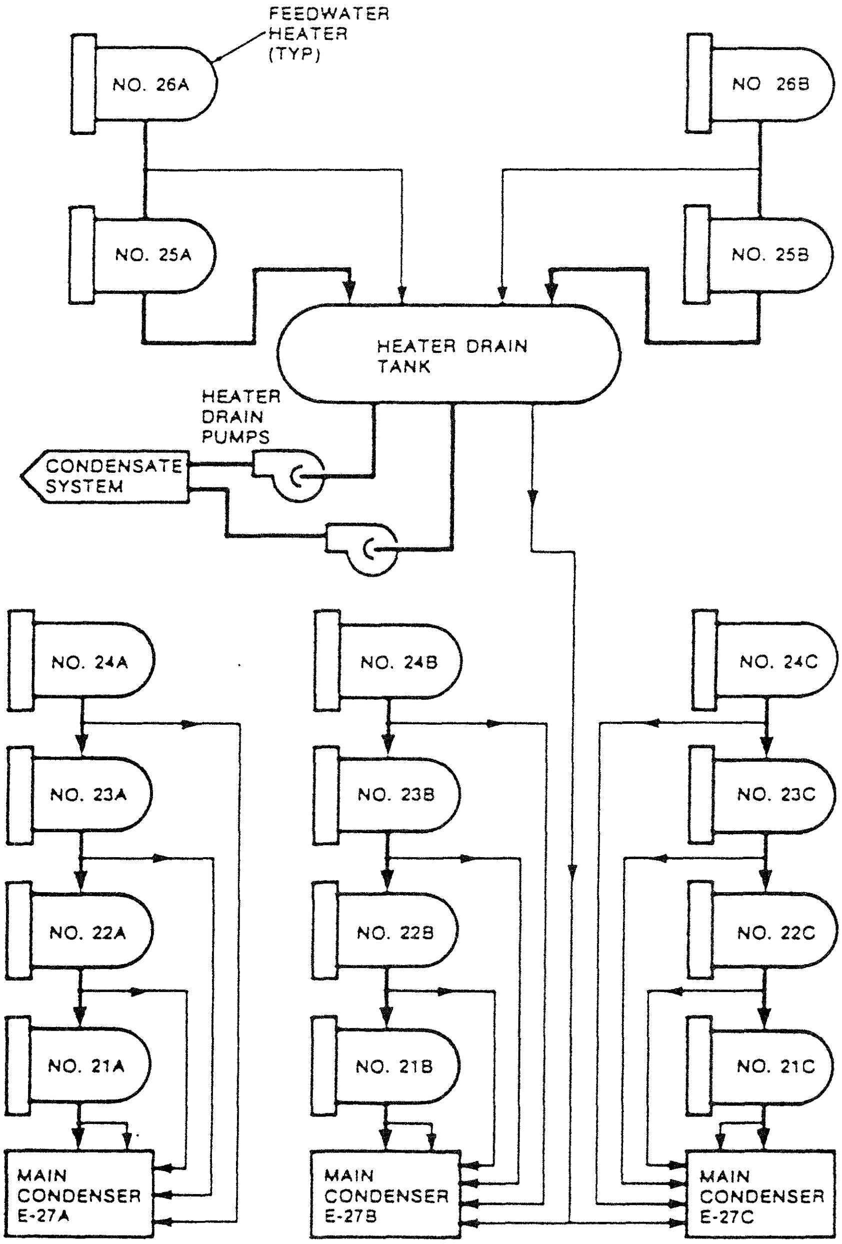


Figure 5.4 A schematic of Heater Drain System

generator. The extraction steam that condenses in the feedwater heaters is termed the heater drain and is collected by the heater drain system to be returned to the steam generator.

The heater drain flow path is designed to cascade from the higher pressure feedwater heaters to the lower pressure feedwater heaters. This design provides the maximum use of the energy stored in the steam-water mixture. The feedwater heater drains are divided into two operational sections. Feedwater heaters 26 and 25 drain to the heater drain tank (HDT), and the remaining feedwater heaters drain to the main condenser.

Drains from feedwater heaters 26 cascade to the shell side of feedwater heater 25. The shell side of feedwater heater 25 drains to the heater drain tank. The HDT collects the drains from these heaters, in addition to providing the suction head required for the heater drain pump. The two heater drain pumps draw a suction on the heater drain tank and discharge to the condensate header upstream of the steam generator feed pumps. The drains from the remaining sets of feedwater heaters cascade to the lower pressure heaters until finally feedwater heater 21 drains to the main condenser. These sets of feedwater heaters are designed to operate in three separate banks (A, B and C). For example, feedwater heater 24A drains to the shell side of feedwater heater 23A. In turn, feedwater heater 23A drains to feedwater heater 22A, which drains to feedwater heater 21A. Then, as mentioned above, feedwater heater 21A drains to the main condenser hotwell (E-27A).

5.5 Summary

Generally, the functions of the condensate and feedwater system described above are to provide a heat sink for the steam-water conversion cycle and to maintain the proper steam generator water level. It is the major part of the secondary coolant loop of a PWR nuclear plant and is directly related to the electricity generation unit (steam turbine and electrical generator). It has important impacts on the plant's electricity generation ability.

The components in the system can be roughly categorized as passive components, such as, condenser hotwell, heaters, *etc.*, and active components, such as pumps, *etc.*

CHAPTER 6. EVALUATION OF EXPECTED SYSTEM RELIABILITY AND CAPACITY FACTOR

The system reliability and capacity factor are the integrated effects of the performance of the individual system components. Each component in the system has its effect upon the system performance. Thus, to predict the system reliability and capacity factor, we need to:

- Estimate the reliability of a component or its availability if the component is repairable;
- Understand the consequences for the system of each component's malfunction;
- Determine which system power capacity level corresponds to each combination of component failures;
- Calculate the probability of the system being in each of the possible power capacity levels.

Also, because of the complexity of the problem, we need to simplify the system to a degree which can be analyzed yet still captures the essential nature of problem.

6.1 Component Reliability and Availability

A component's failure rate can be defined as the ratio of the mean number of failures of a single component in a given period of time to the total operating time in the same period. The component's repair rate is defined as the ratio of the mean number of repairs of a single component in a given period of time to the total repair time in the same period. From these definitions, the failure rate λ and the repair rate μ can be obtained as the inverses of the mean time to failure (MTTF) and mean time to repair (MTTR), respectively.

$$\lambda = \frac{1}{MTTF} \tag{6-1}$$

and

$$\mu = \frac{1}{MTTR} \tag{6-2}$$

If a component has a constant failure rate λ, and a constant repair rate μ, the reliability R(t) and availability A(t) of this component, respectively, are given by relationships:

$$R(t) = e^{-\lambda t} \tag{6-3}$$

and

$$A(t) = \frac{\mu}{\lambda + \mu} + \frac{\lambda}{\lambda + \mu} e^{-(\lambda + \mu)t} \tag{6-4}$$

For most components, the repair rate is relatively constant, but the failure rate may be time-dependent as it depends upon the component's age. If the failure rate is the time-dependent function λ(t) and the repair rate is constant, the reliability and availability are obtained as:

$$R(t) = EXP[-\int_0^t \lambda(\xi) d\xi] \tag{6-5}$$

and

$$A(t) = EXP[-\Lambda(t)] + EXP[-\Lambda(t)] * \int_0^t \mu * EXP[\Lambda(\zeta)] d\zeta \tag{6-6}$$

where

$$\Lambda(t) = \int_0^t \lambda(\tau) d\tau \tag{6-7}$$

For most mechanical components such as the components in the feedwater supply system, their failure rates are poorly quantified, but may obey the "bathtub" shape as shown in Figure 6.1.

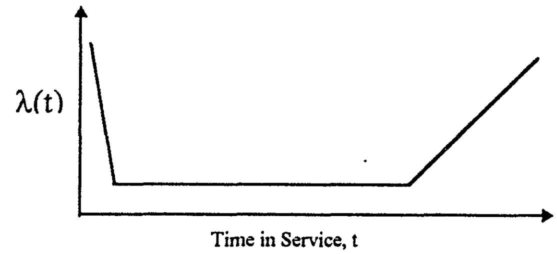


Figure 6.1 Bathtub shape failure rate function

A component with a bathtub shape failure rate function will have a decreasing failure rate at beginning of life over a short "burn-in" period, stay nearly constant over its useful lifetime, and then increase its failure rate rapidly due to wearout. Research shows that the "burn-in" period has little effect on system capacity factor if this period is short compared with the mean time to failure of the component.[1] Furthermore, since components are usually operated within their useful lifetimes, regarding the failure rate as being constant is proper for most components if the wearout effect is negligible. Most of the available data and the results presented in this report are based upon the analyses of constant failure and repair rates.

6.2 Fault Tree Method

A fault tree symbolically represents the conditions that may cause a system to fail. It can pinpoint system weaknesses in a visible form. To construct fault trees, we start with

[1] See Chapter 7: "Results of System Reliability and Capacity Factor Analysis".

a particular system failure or undesired event and work backwards to explore all the combinations of component failures that may lead to this failure. The basic steps to be followed in developing fault trees are as follows:

a) Identify a particular undesired event or failure condition (called the top event) of the system under consideration.
b) Study and understand thoroughly the system and its intended use.
c) Determine the higher order functional events that can cause the undesired event identified in (a). Also, determine the logical relationships of lower order events that can cause the higher order functional events.
d) Construct a fault tree using a set of basic building blocks. This tree pictorially shows the different combinations and sequences of other events that lead to the top event. All of the input fault events must be defined in terms of basic, independent, and identifiable faults.
e) Evaluate the fault tree qualitatively and/or quantitatively as required.

6.3 Event Tree Method

An event tree pictorially represents the complete event-space, consisting of the events that are possible in a system. By constructing the event tree of a system, it is possible to tabulate the system capacity level and corresponding combinations of component states.

In constructing an event tree, we need to systematically go through every possible state of the system components. In the case of continuously operated systems, the components can be considered in any arbitrary order. But if the system involves standby units and sequential logic, the sequence of events must be considered in the chronological order in which they occur.

6.4 Calculation of System Reliability and Capacity Factor

System reliability and capacity factor are the combined effects of the performance of components composing the system. How the performance of the components affects the system depends upon the logical relationship between the individual components, and between components and systems.

If n components are arranged logically in series, the reliability RB(t) and availability AB(t) of the component ensemble, respectively, are:

$$RB(t) = \prod_{i=0}^{n} R_i(t), \tag{6-8}$$

and

$$AB(t) = \prod_{i=0}^{n} A_i(t). \tag{6-9}$$

where R_i and A_i are respectively the reliability and availability of the i th component.

If n components are arranged logically in parallel, the reliability and availability of the component ensemble, respectively, are:

$$RB(t) = 1 - \prod_{i=0}^{n} [1 - R_i(t)] \tag{6-10}$$

$$AB(t) = 1 - \prod_{i=1}^{n} [1 - A_i(t)] \tag{6-11}$$

For systems consisting of a mixture of logically series and parallel component arrangements, the corresponding relationships for the reliability R(t) and availability A(t) will reflect a mixture of these concepts.

Assume there are totally N system capacity states. For each system state, j, there is a corresponding power capacity level, C_j, and a probability $P_j(t)$ of the system being at this state. $P_j(t)$ is the mixed effect of all of the components' availability $A_i(t)$ or unavailability $UA_i(t)$, depending upon the combination of component failure modes corresponding to the j th system state. Then the expected capacity of the system at time, t, $<C(t)>$ is obtained as:

$$<C(t)>=\sum_{j=1}^{N} P_j(t) * C_j , \qquad (6\text{-}12)$$

where N is the total number of system states, and the average capacity factor of the system over the time interval [0,T] is given by the relationship:

$$<CP(T)>=\frac{1}{T*C_0}*\int_0^T \sum_{j=1}^{N} P_j(t)*C_j*dt , \qquad (6\text{-}13)$$

where C_0 is the full system capacity value.

6.5 Modeling the System

In most practical situations, the reliability and availability of a system consisting of hundreds of components is still too complicated to analyze. Theoretically, for a system of n components, the total number of system states will 2^n. This number is so huge that no computer can analyze it completely if the value of n is the hundreds. Fortunately, most components have no important effects upon the system capacity factor; or alternatively their effects upon the system capacity factor can be estimated in terms of the major component with which they are associated. It is possible for us to represent a system by a simplified model which can be handled practically and still represent the nature of the system realistically. The basic steps to simplify a system are as follows:

1) Identify the major components of the system;
2) Identify components which are unimportant for system capacity factor and may be ignored in the model;
3) Simplify the system configuration by subsuming the effects of auxiliary components in terms of their effects upon major components;
4) Calculate the effective component failure rates.

Following the steps above, we have obtained a simplified model of the feedwater supply system at the Seabrook Nuclear Power Station, as shown in Figure 5.1. This model consists of 40 major components. Each major component in the figure represents a number of actual components. Note that the startup feed pump and the steam generator recirculation and wet lay-up pump are not shown in Figure 5.1, because they do not have a significant effect upon the system's capacity factor.

A system with 40 components still has 2^{40} system states. However, most of them are zero-capacity states because they involve the failed components which are minimum cut sets of system failure. In order to focus upon the feedwater supply system, we assume that all other systems in the plant are in successful states. The thermal efficiency of the plant is taken as the index of the capacity of the feedwater supply system. Corresponding to the full capacity state of the feedwater supply system, the thermal efficiency, η, of the plant is equal to 0.33. By applying the fault tree and event tree methods, all non-zero capacity states of the system and corresponding combinations of component failure modes can be identified as follows:

1) If all components succeed, $\eta=0.33$;
2) If only one of the condensate pumps fails and all other components succeed, $\eta=0.33$;
3) If one of the condensers fails and all other components succeed, $\eta=0.22$;
4) If one feedwater heater fails and all other components succeed, $\eta=0.31$;
5) If two feedwater heaters fail and all other components succeed, $\eta=0.29$;
6) If one heater drain pump fails and all other components succeed, $\eta=0.264$
7) For all other combinations of component modes, $\eta=0$.

6.6 Component Failure Rate and Repair Rate Data

Accurate failure rate data of the system components is the key to make system reliability and availability analyses valuable. The weakest aspect of reliability and availability analysis involves the nuclear industry-wide lack of good maintenance data. In the work of this report, we use the component performance historic records maintained at Seabrook as the plant-specific data source and we are seeking better databases such as NPRDS, as generic data sources.

The data in the plant's records or other databases is a collection of single-incident data which usually includes the information about which components have failed, what the results of failures are, when the failures occurred, what repair actions took place, and when the components went back into service. In order to develop the processed data, such as estimated failure rates, event frequencies, etc., from the "raw" data of component performance historical records., the following steps should be followed:

1) Count the number of failures of a particular component that occurred during a certain operational period. Divide the total operation time by the number of failures to yield the estimated mean time to failure (MTTF) of this component. The Inverse of the estimated MTTF is the estimated mean failure rate of this component.
2) Count the number of repairs of a particular component that occurred during the same operational period and sum up the time spent in each repair. Divide the total repair time by the number of repairs to yield the estimated mean time to repair (MTTR). Its inverse is the estimated repair rate of this component.
3) Based upon the logical relationship between components, the effective failure rates of major components can be obtained by using the method described in section 6.4.

By applying this method and combining results obtained from the "Seabrook Components Reliability Analysis Report", we can obtain the failure rates of the components in the feedwater supply system at Seabrook as shown in Appendix.

CHAPTER 7 RESULTS OF SYSTEM RELIABILITY AND CAPACITY FACTOR ANALYSIS

7.1 Results of Reliability Analysis

Reliability analysis of the system operating without repair and without common-cause failures includes calculating the following quantities:

- The reliability of the feedwater supply system at the end of one year of continuous operation based upon the Seabrook station data.
- The reliability of the system at the end of one year of continuous operation if only the components with failure rates greater than one-fortieth of the maximum component failure rate (which are the SGFPs, condensate pumps, and heater drain pumps) are considered.
- The reliability of the system at the end of one year if only the components with the maximum failure rate (which are SGFPs) are considered.
- The sensitivity of system reliability to maximum and minimum component failure rates.

The results of the analyses of the reliability, R, are shown as follows:

1) Complete system: $R_{system} = 7.92\text{x}10^{-9}$
2) Only considering failures of components with $\lambda \geq \lambda_{max}/40$: $R_{system} = 1.26\text{x}10^{-8}$
3) Only considering failures of components with $\lambda = \lambda_{max}$: $R_{system} = 2.46\text{x}10^{-8}$
4) A sensitivity analysis of system reliability provides the following results, taking into account possible system improvements or degradation:

- If $\lambda_{max,new}=\lambda_{max,old}/10$, $R_{system,\ new} = 0.056$

$$\Delta R = \frac{R_{system,new} - R_{system,old}}{R_{system,old}} = 7.05 * 10^6$$

- If $\lambda_{min,new}=\lambda_{min,old}*10$, $R_{system,\ new} = 7.90x10^{-9}$

$$\Delta R = \frac{R_{system,new} - R_{system,old}}{R_{system,old}} = -2.37 * 10^{-3}$$

The absolute values of the system reliability shown above are not very meaningful because no repair of failed components is considered and very conservative failure rate data are used. However, the importance of the SGFPs' performance to system reliability is shown clearly. Considering the total system reliability of 10^{-9}, the SGFPs reduce the reliability of the system from unity to 10^{-8}, while all other components only reduce it by an additional factor of 10^{-1}. If the SGFPs performance can be improved by a factor of 10, the system reliability can be improved by almost 10^7. Therefore, we conclude that the SGFP is the component most in need of improvement.

7.2 Results of Capacity Factor Analysis

The capacity factor analysis includes a number of studies as follows:

I. Based upon the failure rate data from Seabrook, we

- Calculated the system capacity factor;
- Optimized the components' performance to achieve high system capacity factor;

- Studied the effect of adding redundancy of the weakest component (SGFP) on the system capacity factor.

II. By placing components into two categories: active components which include condensate pumps, heater drain pumps and SGFPs; and passive components which include all other components, assuming components in the same category have the same failure rate and repair rate respectively, we

- Studied the sensitivities of system capacity factor to the passive components failure rate and active components failure rate;
- Studied the effects of repair of failed components and sensitivities of system capacity factor to the passive component's repair rate and active components repair rate;
- Studied the effects of human error on system capacity factor;
- Studied the effects of common cause failure on system capacity factor.
- Studied the effects of time-dependent failure of components (wearout effects) on system capacity.

The results of the capacity factor analysis are shown as follows:

7.2.1. Results Using Failure Rate Data From the Seabrook Nuclear Power Plant:

1) average capacity factor of system within 1 year operation without repair,

- expectation of system capacity factor: CP_{exp}=0.10;
- the capacity factor considering only the full capacity state: CP_{exp} = 0.054.

As shown above, the full capacity state only counts for about 50% of the total capacity factor over one year continuous operation, thus partial capacity states of the system are important for capacity analysis.

2) Improvement of component performance needed to achieve high system capacity factor:

- Reducing the failure rate of condensers by 10
- Reducing the failure rate of condensate pumps by 10
- Reducing the failure rate of Steam Packing Exhauster by 10
- Reducing the failure rate of heaters by 50
- Reducing the failure rate of SGFP by 2500
- Reducing the failure rate of Heater Drain Pumps by 50

Taking these improvement simultaneously, the average system capacity over four years of operation will be: $C_{Pexp} = 0.96$.

3) The effect of redundancy is shown on Figure 7.1. If we define the redundancy "worth" as the absolute difference of expected capacity factor between the system with redundancy and the system without the redundancy, we find that the redundancy "worth" is not significant if the component is very reliable (low failure rate) or very unreliable (high failure rate), and that there is a maximum value of the redundancy "worth" of components when the failure rates of components change. If components are repairable, the shape of the redundancy "worth" curve as a function of the failure rate is similar, but the maximum value increases when the repair rate of the components increases (which means that the repair time of components is shortened). This conclusion is useful in determining the

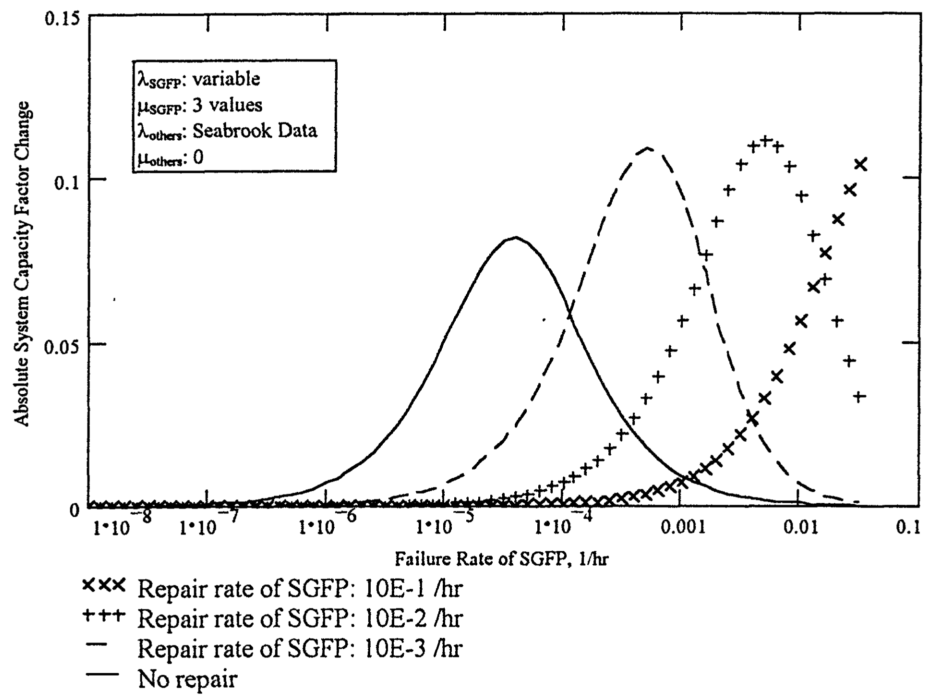


Figure 7.1 Absolute System Capacity Change Due to Adding One Redundant SGFP

strategy for improving system reliability. For example, if a component is reliable enough so that its failure rate is lower than the failure rate value at the point with maximum redundancy worth, we may use a larger number of less reliable but cheaper components arranged redundantly. The overall costs may actually end up being lower than before.

7.2.2. Results Categorizing the Components into Passive and Active Components:

A. Without Consideration of Wearout

1) In addition to using plant-specific data, we have examined the required domains of component performance by performing sensitivity analyses, where all of the active and passive system components are treated respectively as being identically reliable.

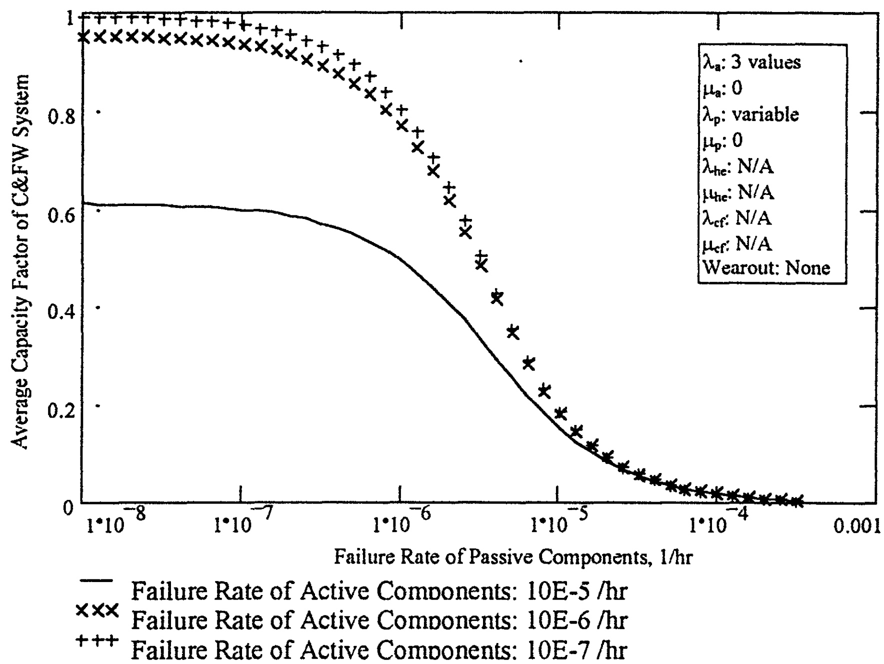


Figure 7.2 System Capacity Factor v/s Passive Components Failure Rate

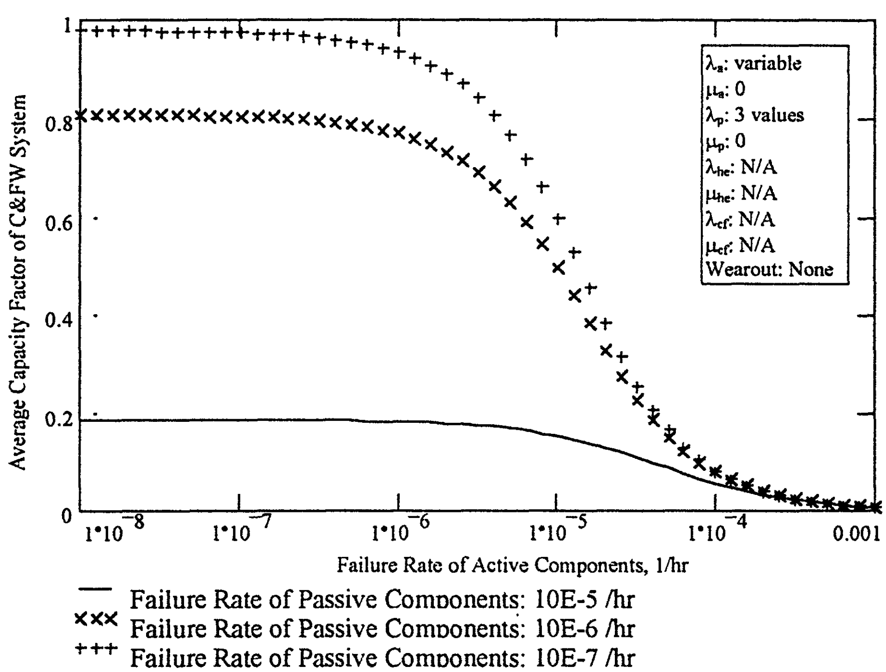


Figure 7.3 System Capacity Factor v/s Active Components Failure Rate

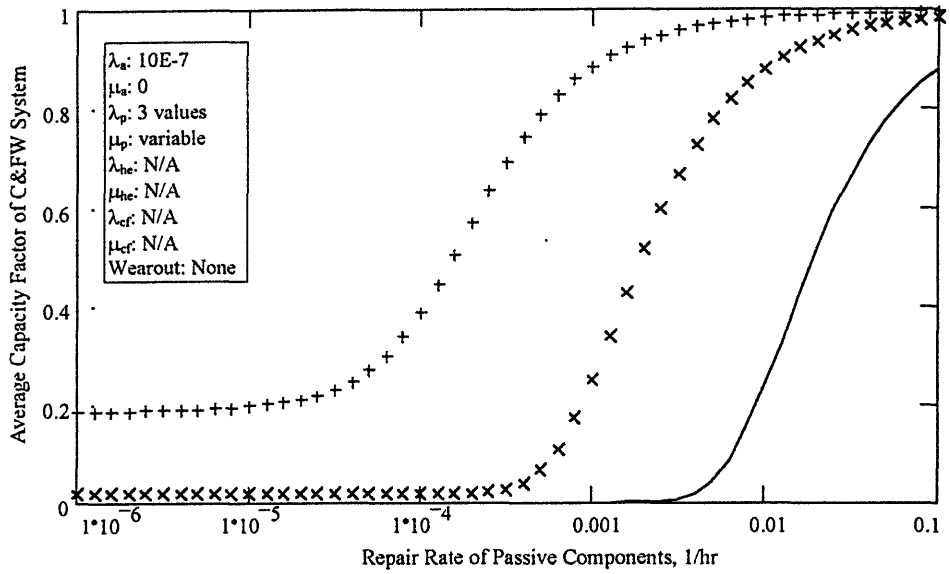
Sensitivities of the system capacity factor versus passive components failure rate and active components failure rates are shown on Figure 7.2 and Figure 7.3, respectively.

It is shown in Figure 7.2 that the passive component failure rates need to be less than 10^{-7} /hr in order to achieve a high system capacity factor. Otherwise, even if the active component failure rates are very small, the system capacity factor is still low. A current typical value of passive component failure rate is about 10^{-6} /hr so it may be possible to get to 10^{-7} /hr by improving the components themselves.

It is shown in Figure 7.3 that in order to achieve high system capacity factor, active component failure rates need to be less than 10^{-6} /hr. A current value is around 10^{-4} /hr, so it is much more difficult to achieve the desired capacity factor goal by only improving the components themselves. We also need to consider improving the repair rate of the active components.

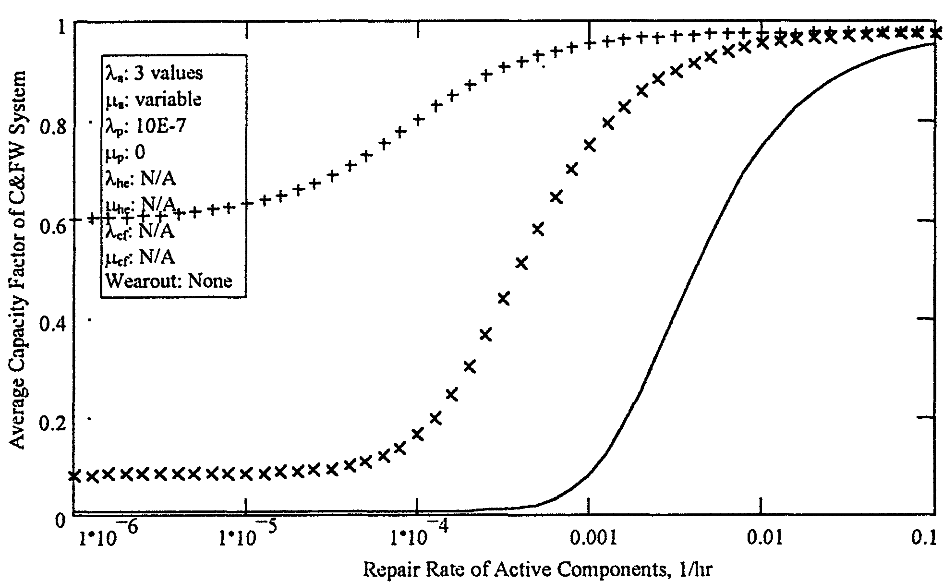
The effects of repair and sensitivities of capacity factor to passive components and the active components repair rates are shown on Figure 7.4 and Figure 7.5, respectively.

The system capacity factor can be improved greatly by decreasing the repair time of the failed components. Without repairing failed components (i.e., repair rate equals zero,) the system capacity factor is very low. System capacity factor starts to increase when the component repair rate is one order of magnitude greater than the failure rate. The greater the repair rate (i.e., the shorter the repair time), the higher the system capacity factor. To achieve high capacity factors, the repair rate needs to be two orders of magnitudes greater than the failure rate, for both passive and active components. After this point, however, a continued increase in the repair rate has little effect upon improving



— Failure rate of passive components: 10E-3 /hr
xxx Failure rate of passive components: 10E-4 /hr
+++ Failure rate of passive components: 10E-5 /hr

Figure 7.4 System Capacity Factor v/s Passive Components Repair Rate



— Failure rate of active components: 10E-3 /hr
xxx Failure rate of active components: 10E-4 /hr
+++ Failure rate of active components: 10E-5 /hr

Figure 7.5 System Capacity Factor v/s Active Components Repair Rate capacity factor since the capacity factor is already so high that any further improvement is small.

The concept of the effective failure rate can be introduced now since we have already studied the effects of repairs. Assume that a component with failure rate λ and repair rate μ results in the system average capacity factor being CP_0. If no repair is applied to this component ($\mu_0 = 0$), this component's failure rate needs to be reduced to λ_0 so that the system can achieve the same capacity factor of CP_0 without changing anything else. We define that this component, with λ and μ, has the effective failure rate λ_0. This concept is illustrated by Figure 7.6 and Figure 7.7.

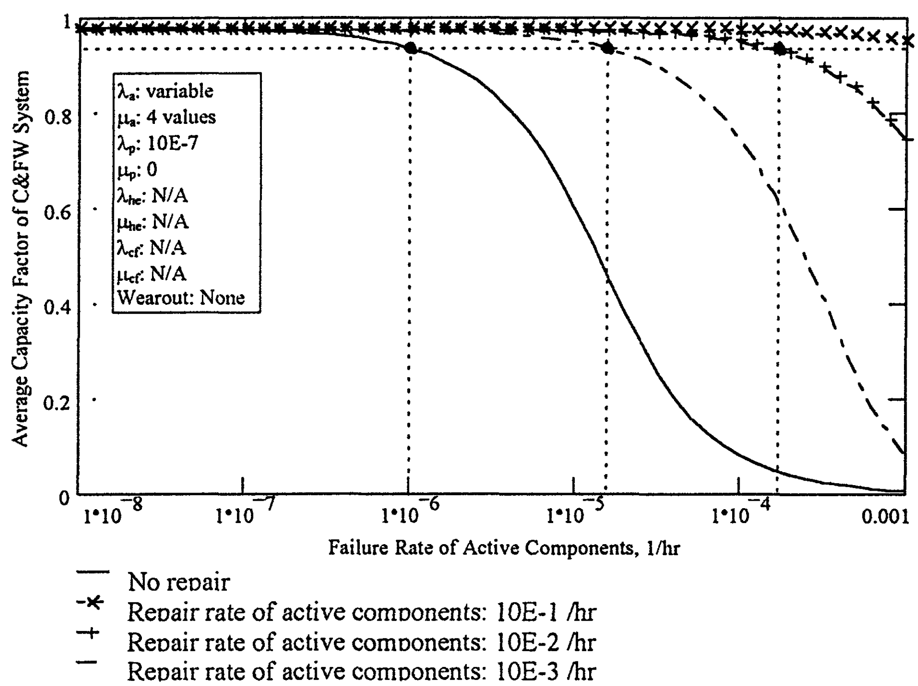


Figure 7.6 Illustration of The Effective Failure Rate of Active Components

As shown on Figure 7.6, the system's capacity factors will be same if the active components' failure rate and repair rate combination are ($\lambda_a = 10^{-6}$ /hr, $\mu_a = 0$ /hr), ($\lambda_a = 1.5\text{x}10^{-5}$ /hr, $\mu_a = 10^{-3}$ /hr), or ($\lambda_a = 1.5\text{x}10^{-4}$ /hr, $\mu_a = 10^{-2}$ /hr). Therefore, the active components can have an effective failure rate of 10^{-6} /hr even if their failure rate is $\lambda_a = 1.5\text{x}10^{-5}$ /hr, if they can be repaired with a repair rate of $\mu_a = 10^{-3}$ /hr. For active components with combination of ($\lambda_a = 1.5\text{x}10^{-4}$ /hr, $\mu_a = 10^{-2}$ /hr), the effective failure rate is same as $\lambda_{eff} = 10^{-6}$ /hr.

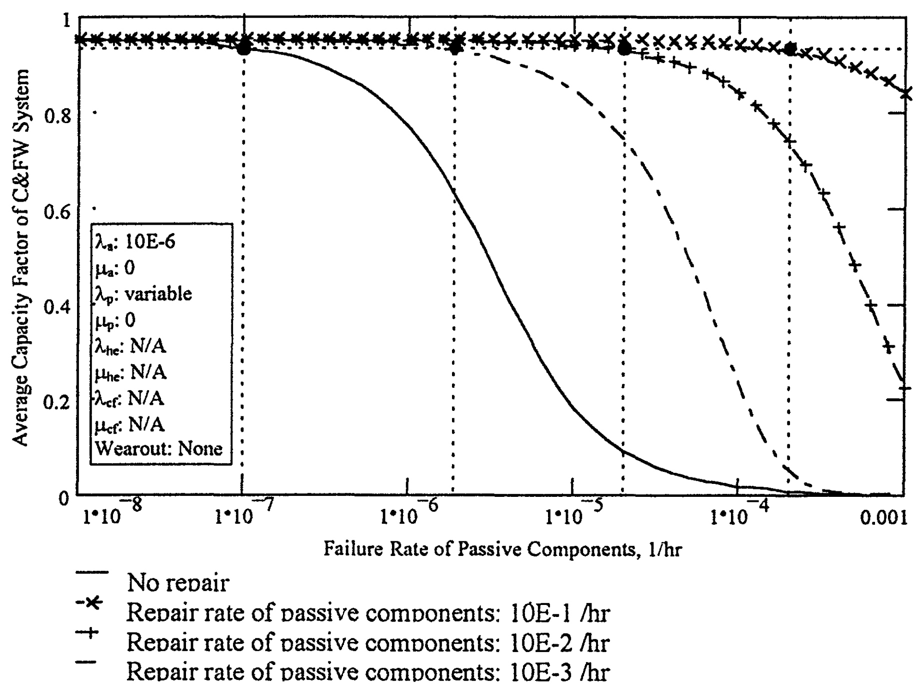


Figure 7.7 Illustration of The Effective Failure Rate of Passive Components

In Figure 7.7, we find that the system capacity factors are the same if the passive components have combinations of failure rate and repair rate as ($\lambda_p = 10^{-7}$ /hr, $\mu_p = 0$ /hr),

(λ_p = 1.5x10^{-6} /hr, μ_p = 10^{-3} /hr), (λ_p = 1.5x10^{-5} /hr, μ_p = 10^{-2} /hr), and (λ_p = 1.5x10^{-4} /hr, μ_p = 10^{-1} /hr). Therefore, all passive components with combinations of (λ_p = 1.5x10^{-6} /hr, μ_p = 10^{-3} /hr), (λ_p = 1.5x10^{-5} /hr, μ_p = 10^{-2} /hr), or (λ_p = 1.5x10^{-4} /hr, μ_p = 10^{-1} /hr) have an effective failure rate of 10^{-7} /hr.

Common cause errors, including human errors, have been analyzed as minimal cut sets for the system. The effect of human error on capacity factor is shown in Figure 7.8 under the assumption that human error can be corrected within two days, e.g., plant operational staff usually should be able to recognize and correct human error within two days. The effect of common cause failure on capacity factor is shown in Figure 7.9 with the assumption that common cause failure can be repaired within an average of one week.

Basically, effects of human error and common cause failure should have the same nature since they are all the minimum cut set of system failure. We see that only with a high system capacity factor are the effects of human error and common cause failure significant. Improvement of system performance should therefore focus on other means

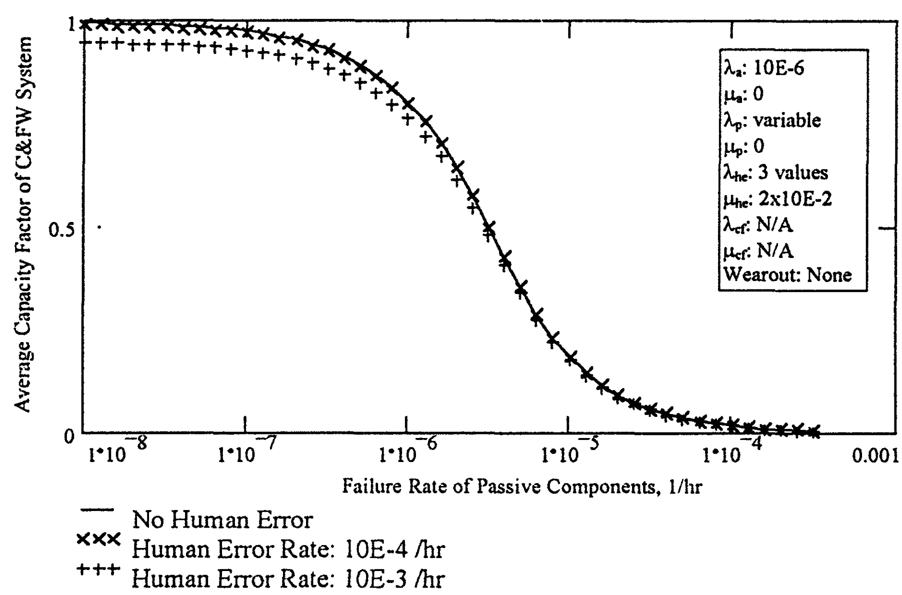


Figure 7.8 Human Error Effect on System Capacity Factor

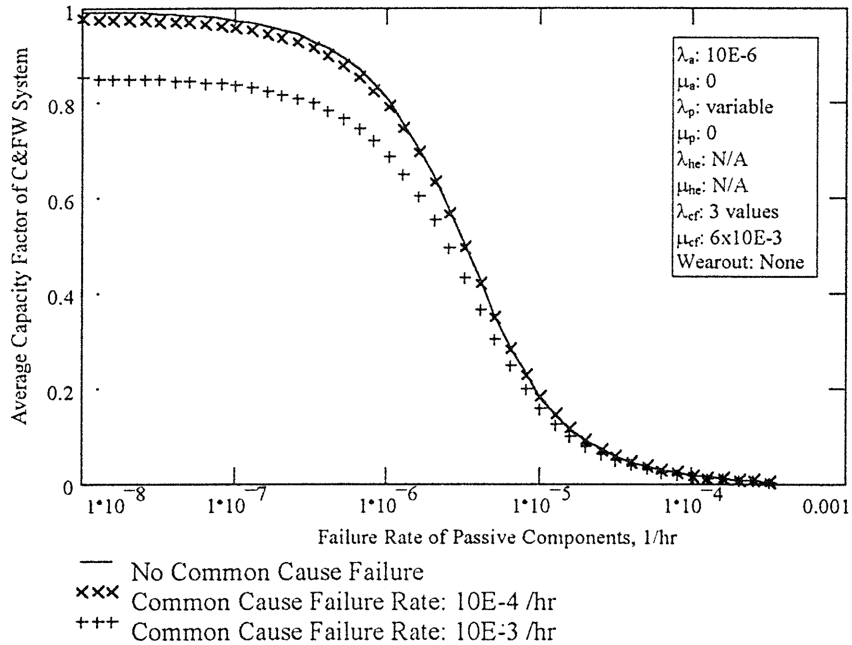


Figure 7.9 Common Cause Failure Effect on Capacity Factor

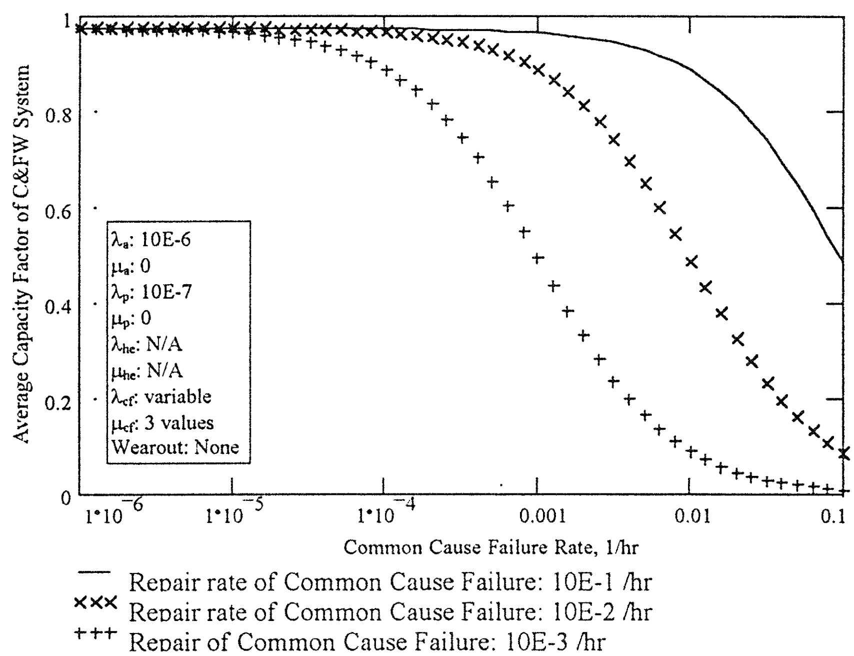


Figure 7.10 Effect of Common Cause Failure Repair Rate on Capacity Factor

besides the elimination of human error and common cause failure when the system capacity factor due to independent failure is low.

Figure 7.10 shows different effects of common cause failure combined with different repair rates. Like independent component failures, the repair rates of human error or common cause failures need to be two orders of magnitude greater than their failure rates in order to achieve high capacity factor.

B. Consideration of Wearout Effects

The results of studying wearout effects of active components upon system capacity factor are shown in the following figures. Three cases are studied in order to understand the effects of active components wearout.

1) The sensitivity of the wearout effects on the system capacity factor versus inception of wearout is studied. The bathtub shape failure rate (hazard) functions $\lambda_a(t)$ of

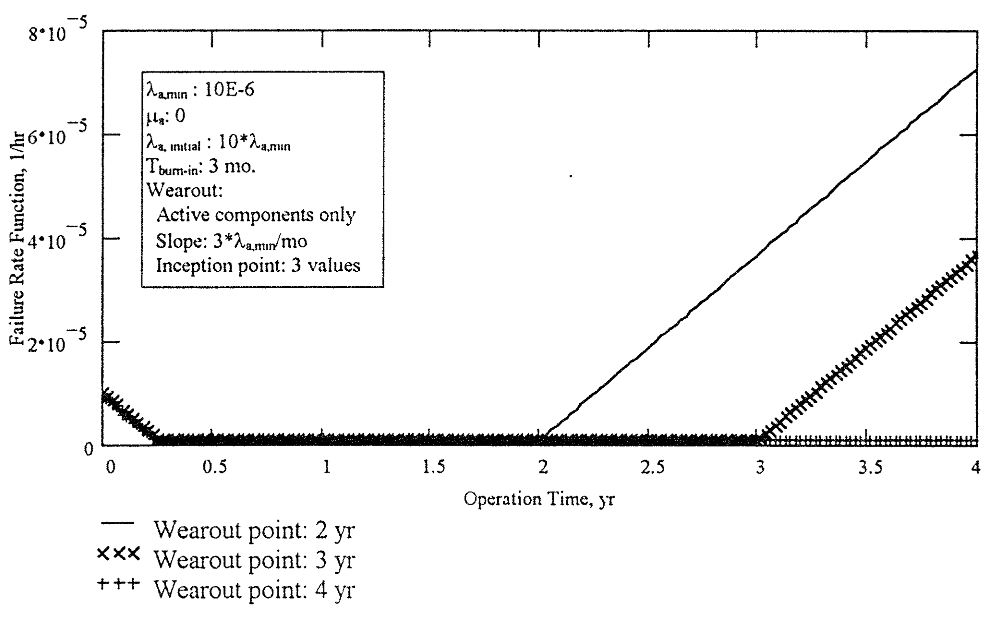


Figure 7.11 The Bathtub Shape Failure Rate (Hazard) Function of Active Components (Different Inceptions)

active components with different inceptions of wearout are shown on Figure 7.11. The "burn-in" period at the beginning of operation is assumed to be three months. Components have a minimum failure rate $\lambda_{a,min}$ during their normal life. The initial failure rate is assumed to be 10 times $\lambda_{a,min}$. The wearout slope is assumed to be the same as the slope of "burn-in", which is 3 $\lambda_{a,min}$ / month.

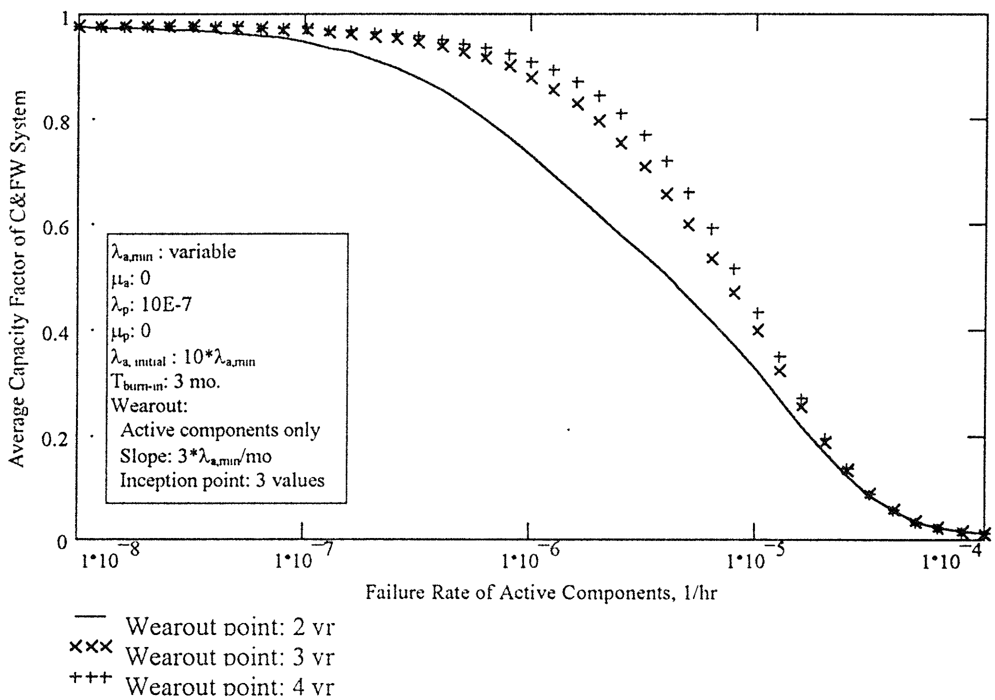


Figure 7.12 Wearout Effects On System Capacity Factor (Different Inception)

The result of this analysis is shown on Figure 7.12. It is found that the effect of wearout is not significant if the wearout of components starts after three years operation in a four-year refueling interval. However, the effects is much more significant if the wearout starts after two years operation. Currently, nuclear power plants are usually operated less than two years before maintenance. Thus the data obtained based on current plant operation is not very meaningful for revealing wearout effects. If the components wearout is to happen after three years of operation, the failure rate data calculated from current history data is applicable to four-year-operation analyses. If the components wearout is to start after only two year operation, however, using the failure data obtained from current history data is doubtful. We may need to multiply the failure rate by some wearout factors to study the plant with a four year operation cycle.

2) The sensitivity of wearout effects versus wearout rate (indicated by the slope of the wearout line in the bathtub curve) is also studied. The bathtub shape failure rate functions are shown on Figure 7.13 with three different wearout rates: 1 $\lambda_{a,min}$/month, 3 $\lambda_{a,min}$ /month and 9 $\lambda_{a,min}$/month. The inception of wearout is at end of three-year operation.

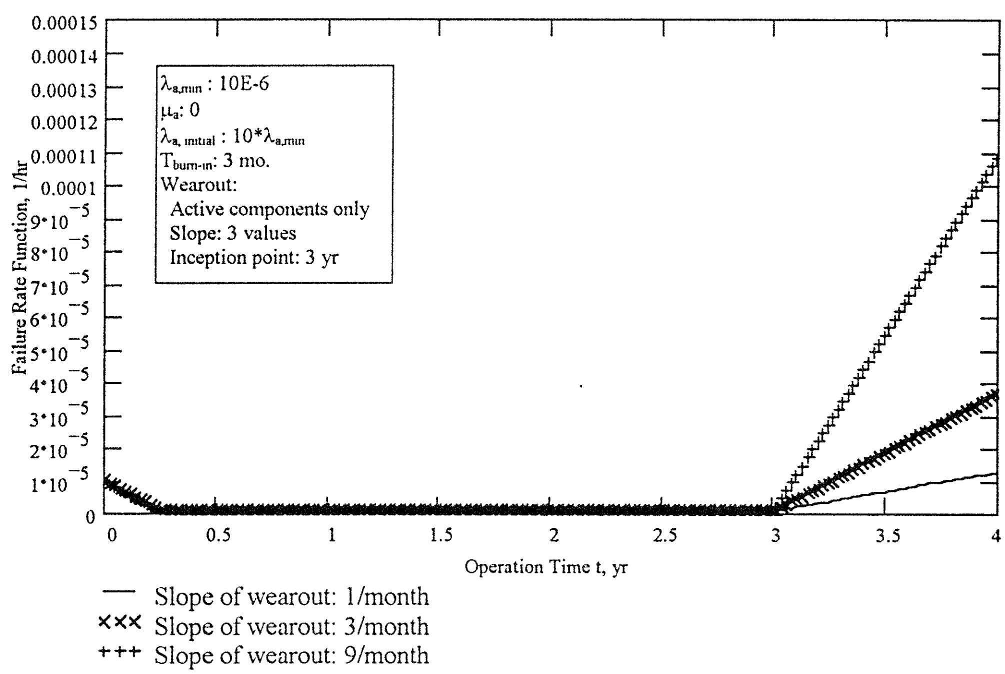


Figure 7.13 Bathtub Shape Failure Rate (hazard) Functions of Active Components (Different Wearout Rates, Wearout Inception: 3 yr.)

The result of this study is shown in Figure 7.14. As in the result we obtained from Case 1 (Figure 7.12), the wearout effects are not significant if the wearout is to start at the end of three-year operation. Figure 7.14 shows that the wearout effect is still small even though the wearout rate has been increased by a factor of three. This result supports the conclusion obtained earlier: If the wearout inception is three years, using the failure rate data calculated from current history data is acceptable for four year operation analyses.

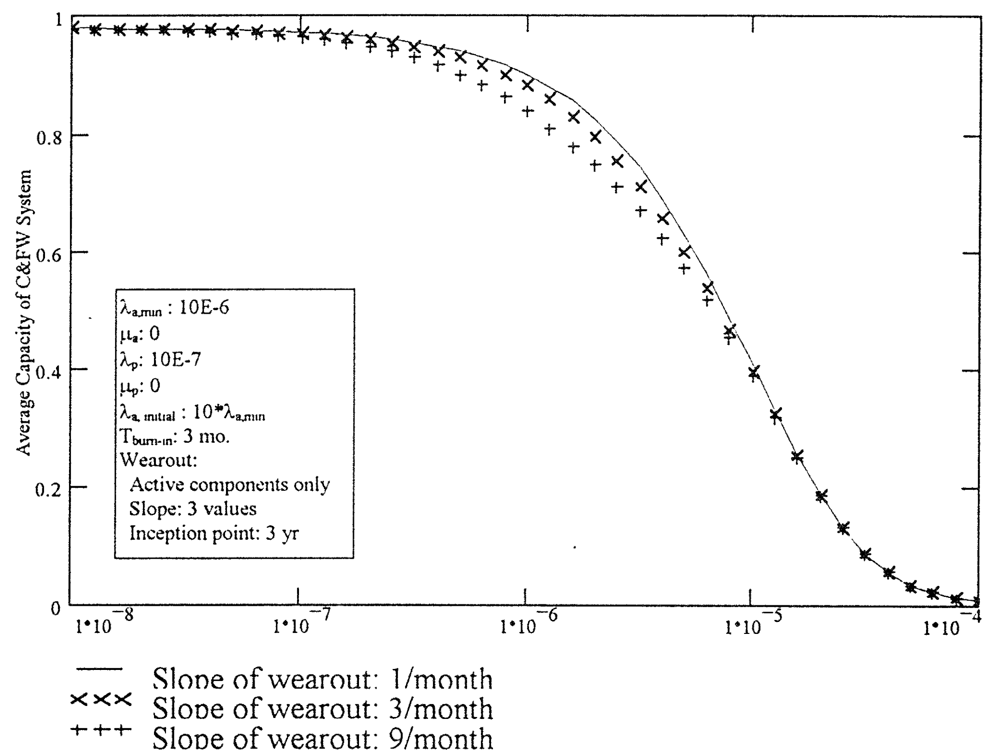


Figure 7.14 Wearout Effects on System Capacity Factor
(Different Wearout Rates, Wearout Inception: 3 yr.)

3) If the inception of wearout is at the end of two years of operation, the effects of active component wearout will be much more significant. The sensitivity of these

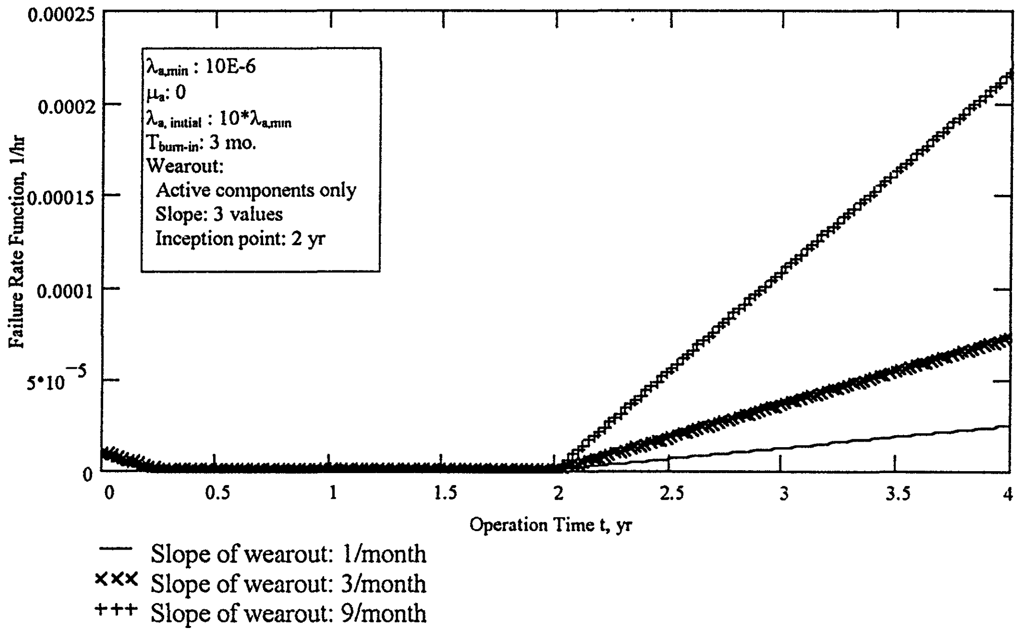


Figure 7.15 Bathtub Shape Failure Rate (hazard) Functions of Active Components (Different Wearout Rates, Wearout Inception: 2 yr.)

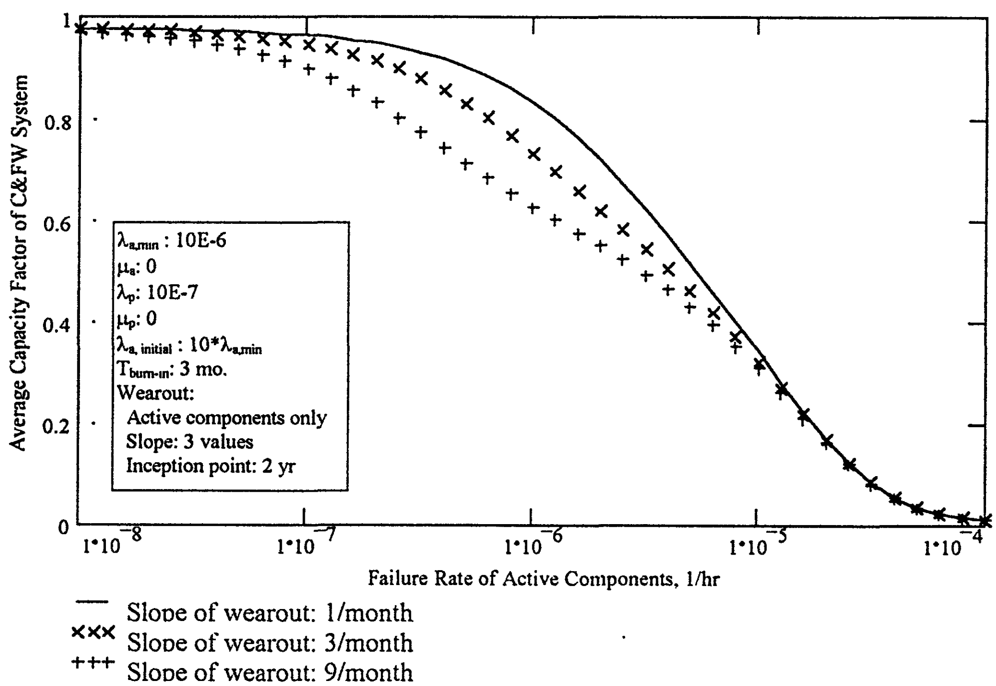


Figure 7.16 Wearout Effects on System Capacity Factor (Different Wearout Rates, Wearout Inception: 3 yr.)

effects versus wearout rate is also more significant. In Figure 7.15 are shown the bathtub shape failure rate functions of active components with three different wearout rates and wearout inception at the end of two-year operation. As in Case 2, the three different wearout rates studied are: 1 $\lambda_{a,min}$ /month, 3 $\lambda_{a,min}$ /month and 9 $\lambda_{a,min}$ /month.

The results of this study are shown on Figure 7.16. We find that the effects of active components wearout on system capacity factor are much more significant if the wearout begins at the end of two-year operation rather than at the end of three-year operation. And, the difference in wearout rate causes more system capacity factor change. From this result we learn that: If the wearout of active components begins at the end of two-year operation, using the failure rate data calculated from current data may not be acceptable. The criteria to determine whether the wearout effects are significant or not depends not only upon the inception of wearout, but also upon the wearout rate.

Chapter 8 CONCLUSIONS OF SYSTEM RELIABILITY AND CAPACITY FACTOR ANALYSIS

Based upon the results of these analyses we arrive at the following conclusions:

1. The steam generator feed pump (SGFP) is the component most in need of improvement in the condensate and feedwater system at Seabrook based on the failure rate data from Seabrook.
2. Adding redundancy of key components may be not the preferred way to improve the overall system capacity factor. The "worth" of redundancy depends upon the failure rates of the individual components.
3. To achieve a high system capacity factor, the passive component failure rates need to be less than 10^{-7} /hr. Otherwise, even if the active component failure rates are very small, the system capacity factor is still low. The current typical values of the passive component failure rate are about 10^{-6} /hr, so it may be possible to get to 10^{-7} /hr by improving the components themselves.
4. To achieve high system capacity factor, the active component failure rates need to be less than 10^{-6} /hr. The current value is around 10^{-4} hr, so it is much more difficult to achieve this goal only by improving the components themselves. We also need to consider improving the repair rate of the active components.
5. To achieve high capacity factors, the repair rate needs to be two order of magnitude greater than the failure rate, for both passive and active components.

6. Only with a high system capacity factor are the effects of human error and common cause failure significant. Improvement of system performance should therefore focus on other means besides the elimination of human error and common cause failure when the system capacity factor is low.

7. Like component failures, the repair rates responding to human error and common cause failures need to be two orders of magnitude greater than their failure rates.

8. System capacity factor can be improved by using more reliable components, shortening the repair time, and adding redundant components. As a strategy to improve system capacity factor, shortening the repair time and using more reliable components should be given higher priority; adding redundant components should be considered only as a lower priority approach.

9. The effect of component wearout upon system performance depends upon the normal failure rate of the component. In particular, if the component makes the system's performance either very favorable or very unfavorable, there seems to be no effect of component wearout upon system capacity factor.

10. .For wearout inception at the three year point, the effect of component wearout upon a system with four-year continuous operation is neither significant, nor sensitive to the wearout rate. Thus, the component failure rate data obtained from current operation history is applicable to the analysis of system performance with four year continuous operation if this component is to start wearout at the end of three-year operation.

11. For wearout inception at the two year point, the effect of component wearout on a system with four year continuous operation is more significant and more sensitive to the wearout rate. Thus, we need to consider not only the wearout inception, but also the wear rate.

12. Theoretically, the system capacity factor can be improved to any level if repairs can be done quickly enough and independent of the failure rates of the components. But in reality, the repair time has a minimum time limit. Assume this limit is two days. Furthermore, it usually takes two days to start up the reactor from zero power to full power-effectively adding one day to the time of the system being down if we assume that the power increases linearly in these two days. Thus, the total minimum limit for repair time is about three days. To achieve a high capacity factor, the MTTF should be 100 times greater than the MTTR. This gives a lower limit of MTTF as 300 days, corresponding to a failure rate of 1.4×10^{-4}/hr. So for those components with failure rates higher than 1.4×10^{-4}/hr, improving the component itself to make it more reliable should be the first consideration. For those components with failure rates lower than 1.4×10^{-4}/hr, shortening the repair time should be the first consideration.

Chapter 9 SUMMARY AND FUTURE WORKS

Extending the operating cycle length is a good strategy to enhance the capacity factor of a commercial nuclear power plant. The economic analysis shows that if the unplanned outage rate can be limited within a certain level, the economic penalty of the operating cycle extension can be offset by economic gains from the enhanced plant capacity factor.

The economic penalty is from extra fuel cost, a transition cost and perhaps increased operation and maintenance (O/M) costs. The extra fuel cost is the dominant negative economic factor for operating cycle extension. This cost includes the costs for the higher enrichment of fuel, premature discharge of fuel relative to multi-batch fuel management, increase in control rod worth, increased concentration of burnable poisons, higher quality of cladding, fuel-handling, and storage and disposal of the less-than-fully-burned transition cycle core.

The economic gains of extending operating cycle length are mainly from the additional generated electricity and the reduced number of refueling outages over a certain time period.

The analysis in this thesis is not very detailed. Because of the lack of precise monetary data for many economic factors. In the future, a more comprehensive economic analysis needs to be carried out, the economic factors should be considered in more detail, and data quantifying every cost and benefit should be obtained.

The reliability and capacity factor analysis done on the condensate and feedwater system is an example of the methodology for obtaining high plant capacity factor. To achieve the goal, we need to analyze the entire plant with a more detailed model. Sequentially, there are three major directions for future work: collecting actual component performance data, analyzing other important systems, and optimizing the analysis model.

Accurate data of components failure rates and repair rates is always the key to making analysis valuable. Study of component failure nature is necessary to get accurate data. The time-dependency of component failure will have to be studied.

All systems with significant effect on plant capacity factor need to be analyzed; two obvious candidates are the Turbine Generator and Steam Generator.

Safety-related standby systems may be worthy of attention. The characteristics of a standby system may be greatly different from those of an operational system.

To optimize the analysis model, the following topics should be considered:

1) Categorization of components. By categorizing system components into more groups, we may obtain more accurate information about the system.
2) Studying the effects of dependency among components.

More detailed studies on human error and common cause failure effects are also in order.

Appendix

Failure Rate Data of Major Components of the Condensate and Feedwater System

COMPONENT	FAILURE MODE	PLANT EFFECT	FAILURE RATE	REMARK
CONDENSATE SYSTEM:				
E-27A	LOSS OF FUNCTION, LOSS OF HEAT TRANSFER	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-6}/H	
E-27B	LOSS OF FUNCTION, LOSS OF HEAT TRANSFER	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-6}/H	
E-27C	LOSS OF FUNCTION, LOSS OF HEAT TRANSFER	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-6}/H	
P-30A	MOTOR DRIVEN PUMP FAILS TO RUN (INCLUDE DEGRADED OPERATION)	NO TRIP	$3x10^{-5}$/H	
P-30B	MOTOR DRIVEN PUMP FAILS TO RUN (INCLUDE DEGRADED OPERATION)	NO TRIP	$3x10^{-5}$/H	
P-30C	MOTOR DRIVEN PUMP FAILS TO RUN (INCLUDE DEGRADED OPERATION)	NO TRIP	$3x10^{-5}$/H	
E-73	HEAT EXCHANGER PLUGS	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	NO DATA	
E-21A	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}$/H	

E-21B	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	
E-21C	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	
E-22A	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	
E-22B	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	
E-22C	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	
E-23A	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	NO DATA	
E-23B	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	
E-23C	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}/H$	

E-24A	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}$/H	
E-24B	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}$/H	
E-24C	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}$/H	
E-25A	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}$/H	50% CAPACITY
E-25B	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$3x10^{-6}$/H	
FEEDWATER SYSTEM:				
P-32A	TURBINE DRIVEN PUMP FAILS TO RUN (INCLUDES DEGRADED OPERATION)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-3}/H	LOSS 1/2 FEEDWATER
P-32B	TURBINE DRIVEN PUMP FAILS TO RUN (INCLUDES DEGRADED OPERATION)	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-3}/H	LOSS 1/2 FEEDWATER

E-26A	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	PLANT TRANSIENT	$3x10^{-6}/H$	LOSS OF PARTIAL FW HEATING AND FLOW
E-26B	HEATER EXCHANGER EXTERNALLY LEAK (SHELL RUPTURE)	PLANT TRANSIENT	$3x10^{-6}/H$	LOSS OF PARTIAL FW HEATING AND FLOW
V28	MOTOR VALVE OPERATOR FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	NO DATA	
V37	MOTOR VALVE OPERATOR FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	NO DATA	
V46	MOTOR VALVE OPERATOR FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	NO DATA	
V55	MOTOR VALVE OPERATOR FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	NO DATA	
V330	CHECK VALVE FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$10^{-7}/H$	LOSS OF FEEDWATER TO SG A
V331	CHECK VALVE FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	$10^{-7}/H$	LOSS OF FEEDWATER TO SG B

V332	CHECK VALVE FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-7}/H	LOSS OF FEEDWATER TO SG C
V333	CHECK VALVE FAILS TO REMAIN OPEN	TURBINE TRIP, REACTOR TRIP, MANUAL SHUTDOWN WITHIN 30 MINUTES	10^{-7}/H	LOSS OF FEEDWATER TO SG D
HEATER DRAIN SYSTEM:				
HD-P-31A	MOTOR DRIVEN PUMP FAILS TO RUN (INCLUDES DEGRADED OPERATION)	PLANT TRANSIENT	$3x10^{-5}$/H	
HD-P-31B	MOTOR DRIVEN PUMP FAILS TO RUN (INCLUDES DEGRADED OPERATION)	PLANT TRANSIENT	$3x10^{-5}$/H	
HD-TK-22	TANK EXTERNALLY LEAKS	PLANT LEAK	3x10-8/H	LOSS OF BOTH HD PUMPS SUCTION SOURCE

References:

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2. Seabrook Station Detailed Systems Text: "Feedwater System," Rev. 3, (1991)
3. Seabrook Station Detailed System Text: "Heater Drain and Vent System," Rev. 5, (1993)
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