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LOSS OF BENEFITS RESULTING FROM MANDATED NUCLEAR PLANT SHUTDOWNS

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Abstract

This paper identifies and discusses some of the important consequences of nuclear power plant unavailability, and quantifies a number of technical measures of loss of benefits that result from regulatory actions such as licensing delays and mandated nuclear plant outages. The loss of benefits that accompany such regulatory actions include increased costs of system generation, increased demand for nonnuclear and often scarce fuels, and reduced system reliability. This paper is based on a series of case studies, supplemented by sensitivity studies, on hypothetical nuclear plant shutdowns. These studies were developed by Argonne in cooperation with four electric utilities.

1 Introduction

1.1 Background

Regulatory decision-making, as it pertains to the licensing of nuclear power plants and the formulation and implementation of standards, basically involves balancing the risks of reactor operation against the loss of benefits that would result from a particular regulatory action taken to reduce those risks. This fundamental concept is illustrated in Fig. 1. On the basis of reactor evaluations, plant safety inspections, or other generic safety issues, the Nuclear Regulatory Commission (NRC) may consider taking various types of regulatory actions. These actions could involve reactor deratings, shutdowns of varying lengths, or licensing delays for single or multiple nuclear generating units. The increased costs of system generation, increased demand for nonnuclear and often scarce fuels, and reduced system reliability that would likely accompany such regulatory actions would result in a loss of benefits to the affected utility's customers. In addition, unless the affected utilities can mitigate the effects, such mandated nuclear plant outages could ultimately lead to serious environmental, human health and safety, and socioeconomic effects due to blackouts or the use of alternative replacement fuels such as coal. Such losses of benefits from nuclear shutdowns may or may not be important compared to the consequences of operation in any particular case. However, determining the consequences of nuclear power unavailability is necessary to demonstrate explicitly the risk-benefit tradeoffs inherent in any decisions involving nuclear power plant licensing or operation.

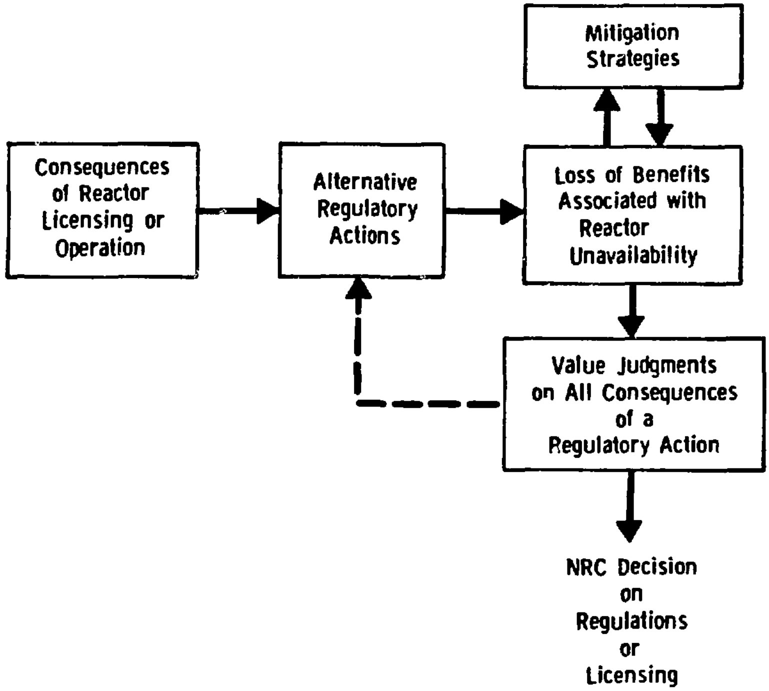

Fig. 1 Framework for NRC Analysis of Alternative Regulatory Actions

The loss-of-benefits research described in this paper, although applicable to a broad spectrum of licensing and regulatory decision problems (as illustrated in Fig. 1), was primarily motivated by safety goal considerations. Safety goals, or criteria for acceptable levels of risk, have been intensively developed since the accident at Three Mile Island. These goals are intended to clarify the NRC's interpretation of what constitutes adequate protection against the risks of nuclear power plant accidents (Refs. 1-3). The loss of benefits associated with mandated reactor outages is an important consideration in setting and implementing safety goals. This is illustrated in Fig. 2, which shows the relationship between loss-of-benefits considerations and four numerical guidelines (two primary and two secondary) proposed by the NRC as part of its draft policy statement on nuclear power plant safety (Ref. 4).* If a particular reactor failed to meet the proposed prompt mortality risk (which defines the individual and societal risk of prompt mortality due to accidents), delayed mortality risk, or large-scale core melt guidelines, the NRC would have to decide whether that reactor should operate. Four general options are shown in Fig. 2. Before making any decision, however, the NRC must have data on the loss of benefits associated with each option, including information about the costs of making the necessary safety

*As proposed, the safety goals do not include risks from routine emissions, from the nuclear fuel cycle, from sabotage, or from diversion of nuclear material.

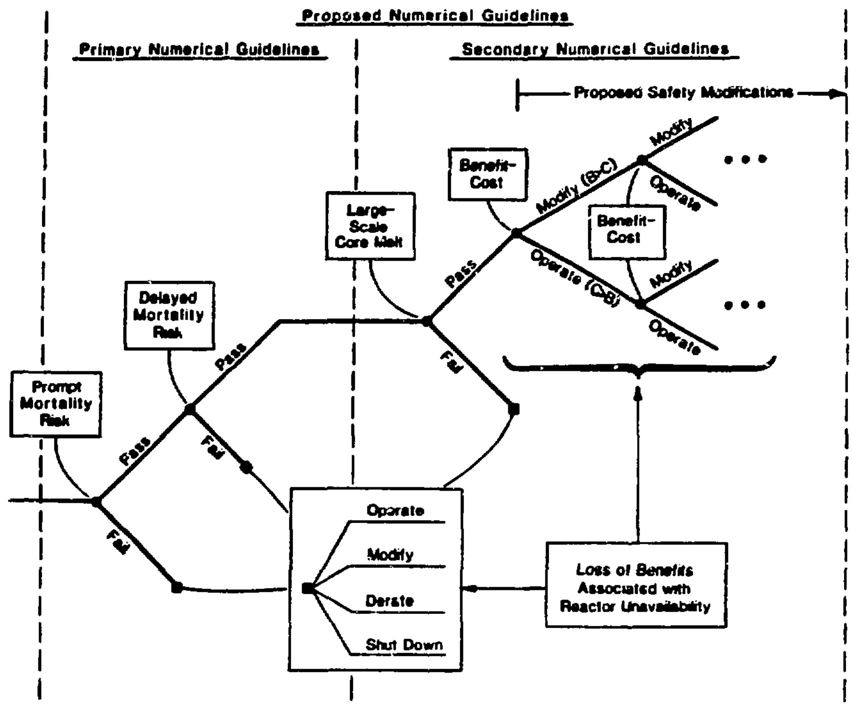

Fig. 2 Simplified Decision Tree Illustrating the Importance of Loss-of-Benefits Considerations in Implementing Proposed Numerical Guidelines

modifications. If a safety modification is proposed for a reactor that already meets these three guidelines, then a benefit-cost guideline would be applied. In such cases, the benefit of an incremental reduction in public risk must be compared against the costs of both the safety modification and the loss of benefits. The simplified decision tree shown in Fig. 2 illustrates the importance of loss-of-benefits data in setting and implementing safety goals.

1.2 Objectives and Approach

This paper briefly summarizes the first phase of an Argonne National Laboratory (ANL) loss-of-benefits research program sponsored by the NRC Office of Nuclear Regulatory Research. The paper focuses on one component of the analytical framework illustrated in Fig. 1, namely, the loss of benefits associated with the unavailability of a nuclear generating unit. The loss-of-benefits analysis presented here is based on the results of a series of case studies developed by ANL on hypothetical nuclear plant shutdowns (Ref. 5). These case studies were performed in conjunction with four utility companies that have substantial commitments in nuclear facilities. For each utility system studied, specific reactors that are now in service were selected for the shutdown analysis. Table 1 identifies the specific utility companies and

Table 1 Utility Companies and Reactors Considered in Loss-of-Benefits Case Studies

Utility	Reliability Council[a]	Reactor	Reactor Type[b]	Station Size (MWe)	% of System Capacity
Commonwealth Edison Co.	MAIN	Zion 1,2	PWR	2080	12
Duke Power Co.	SERC	Oconee 1,2,3	PWR	2580	21
Northern States Power Co.	MARCA	Prairie Island 1,2	PWR	1040	17
Tennessee Valley Authority	SERC	Browns Ferry 1,2,3	BWR	3201	12
Consolidated Edison Co./ Power Authority of the State of New York[c]	NPCC	Indian Point 2,3	PWR	1838	16
General Public Utilities[d]	MAAC	Three Mile Island 1,2	PWR	1672	25

[a]MAIN = Mid-America Interpool Network; SERC = Southeastern Electric Reliability Council; MARCA = Mid-Continent Area Reliability Coordination Agreement; NPCC = Northeast Power Coordinating Council; MAAC = Mid-Atlantic Area Council.

[b]PWR = Pressurized water reactor; BWR = Boiling water reactor.

[c]Based on a General Accounting Office Study of the economic effects of closing the Indian Point nuclear power plant (Ref. 6).

[d]Based on a General Accounting Office study of the financial impacts of the Three Mile Island accident (Ref. 7).

reactors considered in the case studies, and lists a number of pertinent utility and reactor characteristics.*

As Table 1 shows, the utilities affected by the shutdowns are located in three different national electric reliability council areas (five including the TMI and Indian Point studies). In terms of reactor capacity, the magnitudes of the shutdowns vary by a factor of three, from 1040 MWe for the two-unit Prairie Island Nuclear Station, to 3201 MWe for the three-unit Browns Ferry Nuclear Station. From a systems perspective, however, the magnitudes of the shutdowns are quite different, ranging from 12% of total system capacity in the case of Browns Ferry (the largest reactor outage), to 21% in the Oconee study (about 25% in the case of Three Mile Island, which, unlike the other cases identified in Table 1, represents an actual reactor outage). All of the generating units except Browns Ferry are pressurized water reactors.

The basic approach used in the case studies is illustrated in Fig. 3. Initially, meetings were held with key staff members of each of the cooperating utilities to discuss the objectives of the study and to define a

*For perspective, selected results of two General Accounting Office (GAO) studies on the potential economic effects of the Three Mile Island (TMI) outage and of closing the Indian Point nuclear power plant are also presented when applicable (Refs. 6,7). While the objectives, approach, and emphasis in the two GAO studies are not identical with those in the ANL investigations, the GAO studies do provide useful information on the corporate and financial effects of reactor shutdowns.

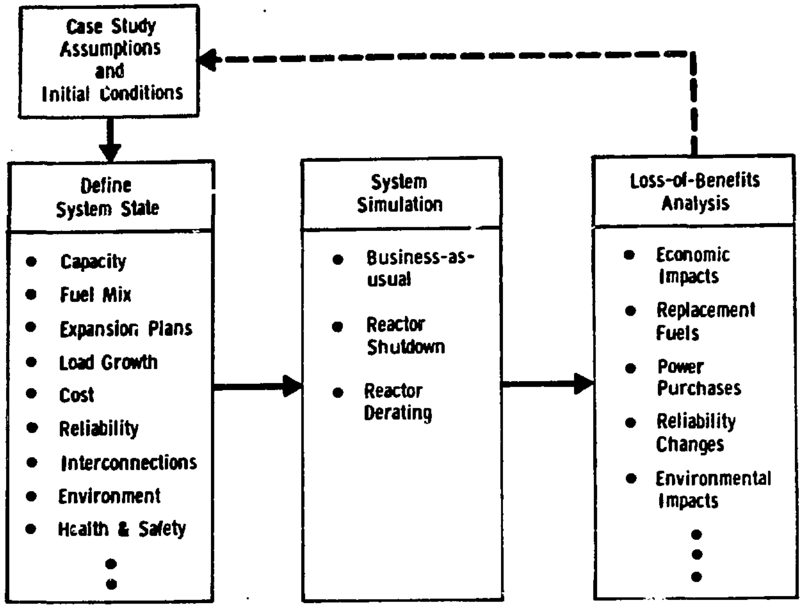

Fig. 3 Case Study Approach to Loss-of-Benefits Analysis

consistent set of initial conditions and case study assumptions. The definitions included, for example, characterizations of utility plans for new generating capacity, the types and costs of alternative fuels, future economic conditions, and anticipated demands on the system by utility customers. Although broad case study guidelines were specified by ANL, the assumptions and initial conditions were primarily supplied by the cooperating utility companies. Figure 3 shows a partial list of the important factors that were used to characterize each utility system.

On the basis of these characterizations, alternative cases were defined and examined for each utility; each case reflected different assumptions about the operation of the nuclear reactors selected for analysis. Two basic cases were analyzed over a 10- to 15-year simulation period for each utility system:

- A base case, which represents a business-as-usual analysis of the utility system and assumes that the reactor of interest is available for normal scheduled service, and

- A shutdown case, which assumes that the reactor of interest is ordered permanently shut down.

To provide a consistent basis for analysis, utilities were not allowed to adjust their construction schedules in the shutdown cases (with the exception of Commonwealth Edison). However, some type of long-term response to a permanent reactor shutdown would be likely, such as installing replacement capacity, upgrading interconnections, or implementing more-vigorous load management programs. The case studies intentionally excluded such responses for several reasons, including: (1) capacity expansion plans would be difficult to change in the first few years after a shutdown occurs, which is the period of greatest interest in the case studies; (2) comparisons between the base and shutdown cases would be more difficult if they were examined under different load-growth assumptions; (3) comparisons between utilities (i.e., with other case studies) would be considerably more complex; and (4) identifying and defining the myriad effects of the additional conservation or load management programs that would result from the nuclear plant outages is a difficult task. However, both the base and shutdown cases in the Zion and Browns Ferry case studies were analyzed for two different load-growth scenarios. These analyses illustrate the importance of the load-growth assumption and its impact on the magnitude of the short- and long-range effects of a reactor shutdown.

The system simulation data generated by the four utility companies were supplied to ANL for the loss-of-benefits analysis. This analysis focused on the potential economic, fuel use, and reliability effects of the hypothetical reactor outages on the associated electric utility system and its customers. The economic effects were measured by changes in production costs, which represent the change in variable costs incurred to produce the electrical energy (replacement fuel, including power purchases, and variable operation and maintenance costs are the main contributors), and changes in revenue requirements, which encompass the production-cost results as well as the unrecovered portion of the capital costs and other fixed-cost components. The mix of fuel types used to generate replacement energy in a reactor outage was also analyzed. The reliability performance of the utility systems was measured with three main reliability indexes: reserve margin (a commonly used deterministic index) and loss-of-load probability (LOLP) and unserved energy (two probabilistic indexes that account for forced outages of the generating units, scheduled maintenance, unit size effects, and load variation). More-detailed analyses of environmental, human health and safety, and socioeconomic effects, and analyses that extend these technical results into measures of loss of benefits which potentially are more comparable to the risks of continued nuclear power plant operation, are not presented in this paper but are also part of the ANL program.

The short-term impacts of a shutdown (i.e., the first few years of the study period) were emphasized because the case study assumptions are most appropriate during these early years. In addition, the monthly effects in the first year were examined to determine the costs of a relatively short (two- to three-month) shutdown. The short-term results also indicate whether a shutdown order (for example, for a safety modification that is not particularly difficult or time-consuming) could result in significantly lower outage costs if the utility was allowed to schedule repairs rather than required to shut down immediately when the order is issued. The analysis also led to a number of sensitivity studies and suggested changes in the initial assumptions used to define the case studies; this feedback is shown in Fig. 2. The Commonwealth Edison data and an ANL reliability and production-cost model (RELCOMP [Ref. 8]) were used to analyze in greater detail short-term effects and some of the key assumptions for the Zion case study.

2 Case Study Results

2.1 Comparison of Case Study Characteristics

Many of the key assumptions and initial conditions of the case studies are compared in Table 2. As this comparison shows, the cases vary in terms of key assumptions such as peak load growth, future performance of nuclear generating units (i.e., capacity factors), and escalation of fuel prices over the various study periods. For example, the peak load growth rate ranges from 4.4% for Duke Power to approximately 2% for Northern States.* The annual capacity factors assumed for the reactors examined vary from 54% in the Zion case study to 77% in the Prairie Island case study. On the basis of lifetime capacity factors of the nuclear stations, some of these values reflect somewhat optimistic expectations for overall reactor performance.

Other important differences between the studies include the fact that unserved energy is included in the Oconee case study and is priced at the level of oil-fired combustion turbine-generated electricity purchased from neighboring utilities but is not included in the other case studies. The costs of reactor decommissioning were included in the Zion and Prairie Island case studies, but not in the Oconee and Browns Ferry studies. Replacement capacity was assumed to be added by 1990 in the Zion study and one sensitivity study for the Browns Ferry case study. Other differences are apparent from the information provided in Table 2.

As briefly described in the introduction, these variations between the cases arise in part because the assumptions and initial conditions used in the case studies were primarily supplied by each of the cooperating utilities. Although broad case study guidelines were specified, each utility viewed the hypothetical shutdowns in a slightly different manner, and performed the system simulations using their own production-cost, financial, and reliability models. These models required slightly different input data and assumptions, and have different capabilities and limitations. While these differences between the cases make precise loss-of-benefits measurements impossible, the case studies provide a good starting point for making first-cut estimates of the consequences of reactor outages on utility companies and their customers.

2.2 Production-Cost Increases

The increase in production costs (fuel and variable operation and maintenance costs) experienced by a utility is perhaps the most recognized result of a reactor outage. Figure 4 compares the production-cost increases for the shutdown cases per megawatt-year of reactor outage. The figure indicates both the range of values (in undiscounted dollars) over the appropriate study periods and specific values for the first year of reactor outage. As these normalized results show, the relative production-cost increases vary

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*Since the completion of the case studies, Duke Power, Commonwealth Edison, and Tennessee Valley Authority (TVA) have all lowered their expected load growth projections (Refs. 9,10,11).

Table 2 Comparison of Assumptions and Initial Conditions for Case Studies

Parameter	Case Study: Zion[a]	Oconee	Prairie Island	Browns Ferry[b]
Study period	1981-1995	1982-1996	1982-1996	1982-1995
System capacity (MWe)	17,388 (1980)	12,048 (1979)	6,051 (1980)	27,455 (1980)
Nuclear capacity in system	29% (1980)	21% (1979)	25% (1980)	12% (1979)
Capacity of reactor shutdown (MWe)	2,080	2,580	1,040	3,201
% of system capacity shutdown	12%	21%	17%	12%
New capacity added during study period (MW)	10,986	9,490	1,643	17,044
New nuclear capacity added during study period (MW)	6,636	8,490	0	17,044
Replacement capacity added during study period (MW)	2,150	0	0	0[c], 4000[d]
System peak load (MW)	14,228 (1980)	9,844 (1979)	4,873 (1980)	20,745 (1980)
Peak season	Summer	Summer/Winter	Summer	Summer/Winter
Assumed peak load growth (%/yr)	1.5 and 3.0	4.4	2.1	1.8 and 3.6
Station lifetime capacity factor (1980)	58%	60%	71%	55%
Assumed station capacity factor	Variable: 54%-69%	1985: 68% 1990: 70%	77%	Variable: 60%-68%
Average consumer energy costs (¢/kWh)	5.31 (1980)	3.0 (1979)	3.9 (1980)	2.9 (FY 1979)
Annual fuel escalation rates (%/yr)	All fuels: 9%	Nuclear: 4-8% Coal: 8-10% Oil: 8-10%	Nuclear: 9-13% Coal: 7-9% Oil: 10-17%	Nuclear: 8-16% Coal: 8-12% Oil: 12-20%
Unserved energy	Not included	Included	Not included	Not included
Decommissioning cost	Included	Not included	Included	Not included
Primary replacement fuels	Coal, Purchases	Coal	Coal	Coal, Purchases

[a]Some data are specific for the 3% load-growth case.

[b]Some data are specific for the 3.6% load forecast.

[c]High and low cases.

[d]Replacement case.

substantially among the utilities. The values for the first year of reactor outage range from $0.125 million per MWe-year for Northern States Power to $0.33 million per MWe-year for Consolidated Edison. TVA also shows a relatively high first-year production-cost increase. Northern States shows the widest variation in normalized production-cost increases, ranging from $0.125 million per MWe-year to about $1.35 million per MWe-year. Commonwealth Edison and TVA, both large utility systems in comparison to the others studied, show narrow distributions over their respective study periods, partly because these studies assume significant quantities of new nuclear capacity come on line during the study period. These data, although not developed on a totally consistent basis (e.g., escalation rates for fuels varied somewhat from utility to utility, as shown in Table 2), imply that the shutdown of a 1000-MWe reactor would lead to first-year outage costs of $300,000 to $1,000,000 per day of outage. Information about replacement fuels and costs, reserve capacity, and other factors would be necessary to make detailed estimates.

Discounted production-cost increases for the reactor shutdown cases are compared in Table 3. Increases for both the first year of reactor outage

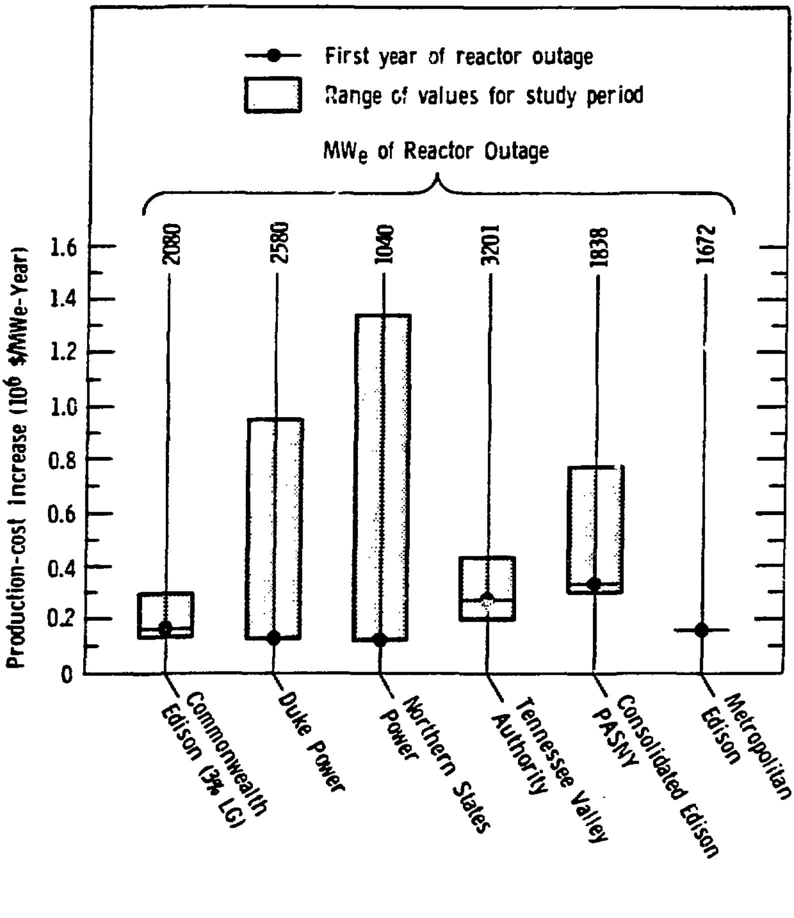

Fig. 4 Relative Production-Cost Increases of Reactor Shutdowns

Table 3 Discounted Production-Cost Increases for Reactor Shutdowns (10^6 1981$)[a]

Case Study	First Year of Reactor Outage	Cumulative: Years 1-5	Cumulative: Years 1-10
Zion (1.5% load growth)	310	1,097	1,811
Zion (3.0% load growth)	311	1,166	2,037
Oconee	267	1,415	2,909
Prairie Island	103	772	1,753
TVA (low forecast)	295	1,136	1,879
TVA (high forecast)	679	2,597	4,200
TVA (with replacement)	1,314	7,052	13,239

[a]Assumed discount rate of 12.75%.

and five and ten-year cumulative increases are shown. The discounted cost increases for the two Zion cases are nearly identical; the ten-year cumulative results for the Prairie Island and TVA (low forecast) cases are similar to the Zion case study results ($1.7-2.0 billion). Larger increases are shown for the Oconee and TVA (high forecast) cases, in which extensive power purchases were assumed. In the TVA (with replacement) case, combustion turbine generation and purchases are used to replace Browns Ferry before 1991, when a 4,000-MWe coal plant is added. This addition results in production-cost increases that are significantly higher than those predicted in the other cases.

The major contributors to the annual production-cost increases over the study periods are (1) increased expenditures for fuel due to the use of more-expensive replacement fuels, and (2) increased expenditures for economy and emergency power due to increased purchases. For example, Consolidated Edison relies exclusively on expensive oil-fired replacement capacity and power purchases, while Northern States Power and Duke Power rely primarily on less-expensive coal to generate replacement power. TVA relys heavily on power purchases in the shutdown case. Increased fuel costs represent about 78% of the total cost increase in the first year of outage for Northern States Power, and about 67% in the last year. Increased fuel costs in the Duke study are responsible for about 60% of the total cost increase in 1982; Duke's fuel-cost increase declines to about 9% in 1996, when unserved energy costs become dominant.

Monthly production-cost results for the first year of reactor outage indicate that operating costs vary seasonally among the utilities affected by the hypothetical reactor shutdowns. However, the specifics of the maintenance schedule are important considerations in several of the case studies. In some cases, rescheduling the maintenance for the generating system can significantly change the monthly costs. Replacement energy costs for a Browns Ferry shutdown, for example, are highest during the summer and winter months, while for Commonwealth Edison, monthly operating costs show less seasonal variation.

It is evident that, in some cases, outage costs could be substantially reduced if short-term (e.g., one- to three-month) outages were scheduled to coincide with planned outages, or if only one unit in a multiple reactor facility were shut down at a time. For example, in one of the TVA cases, the monthly production-cost increases vary over $50 million; if a three-month repair could be postponed from July to October, nearly $132 million could be saved (assuming the maintenance schedule does not change).

The production-cost increases that result from reactor shutdowns are ultimately reflected in higher electricity costs to the consumer (rate increases also reflect other financial considerations, however, such as decommissioning costs and recovery of capital). The average incremental increases in annual electricity prices for Duke Power and Commonwealth Edison were similar, ranging from 0.4¢/kWh to 1.8¢/kWh over the study horizon. On the basis of average customer costs in 1980, these increases would represent about a 7% cost increase for Commonwealth Edison's customers and a 13% increase for Duke Power's customers. The increase for Consolidated Edison was more substantial, about 3.0¢/kWh, which represented a more than 20% increase in rates.

The use of replacement energy with a high variable cost, such as oil-fired generation, leads to high production costs. Figure 5 compares the normalized production-cost increases for the first year of outage with the fraction of replacement energy that is supplied by oil-fired power plants and

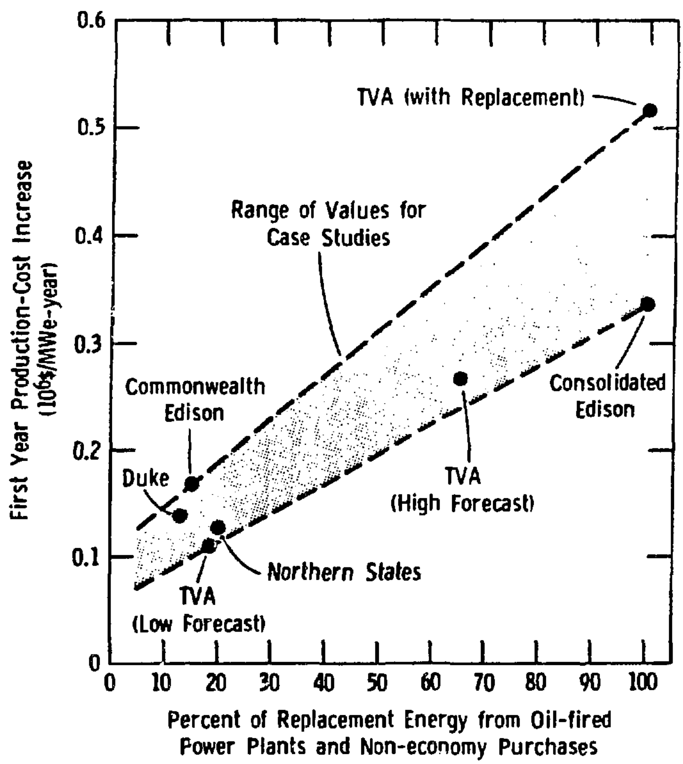

Fig. 5 Relationship between Oil-Fired Replacement Energy and First-Year Production-Cost Increases for Case Studies

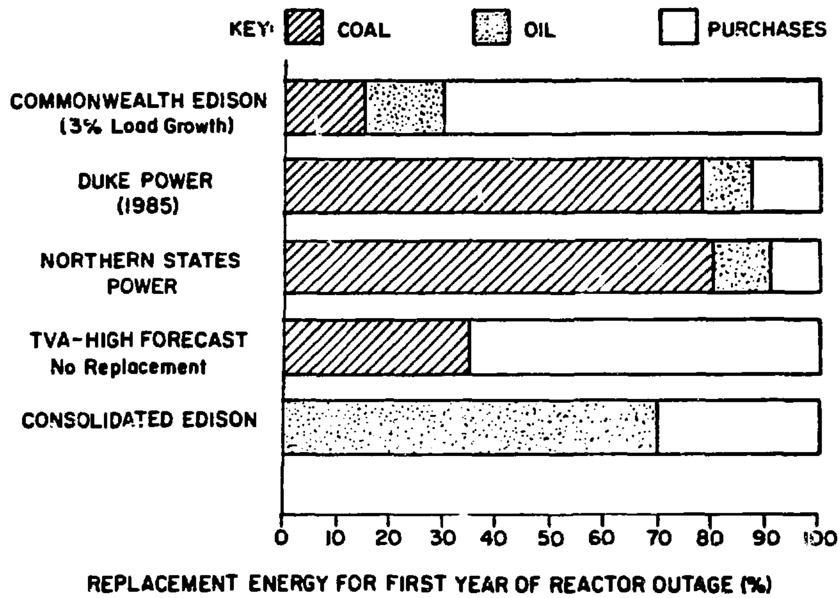

Fig. 6 Comparison of Replacement Energy for the First Year of Reactor Outage

noneconomy power purchases, which are mainly generated by combustion turbines. These results show that for the Duke, Northern States, Commonwealth Edison, and TVA (low forecast) cases, in which less than 20% of the total replacement energy comes from oil-fired sources (Fig. 6), the first-year production-cost increases range from \$0.1-0.175 million per MWe-year of outage. As the fraction of oil use increases, however, a large increase in production costs also occurs. The Consolidated Edison and TVA (with replacement) case results clearly show this trend. While the data displayed in Fig. 5 are not sufficient to develop a precise relationship, it is evident that the fraction of total replacement energy that is derived from expensive oil-fired power plants and noneconomy power purchases is an important indicator of the monetary costs of a reactor outage.

2.3 Changes in Generating System Reliability

The hypothetical reactor shutdowns substantially reduce the reserve margins of the Duke and Northern States systems; the reserve margin for Duke drops from 14% to -8.1% in the second year of the Oconee outage, while it falls from 13.3% to -4.4% in 1985 for the Prairie Island outage. The impact of a Browns Ferry outage on TVA's reserve margin is less severe, although TVA's planning requirement is considerably higher than the 15% planned for the Commonwealth Edison and Northern States Power systems. After 1985, the reliability of the Duke and Northern States systems continues to decline, while the capacity additions assumed for the Commonwealth Edison system ensure a relatively stable reserve margin.

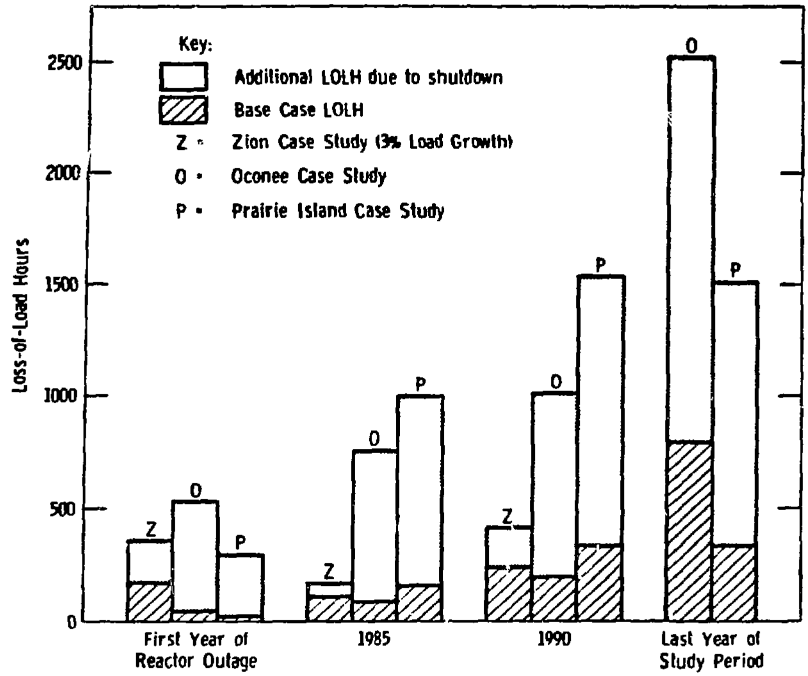

Fig. 7 Comparison of Loss-of-Load Data for the Zion, Oconee, and Prairie Island Case Studies

A more direct measure of system reliability (which accounts for unit operating parameters) is displayed in Fig. 7. This figure compares, for selected years, the loss-of-load hours in the Zion, Oconee, and Prairie Island case studies. While increases in loss of load are evident in each case, the results for the Oconee and Prairie Island case studies are particularly dramatic. Loss-of-load hours increase to 1000 by 1985 in the Prairie Island case study, and to over 2500 by 1996 in the Oconee case study. The increase in loss-of-load hours associated with the Zion outage is small in comparison to the two others shown.

The results of the Oconee, Prairie Island, and Browns Ferry case studies have also been used to determine if a change in loss of load can be predicted from the change in reserve margin caused by the reactor outage. The ratio of annual LOLP without the reactors to the LOLP with the reactors is plotted in Fig. 8 as a function of reactor capacity, which is in units of percent of annual peak load. As the reactor capacity becomes insignificant with respect to the peak load, i.e., as it approaches zero, the LOLP ratio would approach 1.0. This trend is generally indicated by the figure. Note, however, that this is not a linear relationship because the LOLP ratio is plotted on a log scale. The similarity of the case study results tends to indicate that this type of relationship may be valuable for estimating the change in LOLP or perhaps in unserved energy. If a value for unserved energy or for a change in another reliability index is assumed, the costs attributable to the change in reliability may also be estimated and compared with the production-cost increases.

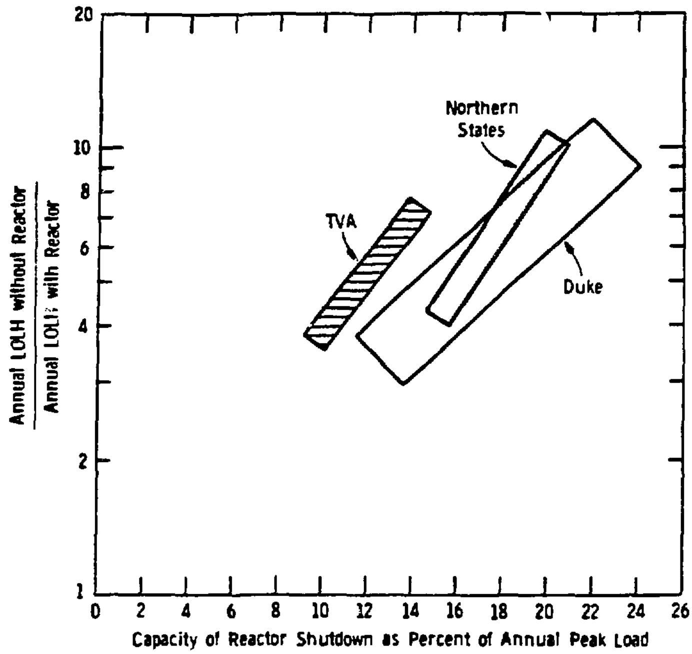

Fig. 8 Relationship between Reactor Capacity Shut Down and Change in Loss-of-Load

3 Results of Sensitivity Analyses for the Zion Case Study

One concern expressed by the utilities during our case studies was over the likelihood that only one nuclear station would be affected by a shutdown order. That is, our case studies assume that only one nuclear station, including all reactors at that location, is shut down, while other nuclear units within the utility system and neighboring utilities continue to operate. While such a situation could develop, for example, because of an exceptionally large population within a short distance of a particular site or because of a defect that is found to be characteristic of only a particular type and vintage of reactor, it is also possible that a shutdown order could affect large numbers of nuclear units. Our case studies did not include such possibilities primarily because the case studies represent the initial effort to determine the effects of nuclear outages and because treatment of multiple station outages is an additional complexity. However, for our sensitivity analyses of the Commonwealth Edison case study, we examined the effect of shutting down Quad Cities 1&2 (591 MWe of each is owned by Commonwealth Edison) and Dresden 2&3 (794 MWe each) in addition to Zion 1&2 (1040 MWe each). Dresden 1 (207 MWe) is shut down for cleaning and repairs for several years at the beginning of the study period.

The results for varying Zion's capacity factor indicate a linear relationship between costs and quantity of nuclear generation over a Zion capacity factor range of 45–75%. This is equivalent to a range in nuclear generation of 5.5×10^9 kWh. By examining the effects of a potential shutdown at Quad Cities and Dresden as well, the range of nuclear generation for the initial year was extended to 26.8×10^9 kWh, or all nuclear generation expected in the first year (1981).

Table 4 shows the increase in operating costs for several levels of nuclear outages. Purchases (firm and economy) from other utilities are held constant at 1300 MWe. The availability of purchases has been assumed constant for these cases because multiple nuclear station outages would no doubt affect other utilities as well and would probably severely limit the availability of purchased power.

The increase in costs for increasing levels of nuclear outage is nonlinear, as indicated by the column in Table 4 showing average increase in cost for replacement energy. The loss of Dresden 2 and 3 (the last nuclear units shut down) increases operating cost by $472 million, or 5.9¢/kWh of Dresden energy replaced. Replacing energy from Zion 1 (the first unit shut down) cost an additional 4.0¢/kWh.

The effect of multiple nuclear outages on reliability in 1981 is shown in Fig. 9. Both LOLP and unserved energy are shown for cases having Zion shut down; Zion and Quad Cities shut down; and Zion, Quad Cities, and Dresden shut down. The unserved energy increases from 2.6×10^6 kWh in the base case to 556×10^6 kWh when all reactors are unavailable. LOLP increases from 0.19 d/yr to 7.6 d/yr. The unserved energy is increasing faster than LOLP for the most severe shutdown cases. The difference arises because unserved energy is a measure of the severity of failure, while LOLP measures only the likelihood that full demand cannot be met. Thus, as failures become more severe and lengthy, unserved energy may be a better indicator of system reliability.

Figure 9 also shows the quantity of firm capacity that would be needed to reduce the LOLP to 0.1 d/yr in each case. Increased purchases cannot help the situation because these values for LOLP are based on the assumption that input capabilities are fully used. Thus, severe reliability problems for the Commonwealth Edison service area are likely if all of the operating reactors are shut down at the same time.

Table 4 Production Cost for 1981 Shutdown of Multiple Nuclear Stations with No Increase in Purchases

Reactor Shut Down	Lost Nuclear Generation (10^9kWh)	Increase in Production Cost Compared to Base Case (10^6\$)	Average Increase in Cost for Replacement Energy (¢/kWh)	Increase in Total System Generation Cost (¢/kWh)
Zion 1	6.0	242	4.0	0.35
Zion 1&2	12.0	503	4.2	0.73
Zion 1&2, Quad Cities 1&2	18.8	870	4.6	1.27
Zion 1&2, Quad Cities 1&2, Dresden 2&3	26.8	1342	5.0	1.96

NOTE: Purchases were held fixed at 1300 MWe for the above cases. Costs would be reduced if additional purchases were available. However, multiple nuclear station outages could mean that other utilities would be unable to sell large blocks of power. Unserved energy has been included at a cost equivalent to combustion turbines using distillate fuel (\$127/MWh). Base case capacity factors for Zion 1 and 2 were 66%.

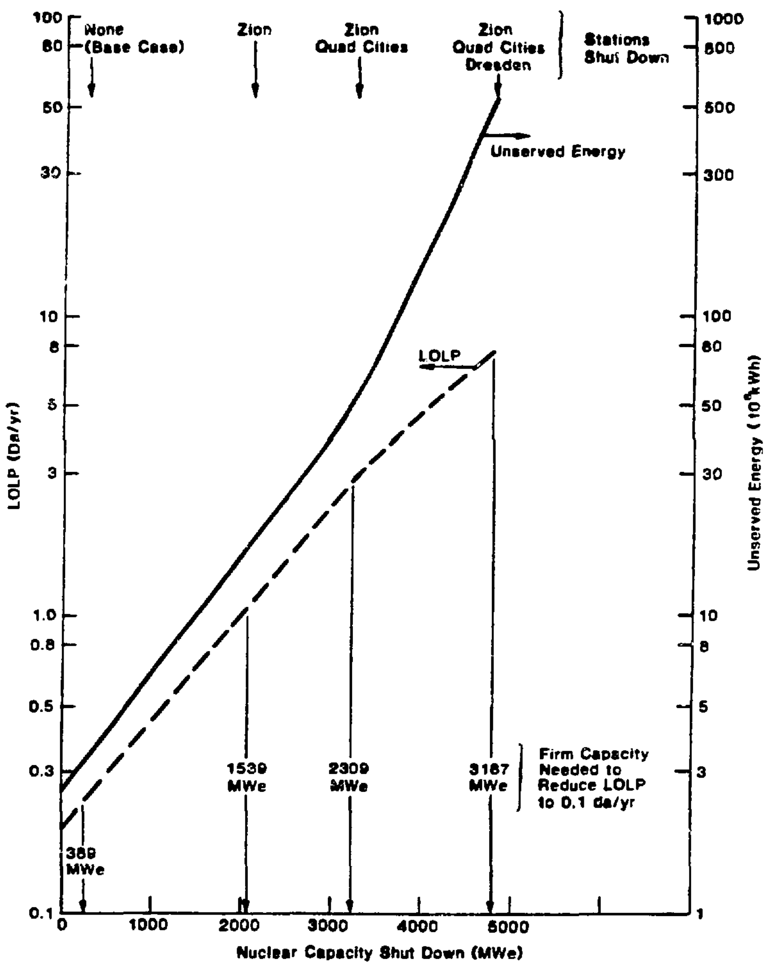

Fig. 9 Effect of Multiple Nuclear Outages on Reliability

4 Conclusions

The loss of benefits that result from mandated nuclear power plant shutdowns, whether temporary or permanent, are potentially significant and warrant consideration in the regulatory decision-making process. The importance of these effects was illustrated in four case studies of hypothetical reactor shutdowns and through a series of detailed sensitivity studies of reactor outages for the Commonwealth Edison system. These studies focused on a number of technical measures of the loss of benefits, namely, potential economic, fuel use, and reliability effects. While broad generalizations regarding the loss of benefits are difficult due to the diverse factors that characterize the utility systems examined (e.g., installed capacity, fuel mix, reserve capacity, and interconnections), several major results are apparent:

- Significant increases in production costs can be expected whenever an operating reactor is shut down. Case study results showed increases in production costs ranging from less than 10% to over 60%; the increases for the first year of reactor outage ranged from $0.125 million per MWe-year to $0.33 million per MWe-year.

- The production-cost increases exhibit a seasonal dependence, subject to maintenance schedules and peak load variations. In some cases, substantial cost savings could be realized by allowing flexibility in the scheduling of short-term (e.g., one- to three-month) outages. Savings over a three-month period exceeded $100 million in some cases.

- Rescheduling maintenance for key generating units can be a significant perturbation on the effects of short-term outages lasting up to a few months.

- Production-cost increases are very sensitive to the mix of replacement fuels and the amount of energy purchased from outside the system. The degree to which expensive oil-fired generation is used is a key variable; this includes oil use both within the utility system and for emergency power purchases.

- Production-cost increases are sensitive, even in the early years of a shutdown, to different rates of load growth. To the extent that large purchases can be obtained to replace the lost nuclear energy, load growth becomes a less important parameter.

- The installation of replacement capacity can help mitigate the long-term (greater than ten-year) economic impacts of a reactor outage. However, replacement capacity costs are high and add to the overall financial consequences of a reactor shutdown.

- The increases in production costs that result from reactor outages, along with other financial considerations such as replacement capacity costs, are ultimately reflected in higher electricity costs to the consumer. Increases ranging from 0.4¢/kWh to over 7.0¢/kWh were found in the case studies.

- Serious reliability problems can result from a reactor outage; the degree of seriousness depends on factors such as system reserves and the fraction of system capacity lost. In some cases, short-term reserves are adequate, but, depending on assumed load growth and whether replacement capacity can be installed, long-term reliability problems could occur. In other cases, serious capacity deficiencies occur immediately after shutdown, with reserve margin deficits of up to 25% (based on planning index) projected for some years.

- Generating system reliability generally depends more on time of year than production costs do. For example, a 16-week period of the summer accounted for 91% of the annual contribution to LOLP in one case study. If reliability issues were a major factor in the loss of benefits for a particular short-term shutdown, providing flexibility in the timing of the shutdown could result in significant cost savings and improved system reliability.

- In the worst cases, the reduction in generating system reliability due to power system outages could cause economic losses (e.g., due to unserved energy) that are comparable to or greater than the production-cost increases.

The case studies and sensitivity studies represent the initial output of an effort to better describe and estimate the effects of nuclear plant unavailability. This research is part of a broader ANL program that provides data and methods to help the NRC make decisions about regulations for and licensing of nuclear power plants. Conventional costs, fuel use, and reliability are only three of the types of effects being examined; more-detailed analyses of environmental, human health and safety, and socioeconomic effects are also desired. For example, replacement generation, especially coal-fired, also causes human health and safety risks and environmental impacts. The risks and impacts of replacement energy, along with the loss-of-benefits effects described in this paper, are important considerations in decisions to implement safety-related regulations that could cause delays, shutdowns, or early retirements of nuclear units.

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