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NUCLEAR ECONOMICS 2000: DETERMINISTIC AND PROBABILISTIC PROJECTIONS OF NUCLEAR AND COAL ELECTRIC POWER GENERATION COSTS FOR THE YEAR 2000

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ABSTRACT

The total busbar electric generating costs were estimated for locations in ten regions of the United States for base-load nuclear and coal-fired power plants with a startup date of January 2000. For the Midwest region a complete data set that specifies each parameter used to obtain the comparative results is supplied. When based on the reference set of input variables, the comparison of power generation costs is found to favor nuclear in most regions of the country. Nuclear power is most favored in the northeast and western regions where coal must be transported over long distances; however, coal-fired generation is most competitive in the north central region where large reserves of cheaply mineable coal exist. In several regions small changes in the reference variables could cause either option to be preferred. The reference data set reflects the better of recent electric utility construction cost experience (BE) for nuclear plants. This study assumes as its reference case a stable regulatory environment and improved planning and construction practices, resulting in nuclear plants typically built at the present BE costs. Today's BE nuclear-plant capital investment cost model is then being used as a surrogate for projected costs for the next generation of light-water reactor plants. An alternative analysis based on today's median experience (ME) nuclear-plant construction cost experience is also included. In this case, coal is favored in all ten regions, implying that typical nuclear capital investment costs must improve for nuclear to be competitive.

To investigate the effects of uncertainties, power generation cost sensitivity to changes in key input variables was examined for the midwest region. Both single-variable and multivariable sensitivity studies were performed. A Monte Carlo methodology was used to perform the multivariable probabilistic uncertainty analysis, which using the capital-cost range for the BE nuclear plants implies that nuclear life-cycle costs have a 74% chance of being less

than those for coal. For the ME nuclear plants, nuclear life-cycle costs have only a 7% chance of being more economic than coal.

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1. INTRODUCTION

The effect on the balance of trade and the U.S. economy of large and embargo-susceptible imports of oil indicates that the only practical alternatives for new base-load electric power generation through the end of the century are light-water reactor (LWR) and coal-fired plants. The competitive edge that nuclear power enjoyed in the late 1960s and 1970s has eroded mainly because of rapid escalation of capital investment costs and, to a lesser extent, because of a slow-growth energy economy. For similar reasons coal demand also has weakened, resulting in decreasing coal prices. This report, which is an update of a previous Oak Ridge National Laboratory (ORNL) analysis published in 1983,[1] provides analysis in support of the thesis that nuclear can be a viable option for future base-load power generation and identifies through sensitivity analyses those areas that have a strong impact on costs. The comparative cost of power from the nuclear and coal options is examined for plant startup in the year 2000. It is assumed that new base-load generating capacity will need to be operational in the post-2000 era.

The reference data set reflects the better of recent electric utility nuclear plant construction cost experience (BE). If a stable regulatory environment and improved planning and construction practices exist, then plants can be built at today's BE construction costs. However, if current trends, as represented by today's median construction cost experience (ME) continue, then the nuclear option will not be competitive. For its reference case this study assumes that a stable regulatory environment and improved planning and construction practices will be achieved. The BE cost model then is being used as a surrogate for the projected costs of the next generation of LWR plants.

In the reference set of assumptions, the next generation ME nuclear-plant investment costs are assumed to be consistent with today's

BE. In an alternate set of assumptions, the competitiveness of future nuclear and coal-fired plants was examined by assuming that improvements are not made to reduce nuclear-plant capital costs.

Levelized power generation costs were estimated for locations in each of ten federal regions of the contiguous United States. This regional breakdown corresponds to the one used by the Energy Information Administration (EIA) in their energy forecasting system and is defined in DOE/EIA-0095(85).[2] Since very little coal or nuclear electric power is generated in Alaska or Hawaii, these two states are not included in the federal regions used in this report. Coal prices for each of the ten EIA regions were projected based on current costs from the *EIA Electric Power Quarterly*[3] and a 1%/year real price increase. Variations by region in capital investment and coal costs are accounted for in the levelized cost computations. A reference city was selected in each of the ten regions to provide a basis for estimating regional power-plant capital investment cost differences. Because coal prices and construction costs can vary widely even within a given region, these results must be thought of as typical.

The levelized power generation costs that are presented in this report are used to compare the relative economics of options based on lifetime costs; however, levelized costs provide little insight into how the power costs of the two options behave throughout the life of the plants. An examination of the year-by-year cash flow and revenue requirements (annual power costs) was made for both the nuclear and coal options in the reference midwest region. These results can be used to examine the problem of initially high power costs resulting from the large capital investments required, commonly referred to as "rate shock."

In addition to the estimation of the cost of power at a reference set of variables and unit price projections, this report also examines the sensitivity of the results when alternative financial parameters and costs are applied. The sensitivity analyses apply specifically to the reference midwest region, but trends are applicable to all regions. Alternate capital investment cost assumptions, plant lead times, capacity factors, coal and uranium price projections, and other nuclear-fuel service prices were investigated. Because one-variable-at-a-time sensitivity analysis can be used to identify the key power generation cost-driving variables, the results from these analyses can be used to focus attention on those areas for which changes can be made to improve the competitive stance of the nuclear option.

An important feature of this report is the inclusion of probabilistic analysis as a methodology for multivariable sensitivity or uncertainty studies (MVSS). Probability ranges and distributions have been chosen for the key input variables affecting busbar cost, and a Monte Carlo code is used to sample from these input distributions, repeatedly run the LEVCOST power generation cost model, and analyze the output statistics for the levelized cost of power that is the figure-of-merit in the analysis. This powerful technique allows the assessment of the relative busbar cost risk associated with the coal and nuclear options.

This report relies on a companion report entitled *Nuclear Energy Cost Data Base: A Reference Data Base For Nuclear and Coal-Fired Power Generation Cost Analysis*[4] (NECDB), which documents most of the technical parameters and the methodology used in this report. The present report can be read as a stand-alone report; however, if questions arise regarding the data parameters or methodology, then the companion NECDB report should be consulted.

The conclusions pertaining to the relative projected economics of nuclear power vis-à-vis coal-fired power are supported by detailed analysis. The sensitivity studies identify those factors that carry the most leverage on the relative economics. This report deals only with the financial and economic factors impacting the competitiveness of nuclear plants. Institutional factors are not addressed.

Chapter 2 provides a summary of the study and conclusions for those readers who do not wish to delve into the justifications for the inputs to the analysis but are interested only in the results and conclusions. Appendix A contains a list of nomenclature that is specific to this report.

Detailed discussion of the mathematical methodology involved in probabilistic uncertainty analysis is omitted in the body of this report. Appendix B gives a more-detailed discussion of how the uncertainty analysis was performed and what its mathematical underpinnings are. Chapter 3, however, contains a very brief description of the rationale and methodology used and discusses the economic analysis methodology used in the LEVCOST model.

Chapters 4 and 5 deal with the input and results of the deterministic analyses. Chapters 6–8 deal with the sensitivity studies and probabilistic analyses.

Finally, uncertainty ranges are not applied to entities that cannot be readily represented in numerical form. Examples of such entities would be political and institutional factors, such as whether regulatory reform has or has not been implemented or whether improved construction practices have or have not been instituted. Any attempts to predict the probabilities of these events would go well beyond the forecasting and analytical capabilities of this report's authors.

2. SUMMARY AND CONCLUSIONS

Projections were made of future power generation costs for new base-load nuclear and coal-fired power plants beginning operation in 2000. Based on a reference set of variables, these costs were estimated for each of the ten EIA regions. The reference nuclear data set is based on regulatory and nuclear-plant construction improvements being implemented such that the expected average construction cost of these future nuclear plants is equal to today's BE. Coal-fired plant construction has not experienced many of the factors that have driven up the investment costs of nuclear plants in recent years. Although some future improvements in coal-fired plant investment costs may be expected, there are other factors, such as acid-rain legislation, that may increase costs. In this study, it is assumed that today's coal-fired plant investment costs will be typical of future plant investment costs. Alternatively, the competitiveness of nuclear and coal-fired plants is also estimated as though nuclear-plant construction improvements are not made and today's ME nuclear construction costs prevail. A major conclusion is that nuclear must reduce its capital investment costs to compete with coal.

Using the discounted revenue requirements method, levelized power generation costs are computed and are expressed in constant 1986 dollars. These busbar cost results are used as a figure-of-merit to allow comparisons of competing plant types. Two alternative measures of project merit, annual revenue requirements and cash flow, are also used for the reference cases in this report.

The levelized 30-year costs for BE nuclear and coal-fired plants, based on reference parameters, are presented in Fig. 2.1. Results are given for each of the major cost categories that compose the total power generation cost. In addition to the capital investment, operation and maintenance (O&M), and fuel costs, both nuclear and coal plants incur an additional cost to pay for decommissioning. This cost is small, composing <0.2 and 1.5% of the total power generation costs for the reference coal and nuclear plants, respectively. The capital investment cost is the predominant cost component in the cost of power from nuclear plants,

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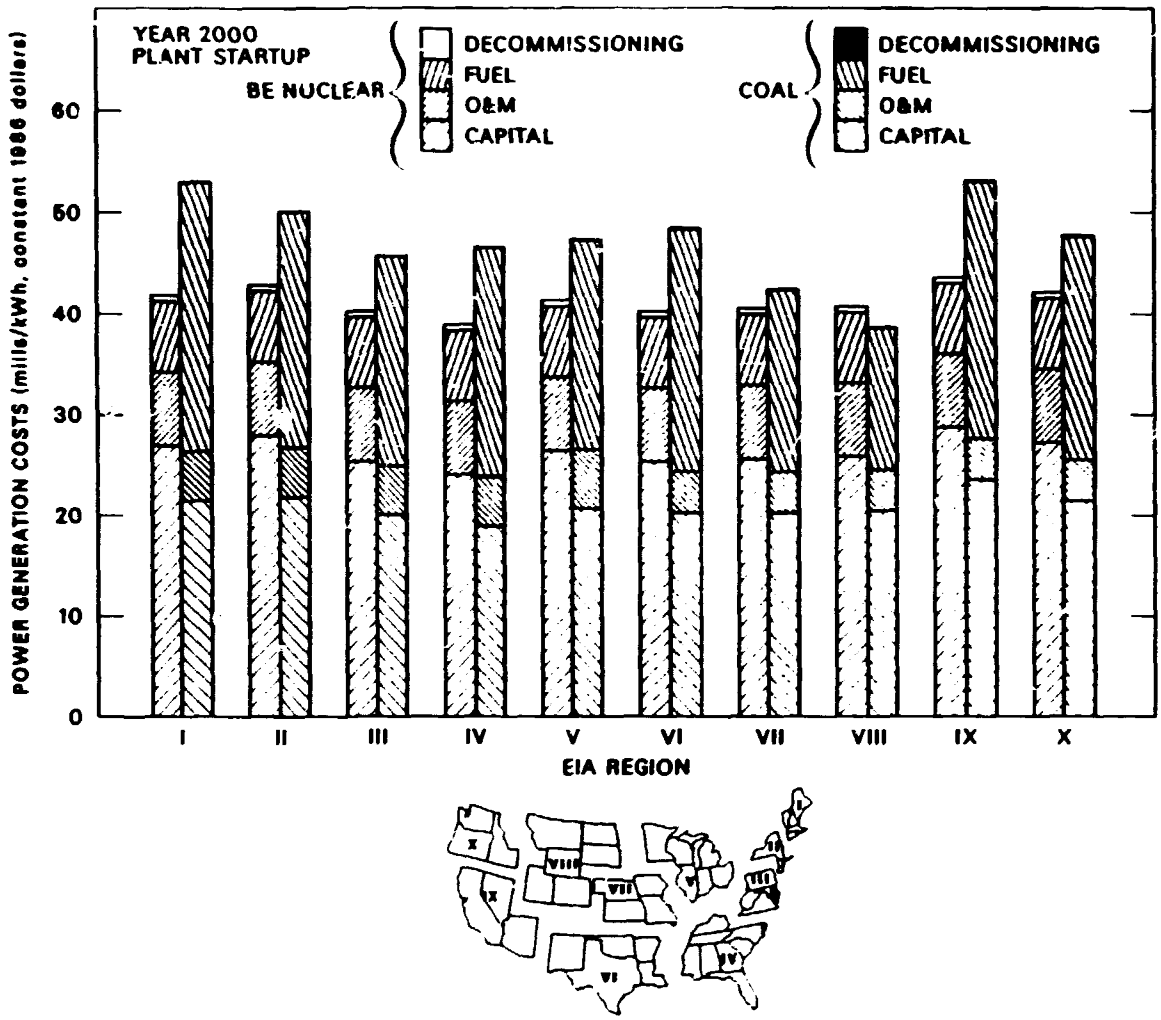

Fig. 2.1. Regional power generation costs for BE nuclear and coal-fired plants at reference parameters.

making up ~64% of the total levelized cost for the BE reference plant constructed in the midwest region. Although capital investment cost is important for coal plants (44% of total cost in the reference case for the midwest region), the cost of coal is generally of equal or greater importance.

At reference conditions based on 30-year levelized power generation costs, nuclear plants were found to be cheaper than coal-fired plants in all regions except the north central. Uncertainties in the various cost parameters, especially the capital investment cost and price of coal, could cause shifts in the economic choice in most regions.

The results of this analysis are presented in map form in Fig. 2.2. Each region is shaded according to how the options compare based on their 30-year levelized costs. If the total levelized power generation cost of one option is less than the other by at least 10%, then it is assumed to have a clear economic advantage. Neither option was judged to have a significant economic advantage in those regions where the power costs of both options were found to be within 10%. As can be seen from Fig. 2.2, the levelized power costs of BE nuclear plants are much lower than those for coal-fired plants in eight of the ten regions. In most of these regions, delivered coal prices are high, caused by high mine-mouth prices, high transportation costs for coal that must be hauled over long distances, or both. In the north central region, levelized power costs of coal-fired plants are projected to be ~5% lower than those for BE nuclear plants, but the economic advantage is not clear. The advantage for BE nuclear power, 4.5%, in the central region is also not clear (i.e., the levelized costs are within 10%). Large reserves of cheaply mineable coal are located in or near these two regions, thus holding down the price of mine-mouth coal. Also, transporting the coal to the generating plant site is less costly because of proximity of the mines. In the central and north central regions the cost of power from either option is projected to be within ±10% so that both options could be considered economically competitive. These results, used in a weighted average for the entire nation, support the contention that if BE nuclear costs can be achieved as a standard for the future, nuclear plants will have a clear economic advantage over coal-fired plants as sources of base-load power in the future.

For the reference case the comparison of nuclear and coal-fired generation costs was also performed using the range of delivered coal prices in each region (Fig. 2.3). Coal prices will vary within a region because of different transportation requirements and shipping modes. In the southwest, central, north central, and west regions, the comparison between BE nuclear and coal-fired generation costs depends on the specific location within a region. In the northeast, New York-New Jersey, mid-Atlantic, south Atlantic, midwest, and northwest regions, BE nuclear

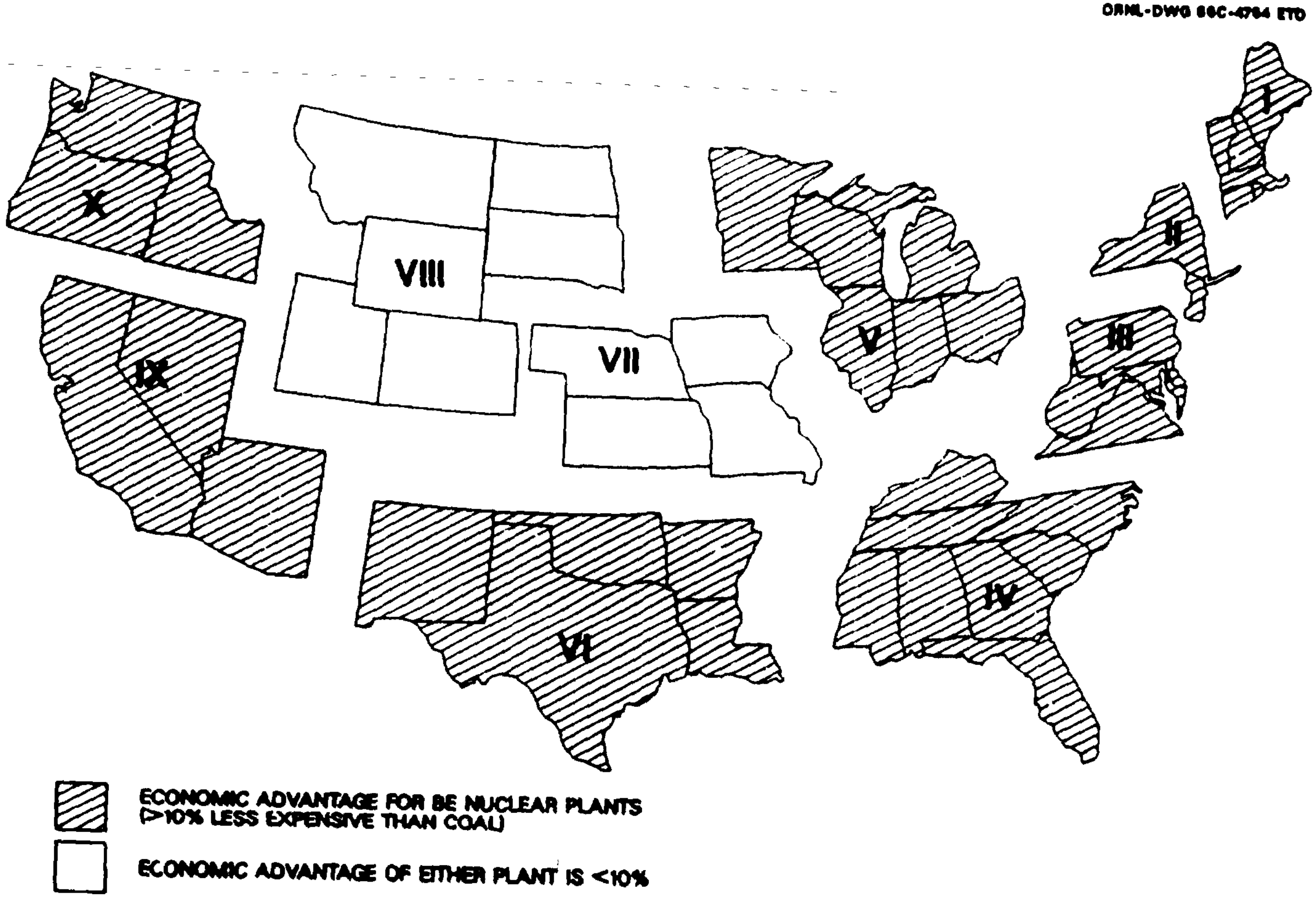

Fig. 2.2. Delineation of the United States by base-load generation plant type yielding the lowest levelized power costs for startup in the year 2000 (reference parameters for coal and BE nuclear).

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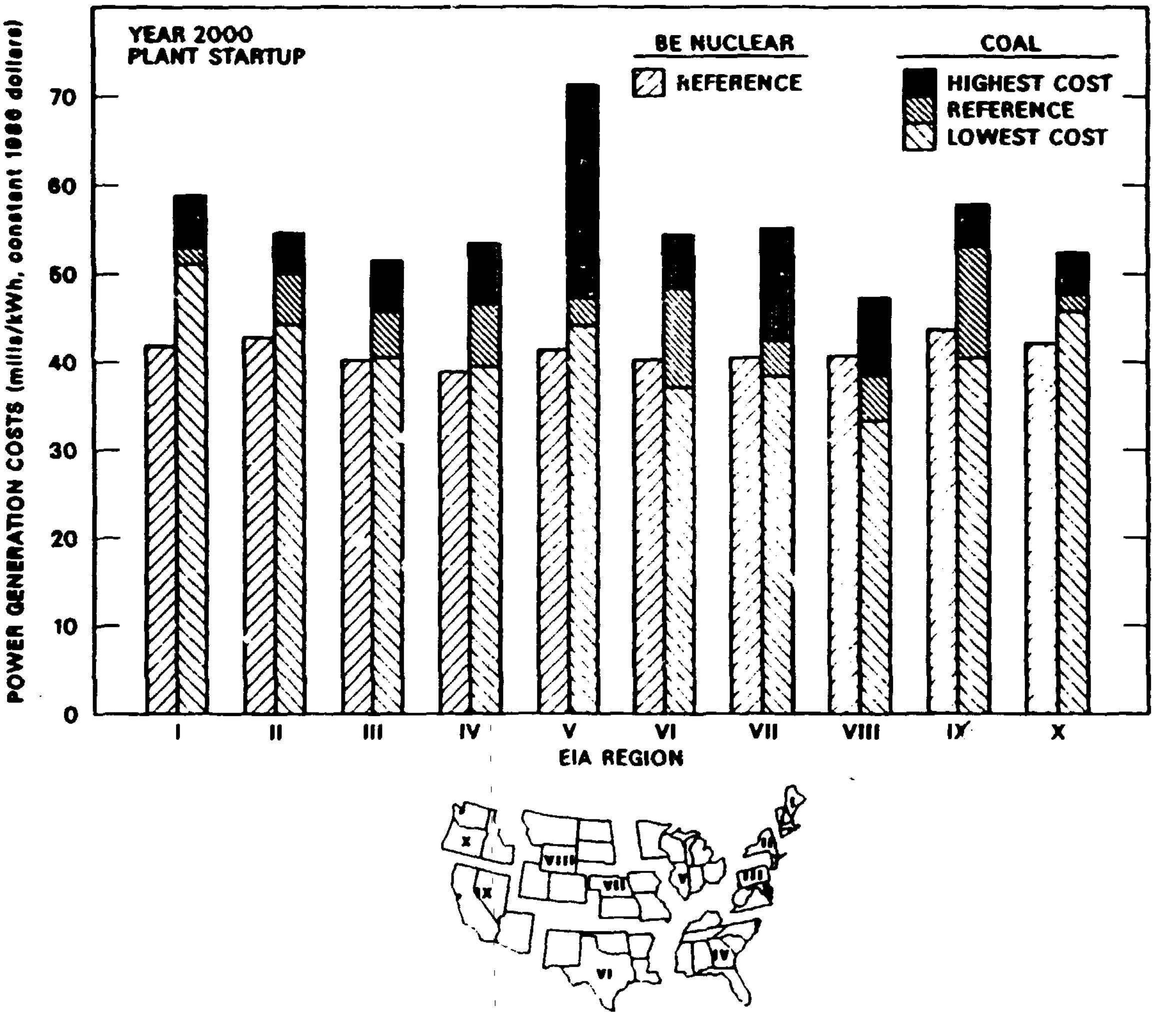

Fig. 2.3. Regional power generation costs from coal-fired plants reflecting regional variations in coal prices vis-à-vis power generation costs from BE nuclear plants.

generation costs are less than coal-fired generation costs even at these regions' least expensive coal sites.

The levelized power generation costs (vis-à-vis coal) for the case with new nuclear capital investment costs typical of today's ME plants are presented in Fig. 2.4. Here the coal option is favored by a significant (>10%) margin in all ten regions. Only the capital portion of the levelized cost is altered. The O&M, fuel, and decommissioning portions of the levelized cost are assumed the same as for the BE nuclear reference case. Even when the highest coal prices in each region are

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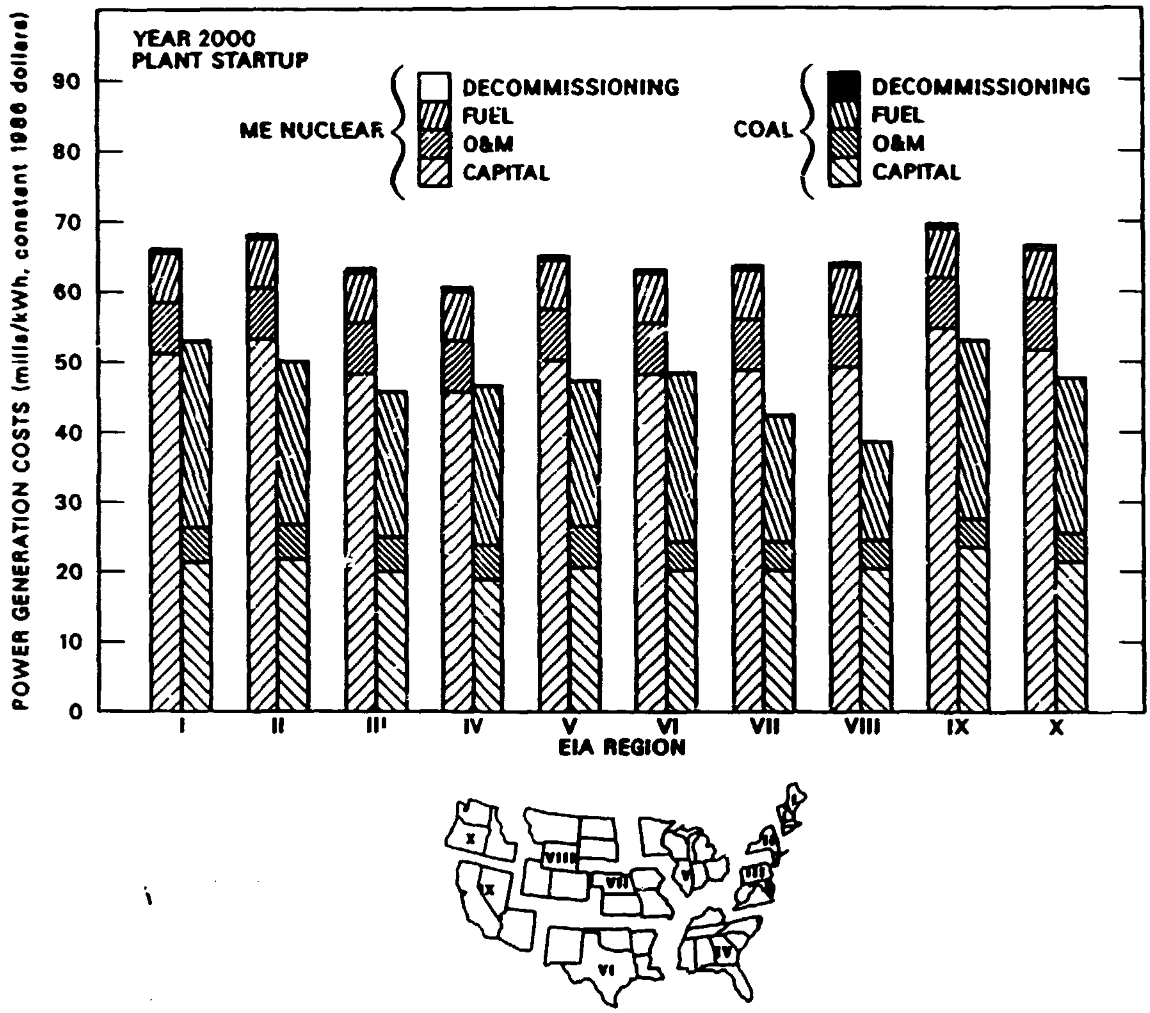

Fig. 2.4. Regional power generation costs for ME nuclear and coal-fired plants.

considered (Fig. 2.5), coal-fired plants are more economic than ME nuclear plants in nine of the ten regions.

The coal and BE nuclear options were also compared based on annual revenue requirements and cash flow. This information provides valuable insight into how the options compare on a year-by-year basis. The annual cost of power based on revenue requirements for BE nuclear and coal-fired plants constructed in the midwest region is shown in Fig. 2.6 in constant 1986 dollars. Initially, the revenue requirements for the BE nuclear plant are slightly higher than those for the coal-fired plant because of the higher capital investment cost. This nuclear

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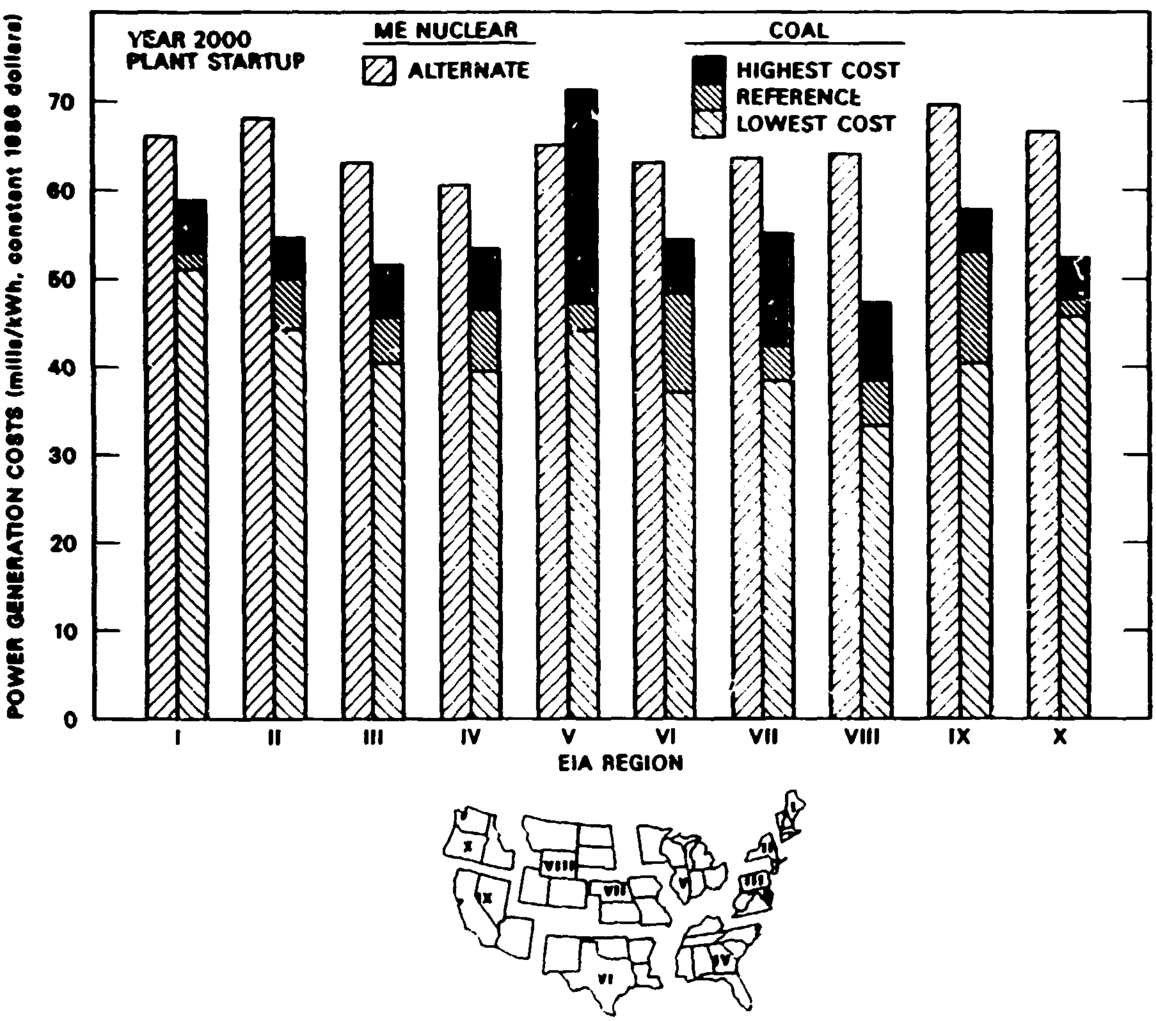

Fig. 2.5. Regional power generation costs for coal-fired plants reflecting regional variations in coal prices vis-à-vis power generation costs from ME nuclear plants.

disadvantage decreases rapidly as the capital investment is amortized. The revenue requirements for the coal option do not decrease as rapidly because fuel costs, which compose a large portion of the total coal-fired plant power cost, are escalating above the general inflation rate (1% above for the reference case). The revenue requirements for the BE nuclear plant become equal to those of the coal-fired plant during the second year of operation in the example shown, becoming increasingly smaller thereafter. This break-even point will vary from region to region.

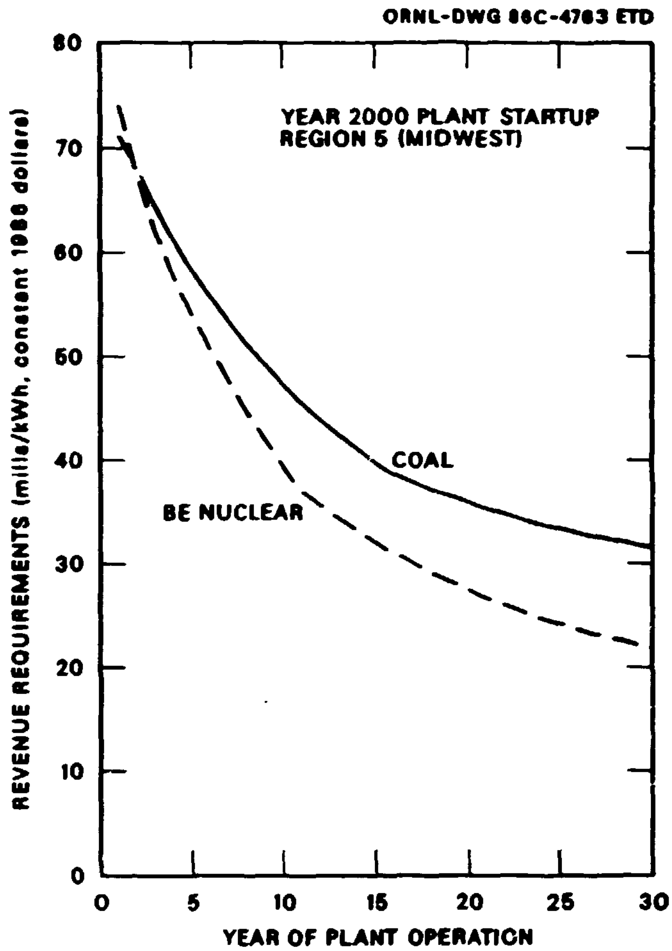

Fig. 2.6. Constant-dollar revenue requirements for BE nuclear and coal-fired plants.

Figure 2.7 shows a comparison of coal and BE nuclear based on nominal-dollar annual cash flows. (In Chap. 3 the basis for the cash-flow calculation is given.) Although coal has a smaller cumulative capital expenditure than nuclear, the magnitude of the negative cash flows is similar because coal-plant capital expenditures are spread over a shorter load time (i.e., 6 vs 8 years for nuclear). For both options, positive cash flows start during the first year of plant operation (i.e., when revenues are collected). Each positive cash flow experiences a sharp drop after the plant is fully depreciated for tax purposes (10 years for nuclear and 15 years for coal under the 1982 tax law). The discontinuities in the nuclear cash-flow curve result because the nuclear fuel is on a 13-month reload cycle; thus, the costs incurred for

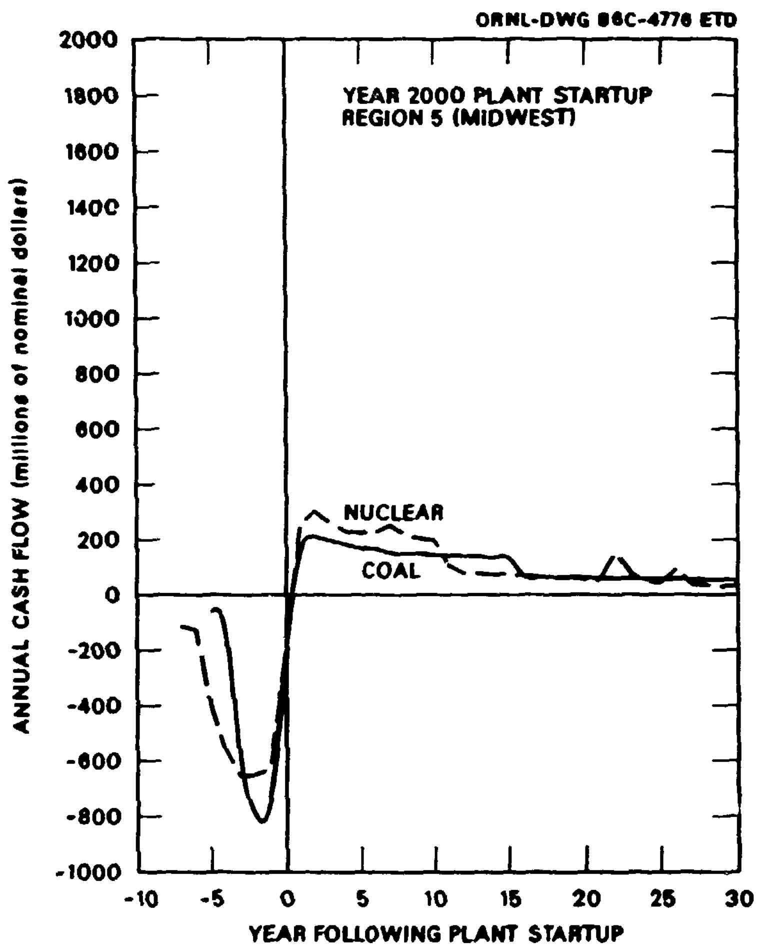

Fig. 2.7. Annual cash flows for reference case power plants: coal and BE nuclear.

the purchase of fuel-cycle services are not the same in every calendar year.

The cost parameters used in the analysis involve large uncertainties because projections had to be made over the next 50 years in some cases. The sensitivities to changes in some key parameters were investigated to examine their impact on the comparison. Table 2.1 summarizes the result of these one-variable-at-a-time sensitivity studies for the midwest region. In general, those parameters that affect capital charges have a greater impact on nuclear generation costs; those that affect fuel costs affect coal-fired generation costs more severely. For plants coming on-line at a specific date, uncertainties in base construction costs, cost escalation rates, cost of money, plant

Table 2.1. Changes in projected BE nuclear and coal-fired power generation costs with assumed changes in financial and technical parameters[a,b]

Financial or technical parameter	Δ for coal (mills/kWh)[c]	%	Δ for nuclear (mills/kWh)[c]	%
Overnight cost capital investment cost reduce by 10%	−2.06	−4.14	−2.63	−6.4
Inflation rate reduced by 1/2 percentage point (from 5 to 4.5%)	−0.13	−0.26	−0.23	−0.57
Capacity factor increased by 5 percentage points (from 70 to 75%)	−1.63	−3.14	−2.28	−5.5
Design and construction period reduced 1 year with year of first commercial operation fixed (coal changed from 6 to 5 years, nuclear changed from 8 to 7 years)	−0.53	−1.12	−0.79	−1.9
Design and construction period decreased 1 year with steam-supply order date fixed	−0.74	−0.16	−0.82	−2.0
Real cost of money reduced by 1 percentage point (3.8 to 2.8%)	−2.89	−6.1	−4.47	−10.19
O&M cost escalation rate increased 1 percentage point (0 to 1%)	1.82	3.8	2.26	5.15
Coal cost escalation rate increased 1/2 percentage point (1.0 to 1.5%)	3.03	6.4		
Coal cost escalation rate decreased 1/2 percentage point (1.0 to 0.5%)	−2.63	−5.6		
Real escalation during construction increased 1 percentage point (0 to 1.0%)	2.44	5.2	2.72	6.6
Change from 30- to 20-year analysis period with plant life constant at 40 years	3.15	6.7	4.94	12.0
Change from 30- to 40-year analysis period with plant life constant at 40 years	−1.56	−3.3	−2.80	−6.8
Change from 40- to 30-year plant lifetime with analysis period constant at 30 years	0.37	0.78	0.49	1.18
Change from 40- to 50-year plant lifetime with analysis period constant at 30 years	−0.22	−0.47	−0.29	−0.71
Uranium enrichment cost increased by $10/SWU (from $60 to $70/SWU)			0.25	0.60
Uranium enrichment cost decreased by $10/SWU (from $60 to $50/SWU)			−0.25	−0.60
U_3O_8 price escalation rate increased by 1/2 percentage point (1.0 to 1.5%)			0.50	1.2
U_3O_8 price escalation rate decreased by 1/2 percentage point (1.2 to 0.7%)			−0.43	1.0

[a]For midwest region, best-experience nuclear.

[b]Total generation costs are expressed in mills/kWh, based on constant 1986 dollars.

[c]Base power generation costs in mills/kilowatt hour: coal, 47.34; nuclear, 41.25.

lead times, and plant capacity factors are particularly important for the capital investment cost. For the nuclear plant, the uranium ore and enrichment prices are the cost factors whose uncertainties would have the most effect on fuel cost. Although the capital investment cost uncertainties are important, variations in the regional price of coal (which includes transportation) and uncertainty in coal's future escalation rate are the overriding cost considerations in the uncertainty of the cost of power from coal-fired plants.

A multivariable probabilistic uncertainty analysis was also performed. Twenty-two input probability distributions were accessed by the Monte Carlo simulator. Four of these were for financial variables (applicable to both coal and nuclear), 11 for nuclear only, and 7 for coal only. The actual input distributions used appear in Chap. 8, which also discusses the individual output distributions for the power generation cost for both coal and BE nuclear (midwest region) resulting from 1000 executions of the LEVCOST model by the Monte Carlo simulator. The statistical parameters for the output probability distributions are given in Chap. 8, and the locations of the reference deterministic cases on the busbar cost axis are shown. Although the BE nuclear power generation cost distribution generally lies in a lower-cost region than the coal distribution, it has a higher standard deviation or dispersion, thus indicating the greater uncertainty associated with nuclear costs. Most of this greater dispersion is the result of a high uncertainty in the overnight capital investment cost for nuclear, a key input variable.

Within each of the 1000 cases executed by the Monte Carlo simulator, the financial conditions for coal and nuclear were held the same, and a nuclear-minus-coal power generation cost figure-of-merit was calculated. The cumulative distribution for this nuclear-minus-coal cost is shown on Fig. 2.8. The BE nuclear-plant cost distribution shows that in 74% of the cases run, nuclear was more economic than coal; however, there was a 26% chance that coal will be more economic than nuclear. If the alternate, ME cost distributions for the nuclear-plant overnight cost and nuclear lead time are substituted for the BE distributions for these two variables and the simulation is repeated, a vastly different result is observed. Figure 2.9 shows the nuclear-minus-coal power generation cost figure-of-merit and the fact that nuclear has only a 7% chance of being more economic than coal for the ME nuclear scenario. Chapter 8 discusses the relative probabilities for both coal and ME nuclear and their statistical parameters.

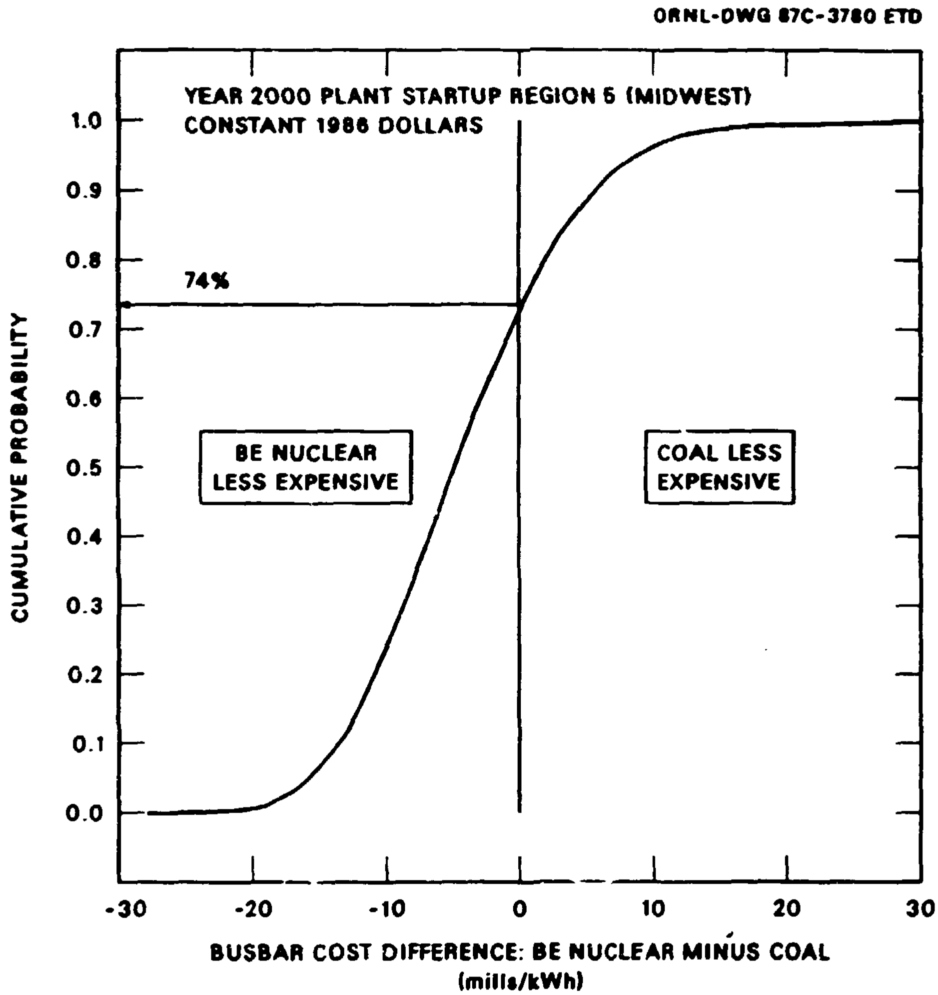

Fig. 2.8. Probabilistic MVSS analysis for reference uncertainty scenario: output cumulative probability histogram for difference between BE nuclear and coal-fired busbar power costs.

The following are this study's general conclusions.

1. For the reference case new base-load nuclear power plants were found to have an economic advantage over coal-fired plants in most regions of the country if the cost reductions from a more certain regulatory environment and improved design and construction practices can be achieved. Based on the reference parameters, the levelized cost of power from the BE nuclear option is projected to be less than coal by a 10% or greater margin in eight of the ten regions of the United States. BE nuclear power was found to have the greatest economic advantage over coal-fired power in the northeast region where coal costs are high. Coal-fired plants were found to have a slight economic advantage (<10%) over nuclear plants in the north central region.

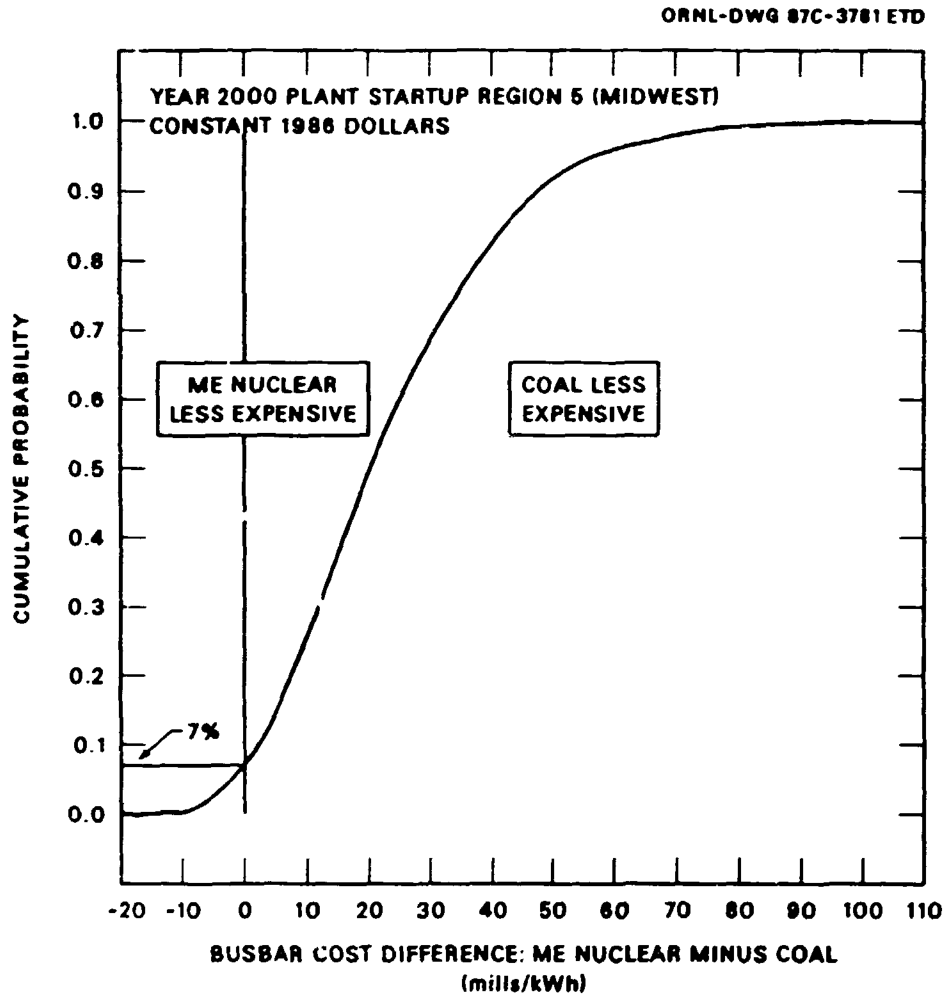

Fig. 2.9. Probabilistic MVSS analysis for alternate uncertainty scenario: output cumulative probability histogram for difference between ME nuclear and coal-fired busbar power costs.

2. If nuclear plant construction costs are not improved and today's ME costs prevail, nuclear loses its advantage over coal in all regions. Improvements in the construction, regulation, and licensing of nuclear plants will be needed for nuclear to regain its historic competitiveness.

3. The results of this analysis show that based on the reference assumption of improved regulatory environment and construction practices, there is a 26% probability that the coal-fired-plant power generation cost will be less than the reference nuclear-plant power generation cost in the midwest region, even though the deterministic analysis

showed nuclear to be ~13% cheaper than coal (a 6.1-mills/kWh difference). There is a larger range of uncertainty for nuclear-plant investment cost than for coal-fired plants, which leads to a greater spread or dispersion in the nuclear power generation cost probability distribution than for coal. If improved regulatory and construction practices are not realized (the ME case), the probabilistic analysis indicates that nuclear will have only a 7% chance of being more economic than coal.

4. Uncertainties in future costs of materials, services, and finances will affect the economics of both nuclear and coal significantly so that, depending on the circumstances, either option could be the lower-cost power producer in any of the regions.

3. METHODOLOGY

3.1 LEVELIZED REVENUE REQUIREMENTS

Given in detail in the NECDB,[4] the methodology used to calculate the levelized power generation costs in this report is basically a year-by-year, revenue-requirements procedure, together with levelization over the plant's economic life.

Revenue-requirements methods are used extensively by public utilities for both rate making and project evaluation. These methods determine the necessary year-by-year revenues needed by the utility to pay operating costs, taxes, return on undepreciated capital investment, and capital investment depreciation. In theory, the utility's rates will be adjusted to meet these revenue requirements so that the revenues received equal the revenue requirements for any given year.

These annual revenue requirements R_n in year n are given by

$$R_n = X_1 V_n + D_n^B + O_n + T_n , \tag{3.1}$$

where

X_1 = rate of return on rate base;
V_n = rate base;
D_n^B = book depreciation;
O_n = operating costs, including fuel, O&M, decommissioning fund, and insurance;
T_n = taxes.

The year-by-year cost of power P_n may be obtained by dividing the annual revenue requirements by the power produced S_n in that year:

$$P_n = \frac{R_n}{S_n} . \tag{3.2}$$

The sum of the present worth of the revenue requirements (PWRR) is a measure of the overall lifetime cost of a project. In effect, it is a single amount of money equivalent to the string of annual revenue requirements. The PWRR is obtained by discounting the annual revenue requirements to the year of plant startup by using the effective cost of money and summing

$$PWRR = \sum_{n=1}^{N} \frac{R_n}{(1 + X)^n} \tag{3.3}$$

(see Appendix A for definition of terms).

In the levelization technique an equivalent single price that will produce the same present worth of revenues as the stream of actual year-by-year prices is determined. Levelized power generation costs can be expressed in either constant or nominal dollars. The nominal-dollar levelized price is an equivalent price that remains constant over the life of the facility in then-current, as-spent dollars even though the buying power of the dollar may be changing with time. An example of such a price is a standard mortgage payment. Alternatively, a constant-dollar levelized price is an equivalent price indexed to a given reference year's purchasing power so that its value in terms of the reference year's purchasing power does not change.

Constant- and nominal-dollar levelized prices are two different ways of expressing the same value. They are both figures-of-merit (equivalent prices) and are not actual prices. In either case the sum (PWRR) of the present worth of revenues produced by these prices must equal the sum of the present worth of the actual year-by-year revenue requirements. In nominal-dollar terms

$$PWRR = \sum_{n=1}^{N} \frac{P_n S_n}{(1 + X)^n} . \tag{3.4}$$

In nominal-dollar levelization an equivalent price $\overline{P}$, which does not change with time, is found:

$$P_n = \overline{P} .$$

Because $\overline{P}$ is constant, it may be removed from the summation; rearranging,

$$\overline{P} = \frac{PWRR}{\sum_{n=1}^{N} \frac{S_n}{(1 + X)^n}} . \tag{3.5}$$

Because inflation may occur during the operating period; the buying power of the dollar will change; thus, this nominal-dollar levelized price is in dollars of no single year's buying power.

The constant-dollar levelized price is defined such that it keeps its buying power in terms of a reference year's dollars. The equivalent nominal-dollar, year-by-year price structure becomes

$$\begin{aligned} P_n &= \overline{P}_o (1 + i)^m \\ &= \overline{P}_o (1 + i)^L (1 + i)^n , \end{aligned} \tag{3.6}$$

where

$\overline{P}_o$ = levelized price in reference year's dollars,

m = number of years between n and reference year o,

L = period in years between reference cost year and year of commercial operation.

In the constant-dollar levelized approach, therefore, the year-by-year price is assumed to rise in nominal-dollar terms at the rate of inflation. In other words, the price in nominal dollars is indexed to the rate of inflation. The present worth of the revenues produced by this set of prices is also equal to the PWRR. Substituting into Eq. (3.4),

$$(1 + i)^L \sum_{n=1}^{N} \frac{\overline{P}_o (1 + i)^n}{(1 + X)^n} S_n = PWRR . \tag{3.7}$$

Because $\overline{P}_o$ is a constant, it may be removed from the summation. Rearranging and noting that $(1 + i)(1 + X_o) = (1 + X)$, where X_o is the real cost of money,

$$\overline{P}_o = (1 + i)^{-L} \frac{PWRR}{\sum_{n=1}^{N} \frac{S_n}{(1 + X_o)^n}} . \tag{3.8}$$

Constant- and nominal-dollar levelized prices are two different ways of expressing the same value. They are both figures-of-merit (equivalent prices) and are not actual prices. In either case, the sum of the present worth of revenues produced by these prices must equal the sum of the present worth of the actual year-by-year revenue requirements.

Further details on the mathematical basis of the method and the relationship between constant- and nominal-dollar levelization are found in the supporting NECDB.[4] Although the expression of results in either constant or current dollars will produce consistent comparisons, the constant-dollar form is preferred. The advantage of constant-dollar prices is that inflation is effectively removed from the results. These prices then can be related to present conditions.

The revenue requirements' approach is an accounting procedure that allocates costs over time. Some of the components of the revenue requirements do not represent actual cash payments in the period in which they are recorded. The actual money transferred is called "cash flow."

Cash flow is a measure of how much money must be raised by the utility (negative cash flow) or is available to repay investment and provide for internal growth (positive cash flow). Cash flow may be defined in several ways depending on its use. For this report, it is defined as the difference between the revenue (as calculated from revenue requirements) and the actual money paid for plant investment, operating costs, fuel investment or costs, taxes paid, interest paid on debt, preferred stock dividends, and common stock dividends.

$$CF_m = R_m - I_m - O_m - T_m - B_m - F_m - C_m \, , \tag{3.9}$$

where

m = period or year;

CF_m = cash flow;

R_m = annual revenue;

I_m = investment in plant or nuclear fuel;

O_m = operating costs that are expensed for tax purposes, including O&M, property taxes, coal costs, interim replacements, insurance, and decommissioning fund payments;

T_m = taxes paid;

B_m = interest paid (bond interest);

F_m = preferred stock dividends paid;

C_m = common stock dividends paid.

The cash flow is negative during the construction period, and money must be raised to meet obligations. The cash flow is normally positive during plant operating life, and this money is then available to repay borrowed money or fund other projects. The interest and dividends paid are sometimes excluded from Eq. (3.9); however, the utility must pay its interest and dividends to be viable, so these items are included.

3.2 UNCERTAINTY ANALYSIS: A BRIEF DESCRIPTION

This section provides a short, general description of a MVSS method for quantifying the uncertainty in a power generation cost estimate. More-detailed discussion of the mathematical methodology appears in Appendix B. With this method, a probability distribution for total levelized power generation (i.e., busbar) cost can be obtained based on the probability distributions of the input variables.

3.2.1 Rationale for Uncertainty Analysis

Chapter 4 of this document deals with the ground rules necessary for developing a single-point power generation or busbar cost estimate. Estimates of this type are called "deterministic" and provide a single value generally representing a projection of the most-likely cost outcome. Of course, cost influencing factors (input variables) cannot be known with complete certainty. Probably, the actual future values of the input variables will differ from what is used in the deterministic estimate today. The deterministic method gives no quantitative measure of this uncertainty. However, a probabilistic analysis can quantify the uncertainty by providing a probability distribution of the expected total power generation cost from a given type of power plant. With such a distribution, one can then state, for instance, that there is an 80% probability that the power generation cost from a given type of power plant will not be greater than a certain value or that there is a 90% probability that the actual power generation cost will be between amounts x and y. With a probability distribution for each power-plant technology alternative, a decision maker can assess the relative economic risk or uncertainty associated with each alternative, as well as know quantitatively the likelihood of one alternative being less costly than another.

3.2.2 Methodology

The starting point for the uncertainty analysis is the deterministic procedure or model used to calculate the single-point levelized power generation cost estimates. Throughout the uncertainty analysis, this deterministic model (LEVCOST) is called upon to provide single-point estimates for different input values, starting initially with the "most-likely," reference, or baseline values for the various input parameters.

After the initial most-likely case, all of the input variables with values that are thought to be uncertain are listed. Each variable is assigned, subjectively, a range of values that it might possibly assume. At this time, no probability is assigned to the variable having a given value within the range because the purpose of this step is only to rank the variables in order of their effects on the figure-of-merit (in this case, levelized power generation cost). The procedure consists of alternately entering each of the variables (one at a time) at their low and then high values into the model while the other variables are entered at their reference value. Thus, only the effect on the model output of changing a single variable at a time is observed. This step is called a single-value sensitivity analysis or study (SVSS). Chapter 7 discusses the results of the SVSSs.

After all variables have been individually entered into the model at their low and high values, the difference in the unit power generation cost at the low and high value is calculated for each variable. The variables are then ranked in order of this difference. Knowing what impact each variable can make on the power cost and which of the input variables are the significant cost drivers, the probabilistic portion of the analysis can be started.

Using the data developed in the SVSSs, a decision can be made regarding the number of variables that will be assigned a probability distribution. Generally, there are a few variables that have a much greater impact than the others on the results. These high-leverage variables are assigned probability distributions. The remaining variables are then entered in the cost calculations at their most-likely or baseline value.

The assigning of the probability distributions is one of the most-crucial and difficult steps in the entire uncertainty analysis because the worth of the overall analysis can only be as good as the quality of the data used in the study. Individuals knowledgeable about the possible values of the sensitive input parameters are used to help in the assignment of the probability distributions. Through careful analysis and questioning, experts provide the probabilities or likelihood of various values occurring for each variable. This information is converted into probability distributions that serve as input to the next step, the "simulation" or the Monte Carlo analysis procedure for performing a MVSSs.

In the Monte Carlo procedure, the values of the sensitive input variables are randomly selected within the ranges defined by their probability distributions. Figure 3.1 shows a flowsheet for the Monte Carlo process. These values are entered into the LEVCOST model to obtain a point estimate of total cost for that specific set of inputs. The process of value selection and cost calculation is repeated many times (usually several hundred) until statistically significant samples of possible inputs and corresponding outcomes have been generated. Then by grouping the outcomes and accumulating the frequency of occurrences, a probability distribution for the total power generation cost that can be used to quantitatively assess the uncertainty associated with the two power-plant alternative will be obtained. Chapter 8 discusses the results of the probabilistic MVSSs.

The Monte Carlo method of performing MVSSs has been used successfully for many financial/economic and research and development (R&D) applications. A recent application[5] within the U.S. Department of Energy (DOE) was its use as an analytical tool in support of a major R&D

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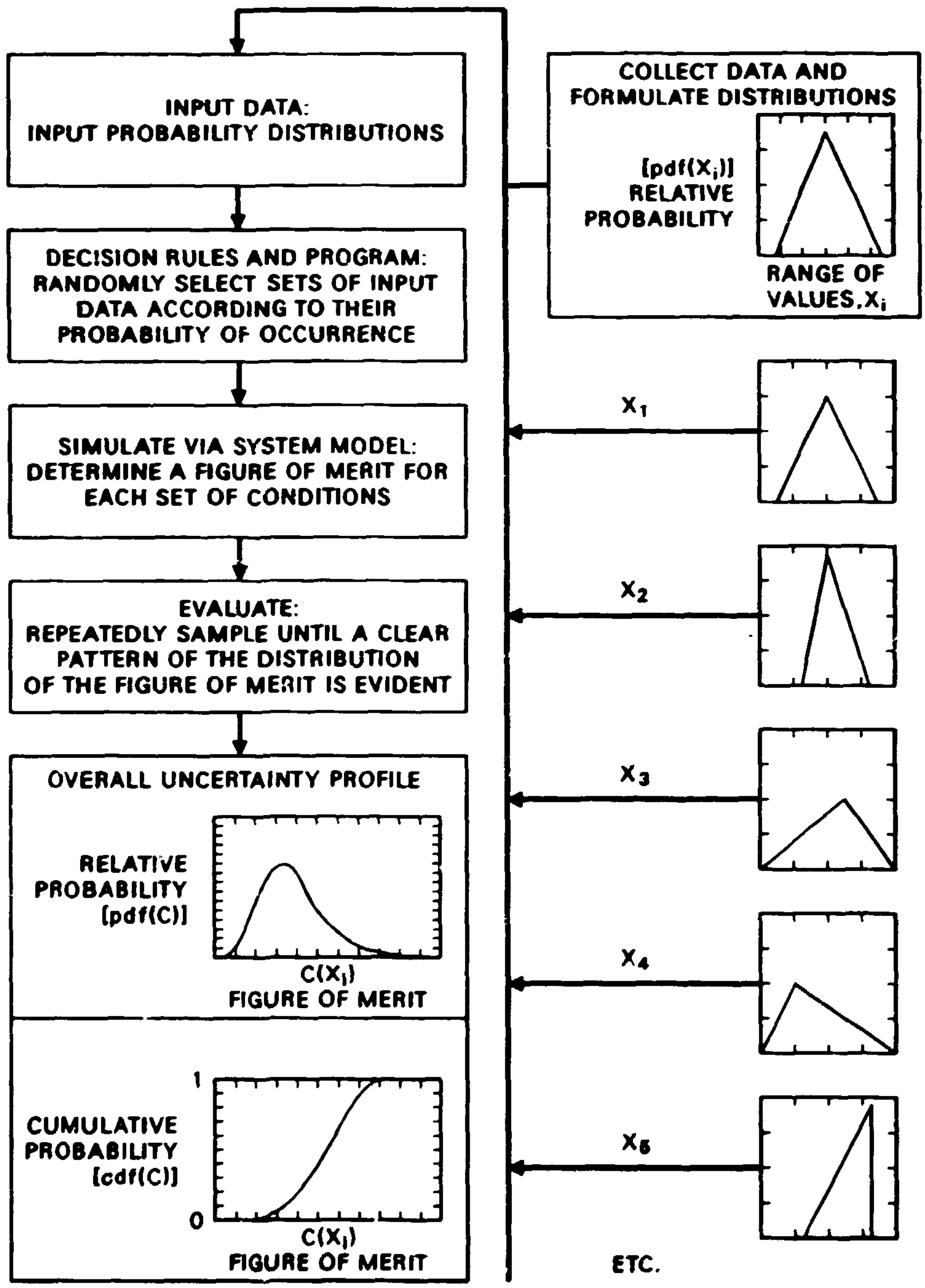

Fig. 3.1. Flowsheet for multivariable sensitivity analysis procedure to evaluate a process subject to multiple uncertainties.

funding decision between the atomic vapor laser isotope separation (AVLIS) and advanced gas centrifuge (AGC) methods for uranium enrichment. A discussion of the applicability of the Monte Carlo method is given in Refs. 6 and 7, and a discussion of its mathematical basis is given in Appendix B and Ref. 6.

4. TECHNICAL AND ECONOMIC DATA

This section (1) describes the reference power plants and (2) tabulates the economic data for the deterministic reference cases.

4.1 TECHNICAL AND FINANCIAL DATA FOR THE REFERENCE CASE

The reference set of technical parameters used to obtain the power generation costs is derived from the NECDB[4] and is given in Table 4.1. The financial parameters are given in Table 4.2.

Table 4.1. Reference technical parameters[a]

Plant size, MW(e)	
Nuclear (LWR: single-unit PWR)	1 × 1,100
Coal (twin unit)	2 × 550
Capacity factor, %	70
Heat rate, average annual Btu/kWh	
Nuclear (LWR)	10,200
Eastern coal	9,900
Western sub-bituminous coal	10,200
Licensing and construction lead times, years	
Nuclear	8
Coal	6
Enrichment plant tails assay, % U-235	0.20
Startup year	2000

[a]For various locations see Table 4.5.

4.2 CAPITAL INVESTMENT COSTS

Reference capital investment cost estimates are summarized in Table 4.3. These costs are for a plant site in the vicinity of Chicago and are based on cost information given in the NECDB.[4] The Chicago site was chosen because the sensitivity analysis uses the midwest region as a reference. This region is centrally located, and other studies have

Table 4.2. Reference financial parameters

Plant life, years	40
Analysis period, years	30
Reference year	1986
Inflation rate, %/year	5
Escalation rate in excess of inflation rate for power-plant construction, %/year	0
Capitalization, %	
Debt	50
Preferred equity	10
Common equity	40
Return on capitalization, %/year	
Debt interest	9.7 (4.5)[a]
Preferred equity return	9 (3.8)[a]
Common equity return	14 (8.6)[a]
Fraction of common equity return paid as dividends	0.6
Average cost of money, %/year	11.3 (6.1)[a]
Federal income tax rate, %/year	46
State income tax rate, %/year	4
Tax-adjusted cost of money, %/year	9.0 (3.8)[a]
Local property-tax rate,[b] %/year	2
Tax depreciation method	TEFRA[c]
Tax depreciation life, years	
Nuclear	10
Fossil	15
Investment tax credit rate, %	8
Interim replacement/backfitting rate,[d] %/year	0.5
Decommissioning cost, millions of 1986 dollars	
Fossil	22
Nuclear	140
Nominal interest rate on decommissioning fund,[e] %/year	6.5
Fixed charge rate,[f] %/year	
Coal	16.6 (9.61)[a]
Nuclear	16.4 (9.54)[a]

[a]Real, inflation-adjusted value in parentheses.

[b]Rate is applied to an initial investment with no escalation because of inflation or decrease because of depreciation.

[c]Tax Equity and Fiscal Responsibility Act of 1982.

[d]Percent of initial investment in constant dollars, escalating at general inflation rate.

[e]Interest rate on tax exempt, highest grade, state and local bonds.

[f]Based on normalized tax accounting.

Table 4.3. Power-plant capital investment cost estimates for a midwestern location[a] for commercial operation in 2000

Cost category	Power-plant type ($M) BE Nuclear 1 × 1100 MW(e)	Power-plant type ($M) Coal 2 × 550 MW(e)
Direct (January 1986 dollars)		
Land and land rights	5	5
Structures and improvements	180	115
Reactor/boiler plant equipment	285	435
Turbine plant equipment	205	200
Electric plant equipment	70	70
Miscellaneous plant equipment	40	35
Main heat-rejection system	45	35
Subtotal	830	895
Indirect (January 1986 dollars)		
Construction services	195	105
Home office engineering and services	200	40
Field office engineering and services	100	35
Owner's costs	130	110
Subtotal	625	290
Total		
Direct and indirect costs (January 1986 dollars)	1455	1185
Contingency allowance (January 1986 dollars)	145	120
Total direct and indirect costs (overnight costs) (January 1986 dollars)	1600	1305
Allowance for escalation (as-spent dollars)	1020	965
Allowance for interest (as-spent dollars)	1070	590
Plant capital investment cost at commercial operation (as-spent dollars)		
Millions of dollars	3690	2860
Dollars per kilowatt	3350	2600
1986 dollars per kilowatt	1690	1310

[a] Chicago area.

compared the nuclear and coal options here. The economic ground rules used in obtaining these estimates (i.e., unit sizes, lead times, and escalation rates) are also listed in Tables 4.1 and 4.2.

For the economic ground rules assumed; a 5%/year escalation rate; a 9.0%/year after-tax, nominal cost of money; and a January 1986 cost basis, it is estimated that for first commercial operation in 2000, a nuclear plant at the midwest site will cost \$3350/kW(e), and a two-unit, coal-fired plant, \$2600/kW(e). The capital-cost estimate for the coal-fired plants applies to plants burning either high- or medium-sulfur bituminous coal or low-sulfur sub-bituminous coal. An inspection of Table 4.3 shows that the sum of the escalation and interest costs before commercial operation is significantly larger than the so-called "overnight," 1986-dollar, estimated construction costs.

Escalation and allowance for funds used during construction (AFUDC) make a large contribution toward the total investment cost. Also, note the impact of the length of the design and construction period (8 years) assumed for the nuclear plant. If the nuclear plant is to be completed by 2000, capital outlays of about \$250 million (as spent dollars) would be required by 1994 before the construction permit for the plant had even been issued. The overnight costs (sum of the direct and indirect costs) for both nuclear- and coal-plant types compose ~43 and 46%, respectively, of the total investment costs. For the nuclear plant, the investment balance is composed of ~27% escalation and 29% AFUDC; however, this balance is ~34% escalation and 20% AFUDC for the coal-fired plant. Escalation of construction costs is a larger fraction of coal-fired plant investment because construction outlays begin and peak at later times than those of the nuclear plant for the same operation date.

The estimates for the overnight nuclear-plant and coal-fired-plant costs were obtained using the CONCEPT[8] computer code and are based on detailed cost models developed by United Engineers & Constructors (UE&C) for the Energy Economic Data Base Program, Phase VII (EEDB-VII).[9] The EEDB-VII cost models, which are in January 1984 dollars, were adjusted to January 1986 by using industry escalation factors. Escalation rates after January 1986 were assumed to be 5%/year for all plant types. The coal-fired plant design includes flue gas desulfurization (FGD) equipment but does not include the cost effect of possible future regulations affecting NO_x control. The allowance for escalation and the allowance for interest were calculated using the computer code discussed in Appendix C of the 1986 NECDB report.[4]

The reference capital investment costs for nuclear plants are based on the better of today's plant construction experiences and reflect the potential effects of proposed improved construction practices and nuclear regulatory and licensing reforms. UE&C developed nuclear-plant investment costs based on both current ME and on an average of the current BE. The BE cost estimate (referred to as "best industry cost experience" in the most recent energy economic data base[10]) is representative of the range of base construction costs for a small group of single-unit nuclear power plants currently entering service whose costs are at the low end of the current range of costs. The EEDB ME cost estimate is representative of the range of base construction costs for those single-unit nuclear power plants currently entering service that have costs near the middle of the current range of costs. Neither the BE nor ME cost estimates should be considered as being the cost of a single specific nuclear power plant. The BE cost estimate should not be considered as the cost of the single-unit nuclear power plant that has the lowest possible cost or shortest possible schedule attainable. Compared with the ME cost estimate, the BE cost estimate reflects >50% fewer craft labor, engineering, and field supervision manhours (in toto) and 2 or more years shorter construction schedule. The BE composite is the basis for the reference cost estimate in Table 4.4. A comparison of the EEDB-VII costs for the reference BE nuclear-plant investment cost estimate vis-a-vis the current ME cost estimate reflects a reduction from 26 to 14 manhours/kW(e) in craft labor and a reduction in the indirect costs resulting from plant standardization and decrease or elimination of engineering required for regulatory, mandated backfitting. In addition, the contingency allowance was reduced from 15 to 10% to reflect assumed increased cost certainties. The 14-manhours/kW(e) requirement used for the reference plant costs is somewhat higher than the pre-Three Mile Island, EEDB-I (Ref. 11) estimate of ~12 manhours/

Table 4.4. Estimated nuclear-power-plant capital investment costs based on median and better current experience[a]

Cost category	Capital cost ($M) Median[b] (ME)	Capital cost ($M) Better[c] (BE)
Direct (January 1986 dollars)		
Land and land rights	5	5
Structures and improvements	270	180
Reactor/boiler plant equipment	330	285
Turbine plant equipment	230	205
Electric plant equipment	100	70
Miscellaneous plant equipment	55	40
Main heat-rejection system	50	45
Subtotal	1040	830
Indirect (January 1986 dollars)		
Construction services	340	195
Home office engineering and services	370	200
Field office engineering and services	395	100
Owner's costs	215	130
Subtotal	1320	625
Total		
Direct and indirect costs (January 1986 dollars)	2360	1455
Contingency allowance (January 1986 dollars)	350	145
Total overnight costs (January 1986 dollars)	2710	1600
Allowance for escalation (as-spent dollars)	1460	1020
Allowance for interest (as-spent dollars)	2410	1070
Plant capital investment cost at commercial operation (as-spent dollars)		
Millions of dollars	6580	3690
Dollars per kilowatt	5980	3350
1986 dollars per kilowatt	3020	1690

[a]Year 2000 startup in Chicago area.

[b]Twelve-year design and construction lead time and 26 craft manhours/kW(e).

[c]Eight-year design and construction lead time and 14 craft man-hours/kW(e).

kW(e) and reflects post-Three Mile Island add-ons. The reference nuclear-plant indirect costs, excluding owner's costs, are ~59% of the direct costs, compared with 105% for the ME plant. The fraction for the "BE" reference plant is still ~1.4 times larger than it was in the pre-Three Mile Island, EEDB-1 cost estimate and indicates that there is still room for improvement.

Capital investment cost factors (Table 4.5) were estimated for various cities by using the CONCEPT[8] computer code. To estimate regional capital investment cost differences, a specific city was chosen for each of the ten EIA federal regions.

4.3 NONFUEL OPERATION AND MAINTENANCE COSTS

The nonfuel O&M cost estimates for coal and nuclear plants (Table 4.6) are based on calculations made with the most recent update

Table 4.5. Regional variations in power-plant capital investment cost estimates for commercial operation in 2000

Region		City	Cost factors[a,b]	
			Nuclear	Coal
I.	New England	Boston	1.02	1.04
II.	New York/New J rsey	New York	1.06	1.06
III.	Mid Atlantic	Baltimore	0.96	0.97
IV.	South Atlantic	Atlanta	0.91	0.92
V.	Midwest	Chicago	1.00	1.00
VI.	Southwest	Dallas	0.96	0.98
VII.	Central	Kansas City	0.97	0.98
VIII.	North Central	Denver	0.98	0.99
IX.	West	San Francisco	1.09	1.14
X.	Northwest	Seattle	1.03	1.04

[a]Fraction of reference capital investment cost estimate (see Table 4.3).

[b]Includes labor and material unit cost differences only. Does not include site-specific differences, such as seismic and atmospheric conditions, or differences in labor productivity.

Table 4.6. Nonfuel operation and maintenance (O&M) costs for base-load power plants[a]

Base-load power plant type	Fixed cost [$/kW(e)/year]	Variable cost (mills/kWh)	Total cost[b] (mills/kWh)
Nuclear (LWR), 1 × 1100 MW(e)	43	0.3	7.3
Coal-fired with FGD (3.5% S, region V: reference case)			
Twin unit, 2 × 550 MW(e)	24	2.1	5.9
Coal fired with FGD (1.5% S, regions I, II, III, IV)			
Twin unit, 2 × 550 MW(e)	25	1.3	4.9
Coal fired with FGD (0.5% S, regions VI, VII, VIII, IX, X)			
Twin unit, 2 × 550 MW(e)	22	0.8	4.1

[a]1986 dollars.

[b]At 70% capacity factor.

of the OMCOST[12] O&M-cost computer program. These estimates are separated into a fixed component that does not vary with plant output and a variable component that is dependent on the energy generated. The total O&M costs at a 70% reference capacity factor are also given. The O&M costs for coal plants were assumed to vary somewhat among regions, depending on the sulfur content of the predominant coals burned. The O&M costs for coal include the management of ash waste and purchase and disposal of the chemicals, such as lime, used in the scrubber system.

4.4 URANIUM PRICES

A major contributor to the overall nuclear fuel cost is the price of uranium ore, which is sensitive to future supply/demand conditions to a greater extent than any other unit cost for the nuclear fuel cycle. A range of uranium price projections is shown in Fig. 4.1. The low price projections assume a stagnant nuclear industry in which there is no real escalation in ore price. For the reference case uranium prices are assumed to escalate at 1%/year in constant dollars from the early 1986 average delivered price of about $34/lb. The high price projection

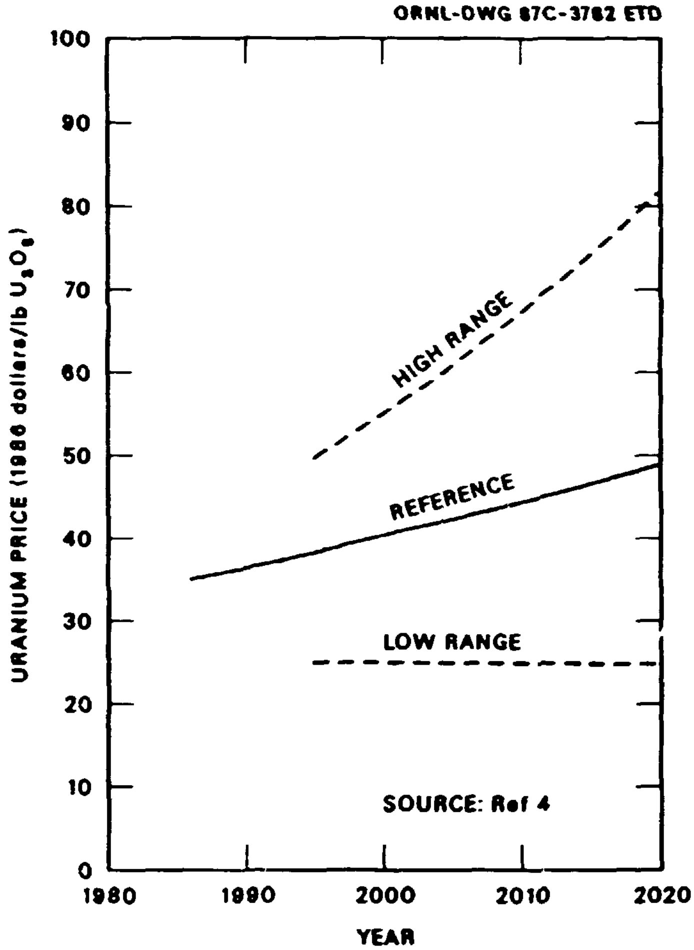

Fig. 4.1. Uranium price projections. *Source: Nuclear Energy Cost Data Base: A Reference Data Base for Nuclear and Coal-Fired Powerplant Power Generation Analysis*, DOE/NE-0078, U.S. DOE, Office of Program Support, December 1986.

assumes a moderate-to-healthy recovery in nuclear plant orders. These projections are discussed in more detail in NECDB.[4]

The range of uranium prices enclosed by the above three projections is representative of future expectations based on conditions as they now exist in the nuclear and electric utility industries. Resolution of nuclear-related issues, together with large coal price increases and/or restrictions on coal-fired generation expansion, could conceivably cause rapid increases in nuclear-plant orders, leading to higher uranium prices as demand increases. A continuation of large, rich ore finds, however, such as in Northern Canada, and a lack of new nuclear-plant orders could result in depressed ore prices well into the next century.

4.5 OTHER NUCLEAR FUEL COST COMPONENTS

A summary of the prices and escalation rates (and ranges) for the components of the nuclear-fuel cost are given in Table 4.7. A once-through, extended burnup, enriched-uranium fuel cycle is assumed (i.e., no plutonium recycle or reprocessing is assumed). Justifications for the ranges given in Table 4.7 are deferred to Chap. 6.

4.5.1 Conversion

Uranium hexafluoride (UF_6) is required for feed to current enrichment processes. This conversion process from U_3O_8 to UF_6 is well

Table 4.7. Nuclear-fuel cost parameters: once-through fuel cycle[a]

Cost parameter	Reference	Range
	Component prices	
U_3O_8, $/lb	34	15-50[b]
Conversion, $/kg U	8	5-10
Enrichment, $/SWU	110[c] (60)[d]	30-110[d]
LEU fabrication, $/kg HM (extended burnup)	240	160-300
Waste disposal, mills/kWh	1	0.75-2.0
	Escalation rates,[e] %/year	
Uranium price	1	0-2
Enrichment price	0	
Other costs	0	

[a]Cost/unit, 1986 dollars.

[b]See Fig. 4.1 and Chap. 6 for details.

[c]FY 1987 price for 100% U.S. contract.

[d]Average SWU price in the post-year-2000 period.

[e]Real escalation rate over and above the 5%/year general inflation rate.

established commercially. The $8/kg of U figure is representative of the current market price. No real escalation is assumed after 1986.

4.5.2 Enrichment

Uranium used in LWRs must be enriched in the U-235 isotope. Currently in the United States, this is done by government-owned facilities using the gaseous diffusion process; however, foreign enrichment is playing an increasing role in supplying U.S. utility demands. The new AVLIS enrichment process being developed in the United States is projected to lead to lower future enrichment costs.

The reference projection in Fig. 4.2 shows the U.S. enrichment price at $110/SWU in 1987 and then assumes that the price of enrichment

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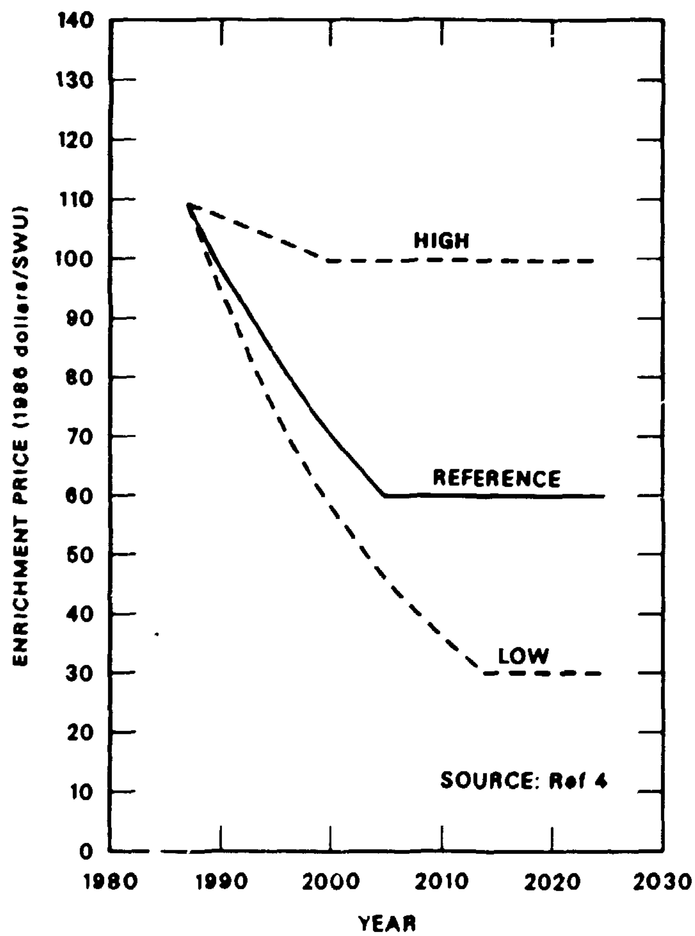


Fig. 4.2. Enrichment price projections. *Source: Nuclear Energy Cost Data Base: A Reference Data Base for Nuclear and Coal-Fired Powerplant Power Generation Analysis*, DOE/NE-0078, U.S. DOE, Office of Program Support, December 1986.

will decrease by 3.4%/year in real terms (corresponding to an increase of 1.5%/year in nominal dollars, including a 5%/year reference inflation rate) to an enrichment price in the year 2005 of about $60/SWU, after which it remains constant (i.e., no real escalation, only an increase at the general rate of inflation). The $60/SWU price is consistent with DOE projections and is at the upper end of the range of projected costs from AVLIS.

4.5.3 LEU Fuel Fabrication

The fabrication of low-enriched uranium (LEU) fuel assemblies is a well-established commercial process. A price of $240/kg of heavy metal (HM) is representative of current market conditions and assumes extended burnup fuel (50 Mwd/kg HM). The fabrication price is assumed to escalate at the rate of inflation (no real escalation).

4.5.4 Waste Disposal

The cost of high-level waste disposal has been determined by legislative mandate via the Nuclear Waste Policy Act of 1982, which prescribes a fee of 1 mill/kWh for electricity generated after April 7, 1983. This fee is reviewed annually and adjusted, if necessary, to accommodate changes in program costs as a result of inflation and program shifts. The fee is assumed to rise annually at the rate of inflation (no real escalation). The fee will cover the cost of transportation and packaging of spent fuel and high-level radioactive waste.

4.6 COAL PRICES

Fuel costs are the largest component of power generation costs for coal-fired plants. The competitiveness of coal-fired plants often hinges on the projected cost of coal. The nonuniform distribution of coal resources in the United States and variations in production cost result in wide variations in delivered coal prices. The average regional price of coal (including transportation) to electric utilities in the fourth quarter of 1985 (Ref. 3) as a function of coal sulfur content is shown in Table 4.8. A map of the United States subdivided

Table 4.8. Regional average coal prices for October–December 1985

Region		Sulfur content (%)			Average for all sulfur levels ($/MBtu)
		0–1	1–2	>2	
I.	New England	2.34 (22)[a]	2.00 (55)	1.94 (23)	2.06
II.	New York/New Jersey	1.80 (18)	1.79 (46)	1.62 (37)	1.73
III.	Mid Atlantic	1.71 (25)	1.57 (40)	1.49 (35)	1.58
IV.	South Atlantic	2.09 (33)	1.71 (35)	1.62 (32)	1.81
V.	Midwest	2.03 (40)	1.65 (14)	1.59 (46)	1.77
VI.	Southwest	1.70[b] (77)	1.18[c] (23)		1.58
VII.	Central	1.31 (57)	1.86 (6)	1.49 (37)	1.41
VIII.	North Central	1.03 (99)	0.85 (1)		1.03
IX.	West	1.46 (100)			1.46
X.	Northwest	1.64 (69)	1.50 (31)		1.60
	Average	1.68 (48)	1.60 (23)	1.57 (28)	1.63

[a]Numbers in parentheses are percent of total purchases (Btu basis) in each sulfur-content category.

[b]Excludes lignite.

[c]Texas lignite, sulfur 0.5 to 2.0%.

into these ten EIA regions was shown in Fig. 2.2. Generally, the price of coal increases as the sulfur content decreases. The percentage of coal sales in each sulfur content category is also shown.

Reference coal price projections are shown in Table 4.9. The January 1986 coal prices for the most part follow the actual 1985 fourth quarter values rounded up to the nearest $0.05/MBtu. The most widely used coal for each region was chosen in most cases. This choice may underestimate future coal prices because utilities may be required to burn lower-sulfur (and more-expensive) coal in the future. The reference coal prices for the southwest and west regions are the average fourth quarter 1985 prices with the mine-mouth power plants (Salt River Project's Navajo plant and the Four Corners plant in New Mexico) removed. Future power plants are projected to be located closer to load centers, and growth in the southwest region is expected to predominate

Table 4.9. Average coal prices for the predominant coal type within each region for the fourth quarter of CY-1985

Region		Coal[a] type	Price ($/MBtu)	
			Reference[b,c]	Range
I.	New England	MSB	2.05	1.90–2.50
II.	New York/New Jersey	MSB	1.80	1.35–2.15
III.	Mid Atlantic	MSB	1.60	1.20–2.05
IV.	South Atlantic	MSB	1.75	1.20–2.50
V.	Midwest	HSB	1.60	1.35–3.45
VI.	Southwest	LSS	1.80	0.95–2.25
VII.	Central	LSS	1.35	1.05–2.30
VIII.	North Central	LSS	1.05	0.65–1.70
IX.	West	LSB	1.90	0.95–2.25
X.	Northwest	LSS	1.65	1.50–2.00

[a]MSB = high-sulfur, bituminous coal
HSB = medium-sulfur, bituminous coal
LSS = low-sulfur, sub-bituminous coal
LSB = low-sulfur, bituminous coal

[b]1986 dollars.

[c]Coal is assumed to escalate at 1%/year in constant dollars with a range of 0 to 2%/year.

along the Texas Gulf coast. Mine-mouth, lignite-fired plants were also excluded in the southwest and central regions.

A coal price escalation rate of 1.0%/year, assumed for the reference case, is the rate implied from projected coal prices in the recent *National Energy Policy Plan*.[13] This is the same escalation rate used in this report for the reference uranium ore price.

4.7 DECOMMISSIONING COSTS

The $140 million (1986-dollar) total decommissioning cost recommendation for the nuclear-plant data base was obtained by escalating the $100 million 1984-dollar Nuclear Regulatory Commission (NRC) estimate[14] to 1986 dollars by using an 8% escalation rate for 2 years and then adding a 20% contingency to allow for future cost escalation in excess of inflation. A nuclear decommissioning cost of 0.6 mill/kWh is assumed on a levelized cost basis. The $22 million cost for decommissioning a coal-fired plant is based on a recent study[15] by Arkansas Power and Light. A decommissioning cost of 0.1 mill/kWh is estimated on a levelized cost basis.

The reference decommissioning costs in 1986 dollars are assumed to escalate in nominal dollars at the reference 5%/year inflation rate (no real escalation). Decommissioning costs are assumed to be accumulated in an external sinking fund over the plant life, earning interest at a rate equal to that for highest-grade, tax-free state bonds.

The reference long-term rate for these bonds is assumed to be 6.5%/year in nominal dollars or ~1.4%/year real (inflation component removed).

5. COMPARISON OF COSTS AT REFERENCE PARAMETERS: DETERMINISTIC ANALYSIS

This chapter includes a deterministic analysis of the relative economics of future nuclear and coal-fired plants by using 30-year levelized power generation costs as a figure-of-merit. Although the current BE plants represent the reference nuclear cost model, an alternate case using the ME nuclear cost model is also included to indicate the relative competitiveness of nuclear with coal-fired generation if projected improvements are not made in nuclear-plant construction and in the regulatory environment. The power costs of each option were evaluated with a data base that projects costs through extrapolations of existing data. Because the projections encompass such a long time, a considerable degree of uncertainty exists in each of the data parameters. The sensitivity of the capital and power generation costs to these uncertain parameters are examined in Chaps. 6-8. The important point to remember regarding these comparisons is that they represent the competitiveness level of each option, based on extrapolations and projections of data, and that these data can be altered by unforeseen events. Also, technological progress and regulatory reform may affect the basic cost parameters, perhaps changing the comparison to a significant degree. The comparison results presented in this section are based on characteristics of recently completed plants and depend on industry experiences in building, maintaining, and operating these types of plants.

This section describes the results of the comparative deterministic analysis performed using the reference set of technical, financial, and cost parameters described in Chap. 4. Regional comparisons are made of the levelized power generation costs for single-unit nuclear and twin-unit, coal-fired plants beginning operation in 2000. (The characteristics of each region are described in Appendix C.) Annual revenue requirements and cash flows are estimated for the reference BE nuclear and coal options in one region (region V: Midwest) and are tabulated in Appendix D.

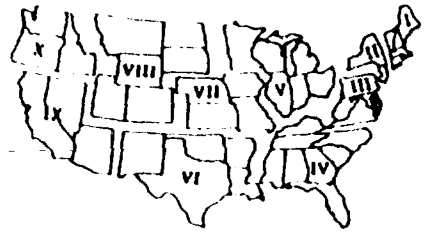
5.1 REGIONAL POWER COSTS

The estimated power generation costs for nuclear and coal-fired plants in each of the ten EIA regions are listed in Table 5.1. The levelized costs are shown in constant 1986 dollars for a plant with an initial commercial operation date of January 2000. Results are given for total cost and for each of the cost categories (i.e., capital investment, O&M, and fuel and decommissioning costs). The regional power generation costs are also shown graphically in Fig. 5.1, which indicates that decommissioning costs are so small that they are barely noticeable on the bar chart.

The levelized power generation costs for the reference BE nuclear plant range from 38.9 mills/kWh (south Atlantic region) to 43.6 mills/kWh (western region); those for the coal-fired plant range from 38.5 mills/kWh (north central region) to 53.1 mills/kWh (western region). Because the cost results from the two options overlap and vary so greatly, especially for coal-fired plants, the examination of specific regional results is necessary to examine how these options compete geographically.

The levelized power costs of the reference BE nuclear plant are substantially (i.e., >10%) lower than for a coal-fired plant in all regions except the Central and North Central. In these other eight regions, delivered coal prices may include significant coal transportation charges or higher underground mining expenses. In the north central region levelized power costs of the coal option are projected to be slightly lower than those for nuclear plants, and in the central region nuclear has only a slight advantage over coal. Large reserves of cheaply mineable coal are located in these two regions, thus holding down the price of mine-mouth coal. In the other eight regions the cost of power from the BE nuclear option is projected to have a >10% advantage. In the central and north central regions both options could be considered economically competitive, and power costs from both options in these two regions are estimated to range from 38.5 to 42.4 mills/kWh. The results restate the fact that nuclear plants, if planned, constructed, and operated in a manner commensurate with the

Table 5.1. Reference case: regional power generation costs for coal-fired plants and better-experience plants



Unit cost component	Region (mills/kWh)									
	I	II	III	IV	V	VI	VII	VIII	IX	X
	Northeast	NY-NJ	Mid-Atlantic	South Atlantic	Midwest	Southwest	Central	North Central	West	Northwest
					Nuclear					
Capital	26.9	27.9	25.3	24.0	26.4	25.3	25.6	25.8	28.7	27.2
O&M	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Fuel	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Decommissioning	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	41.8	42.8	40.2	38.9	41.3	40.2	40.5	40.7	43.6	42.1
					Coal					
Capital	2[illegible].4	21.8	20.0	18.9	20.6	20.2	20.2	20.4	23.5	21.4
O&M	4.9	4.9	4.9	4.9	5.9	4.1	4.1	4.1	4.1	4.1
Fuel	26.6	23.3	20.7	22.7	20.7	24.0	18.0	14.0	25.4	22.1
Decommissioning	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	53.0	50.1	45.7	46.6	47.3	48.4	42.4	38.5	53.1	47.7
					Comparison					
Lower-cost alternative	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear	Nuclear	Coal	Nuclear	Nuclear
Margin, %	21.1	14.7	12.0	16.5	12.9	16.9	4.5	5.1	17.9	11.7
Is margin significant (i.e., ≥ 10%)?	Yes	Yes	Yes	Yes	Yes	Yes	No	No	Yes	Yes

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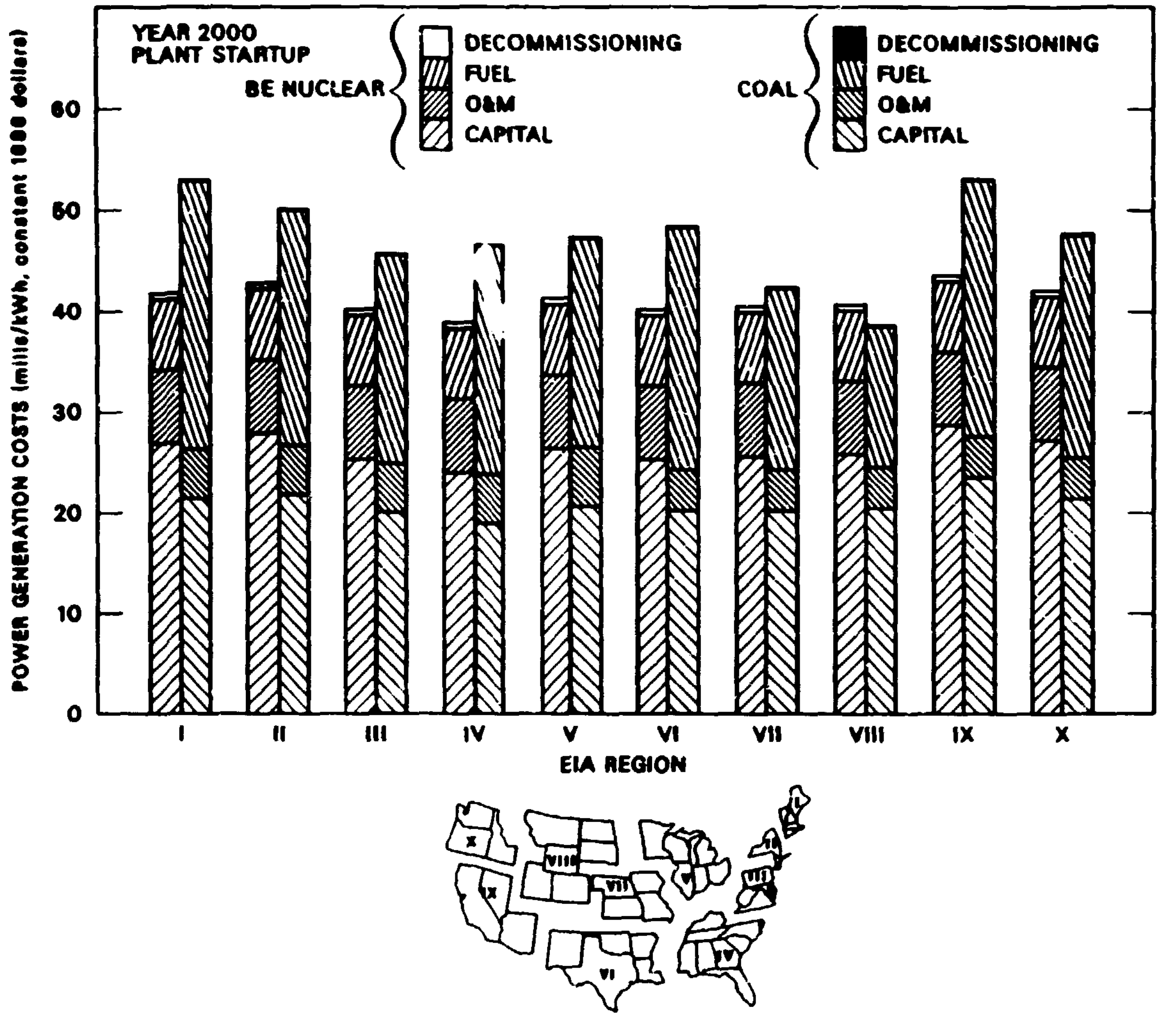


Fig. 5.1. Regional power generation costs at reference parameters: BE nuclear plants and coal-fired plants.

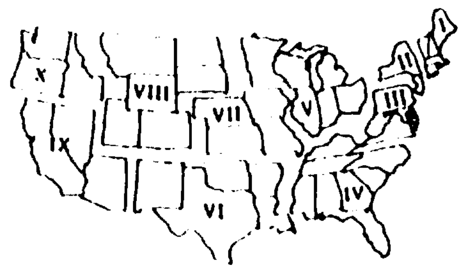
present BE plants in this country, will maintain an economic advantage over coal-fired plants as sources of new base-load power in the future.

In the past, nuclear power has had a substantial economic advantage over coal-fired plants. A 1982 survey[16] by the Atomic Industrial Forum (AIF) found that in 1981, for most utilities with nuclear plants, the average electrical generating cost of nuclear plants was 27 mills/kWh; their coal-fired plants, however, averaged 32 mills/kWh. A recent AIF survey[17] shows that this advantage has reversed in favor of coal, with power generation costs for 1985 of 43 mills/kWh for nuclear and

34 mills/kWh for coal. Increases in the capital investment costs of nuclear plants relative to those of coal-fired plants are continuing to enhance the coal advantage. This trend was also documented in the regional power generation cost study[1] before this one (December 1983). In that report, ME nuclear plants had an economic advantage over coal-fired plants in only one region. In this report, the same comparison using ME nuclear-plant capital investment costs shows that coal would be the economic choice in all regions (Table 5.2 and Fig. 5.2). If recent capital-cost trends persist, the cost of constructing even a BE nuclear plant for commercial operation in 2000 in the midwest region is estimated to be ~28% more expensive than the cost of building a twin-unit, coal-fired plant with the same plant capacity (Tables 4.3 and 5.1). The BE nuclear option is able to remain economically viable because of its low fuel costs. The capital investment cost is the predominant cost component of nuclear plants, composing ~64% (in the midwest region) of the total levelized cost. Instituting changes that will reduce this capital investment cost will serve to greatly improve the competitive stance of the nuclear option. If the reference projected future capital investment costs listed in this report are not realized and today's ME nuclear-plant costs prevail into the future, the nuclear option is not competitive with coal in any region. Even where coal prices are high, coal-fired power would remain the economic choice.

Although capital investment cost is important for coal plants (44% of total cost in the reference case), the cost of coal is generally the overriding cost consideration. There are regional variations in capital investment costs caused by differences in labor rates and delivered material prices. However, much-larger variations occur within a given region in the price of coal. An estimate of these regional coal price variations was given in Table 4.8. These differences within a region result from plant and coal mine locations (affecting transportation requirements), type of delivery (e.g., train, truck, or barge), and contractual differences. The range in the fuel-cost component of the power generation cost for coal-fired plants is provided in Table 5.3 for each region. The power generation costs resulting from these ranges are illustrated in bar-chart form in Fig. 5.3. Coal-fired plant and BE

Table 5.2. Alternative case: regional power generation costs for coal-fired plants and median-experience nuclear plants



Unit cost component	Region (mills/kWh)									
	I	II	III	IV	V	VI	VII	VIII	IX	X
	Northeast	NY-NJ	Mid-Atlantic	South Atlantic	Midwest	Southwest	Central	North Central	West	Northwest
					Nuclear					
Capital	51.2	53.2	48.2	45.7	50.2	48.2	48.7	49.2	54.7	51.7
O&M	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3	7.3
Fuel	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0	7.0
Decommissioning	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6	0.6
Total	66.1	68.1	63.1	60.6	65.1	63.1	63.6	64.1	69.6	66.6
					Coal					
Capital	21.4	21.8	20.0	18.9	20.6	20.2	20.2	20.4	23.5	21.4
O&M	4.9	4.9	4.9	4.9	5.9	4.1	4.1	4.1	4.1	4.1
Fuel	26.6	23.3	20.7	22.7	20.7	24.0	18.0	14.0	25.4	22.1
Decommissioning	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1
Total	53.0	50.1	45.7	46.6	47.3	48.4	42.4	38.5	53.1	47.7
					Comparison					
Lower-cost alternative	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal	Coal
Margin, %	19.8	26.3	27.6	23.1	27.3	23.3	33.3	40.2	23.7	28.4

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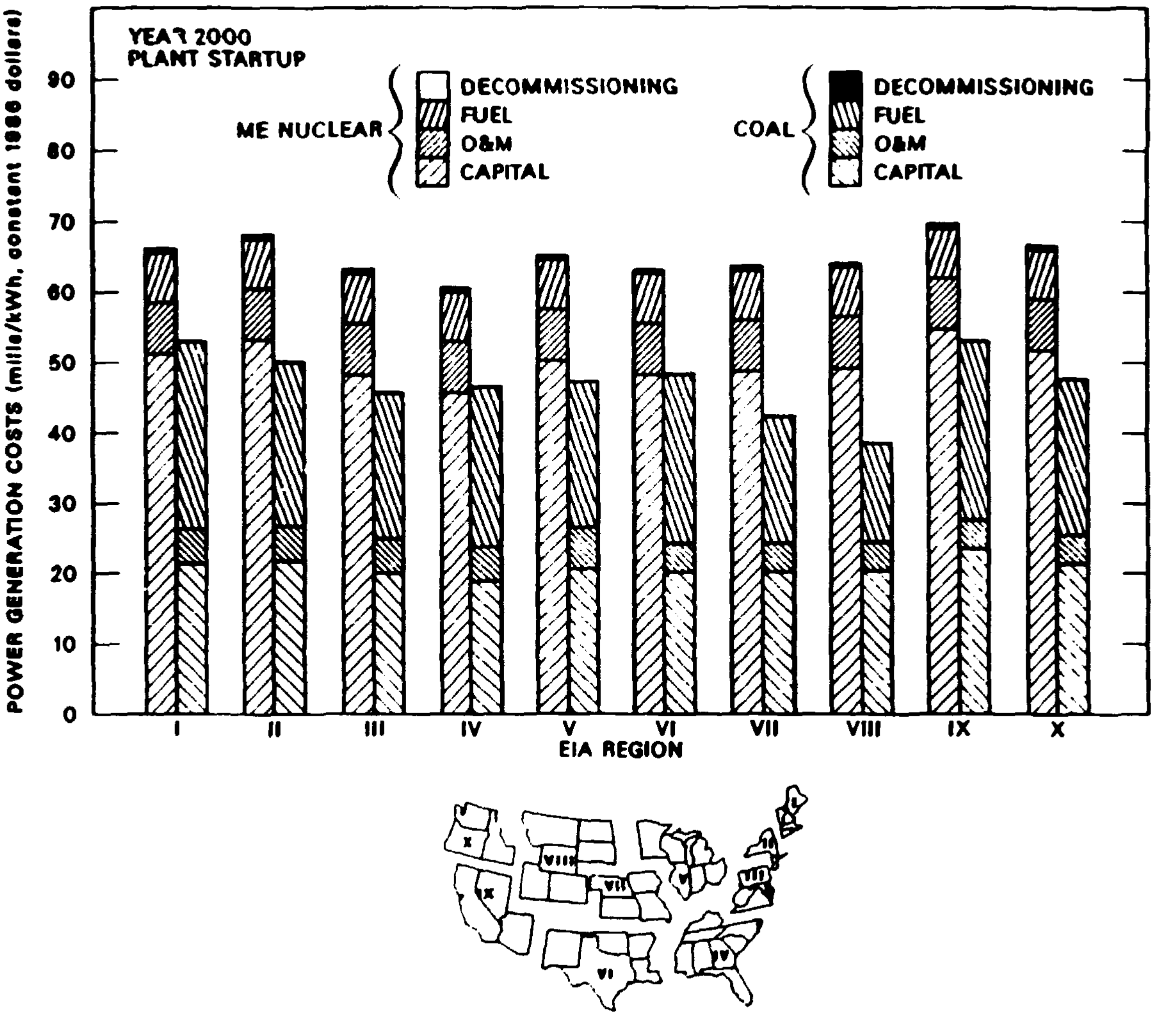

Fig. 5.2. Regional power generation costs for ME nuclear and coal-fired plants.

nuclear plant costs at reference parameters are also indicated in this figure. These results indicate that in region 6 (Southwest), region 7 (Central), region 8 (North Central), and region 9 (West) either nuclear or coal could be the economic choice based on coal price variation alone. The nuclear option has the most difficulty in competing with coal-fired plants in region 8 (North Central) where low-priced coal is available at most locations within the region. [Fuel costs could be minimized in other regions if the coal-fired plant were located at, or very close to, a mine. This situation can occur in all regions where significant coal reserves are present (regions 3 through 10). However,

Table 5.3 Regional range of levelized fuel costs for coal-fired plants[a]

	Region	Range on coal prices (mills/kWh)
I.	Northeast	24.7–32.5
II.	New York-New Jersey	17.5–27.8
III.	Mid Atlantic	15.5–26.5
IV.	South Atlantic	15.6–29.5
V.	Midwest	17.5–44.6
VI.	Southwest	12.7–30.0
VII.	Central	14.0–30.7
VIII.	North Central	8.7–22.7
IX.	West	12.7–30.1
X.	Northwest	20.1–26.8

[a]1986 dollars.

load centers are usually distant from coal mines, precluding utilities from taking advantage of the transportation cost savings.] In regions 1 through 5 and region 10 the reference BE nuclear plants have lower projected power generation costs than coal-fired plants even at the lowest coal-cost locations within these regions. The opposite is true if the ME (alternate or ME) capital investment costs persist for the nuclear option. These results (Fig. 5.4), using the same range of coal costs as before, indicate that in all but one region, even the highest-price coal cases are more economic than ME nuclear.

Table 5.4 compares the power generation costs (in both nominal and constant dollars) for only the reference case (region 5) and shows a 6-mills/kWh (constant dollars) advantage for BE nuclear plants.

5.2 ANNUAL CASH FLOW AND REVENUE REQUIREMENTS

The previous section of this report examined the economics of coal-fired and nuclear plants on the basis of 30-year levelized costs. This method of comparison is very useful when comparing the overall economics of these plants. An informative comparison of future plants, however, should also involve comparisons of projected year-by-year power costs

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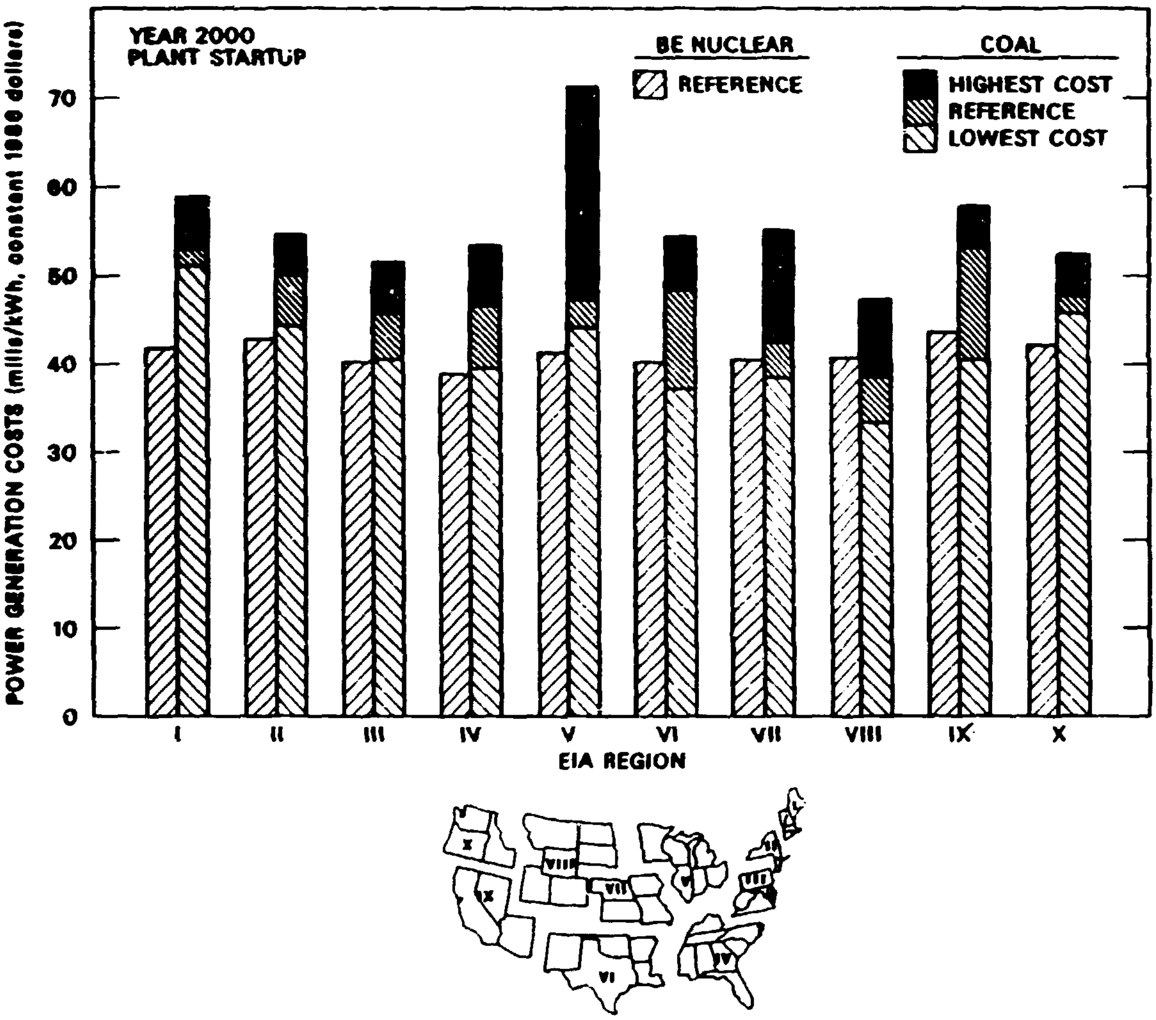

Fig. 5.3. Regional power generation costs for coal-fired plants reflecting regional variations in coal prices vis-à-vis power generation costs from BE nuclear plants.

and cash flows of competing plants. Annual power costs are based on the revenue requirements; cash flow measures actual cash transactions of the utility. These types of comparisons are sometimes more important to utilities than those based on levelized costs. Annual revenue requirements and cash flow methods were discussed in Sect. 3.1 and are described in detail in the NECDB.[4]

The annual revenue requirements are defined as the year-by-year revenues needed by the utility to pay all costs resulting from the project, including the return on investment and return of investment.

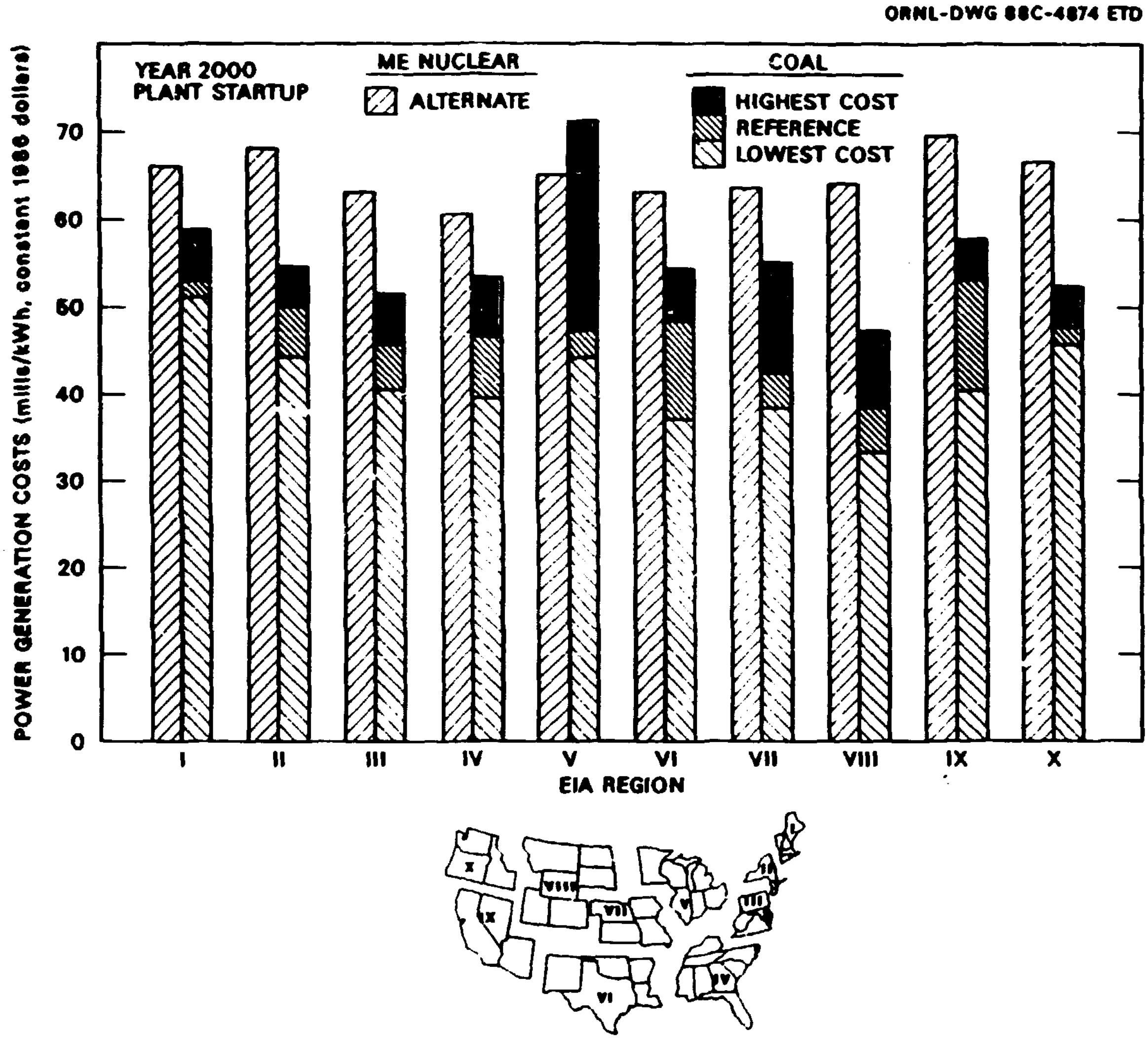

Fig. 5.4. Regional power generation costs for coal-fired plants reflecting regional variations in coal prices vis-à-vis power generation costs from ME nuclear plants.

Comparisons of the revenue requirements for the coal and BE nuclear options in the midwest region are shown in Fig. 5.5 in nominal dollars and in Fig. 5.6 in constant dollars.

Tables D.1-D.3 in Appendix D give the revenue requirements breakdown for BE nuclear plants in both nominal and 1986 constant dollars. Tables D.4-D.6 give the same revenue requirements breakdown for coal-fired plants. These data are for the midwest reference case.

Because of the high capital-related costs, the revenue requirements of capital-intensive projects, such as nuclear plants, are initially

Table 5.4. Power generation costs of base-load plants located in region 5 (Midwest)[a]

Unit cost component	BE nuclear		Twin-unit coal	
	Constant 1986 $	Nominal $	Constant 1986 $	Nominal $
Capital	26.4	89.9	20.6	70.2
O&M	7.3	24.9	5.9	20.1
Fuel	7.0	23.9	20.7	70.8
Decommissioning	0.6	2.2	0.1	0.4
Total	41.3	140.9	47.3	161.5

[a] Mills/kWh.

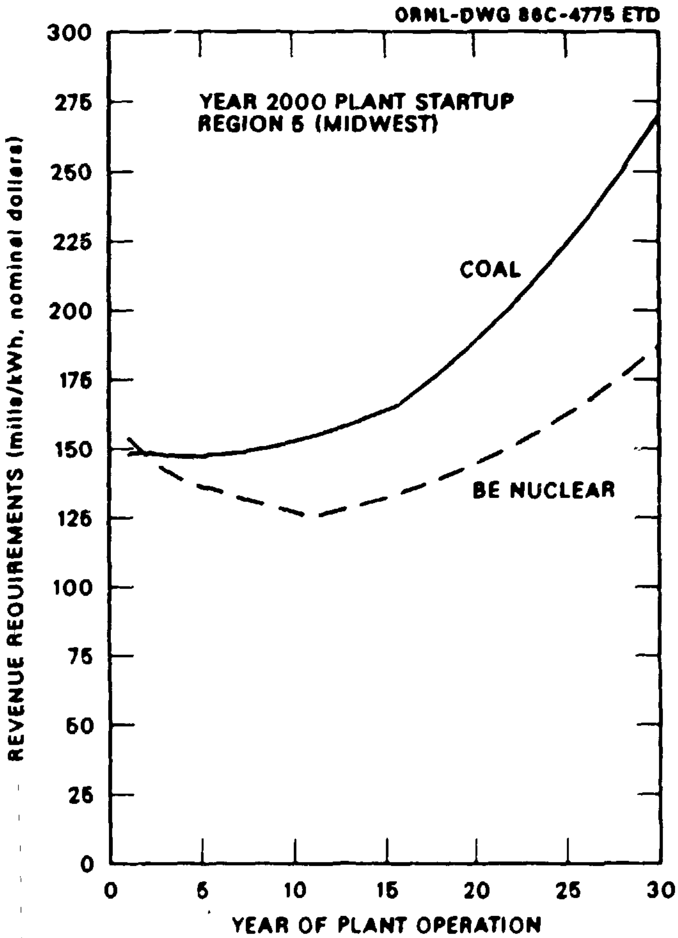

Fig. 5.5. Nominal-dollar revenue requirements for reference case power plants: BE nuclear and coal.

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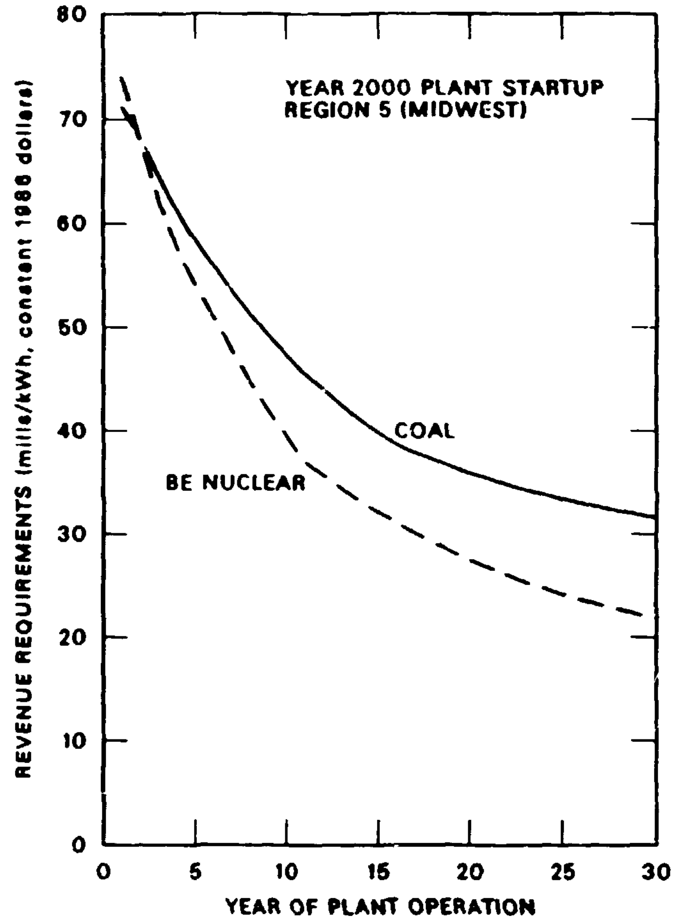

Fig. 5.6. Constant-dollar revenue requirements for reference case power plants: BE nuclear and coal.

very high. Even when expressed in nominal dollars, annual revenue requirements decrease in the early years because the capital-related charges dominate. The capital-related charges are reduced because of amortization of the plant. Eventually, increasing O&M and fuel costs will dominate, causing revenue requirements to increase. For the nuclear option the required return on capital composes the largest portion of the capital-related charges but becomes less important as plant investment costs are amortized.

Less capital-intensive projects, like coal-fired plants, exhibit lower initial revenue requirements, but because of escalation of fuel costs, the annual nominal-dollar revenue requirements can increase at a more rapid rate than the nominal-dollar revenue requirements for nuclear

(Fig. 5.5 and Tables D.3 and D.6). In the reference midwest region, the coal costs compose ~29% of the first-year revenue requirements and rapidly increase their contribution. At the end of plant life, coal costs make up ~66% of the total revenue requirement, compared with a fuel cost of 48% for nuclear. This fact points out that coal-fired plants are subject to uncertainties in fuel price to a greater degree than nuclear. Therefore, the electric rates of those utilities with coal-fired plants are more vulnerable to changes in fuel price.

The comparison of revenue requirements of the two options, as expressed in constant 1986 dollars, is shown in Fig. 5.6 and Tables D.3 and D.6 for the midwest region. In this region, the first-year revenue requirements are ~4% less for the coal-fired plant. The differential decreases rapidly so that during the second year of operation, the revenue requirements from both options are equal. This break-even point will be different in other regions, however. After break-even occurs, the annual power costs of the BE nuclear plant become increasingly less than those of the coal-fired plant. By the thirtieth year the revenue requirements for BE nuclear are 31% less than those for coal.

To ease the impact on customer rates of placing a nuclear or coal-fired plant into the rate base, some public utility commissions are considering a gradual phase-in of the plant investment. This will lower the power costs in early years but raise them later. In other words, the gradual phase-in of a nuclear plant will mitigate the rate shock phenomenon but will not affect the overall economic comparison of these plants if the phase-in is done in a manner consistent with engineering economic principles.

A cash-flow analysis provides valuable information regarding the actual year-by-year net cash transactions that are projected to occur. While the year-by-year revenue requirements indicate the impact of the plant on rates and, therefore, the consumer, the year-by-year cash flow indicates the effect of the plant on the cash requirement of the utility.

Cash receipts result in positive cash flows, and cash payments result in negative cash flows. Net cash flows are negative during the construction period when capital investment payments are made.

Investment tax credits reduce taxes and, therefore, result in positive net cash flows. The net cash flow becomes positive after plant startup because revenues in excess of expenses are being collected. Negative cash flow indicates a need to raise capital, and a positive cash flow shows money is available for debt repayment or internal growth.

The annual cash flows for the BE nuclear and coal options in region V (Midwest) are shown in Fig. 5.7 in nominal dollars. The tabulated data appear in Appendix D in Tables D.7 and D.8 for both BE nuclear and coal, respectively, in nominal dollars. This information can be used to assess the financial risk of constructing a project. In Fig. 5.7 both plants show a decrease in net cash requirements just before plant startup because the full investment tax credit is taken at

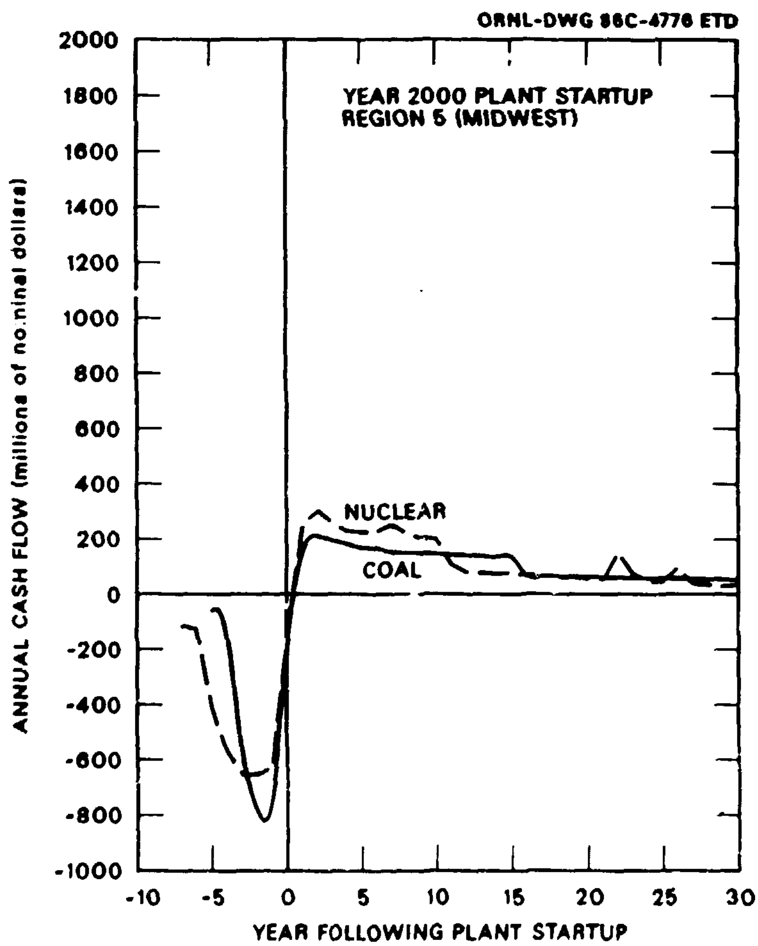

Fig. 5.7. Annual cash flows for reference case power plants: BE nuclear and coal.

this time. The spikes that occur in the nuclear-plant cash-flow curve are due to the uneven distribution of nuclear fuel investments. The large cash-flow requirements of either type of plant during construction may be difficult to manage because of the long lead time before revenues are received; this is especially true for nuclear plants with long lead times. The advantage of reducing the lead time is twofold. First, the total capital investment will be reduced as a result of manpower and other savings. Also, and perhaps even more important, would be the effect of reducing the overall financial risk by shortening the time between initial cash outlays and the time when revenues are received.

6. POWER GENERATION COST SENSITIVITY STUDIES: JUSTIFICATION FOR LEVCOST MODEL INPUT VARIABLE RANGES

As a prelude to both types of sensitivity analysis (SVSS and MVSS), plausible uncertainty ranges for each input variable must be defined. Appendix C explains the mathematical methodology that uses these ranges, and Chaps. 7 and 8 present the results for, respectively, the SVSS and MVSS analyses.

6.1 DEFINITION OF RANGES

A range is essentially defined by its boundaries (i.e., by a low and high value). These end points (low and high) can be thought of as the most-optimistic and most-pessimistic (or vice versa) input values for each parameter.

The low, reference, and high values for the probability distribution for each variable considered for the nuclear and coal-fired plant models are shown in Table 6.1. Financial variables, such as inflation rate and cost of money, are assumed to have the same ranges for each technology.

The ranges of values shown in Table 6.1 are the current opinion of the authors and have their basis in the information contained in the NECDB.[4] A discussion of these input variables follows. The variables are classified into three categories: financial, nuclear plant, and coal plant.

6.2 FINANCIAL VARIABLES

6.2.1 Inflation Rate

The reference long-term average inflation rate is estimated to be 5%/year. Although the inflation rate may temporarily fall below 2%, as was experienced during the recent rapid decline in oil prices, it is highly unlikely that the long-term average rate will be less than the 2% rate last seen in the early 1960s. The average inflation rate between 1973 and 1981 was ~8%/year; this was a period of rapid oil price

Table 6.1. Uncertainty input ranges

Variable	Low value	Baseline value	High value
	Financial		
Inflation rate, %/year	2	5	8
Real cost of money, %/year	1	3.8	7
Real escalation during construction, %/year	−1.5	0	2
Real O&M cost escalation, %/year	−1	0	2
	BE nuclear plant[a]		
Overnight cost, $M	1100	1600	2700
Capacity factor, %	55	70	85
Fuel cost components			
Ore, $/lb U_3O_8	15	34	50
Real ore escalation, %/year	0	1.0	2
Conversion, $/kg U	5	8	10
Enrichment, $/SWU	30	60	110
Fabrication, $/kg HM	160	240	300
Waste disposal, mills/kWh	0.75	1.0	2.0
O&M cost, mills/kWh	4	7.3	12
Decommissioning cost, mills/kWh	0.3	0.6	1.5
Project lead time, years	5	8	12
	Coal plant[a]		
Overnight cost, $M	1000	1305	1600
Capacity factor, %	55	70	85
Fuel cost (coal), $/MBtu	1.40	1.60	2.20
Real coal-cost escalation, %/year	0	1.0	2.0
O&M cost, mills/kWh	3	5.9	8
Decommissioning cost, mills/kWh	0	0.1	0.2
Project lead time, years	3.5	6	8.5

[a]All input costs in constant 1986 dollars.

increases. It is highly unlikely that inflation will proceed at this rate or higher on a long-term, sustained basis. A range of 2 to 8%, symmetric at ~5%/year, was selected here.

6.2.3 Real Cost of Money

The real, long-term, after-tax (tax-adjusted) cost of money to be used in analyses for electric utilities was estimated to be 3.8%/year for the reference case. This rate is 9%/year, including the 5% inflation rate (nominal cost of money). There are differences of opinion on what this rate of return should be, and there are variations from utility to utility. The 1 to 7%/year range represents the outer range of what a utility should receive in the long run to keep economically sound while, at the same time, provide its customers power at a reasonable price.

6.2.4 Real Escalation Rate During Construction

The rate of change, or escalation rate, in power-plant construction costs can be divided into three components: the contribution as a result of the general inflation rate as measured by the gross national product (GNP) implicit price deflator; the contribution as a result of real changes in the costs of labor, equipment, and materials; and the contribution as a result of changes in scope, resulting from regulatory requirements and design changes. Inflation is removed in the real escalation rate. Cost increases caused by future regulatory changes are not included because regulatory reform is expected to reduce changes in scope to a minimum. Since 1980 the average rate of change in the market basket or mix of commodities used for coal-fired and nuclear plant construction has been about the same as, or slightly less than, inflation. This is the basis of the 0%/year baseline value for the real escalation rate during construction. The low value of -1.5%/year assumes that improvement in productivity will be made. The 2%/year high value assumes that construction labor rates rise faster than warranted by inflation and productivity increases and that commodity prices also increase faster than inflation, as occurred during the 1970s. The upper range does not include any major regulatory ratchetting.

6.2.5 Operation and Maintenance Cost Real Escalation Rate

The O&M cost escalation rate is assumed to be the same for both nuclear and coal-fired plants. In the recent past, O&M costs have been rising at a rate greater than inflation. The baseline value of zero real escalation rate is consistent with the basic premise of the analysis that the current problems in the nuclear industry will be solved. Under such circumstances there is no reason why nuclear O&M costs should escalate faster than inflation. The low range of -1%/year assumes gradual productivity and management improvements. The 2%/year upper rate assumes real cost increases for labor and materials.

6.3 NUCLEAR PLANT VARIABLES

6.3.1 Nuclear Plant Overnight Capital Investment Cost

The baseline or reference capital investment cost is for the pressurized water reactor (PWR) BE plant developed for the EEDB-VII[9] by UE&C. The UE&C costs were adjusted to 1986 dollars, an 1100-MW(e) plant size, a Chicago vicinity site, and the inclusion of land and owners' costs. This is the reference nuclear plant cost for the 1986 NECDB.[4]

The BE plant is a step in the right direction but does not include many of the innovations and productivity improvements that could reduce costs further. [These are being considered in current studies by Department of Energy (DOE), Electric Power Research Institute (EPRI), and others.] The low value of $1100 million is speculated to be close to a minimum overnight cost for large PWRs. The $2700 million maximum is the cost of an ME PWR from EEDB-VII, as adjusted for the 1986 NECDB.[4] We estimate that this would be the upper cost range if things go wrong, even with regulatory reform.

6.3.2 Capacity Factor

Although nuclear-plant capacity factors today are averaging ~60%, the resolution of operating and regulatory problems being experienced today should result in routine capacity factors of 70% or better by the year 2000. The 55 to 85% end points span the range from the low average values for the last few years to the best of today's U.S. and foreign experience.

6.3.3 Uranium Price

The current contract price for uranium is about \$34/lb of uranium ore (U_3O_8), the baseline price in the analysis. The spot market price has gone as low as \$15/lb, and this is taken as the minimum price. The \$50/lb ore price used as the high price is near the maximum price reached by uranium ore in the late 1970s. Projections of ore-price costs are shown in Fig. 4.1 and discussed in detail in the NECDB.[4]

6.3.4 Uranium Ore Price Escalation

A 1%/year real uranium ore price escalation is recommended as the baseline or reference value. This escalation rate assumes some depletion of ore reserves and recovery of the current depressed market. The low value of 0%/year assumes continuing discovery of uranium reserves, together with only moderate to negligible nuclear orders. The high value, 2%/year, assumes a moderate to strong nuclear power recovery and/or limited new ore discoveries.

6.3.5 Conversion Price

A primary market price for conversion of \$8/kg is used as the baseline or reference cost. The \$5 to \$10/kg low-value-to-high-value range is slightly wider than the \$6 to \$9/kg range indicated in a utility survey [Stoller Corp. for Electric Power Research Institute (EPRI)],[18] adjusted to 1986 dollars.

6.3.6 Enrichment

The baseline, average enrichment price in the post-year-2000 period is estimated to be \$60/SWU in 1986 dollars, based on DOE projections (Fig. 4.2). The low value of \$30/SWU is based on the low range of the projections of enrichment costs from the AVLIS process. The high value of \$110/SWU assumes that DOE's currently announced prices for the U.S. contract are not reduced further. Enrichment prices are assumed to escalate at the rate of inflation (zero real escalation rates).

6.3.7 Fuel Assembly Fabrication

The \$240/kg baseline nuclear fuel fabrication cost is for high (50-MWd/kg) burnup fuel. It is the reference cost in the NECDB[4] and is consistent with the range of current fabrication costs with a slight surcharge for the extended burnup. The \$160 to \$300/kg range from low to high value is consistent with the Stoller survey[18] for LWR fuel with a slight surcharge for extended burnup.

6.3.8 Waste Disposal

The current waste disposal charge, 1 mill/kWh, is subject to detailed periodic analysis and may be adjusted from time to time, subject to congressional review, to meet projected program costs. The baseline value is taken as the 1 mill/kWh current charge. It is assumed that these charges during the post-2000 period could be as low as 75% of the baseline or as high as double the baseline cost.

6.3.9 O&M Cost

There is a wide distribution in O&M costs of existing plants. The reference baseline value of 7.3 mills/kWh was calculated using the OMCOST, O&M costing procedures. Four to 12 mills/kWh is the range observed from reported 1983 O&M costs for 17 single-unit nuclear plants after adjustment for capacity factor and plant size [reference size = 1100 MW(e)] and to 1986 dollars.

6.3.10 Decommissioning Cost

The baseline decommissioning cost of 0.6 mill/kWh is based on a \$140 million (1986 dollars) cost for decommissioning a nuclear plant. The 0.3-mill/kWh low value factors in both a lower cost for the actual decommissioning and improvements in the tax treatment of the decommissioning fund. The high value of 1.5 mills/kWh contains provision for sharply higher decommissioning costs of \$250 million and for adverse decisions on the nature of the sinking fund.

6.3.11 Nuclear Project Lead Time

The baseline BE total licensing and construction lead time is 8 years, as recommended in the NECDB as an intermediate goal.[4] This figure represents what could be done on a consistent basis if regulatory reforms are enacted and construction practices improved, which is a ground rule for this study. The 5-year low value is consistent with what is now being done in some foreign countries and is a reasonable lower limit, considering increased modularization and factory fabrication, standardization of design, and improved construction practices. The 12-year upper limit is typical of today's plant construction experience.

6.4 COAL PLANT VARIABLES

6.4.1 Coal-Fired Plant Overnight Capital Investment Cost

The coal-fired plant costs are for two 550-MW(e) units on the same site. This gives the same net capacity (1100 MW(e)] as the single-unit nuclear plant with which it is being compared. The costs are based on the EEDB-VII cost models developed by UE&C for high-sulfur, coal-fired plants.[4] The reference overnight cost is $1.305 billion (1986 dollars) for the two 550-MW(e) units. Coal-fired plants are a mature technology showing less variation in cost among plants than nuclear plants show. A range between low- and high-cost values of $1.0 to $1.6 billion (±23%) is assumed for the coal-fired plant overnight costs.

6.4.2 Capacity Factor

The reference capacity factor and capacity factor range for the coal-fired plants were assumed to be the same as for nuclear plants. Historically, coal-fired plants have shown a slightly better availability than nuclear plants. Some of the improvements resulting in higher capacity factors for nuclear plants should be applicable to coal-fired plants and vice versa, thereby closing the gap and giving similar capacity factors for both types of units.

6.4.3 Coal Cost

The baseline coal cost is derived from the average cost of high-sulfur coal in the midwest region for the fourth quarter of 1985. The low-to-high-value range is the approximate range of prices paid for all coal in the region.

6.4.4 Real Coal Cost Escalation Rate

The reference value for the real coal cost escalation rate is 1%/year, based on projected coal prices for the year 1990–2010 given in the *National Energy Policy Plan Projections to 2010*.[13] This rate is very important in estimating costs from future coal plants because the fuel cost can be the principal contributor to the power generation cost. Typically, the projected value of the coal price escalation rate falls in the range from 0 to 2%/year, which we use in this study.

6.4.5 Coal-Fired Plant Operation and Maintenance Costs

The baseline O&M cost of 5.9 mills/kWh is derived from the OMCOST code for high-sulfur, coal-fired plants. There is a wide variation in the O&M costs for existing coal-fired plants. Because most existing plants do not have scrubbers, their O&M costs are considerably lower than those calculated by OMCOST, which includes both scrubber costs and a general and administrative cost, not usually reported under O&M for existing plants. A range of 3 to 8 mills/kWh is assumed.

6.4.6 Coal Plant Decommissioning Cost

The baseline decommissioning cost for coal-fired plants is based on an Arkansas Power & Light study.[15] This cost contributes ~0.1 mill/kWh to the levelized power cost with a range of 0 to 0.2 mill/kWh assumed.

6.4.7 Coal-Fired Plant Project Lead-Time

The most probable baseline licensing and construction lead time is 6 years, as recommended in the NECDB.[4] This is typical of large, coal-fired-plant projects. As with nuclear plants, there is a variation in the length of the design and construction time of a coal-fired plant. A value range from low to high of 3.5 to 8.5 years is assumed.

7. POWER GENERATION COST SINGLE-VALUE SENSITIVITIES

7.1 POWER GENERATION COST AND CAPITAL INVESTMENT COST SENSITIVITIES: FINANCIAL VARIABLES

The sensitivity of nuclear-plant and coal-fired-plant power generation and capital investment costs to changes in individual financial parameters was examined using the LEVCOST computer code. These parameters include inflation rate, cost of money, cost-escalation rate during construction, and escalation of O&M costs. As each parameter was varied over the end points of its range (Chap. 6), all other parameters were held constant at their reference values, including the BE overnight cost for nuclear. Capital investment cost sensitivities are considered for the cost-of-money and escalation-during-construction variables only. Unless indicated, all costs are expressed in 1986 constant dollars.

7.1.1 Inflation Rate

The general inflation rate is assumed to apply to all costs and is the variable used to convert between nominal and constant dollars. If a cost escalates at a rate different than the general inflation rate, the real escalation rate applicable to that cost is such that the total escalation rate is expressed as

$$(1 + g) = (1 + r)\ (1 + i)\ ,$$

where

g = the overall rate of cost change (including inflation),

r = the real or differential cost escalation rate,

i = the general inflation rate as measured by the GNP implicit price deflator.

Figure 7.1 shows the sensitivity of constant dollar power generation costs to the general inflation rate for both coal and nuclear plants. As one would expect, the curve is relatively flat because of the use of constant dollars on the ordinate scale. The small slope that appears is attributable to the fact that depreciation is based on initial capital investment and is not inflated. (Tax depreciation

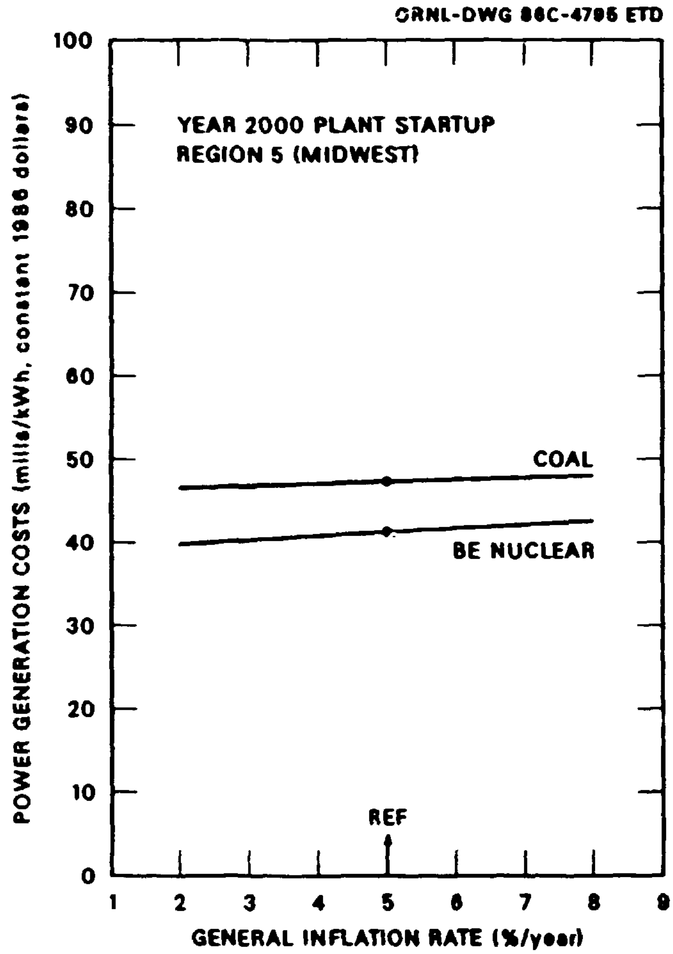

Fig. 7.1. Sensitivity of constant-dollar power generation costs to general inflation rate for BE nuclear and coal-fired plants.

schedules are calculated in nominal-dollar terms.) Because nuclear is more capital intensive and nuclear fuel is also capitalized, the depreciation-related effect is more pronounced, thus the greater sensitivity when compared with coal.

If the ordinate scale is expressed in nominal dollars, as in Fig. 7.2, the effect of inflation becomes starkly evident (i.e., power generation costs show an exponential rise with the inflation rate). The rate of increase is nearly the same for both coal and nuclear. The small difference can again be explained by the noninflation of depreciation and the relative capital intensity of each power option.

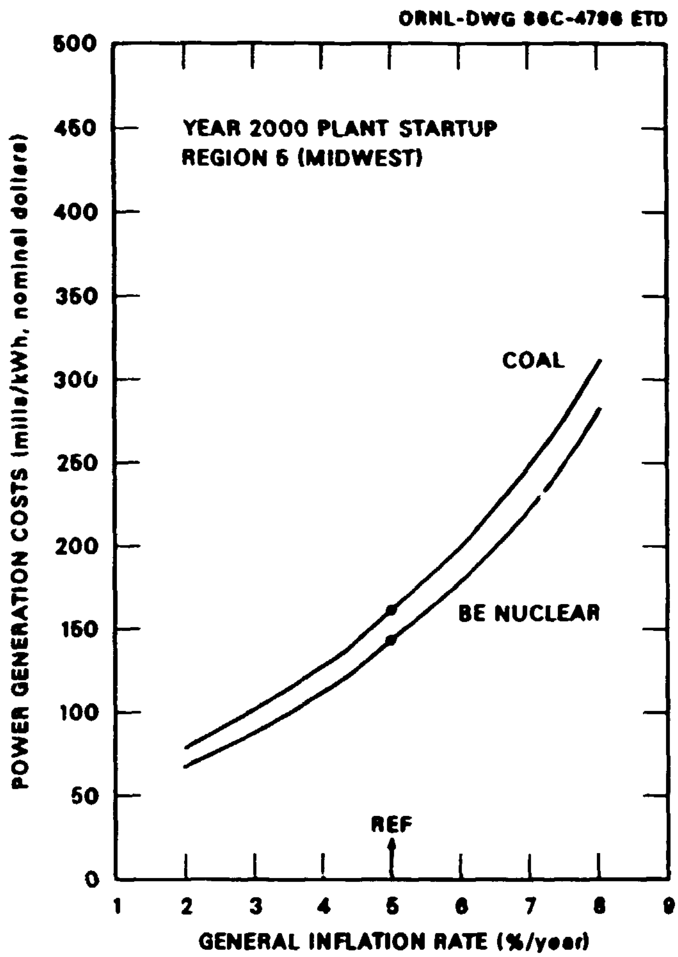

Fig. 7.2. Sensitivity of nominal-dollar power generation costs to general inflation rate for BE nuclear and coal-fired plants.

7.1.2 Interest Rate (Cost of Money)

A change in the cost of money will make an impact on the capital investment costs through its effect on the fixed charge rate and the interest rate during construction. Nuclear-fuel costs are also affected by the cost of money because costs related to fuel procurement and fabrication are capitalized. Because it is the more capital intensive, the nuclear option is affected more by a change in the cost of money than is the coal-fired option.

Utility investors must be compensated for the use of both their debt and equity investment capital during the construction period. AFUDC is a charge made against construction work in progress to compensate these investors. In this analysis, these funds are capitalized and included in the utility's rate base at the time of commercial operation. During operation the utility will recover these funds from its customers through depreciation charges. The Federal Energy Regulatory Commission (FERC) Uniform System of Accounts segregates AFUDC into two components, borrowed funds and other funds. The reference average annual interest rate during construction contains both a return on borrowed and equity funds and is the tax-adjusted cost of money, 9.0%/year (nominal) or 3.8%/year (real).

As shown in Table 4.3, estimated interest during construction (or AFUDC) can be very large. The nuclear plant's AFUDC amounts to \$1.1 billion by the time of commercial operation or ~29% of the total plant investment costs. The AFUDC for the coal-fired plant amounts to \$600 million or 20% of the total investment costs. The smaller quantity for the coal-fired plant, relative to the nuclear plant, is due to the shorter design and construction period.

Figures 7.3 and 7.4 show the sensitivity of the constant-dollar power generation cost and the constant-dollar total capital investment costs to variations in the interest rate, both nominal and real. The power generation costs for the nuclear and coal-fired plant are estimated to change ~11 and 6%, respectively, for each one percentage point change in the interest rate, compounded annually. The total capitalized investment costs for the nuclear and coal-fired plant are estimated to change ~3.9 and 2.6%, respectively, for each one percentage point change in the interest rate. Coal-fired plant costs are less sensitive to changes in interest rates than nuclear costs because of the shorter design and construction period.

Investment risk, as perceived by the financial community, affects the cost of money for a project. These figures can be used to quantify the impact on the comparative results if one project is perceived as being riskier than the other. For example, if the nuclear option has a 0.5% higher after-tax cost of money than coal, then nuclear generation costs would increase by ~6% over the reference value.

7.1.3 Escalation Rate During Construction

The sensitivities of the estimated power generation costs and estimated capital investment costs to changes in the escalation rate for

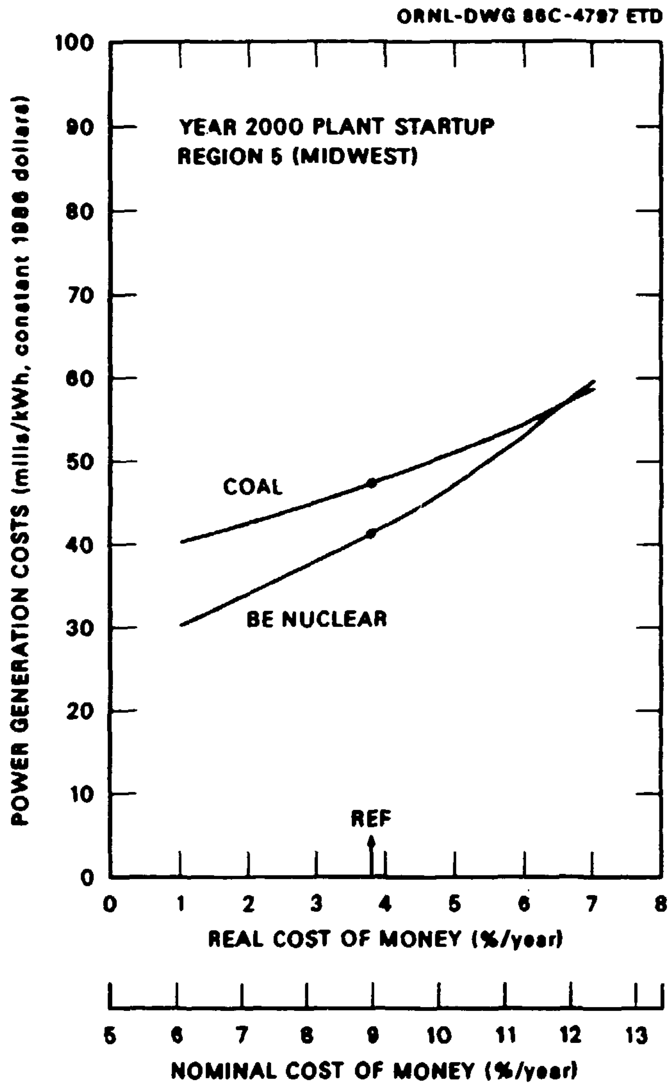

Fig. 7.3. Sensitivity of constant-dollar power generation costs to cost-of-money for BE nuclear and coal-fired plants.

construction costs during the preoperation period are shown in Figs. 7.5 and 7.6, respectively. As expected, this sensitivity to escalation rate is more pronounced for the capital costs alone (Fig. 7.6). The total capitalized costs for the nuclear and coal-fired plants are estimated to change ~10.4 and 11.8%, respectively, for each one percentage point change in the escalation rate, compounded annually. Power generation costs change by ~6.6 and 5.2%, respectively, for the same one-percentage-point change. Capital investment costs for the coal-fired plant are more sensitive to escalation rate because the capital

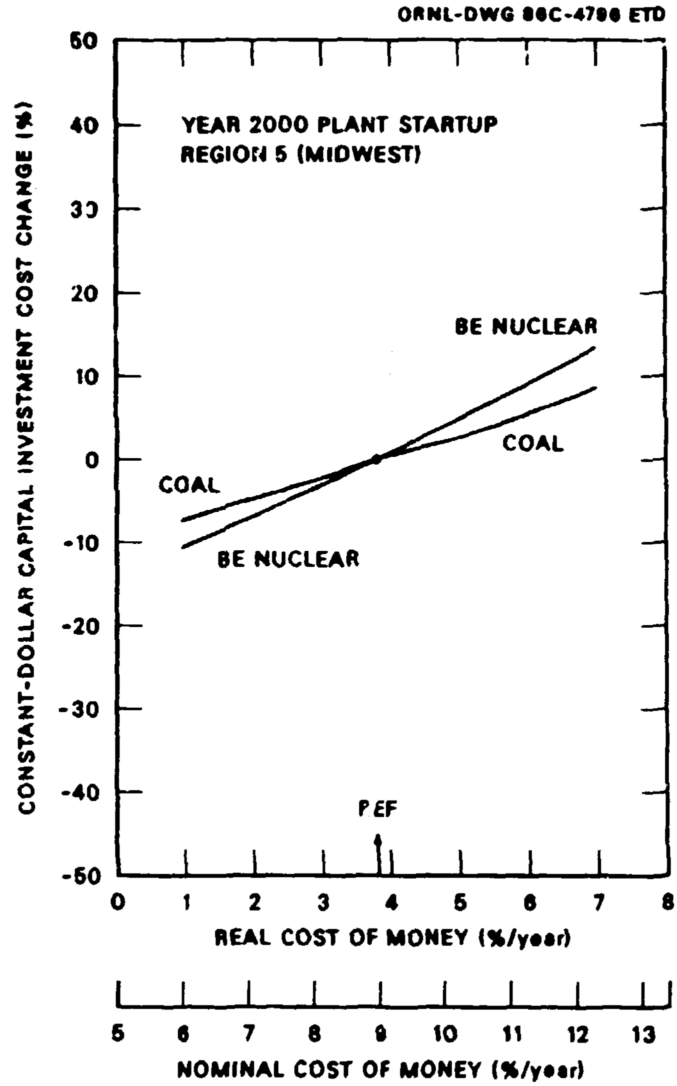

Fig. 7.4. Sensitivity of constant-dollar capital investment costs to cost-of-money for BE nuclear and coal-fired plants.

expenditures occur later in time, relative to a nuclear plant, for a common operation date (year 2000).

7.1.4 Escalation Rate for Operating and Maintenance (O&M) Costs

Figure 7.7 shows the sensitivity of constant-dollar power generation costs to the real escalation rate for both coal and nuclear-plant O&M costs. This financial parameter does not affect capital investment; therefore, no capital-cost sensitivity is shown. A percentage-point change in the O&M real escalation rate (from its reference value of 0%

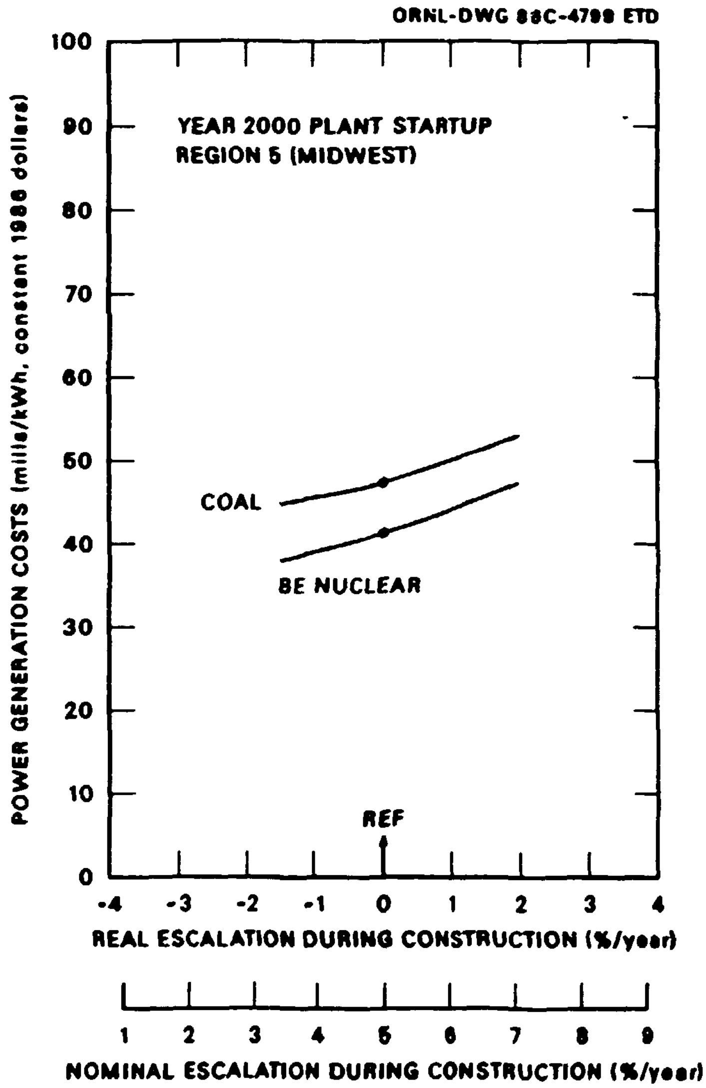

Fig. 7.5. Sensitivity of constant-dollar power generation costs to escalation rate during construction for BE nuclear and coal-fired plants.

for both options) results in a 5.5 and 3.8% change in the power generation costs for both nuclear and coal, respectively. Because the O&M cost component constitutes a slightly greater fraction of the total levelized power generation costs for nuclear, the sensitivity of the nuclear option to an increase in O&M escalation is slightly greater.

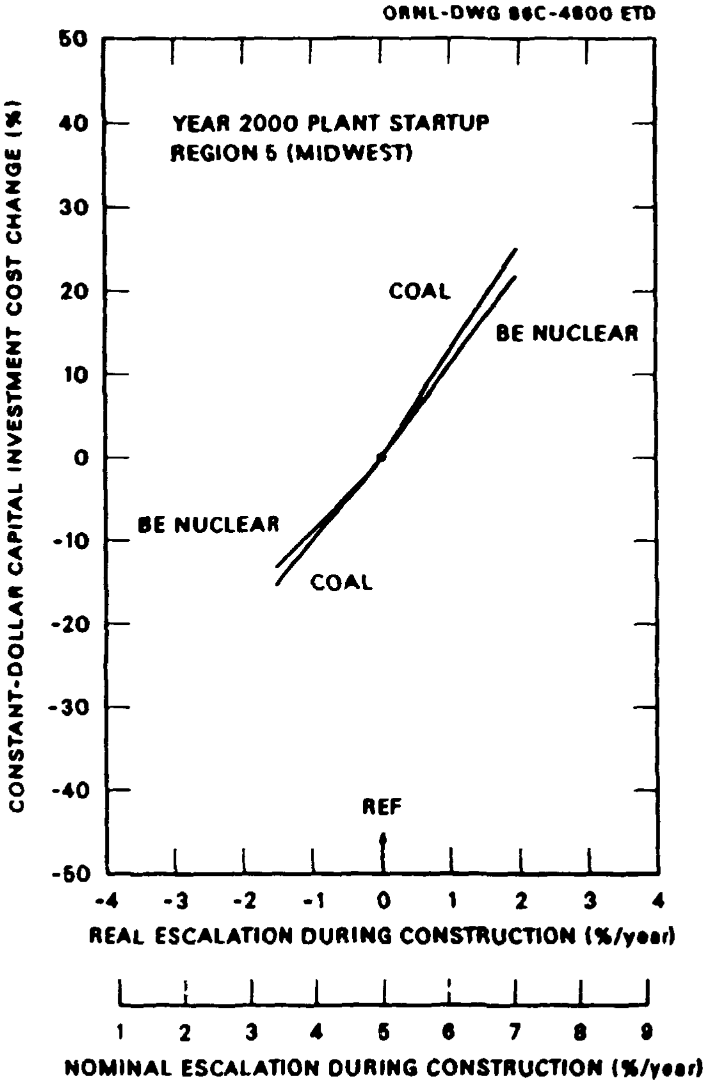

Fig. 7.6. Sensitivity of constant-dollar capital investment costs to escalation rate during construction for BE nuclear and coal-fired plants.

7.2 POWER GENERATION COST AND CAPITAL INVESTMENT COST SENSITIVITIES: COST COMPONENTS COMMON TO BOTH OPTIONS AND CONSTRUCTION SCHEDULES

This section examines the effects on the total power generation costs of changes in the cost components common to both options. The effects of altering the lead times (licensing, design, and construction period) for each option are also considered. Capital-cost sensitivities are presented for these schedule-related SVSSs only.

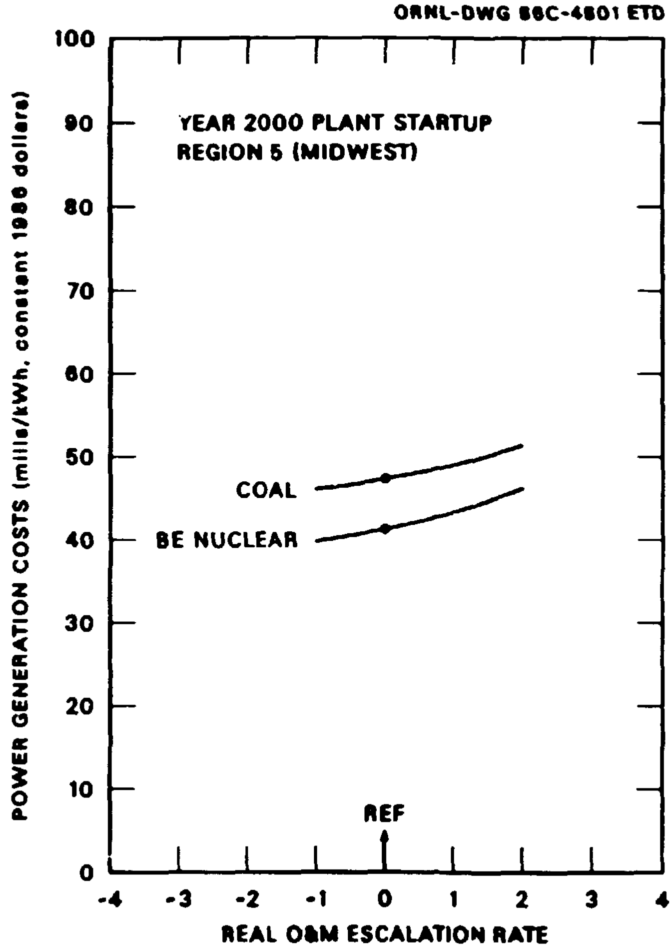

Fig. 7.7. Sensitivity of constant-dollar power generation costs to real escalation of plant operation and maintenance (O&M) costs for BE nuclear and coal-fired plants.

7.2.1 Overnight Cost

Figure 7.8 illustrates the impact on power generation cost from changes in the overnight cost for both options. An increase in the overnight costs of these power plants could result from technology-driven reasons, such as generic design changes resulting from more-stringent environmental or safety regulations. Nuclear costs are more sensitive to investment cost variations because nuclear plants are more capital intensive than are coal-fired plants. The sensitivity of power costs to each ten-percentage-point change in overnight cost is 6.4% for nuclear and 4.4% for coal. These sensitivities can be used to study how changes in investment cost affect the comparison. For example, if the

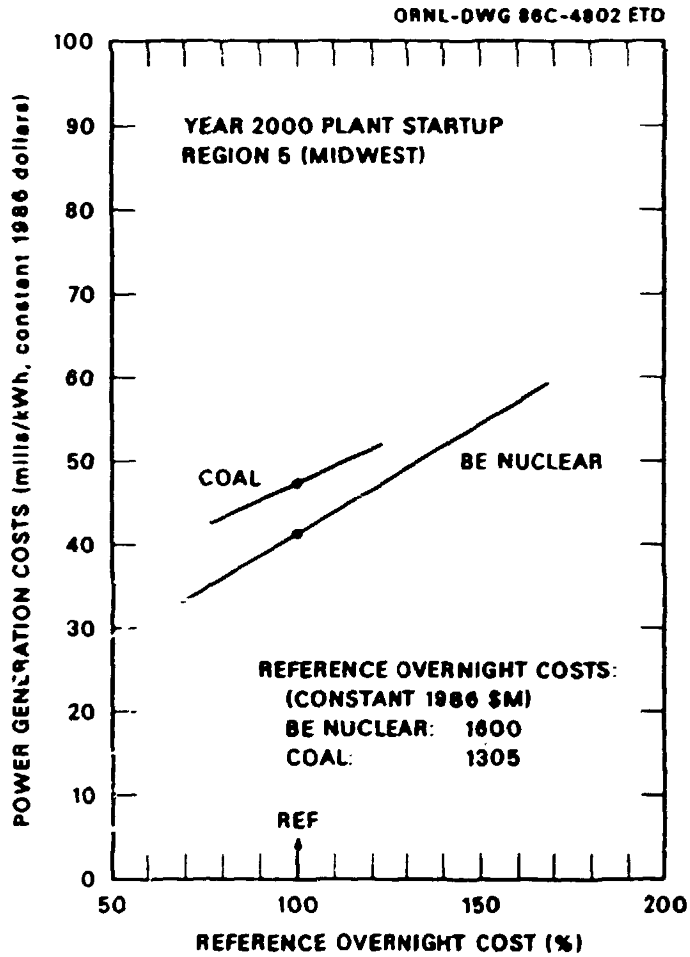

Fig. 7.8. Sensitivity of constant-dollar power generation costs to overnight plant costs for BE nuclear and coal-fired plants.

nuclear overnight cost is 23% higher than its reference BE value and the coal plant overnight cost remains at its reference value, then the generation costs in the midwest region from the coal and nuclear options would be equal.

7.2.2 Sensitivity to Capacity Factor

Figure 7.9 shows how variations in the average plant capacity factor affect the power generation cost of coal and nuclear plants. Lower-capacity factors work to the detriment of the more capital-intensive generation option (i.e., nuclear). As higher-capacity factors are achieved, the difference between the coal and nuclear power generation cost increases, making nuclear even more favorable. The cost leverage

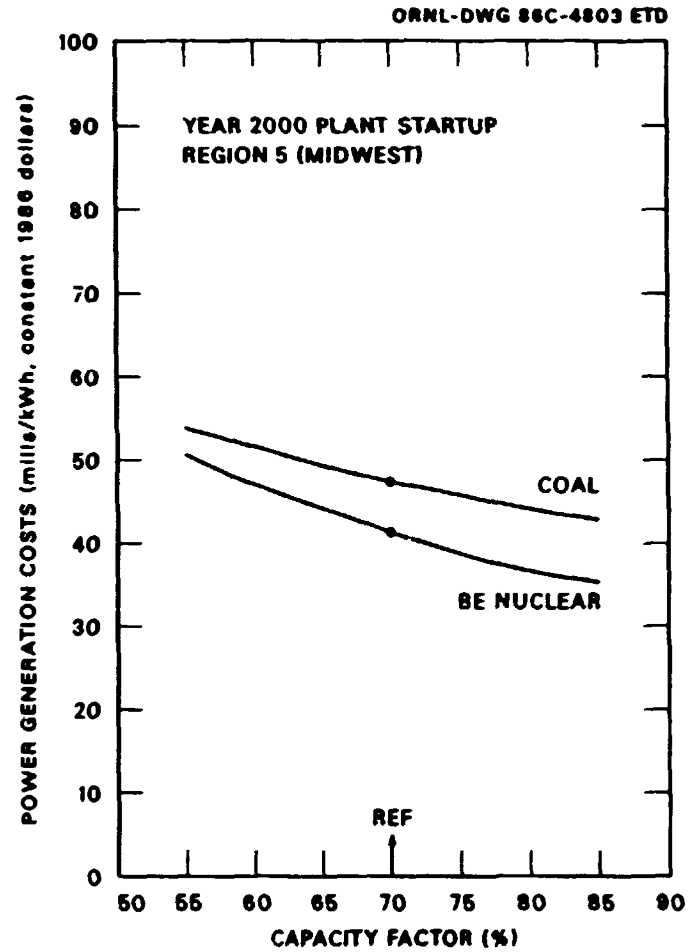

Fig. 7.9. Sensitivity of constant-dollar power generation costs to plant capacity factor for BE nuclear and coal-fired plants.

of capacity factor is very high for both options. A five-percentage-point improvement in capacity factor decreases the coal and nuclear power generation costs by 3.4 and 5.5%, respectively.

7.2.3 O&M Costs

Figure 7.10 shows how altering the coal and nuclear O&M costs from their reference values affects the power generation costs. Because the reference nuclear O&M costs constitute a higher fraction of the overall levelized cost than for coal, a given percentage variation in nuclear O&M costs has a slightly greater effect on the nuclear power generation costs than for coal.

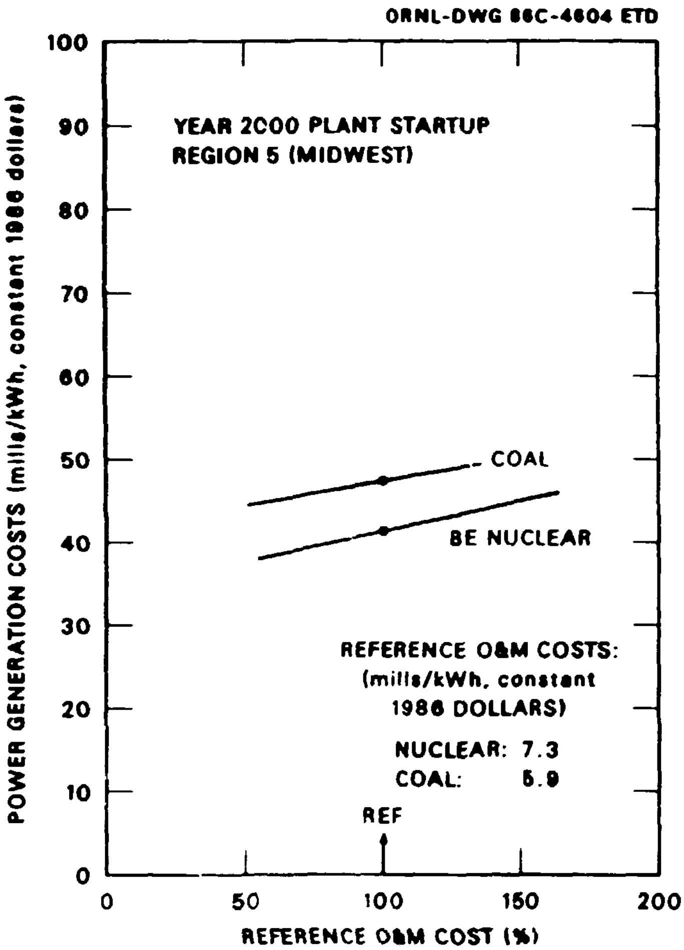

Fig. 7.10. Sensitivity of constant-dollar power generation costs to operation and maintenance (O&M) cost component for BE nuclear and coal-fired plants.

7.2.4 Decommissioning Costs

Decommissioning costs represent very small fractions (0.2 and 1.5%, respectively) of the reference power generation costs for both coal and nuclear. For this reason, the sensitivity curves (Fig. 7.11) for both are rather flat. The nuclear curve shows a greater slope because decommissioning costs constitute a larger fraction of the overall power generation cost for nuclear than for coal.

7.2.5 Fuel-Price Escalation Rate

The sensitivities of power generation costs to both real coal price and real price escalation are given in Fig. 7.12. Uranium and coal price trends may move in opposite directions if one option becomes

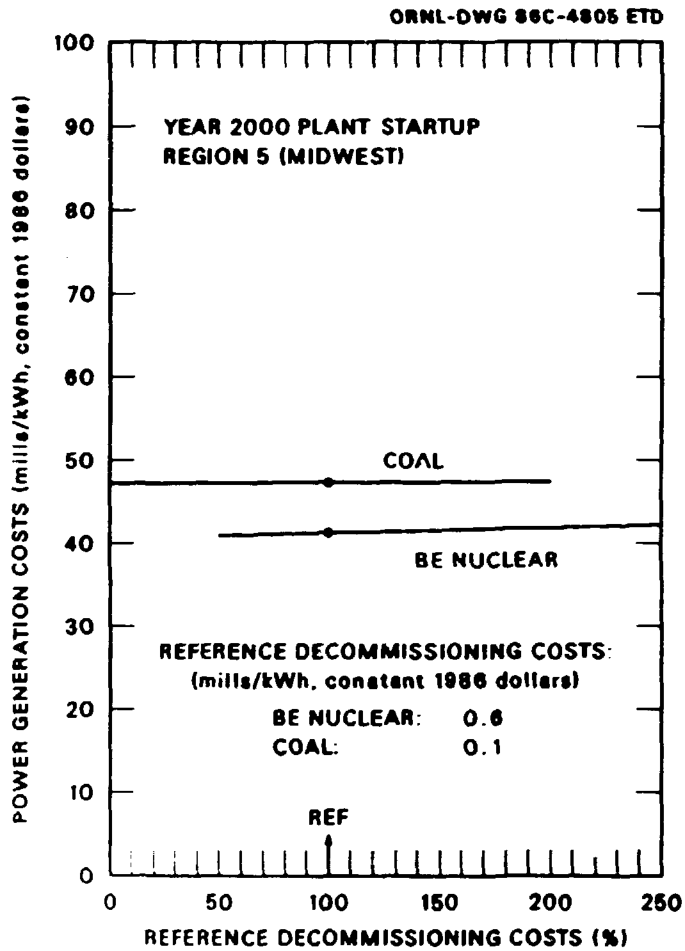

Fig. 7.11. Sensitivity of constant-dollar power generation costs to decommissioning cost component for BE nuclear and coal-fired plants.

dominant; however, general economic conditions should cause the escalation rates of coal and uranium to move in unison. Figure 7.12 demonstrates that coal-fired-plant power costs are more sensitive than nuclear-plant power costs to fuel-price escalation. A 1/2% increase in the escalation rate causes the nuclear power generation cost to increase by 1.2% and the coal power generation cost to increase by 6.4%. This behavior is explainable by the fact that fuel costs constitute a larger fraction of the overall coal-fired-plant power generation costs. Because of the implications of Fig. 7.12, the nuclear option represents an excellent hedge against possible large fossil-fuel price escalation. Future uncertainties that affect the price of coal include possible revision to the Clean Air Act, passage of regulation aimed at reducing acid rain, and the resolution of the NO_x and CO_2 problems.

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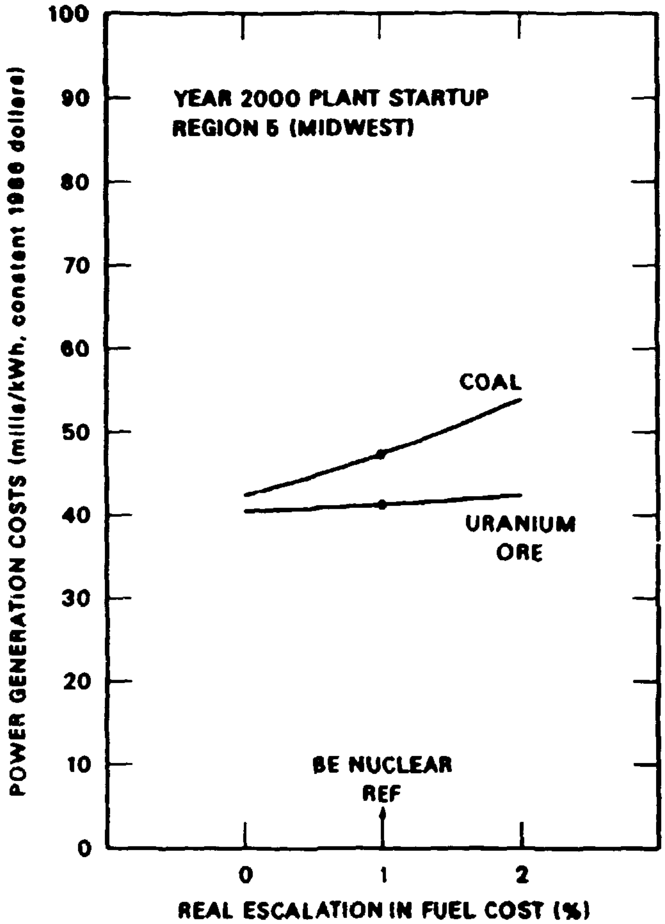

Fig. 7.12. Sensitivity of constant-dollar power generation costs to real escalation in fuel costs for BE nuclear and coal-fired plants.

7.2.6 Plant Lead Times

The long lead times now experienced for constructing a nuclear plant have worked to the detriment of this option. Although the industry is vastly more knowledgeable today after 2 decades of building and operating these plants, lead times for design and construction have increased from ~5 years to current experience (ME) of 12 years or longer. Recent experience, however, indicates that nuclear-plant lead times of 8 years or less (BE) are achievable on a regular basis if certain regulatory reforms are implemented.

Figures 7.13–7.16 illustrate the sensitivity of both nominal- and constant-dollar power generation costs and capital investment costs to

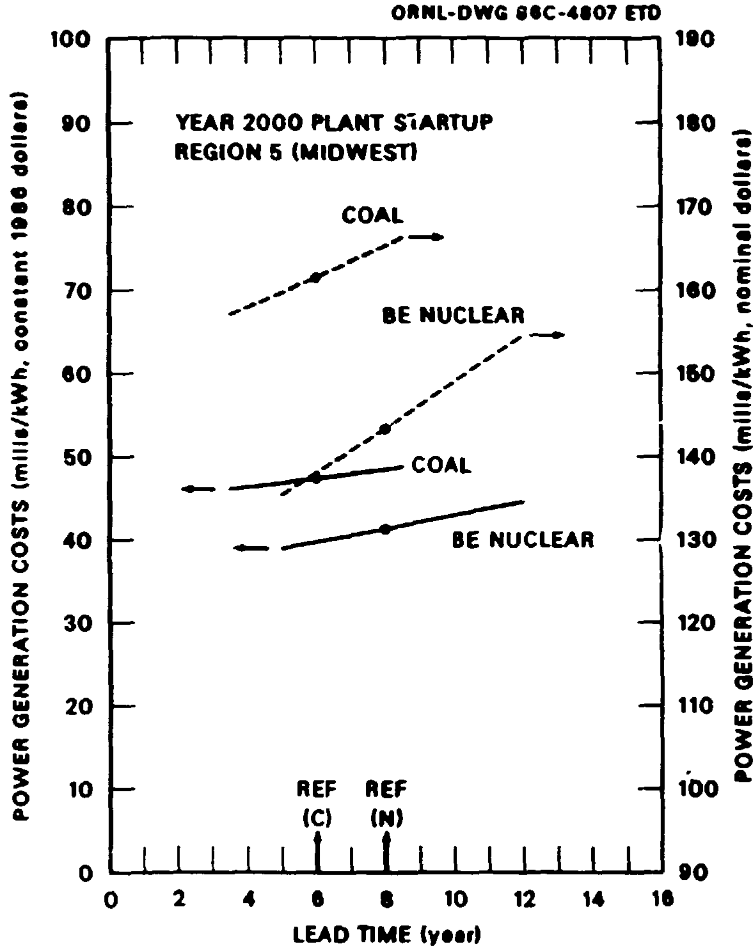

Fig. 7.13. Sensitivity of power generation costs to length of lead time (licensing, design, and construction) with the year of commercial operation held constant.

length of the design and construction period under two sets of assumptions. All of these cost sensitivities to lead time are much more apparent when presented in nominal dollars; thus, both constant- and nominal-dollar changes are plotted in Figs. 7.13–7.16.

In Figs. 7.15 and 7.16 the year of steam-supply purchase (or beginning of project) was held fixed while the design and construction period was varied. A 1-year change in design and construction period under these conditions produces about a 7% change (in nominal dollars) in the total estimated costs of nuclear and coal-fired plants (Fig. 7.16).

In Figs. 7.13 and 7.14 the year of first commercial operation is held fixed (January 2000) while the steam-supply order date (beginning

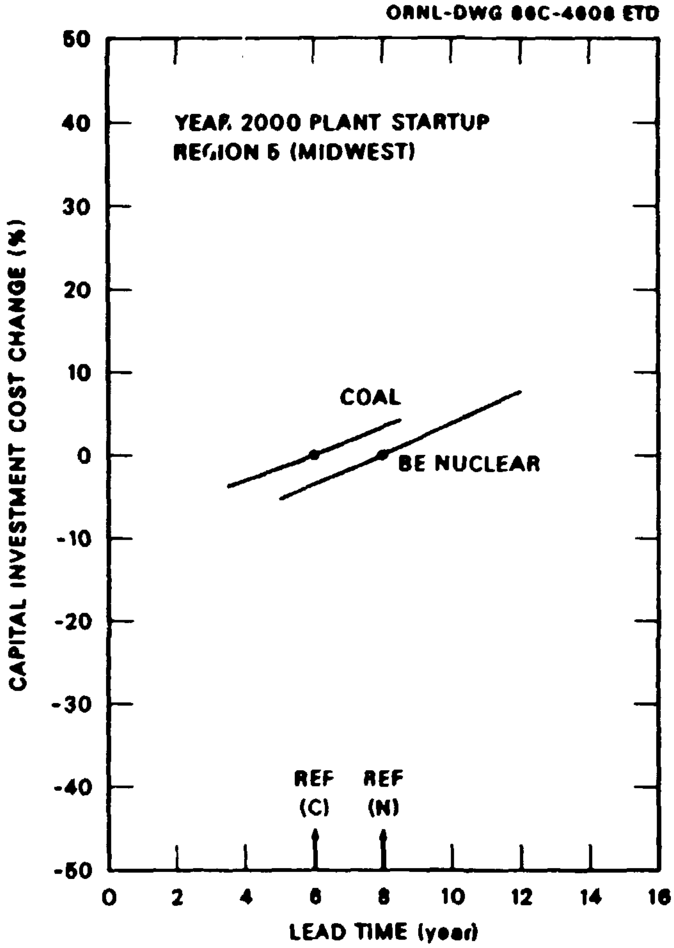

Fig. 7.14. Sensitivity of capital investment costs to lead time with the year of commercial operation held constant.

of project) and construction permit date are varied. Under these latter conditions, capital investment cost in nominal dollars is less sensitive to lead time. The coal-fired-plant, capital-cost investment changes slightly over 1% (in nominal dollars) for each 1-year change in the design and construction period, and the nuclear-plant investment cost changes ~2%. The savings in capital investment costs that would result from a 1-year reduction in lead time would amount to about $66 million for a nuclear plant and about $45 million for a coal-fired plant (nominal dollars).

At the reference lead time, 6 years for coal-fired plants and 8 years for nuclear plants, the levelized cost of the nuclear plant was estimated to be 12.7% lower than that of the coal-fired plant in the

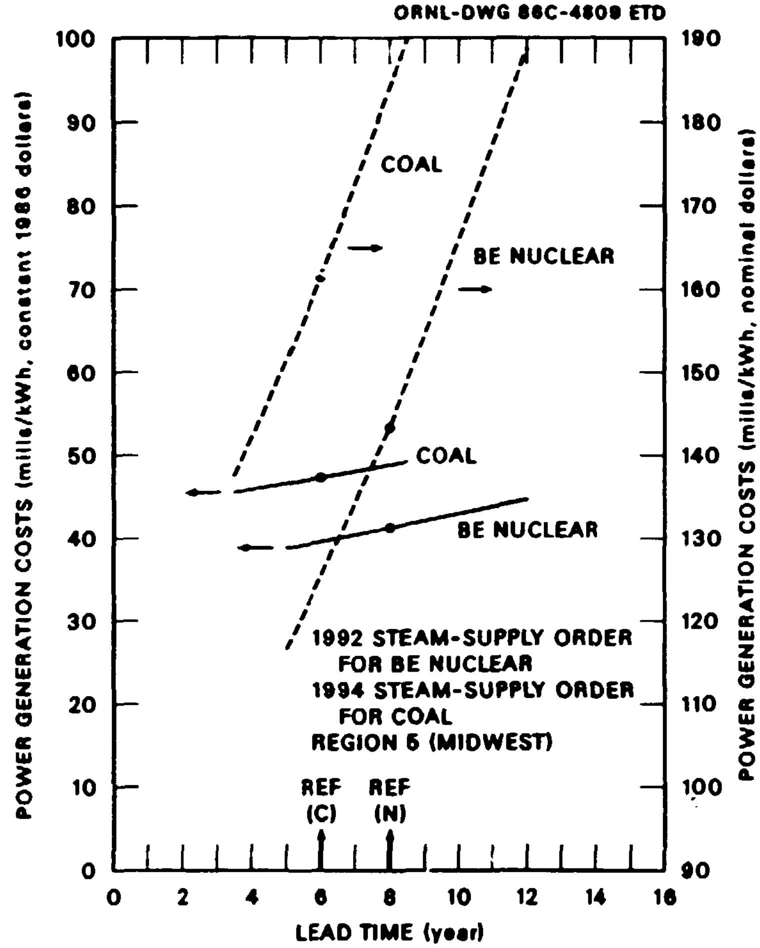

Fig. 7.15. Sensitivity of power generation costs to length of lead time with steam supply order date held constant.

midwest region. If the nuclear lead time were increased to 14 years, then it is estimated that the levelized costs of both options would be equal, provided both plants are brought on-line at the same time. This assumes that the longer-schedule nuclear plant can be built with the same amount of labor as the shorter-schedule plant, which may not be so. For Fig. 7.13 it is evident that the power generation cost of coal-fired plants is less sensitive to plant lead time, compared with that of nuclear plants.

The principal changes in costs resulting from lengthening or shortening the design and construction period result from changes in escalation and AFUDC, which are directly related to the length of the design and construction period and the year of commercial operation. Other

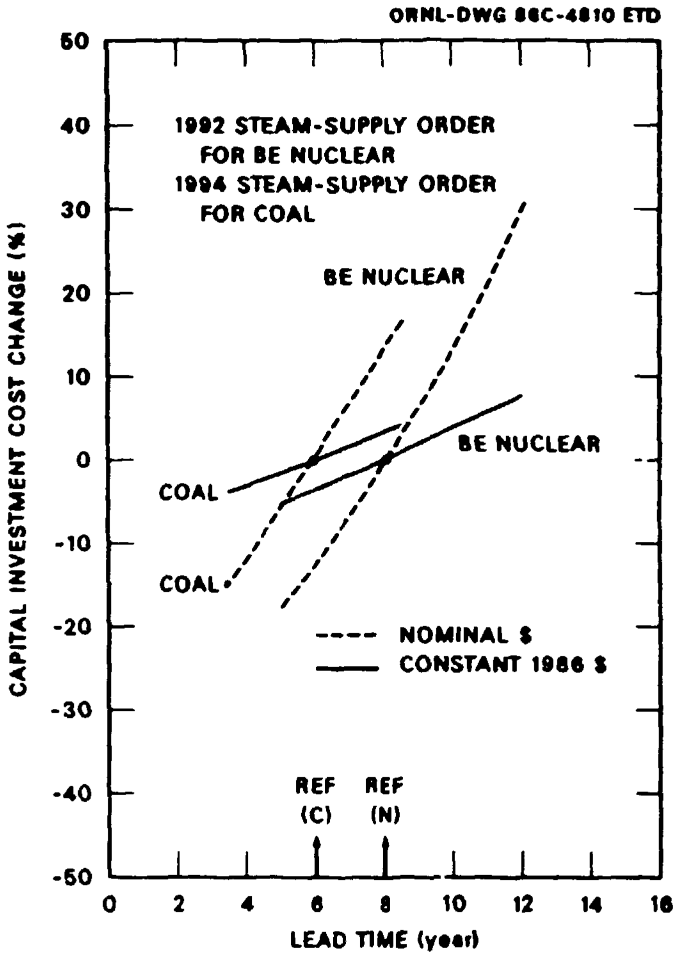

Fig. 7.16. Sensitivity of capital investment costs to lead time with steam supply order date held constant.

factors include estimates of changes in engineering, construction management, equipment leasing, utilization of the construction work force, and other indirect costs.

Figure 7.17 shows the sensitivity of estimated nominal-dollar capital investment costs to year of first commercial operation. The curve in Fig. 7.17 was developed by varying the year of first commercial operation while maintaining a constant design and construction period of 8 years for the nuclear plant and 6 years for the coal-fired plant. Only one curve is shown because the overall escalation rate used for both nuclear and coal-fired plants was 5%/year. Capital investment costs will double for both plant types in slightly under 14 years.

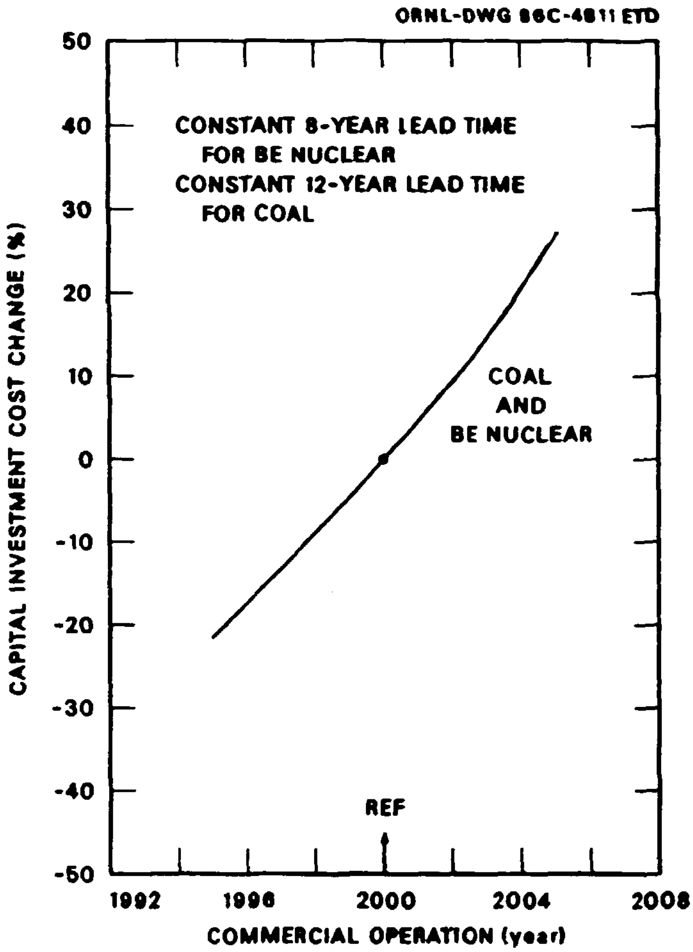

Fig. 7.17. Sensitivity of nominal-dollar capital investment costs to commercial operation date for BE nuclear and coal-fired plants.

7.3 POWER GENERATION COST SENSITIVITIES: NUCLEAR FUEL-CYCLE COMPONENTS

The sensitivity of the power generation cost to variations in the cost of various components of the nuclear fuel cycle are presented here.

7.3.1 Uranium Ore Price

Of the five major fuel-cycle cost components (ore, conversion, enrichment, fabrication, and waste disposal) of the enriched-uranium fuel cycle, ore price makes the greatest contribution to the levelized power generation cost. A \$10/lb U_3O_8 price increase from the reference \$34/lb U_3O_8 would cause a 2.5% increase in the power generation costs (deriveable from Fig. 7.18).

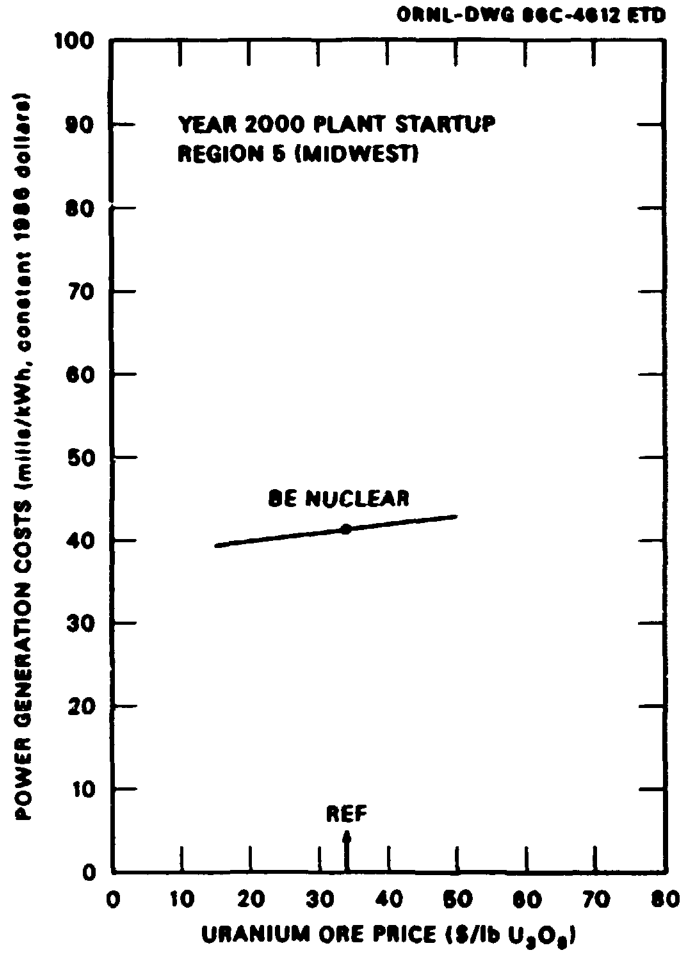

Fig. 7.18. Sensitivity of constant-dollar power generation costs to price of uranium ore (BE nuclear plants).

7.3.2 Enrichment Price

The price of enrichment services has the second largest effect on the power generation cost of the five components mentioned above. Figure 7.19 shows this sensitivity. A \$10/SWU increase in the enrichment price would increase power generation costs by 0.6%.

7.3.3 Other Fuel-Cycle Components

Figure 7.20 shows the relative effects of the costs of conversion, fabrication, and waste disposal on the power generation cost. Note the expanded scale in Fig. 7.20. The costs in order of decreasing power generation cost sensitivity are waste disposal, fabrication, and conversion.

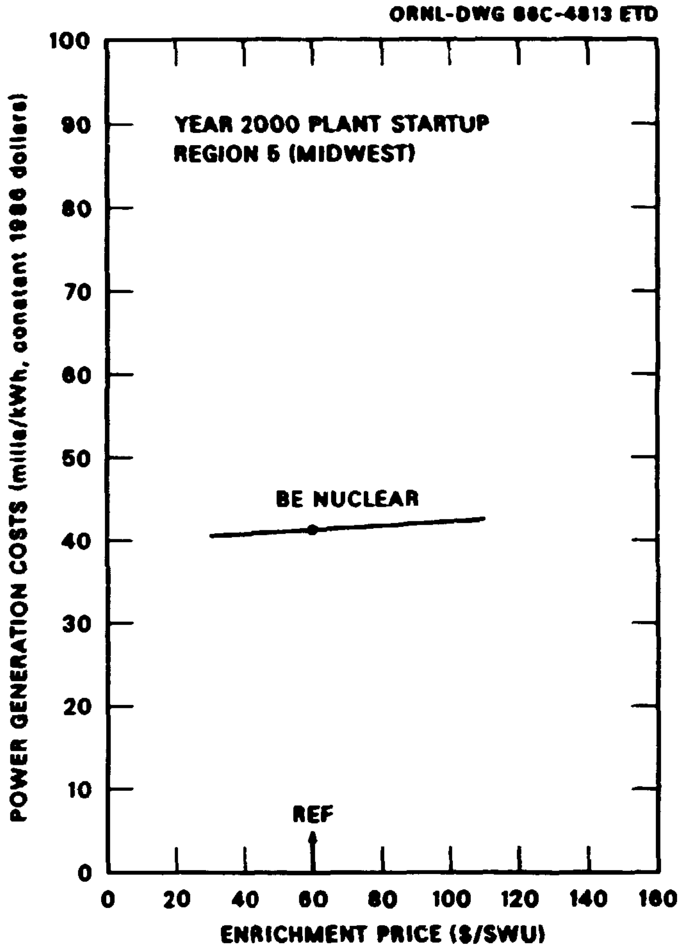

Fig. 7.19. Sensitivity of constant-dollar power generation costs to price of uranium enrichment services (BE nuclear plants).

7.4 POWER GENERATION COST SENSITIVITIES: PRICE OF COAL

As shown in Fig. 7.21 the price of coal has a major effect on the cost of power, as would be expected from an option where approximately one-half of the levelized cost is contributed by the fuel costs. A $0.10/MBtu change in the price of coal causes a 2.7% change in the power generation cost.

7.5 UNIT CHANGE SENSITIVITIES

Table 7.1 shows the major sensitivities in tabular form where the power generation cost differentials are expressed in terms of mills per

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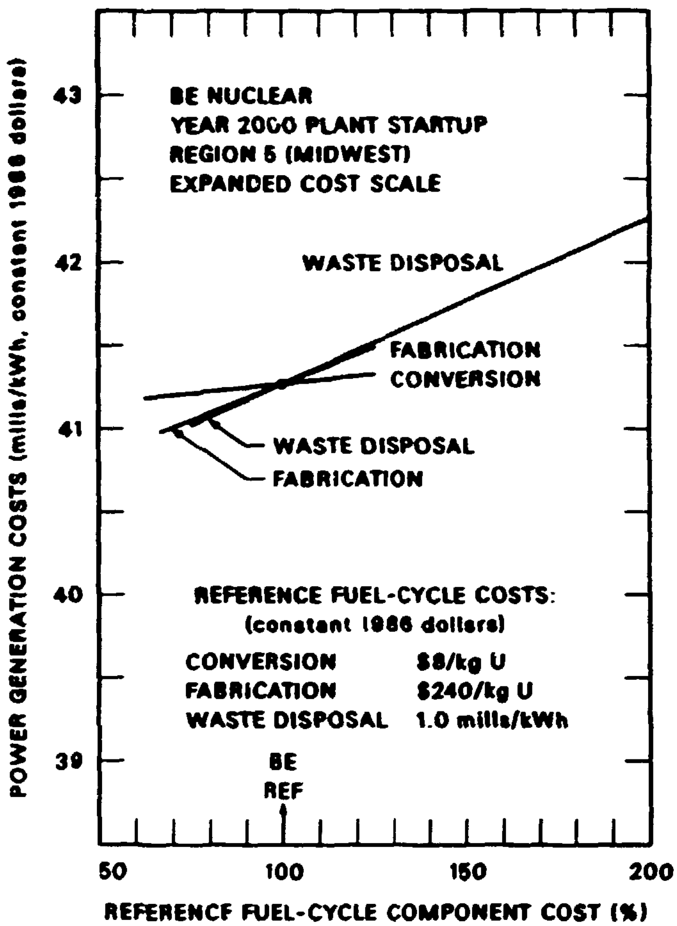

Fig. 7.20. Sensitivity of constant-dollar power generation costs to prices of conversion, fabrication, and waste disposal fuel-cycle services (BE nuclear plants).

kilowatt hour and percent of change. The variations from the reference case are changes that might be considered typical or probable. The "rules of thumb" available from this table can be very useful to the decision maker or analyst.

Included in Table 7.1 is the sensitivity of the power generation cost to the levelization period used in the analysis. This is not an economic parameter, like inflation, that varies in the future; thus, it is not used as an input to the MVSS. A given organization chooses its levelization period dependent on the anticipated project risk. High risk generally causes the desire to recover capital faster; therefore, a shorter levelization period is used. Throughout the probabilistic analysis the levelization period is held at 30 years.

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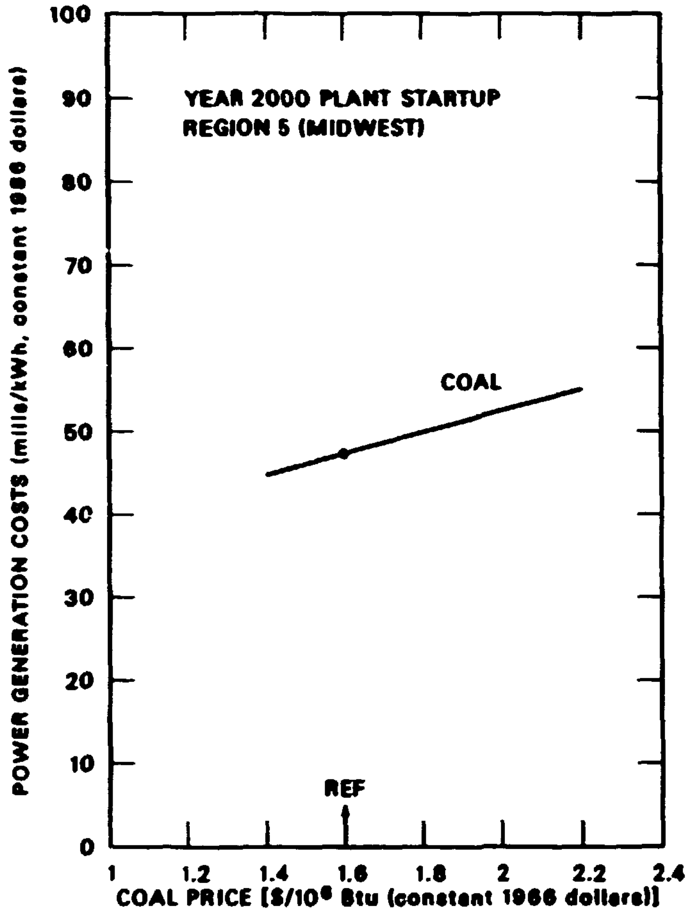

Fig. 7.21. Sensitivity of constant-dollar power generation costs to the price of coal (coal-fired plants).

Table 7.1. Changes in projected BE nuclear-plant and coal-fired-plant power generation costs with assumed changes in financial and technical parameters[a,b]

Financial or technical power	For coal (mills/kWh)[c]	%	For nuclear (mills/kWh)[c]	%
Overnight cost capital investment cost reduce by 10%	-2.06	-4.14	-2.63	-6.4
Inflation rate reduced by 1/2 percentage point (from 5 to 4.5%)	-0.13	-0.26	-0.23	-0.57
Capacity factor increased by 5 percentage points (from 70 to 75%)	-1.63	-3.14	-2.28	-5.5
Design and construction period reduced 1 year with year of first commercial operation fixed (coal changed from 6 to 5 years; nuclear changed from 8 to 7 years)	-0.53	-1.12	-0.79	-1.9
Design and construction period decreased 1 year with steam-supply order date fixed	-0.74	-0.16	-0.82	-2.0
Real cost of money reduced by 1 percentage point (3.8 to 2.8%)	-2.89	-6.1	-4.47	-10.19
O&M cost-escalation rate increased 1 percentage point (0 to 1%)	1.82	3.8	2.26	5.15
Coal cost-escalation rate increased 1/2 percentage point (1.0 to 1.5%)	3.03	6.4		
Coal cost-escalation rate decreased 1/2 percentage point (1.0 to 0.5%)	-2.63	-5.6		
Real escalation during construction increased 1 percentage point (0 to 1.0%)	2.44	5.2	2.72	6.6
Change from 30- to 20-year analysis period with plant life constant at 40 years	3.15	6.7	4.94	12.0
Change from 30- to 40-year period analysis with plant life constant at 40 years	-1.56	-3.3	-2.80	-6.8
Change from 40- to 30-year plant lifetime with analysis period constant at 30 years	0.37	0.78	0.49	1.18
Change from 40- to 50-year plant lifetime with analysis period constant at 30 years	-0.22	-0.47	-0.29	-0.71
Uranium enrichment cost increased by $10/SWU (from $60 to $70/SWU)			0.25	0.60
Uranium enrichment cost decreased by $10/SWU (from $60 to $50/SWU)			-0.25	-0.60
U_3O_8 price escalation rate increased by 1/2 percentage point (1.0 to 1.5%)			0.50	1.2
U_3O_8 price escalation rate decreased by 1/2 percentage point (1.2 to 0.7%)			-0.43	1.0

[a]For midwest region, best-experience nuclear.

[b]Total generation costs are expressed in mills per kilowatt hour based on constant 1986 dollars.

[c]Base power generation costs in mills per kilowatt hour: coal, 47.34; nuclear, 41.25.

8. POWER GENERATION COST SENSITIVITIES: MULTIVARIABLE ANALYSIS

8.1 INPUTS TO THE MVSS

Table 8.1 lists the ranges and types of distributions used for each of the 22 variables considered. Table 8.1 also indicates whether the low and high values are considered optimistic or pessimistic. Figures 8.1-8.3 are simple plots of the actual relative probability distributions used. Figure 8.1 is for the financial variables common to both the coal and nuclear options, Fig. 8.2 is for the nuclear-plant variables only, and Fig. 8.3 is for the coal-plant variables only.

8.2 RESULTS AND INTERPRETATION OF MVSS

The input probability distributions described above were sampled, and 1000 cases or iterations were considered. The output figures-of-merit analyzed include the nuclear power generation cost, the coal power generation cost, and their busbar cost difference (nuclear minus coal).

The results are more easily understood if presented in graphical form. If the 1000 data points for each figure-of-merit are computer sorted and placed in "bins" of appropriate width, a relative probability distribution or "output histogram" can be plotted for each. As a result of the Central Limit Theorem of statistics, the output distributions will have the basic appearance of a bell-shaped curve, which for cost figures-of-merit is often somewhat rightward skewed. Figure 8.4 shows a hypothetical output distribution and the locations of some of its important statistical parameters. If the number of cases within the bins are summed consecutively from left to right at each bin, a cumulative probability distribution can be constructed for each figure-of-merit. These plots are useful for establishing percentiles (i.e., the probability that a given figure-of-merit will have a value Y_i or less within its range).

In this chapter, two uncertainty scenarios are considered. The first scenario deals with the uncertainties about the reference or BE case; regulatory reform and improved design and construction practices

Table 8.1. Parameters for input variable uncertainty distributions: deviations from reference scenario

Variable	Low value	Most-probable (baseline) value	High value	Type of distribution
		Financial		
Inflation rate, %/year	2 (o)[a]	5	8 (p)[b]	Triangular[c]
Real cost of money, %/year	1 (o)	3.8	7 (p)	Triangular[c]
Real escalation during construction, %/year	-1.5 (o)	0	2 (p)	Histogram[c]
Real O&M cost escalation, %/year	-1 (o)	0	2 (p)	Histogram[c]
		Nuclear plant[d]		
Overnight cost (BE range), $M	1100 (o)	1600	2700 (p)	Log-triangular[c]
Capacity factor, %	55 (p)	70	85 (o)	Triangular[c]
Fuel cost components				
Ore, $/lb U_3O_8	15 (o)	34	50 (p)	Triangular
Real ore escalation, %/year	0 (o)	1.0	2 (p)	Triangular[c]
Conversion, $/kg U	5 (o)	8	10 (p)	Triangular
Enrichment, $/SWU	30 (o)	60	110 (p)	Log triangular[c]
Fabrication, $/kg HM	160 (o)	240	300 (p)	Triangular
Waste disposal, mills/kWh	0.75 (o)	1.0	2.0 (p)	Log triangular[c]
O&M cost, mills/kWh	4 (o)	7.3	12 (p)	Log triangular[c]
Decommissioning cost, mills/kWh	0.3 (o)	0.6	1.5 (p)	Log triangular[c]
Project lead time (BE range), years	5 (o)	8	12 (p)	Log triangular[c]
		Coal plant[d]		
Overnight cost, $M	1000 (o)	1305	1600 (p)	Triangular[c]
Capacity factor, %	55 (p)	70	85 (o)	Triangular[c]
Fuel cost (coal), $/MBtu	1.40 (o)	1.60	2.20 (p)	Log triangular[c]
Real coal cost escalation, %/year	0 (o)	1.0	2.0 (p)	Triangular[c]
O&M, mills/kWh	3 (o)	5.9	8 (p)	Histogram[c]
Decommissioning cost, mills/kWh	0 (o)	0.1	0.2 (p)	Triangular[c]
Project lead time, years	3.5 (o)	6	8.5 (p)	Triangular[c]

[a](o) indicates optimistic value.

[b](p) indicates pessimistic value.

[c]Reference value located close to 50 percentile (mode = median).

[d]All input costs in constant 1986 dollars.

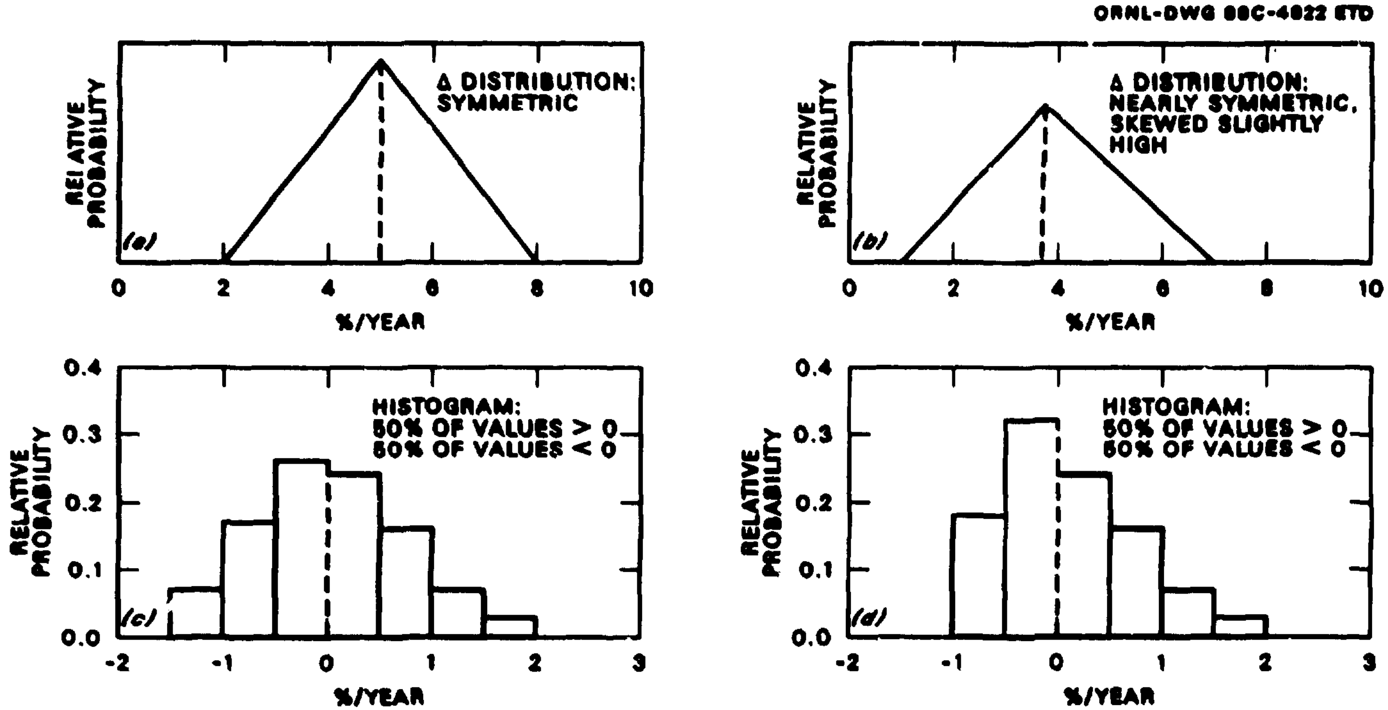

Fig. 8.1. Input distributions for financial variables (same distributions for both coal and nuclear options). (*a*) Inflation rate (base value = 5%), (*b*) real cost of money (base value = 3.8%), (*c*) real escalation during construction (base value = 0%), (*d*) real O&M cost escalation (base value = 0%).

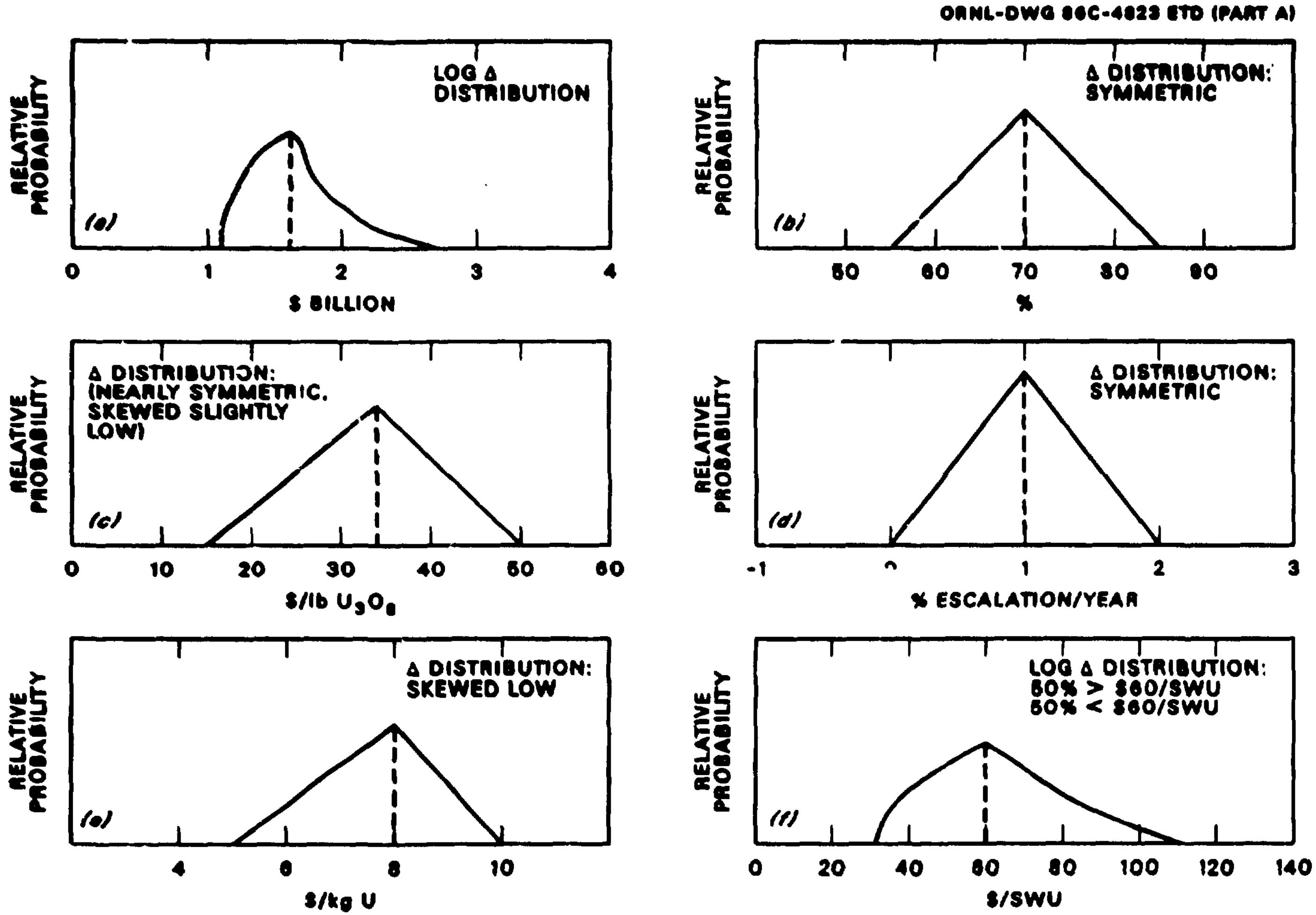

Fig. 8.2. Input distributions for BE nuclear plant variables. (*a*) Overnight cost (base value = \$1.6 billion), (*b*) capacity factor (base value = 70%), (*c*) ore price (base value = \$34/lb U_3O_8), (*d*) real escalation in ore price (base value = 1.0%), (*e*) conversion price (base value = \$8/kg U), (*f*) enrichment price (base value = \$60/SWU), (*g*) fabrication price (base value = \$240), (*h*) waste disposal charge (base value = 1 mill/kWh), (*i*) O&M cost (base value = 7.3 mills/kWh), (*j*) decommissioning cost (base value = 0.6 mill/kWh), (*k*) project lead time (base value = 8 years).

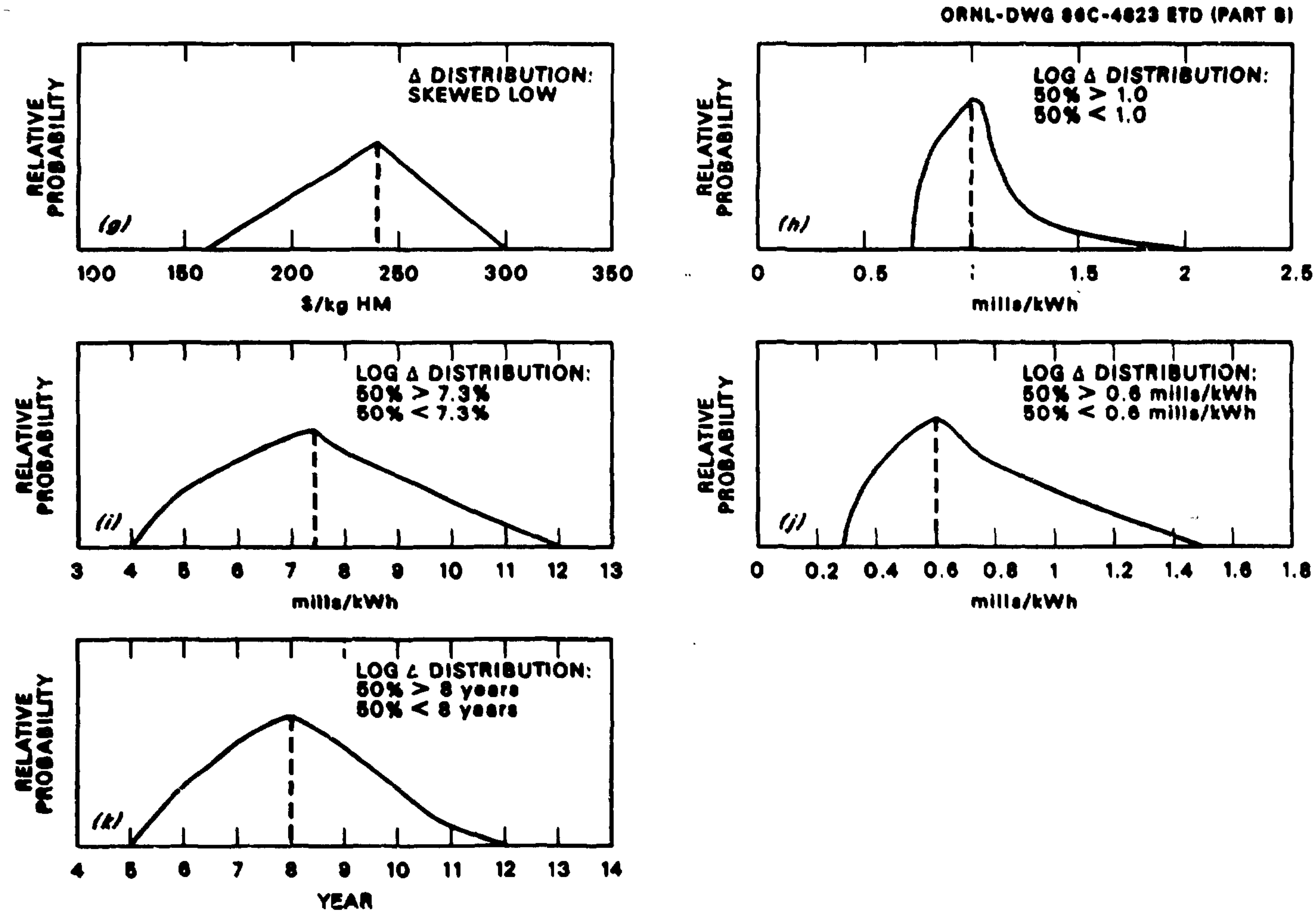

Fig. 8.2 (continued)

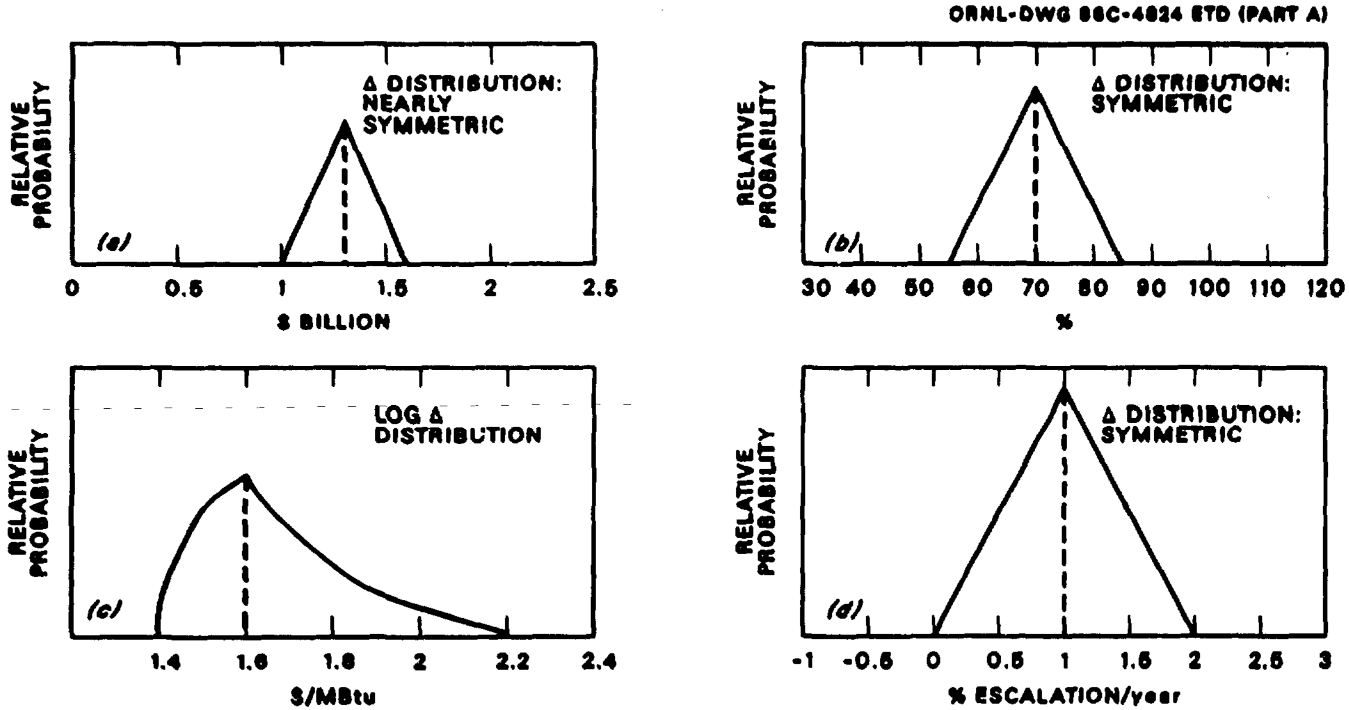

Fig. 8.3. Input distributions for coal-fired-plant variables. (*a*) Overnight cost (base value = \$1.305 billion), (*b*) capacity factor (same as nuclear, 70% base value), (*c*) coal price (base value = \$1.60/MBtu), (*d*) real coal price escalation (base value = 1.0%), (*e*) O&M cost (base value = 5.9 mills/kWh), (*f*) decommissioning cost (base value = 0.10 mill/kWh), (*g*) project lead time (base value = 6 years).

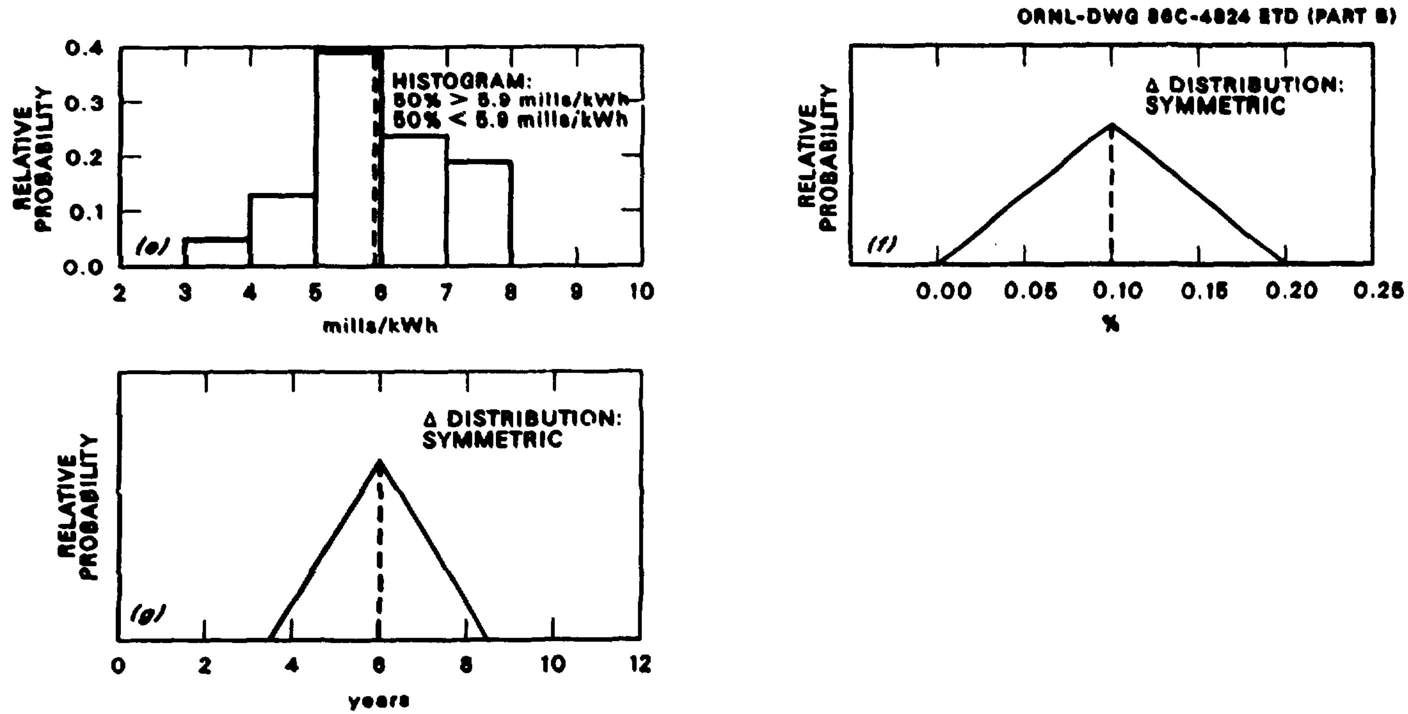

Fig. 8.3 (continued)

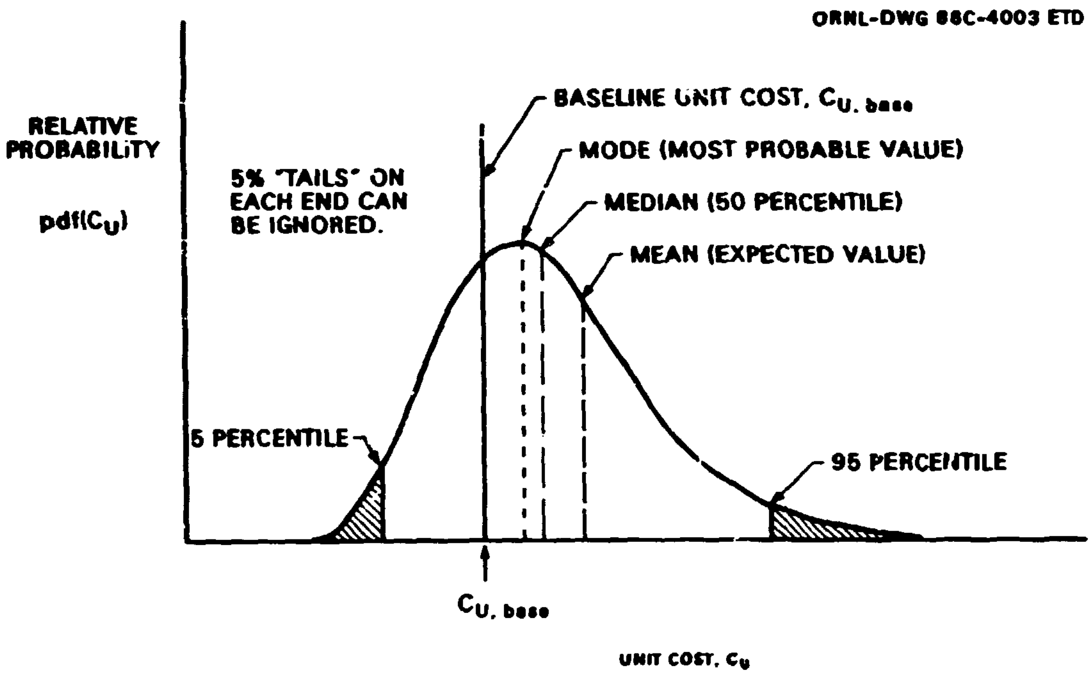

Fig. 8.4. Hypothetical output distribution for a cost figure-of-merit.

are assumed instituted in the future. The second uncertainty scenario revolves around the alternate or ME case in which the regulatory environment is assumed not to improve, and improved design and construction practices are assumed not instituted. No attempt to assign probabilities to the occurrence of regulatory reform or improved design and construction is attempted. These events depend on political and institutional uncertainties that are extremely difficult to quantify. In essence, however, we are assigning a distribution of sorts to these scenarios: a bimodal spike distribution representing "yes and no" answers to the question of reform implementation. For the reference (BE)-based scenario, a "yes" answer to the question of reform, a 100% chance of the reforms cited above being implemented, is assumed. For the alternate (ME)-based scenario, a "no" answer, a 0% chance, is assumed.

8.2.1 Results of the Uncertainty Analysis Based on Deviations from the Reference Values

Table 8.1 shows the parameters and types of distributions used for the uncertainty analysis, based on deviations from the BE nuclear case. The mode or most-likely values represent the values used to produce the reference deterministic case. For many of the 22 input distributions, the mode is also equal to the median value (i.e., one-half of the points drawn from these distributions will lie on either side of the most-likely value).

Figure 8.5 shows the relative probability histogram for the busbar or power generation cost figure-of-merit for both coal and nuclear.

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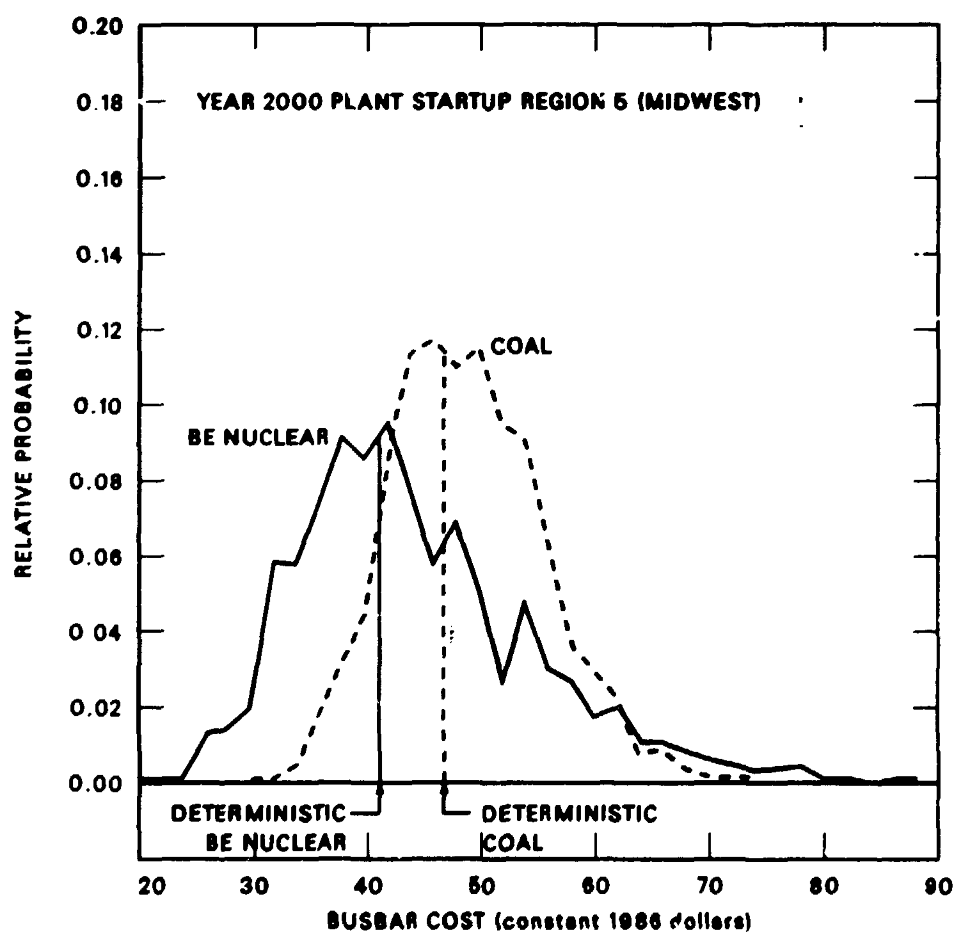

Fig. 8.5. Probabilistic MVSS analysis for reference uncertainty scenario: output relative probability histograms of constant-dollar power generation costs for BE nuclear and coal-fired plants.

This histogram resulted from the sampling and submission to the LEVCOST code of 1000 points for each input distribution. As expected, two bell-shaped curves result; the raggedness in each is a result of finite bin size, statistical sampling error, and the fact that many of the algorithms in the model are not continuous functions and involve step-functions. Table 8.2 shows the statistical parameters calculated by the Monte Carlo driver code for each busbar cost distribution. Also shown in Fig. 8.5 are the locations of the deterministic or reference projections for both coal and nuclear within their respective uncertainty envelopes. As expected, the base cases are very close to the mode values for each distribution. This is not surprising because the base-case value for each input value also represents the mode value. The most interesting information available from these plots deals with the dispersion of the power generation cost for each option, because dispersion (as measured by the standard deviation) is an indication of relative uncertainty. The nuclear power generation busbar cost distribution has a 60% higher dispersion associated with it relative to the coal busbar cost distribution. The higher uncertainty for the nuclear power generation cost can be attributed mainly to the greater dispersion in the nuclear overnight cost input distribution relative to the overnight cost distribution for coal. Figure 8.6 shows the same coal and nuclear output histograms in cumulative probability form. The format makes it easier to determine percentiles. From this curve, it can be seen that ~36% of the 1000 cases in the simulation had power generation costs below the baseline (deterministic) values for both coal and nuclear. This result implies that perhaps the reference cases were somewhat on the optimistic side, which is often the case when the deterministic analysis is performed first.

Figures 8.7 and 8.8 show the relative and cumulative probability plots for the BE nuclear minus coal power generation cost figure-of-merit. To ensure consistency in this analysis, the same input sample was used for the financial variables (Fig. 8.1) for both coal and nuclear within each iteration. This ensures that the coal and nuclear power generating costs are calculated on the same financial basis (for a

Table 8.2. Statistics for output figures of merit[a]

Option	Reference value	Minimum (0 percentile)	5 percentile	Median (50 percentile)	95 percentile	Maximum (100 percentile)	Mode bin	Mean	Standard deviation
BE nuclear (Figs. 8.5 and 8.6)	41.3	21.7	31.7	43.6	64.9	89.6	42-44[b]	45.4	10.4
Coal (Figs. 8.5 and 8.6)	47.3	31.4	39.9	49.5	61.7	75.0	46-48[b]	49.9	6.6
Nuclear minus coal (Figs. 8.7 and 8.8)[c]	-6.0	-26.4	-16.1	-5.1	8.89	30.5	-6 to -12	-4.5	7.8

[a]Power generation costs in mills per kilowatt hour (constant 1986 dollars, midwest region).

[b]Bin width is 2 mills/kWh; most-likely value is somewhere within this bin range.

[c]Negative value indicates that nuclear has economic edge over coal.

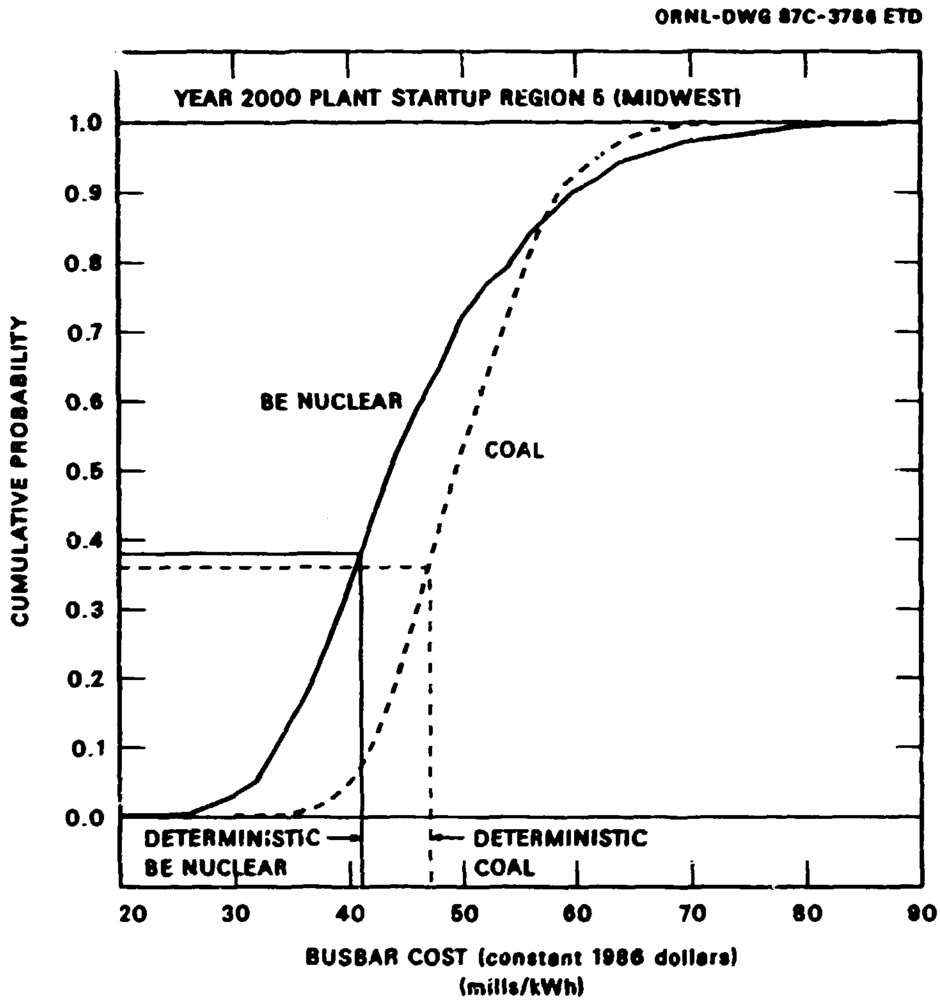

Fig. 8.6. Probabilistic MVSS analysis for reference uncertainty scenario: output cumulative probability histograms of constant-dollar power generation costs for BE nuclear and coal-fired plants.

particular case) before calculation of the cost difference. Figure 8.7 shows that most of the area on the BE nuclear minus coal power generation cost envelope lies to the left of the line where coal and nuclear costs are identical (zero-difference line). Use of the cumulative histogram allows determination that BE nuclear has a 74% chance of being less expensive than coal (i.e., for the given simulation, 74% of the 1000 cases turned out this way). From the same plot it can be determined that there is a 24% chance that BE nuclear will be 10 mills/kWh less expensive than coal. The probability for the base case difference of 6.1 mills/kWh is ~44%.

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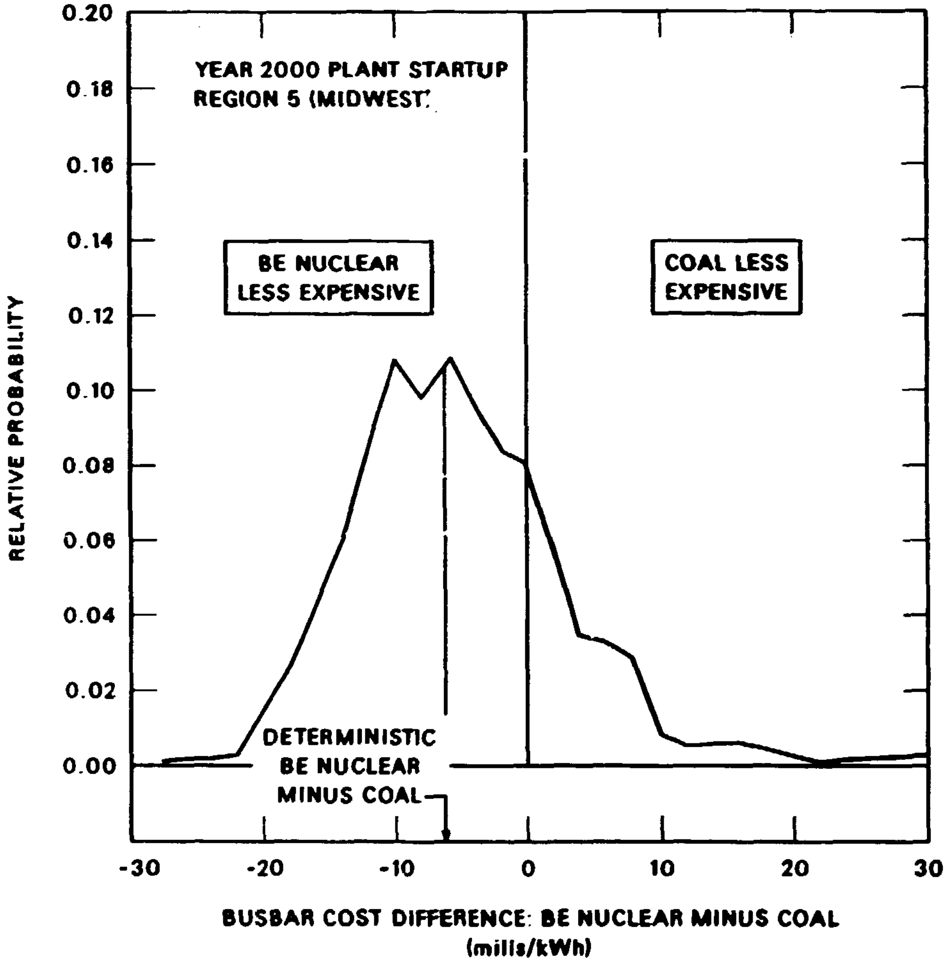

Fig. 8.7. Probabilistic MVSS analysis for reference uncertainty scenario: output relative probability histogram for difference between BE nuclear and coal-fired power generation costs.

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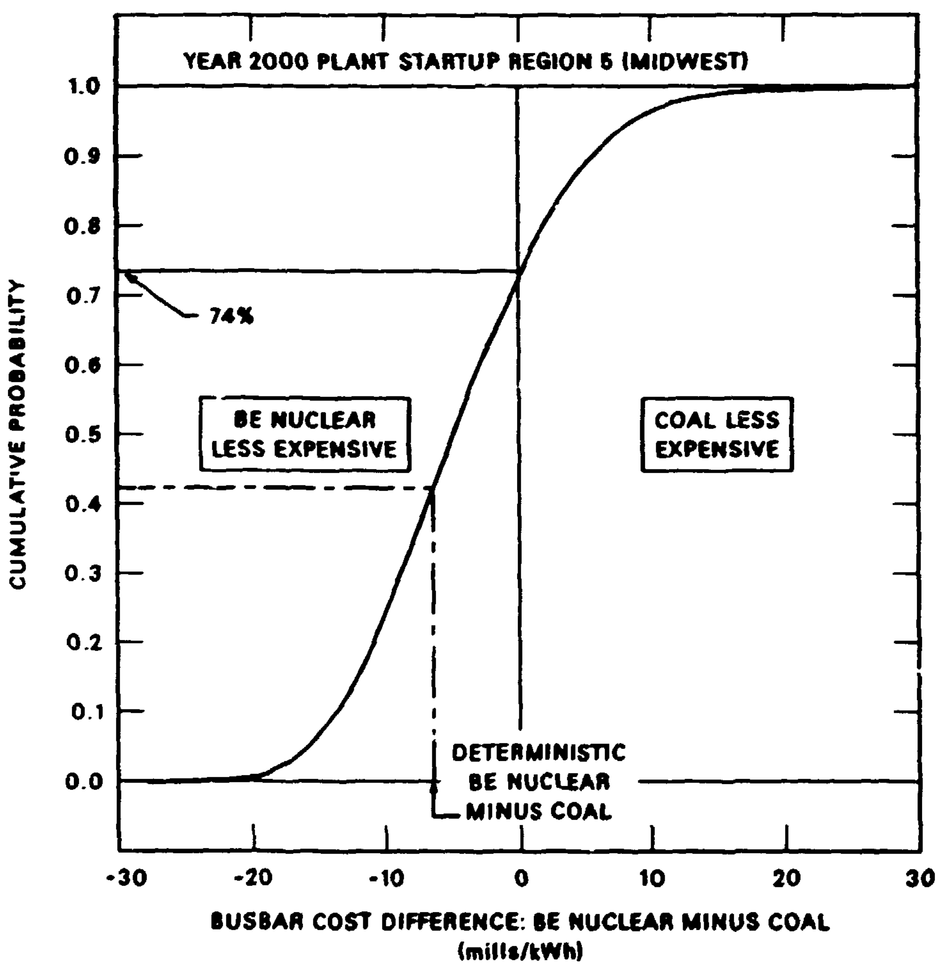

Fig. 8.8. Probabilistic MVSS analysis for reference uncertainty scenario: output cumulative probability histogram for difference between BE nuclear and coal-fired power generation costs.

8.2.2 Results of the Uncertainty Analysis Based on Deviations from the Alternate Case

The alternate (ME) case assumes that regulatory reform and improved design and construction practices are not achieved and that today's median plant cost experience prevails. Data for this scenario were prepared by modifying two of the input nuclear distributions on Fig. 8.2: the overnight cost and the design and construction lead time. All other distributions, including those for coal, remained at their reference-based parameters. Figure 8.9 shows the new input distributions altered to reflect these ME-based deviations. The most-likely ME overnight cost becomes \$2.8 billion with low- and high-range end points of \$1.6 and

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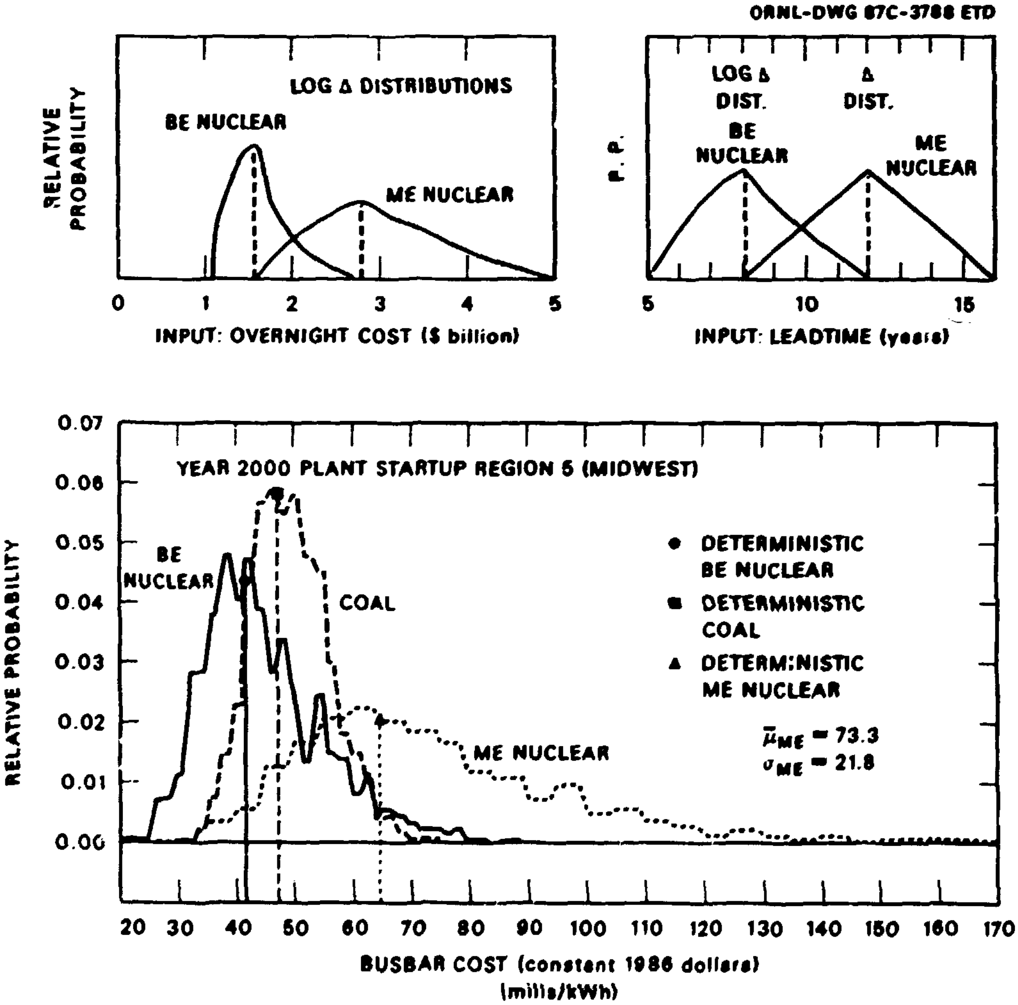

Fig. 8.9. Comparative probabilistic MVSS analysis for alternate (ME nuclear) uncertainty scenario and reference uncertainty scenario (BE nuclear): output relative probability histograms for nuclear and coal-fired busbar power costs.

$5.0 billion, respectively. The most-likely lead time is increased to 12 years with range end points of 8 and 16 years. Figure 8.9 also shows the power generation cost relative probability histograms for this scenario for both coal and nuclear. (Note that coal is unchanged from the earlier reference-based uncertainty scenario.) For comparison the reference BE curve for nuclear is superimposed on the figure; thus, three curves appear. The statistical parameters for the ME nuclear curve appear at the right of the figure. Most notable is the shift of the nuclear curve to the right of coal, indicating higher power generation costs, and the greater dispersion of the ME nuclear curve compared with coal and BE nuclear.

The dispersion of ME nuclear is nearly 3 times that for coal and 1.8 times that of BE nuclear. Figure 8.10 shows the cumulative power

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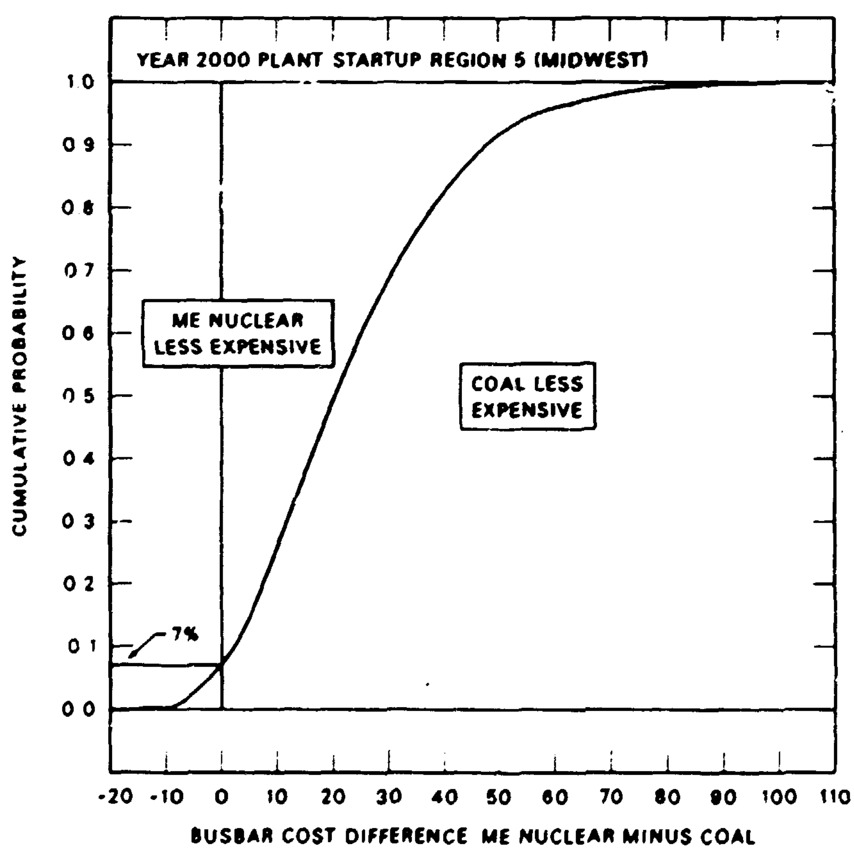

Fig. 8.10. Probabilistic MVSS analysis for alternate uncertainty scenario: output cumulative probability histogram for difference between ME nuclear and coal-fired busbar power costs.

generation cost histogram for ME nuclear minus coal. ME nuclear has only a 7% chance of being less expensive than coal and a <1% chance of being 10 mills/kWh less expensive than coal.

The probabilistic analyses definitively augment the earlier conclusion based on the deterministic analyses and stated in Chaps. 2 and 5: if regulatory reforms and improved design and construction practices are not implemented in the near future, the competitiveness of nuclear-generated power compared with coal-generated power are very bleak.

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Appendix A

NOMENCLATURE

AFUDC	allowance for funds used during construction
AVLIS	atomic vapor laser isotope separation
AGC	advanced gas centrifuge
AIF	Atomic Industrial Forum
B	bond interest
BE	best experience
C	common stock dividend
CF	cash flow
D^B	book depreciation
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EEDB	Energy Economic Data Base
EPRI	Electric Power Research Institute
F	preferred stock dividend
FERC	Federal Energy Regulatory Commission
FGD	flue gas desulfurization
GNP	gross national product
HM	heavy metal
I	investment
i	inflation rate
L	period in years between reference cost year and year of commercial operation
LEU	low-enriched uranium
LEVCOST	levelized power generation cost code
LWR	light-water reactor
m	index (year relative to reference year)
ME	median experience
MVSS	multivariable sensitivity studies
n	index (year relative to start of project)
N	operating life of project
NECDB	Nuclear Energy Cost Data Base
NRC	U.S. Nuclear Regulatory Commission

O	other expensed costs; includes O&M costs, fuel, interim replacement, property taxes, and decommissioning fund
P	price
$\overline{P}$	current-dollar levelized price
$\overline{P}_o$	constant-dollar levelized price
PWR	pressurized water reactor
PWRR	present worth of revenue requirements
R&D	research and development
SVSS	single-valve sensitivity study
UE&C	United Engineers & Constructors

Appendix B

DESCRIPTION OF MATHEMATICAL METHODOLOGY FOR UNCERTAINTY ANALYSIS

B.1 TWO-PRONGED APPROACH TO UNCERTAINTY ANALYSIS

Implicit in the reference scenario for this study are the assumptions that (1) the factors that have contributed to the delays and cost overruns in the present generation of nuclear power plants are behind us and (2) nuclear plants will be built consistent with schedules and costs experienced by the better of today's construction. As with any studies that deal with the future, significant uncertainties are associated with the assumptions involved.

A two-part uncertainty analysis was performed as part of this study. In the first part, called single-variable sensitivity studies (SVSSs), each input variable is altered <u>one at a time</u> over a plausible range that includes a minimum value, the reference value, a maximum value, and other intermediate values desired to produce cost data points for each input variable considered. (Justification for the chosen ranges appears in Chap. 6.) The probability associated with each value is not considered in this SVSS methodology. The SVSS method readily identifies the individual variables that have the most leverage on the economic figures-of-merit, in this case, the total investment cost and busbar power generation cost for both coal-fired and nuclear plants.

In the second part, called multivariable sensitivity studies (MVSSs), a probability distribution is defined for each of the key input parameters. By the use of a distribution, a probability is associated with any value lying between the minimum and maximum values for the ranges chosen. (For this study, both the SVSS and MVSS procedures use the same ranges.) These distributions are used as input to a Monte Carlo simulation, which is used to calculate a probability distribution for the figure-of-merit by simultaneously sampling <u>all</u> input variable distributions and submitting these samples repeatedly to the LEVCOST model. Unlike SVSS, MVSS requires definition of the probabilities within each variable's range.

Particular care needs to be taken in the selection of these input ranges because as in a deterministic calculation, the input determines the output. Chapter 6 describes the ranges used for each of the key input parameters for both the SVSSs and MVSSs and includes a short narrative providing some justification for the minimum, maximum, and reference (most-probable) value for each significant input variable. All inconsequential variables are held constant at their reference values. Justification for the MVSS distributions associated with the ranges is given in Sect. B.4.

B.2 SVSS METHODOLOGY

B.2.1 Cases Considered for each Curve

A SVSS for any variable consists of three or more deterministic cases for which a plot of the cost figure-of-merit vs the variable values used is made. The points plotted are connected to produce a smooth sensitivity curve. For most of these studies, four or five points were plotted. The following were chosen as variable values:

1. the low end of the variable's range,
2. a value slightly below the reference value,
3. the reference or baseline value (the cost figures-of-merit produced in this case have the same values as those in the deterministic case discussed in Chap. 5),
4. a value slightly above the reference value, and
5. the high end of the variable's range.

The "slightly below" and "slightly above" cases are based on changes from the reference values that might be considered typical or highly plausible because of current economic conditions or recent cost experience. These cases are given separate discussion in Sect. 7.5 and are listed in Table 7.1.

B.2.2 Sensitivity Plots: Scales, Comparisons, and Interpretations

Identification of the variables with high-cost leverage requires comparisons of the sensitivity plots and selection of those variables with the greatest average slopes about their reference values. For this reason, the ordinate scales of Figs. 7.1–7.19 and 7.21, which represent either the power generation cost or the total investment cost percent of change, are the same for each plot unless otherwise indicated. The abscissa scales for these figures, of course, vary depending on which variable is being considered. An attempt was made to force each variable's range to occupy a reasonably large fraction of the abscissa scale, thus allowing greater comparability among plots. Wherever possible, both nuclear-plant and coal-fired-plant sensitivities are shown on the same plot. The text to follow explains the significant differences observed in the sensitivities for each power production option. Section 7.1 discusses the sensitivities of both coal and nuclear to changes in financial variables. Section 7.2 discusses sensitivities to various cost components and schedule changes common to both coal and nuclear. Sections 7.3 and 7.4 discuss sensitivities to those variables that are exclusively coal fired and exclusively nuclear related, respectively.

B.3 MVSS SAMPLING METHODOLOGY

Based on the results of the SVSSs, 22 input variables were chosen for use in the MVSS. Four of these are financial variables applicable to both options, 11 plant-related variables apply to nuclear, and 7 plant-related variables apply to coal. It is, therefore, necessary to define 22 separate distributions for use by the Monte Carlo driver code. When the probabilistic analysis or MVSS is started, the Monte Carlo driver code uses a set of 22 different random numbers to sample the 22 distributions. An ensemble of 22 sample values (1 value for each input variable), known as the "return value vector," is submitted to the LEVCOST model just as any set of data would be for a deterministic analysis. (Any low-leverage, non-MVSS variables are set at their reference values.) Resulting from this first run (based on the first input ensemble) is a set of numbers known as the first "figures-of-merit vector," which includes the total capital investment cost and the power generation costs for both options. This vector is stored until the analysis is completed. The above sampling, submission, calculation, and storage procedure is repeated 1000 times (with a different set of random numbers for each of the 1000 iterations) such that the actual input sample distributions closely approximate the theoretical distributions defined for each. After the LEVCOST model has been called 1000 times, a set of 1000 figures-of-merit vectors is available in disk storage. A statistical analysis is performed on each separate figure-of-merit, and its own distribution is plotted and analyzed. In this chapter, only the power generation cost figure-of-merit for each option is considered.

B.4 SELECTION OF MVSS INPUT DISTRIBUTIONS

In Chap. 6 the ranges for each input variable were defined, listed, and justified. For the MVSS it is necessary to be able to associate a probability of occurrence for any value within the defined range. It is also useful to define the probability of the reference value relative to other possible values within the range. For these reasons, this report deals mainly with relative probability distributions (sometimes called "probability density functions" by statisticians). Because future projections rather than historical data are being considered, it is not possible to construct an input distribution directly from a set of data. Because the forecasting process is highly subjective, defining simple distributions based on a minimum number of easily understood defining parameters is desirable. To maintain simplicity, most distributions will be defined by three parameters:

1. A low value: This will represent the most optimistic (or pessimistic for the capacity factor) value deemed plausible for this variable. The probability of variable X_i having this value or any below it is zero.
2. The reference or mode variable: In this study, it is assumed that the reference case value chosen for any variable is also its most likely or mode value. On a relative probability plot the reference value would represent the peak or maximum on the curve.
3. A high value: This will represent the most pessimistic (or optimistic for the capacity factor) value deemed plausible for this variable. The probability of X_i having this value or any above it is zero.

In the histogram, the other type of distribution used, the cumulative probability over all of the bars must total 1.0. The fraction of the area under the relative probability curve envelope between the low value and a given value within the range is known as the "cumulative probability." The cumulative probability associated with the mode or baseline value is important because it essentially gauges the analyst's degree of optimism concerning the reference value. As an example, consider a commodity cost: a variable with a baseline (and mode) value selected close to the low value (i.e., with a cumulative probability $\ll 0.5$). Even though this reference value is considered most likely, any other values for this cost could be said to have a very high probability (i.e., 1.0 minus the cumulative probability) of coming in at over this reference cost; in essence, the analyst has been very optimistic in the selection of his baseline value. For the distributions defined by three points, two types are used:

1. The triangular distribution: The high and low values define the end points, and the apex is defined by the reference (i.e., most-likely) value. The skewness of the triangle (i.e., the relative location of the apex value to the location of the end points) is an indicator of the relative optimism or pessimism associated with the reference value. An isoceles or symmetric triangle represents the special case in which 50% of the area (and, therefore, ~50% of the value sampled) lies on each side of the reference value. In this special case, the mode is said to equal the median, the latter defined as the 50% cumulative probability point or 50th percentile. Figure B.1 shows some example triangular distributions.
2. The log-triangular distribution: Many cost distributions display rightward skewness (i.e., there is a long tail associating low relative probabilities with possible high costs). The reference value will usually lie much closer to the low value than to the high value at the end of t rightward tail. However, associating median behavior (i.e., a 50th percentile location) with the reference (and most-likely) value is often desired. The log-triangular distribution has the attribute of forcing this type of behavior onto a rightward-skewed triangular distribution and is utilized for all

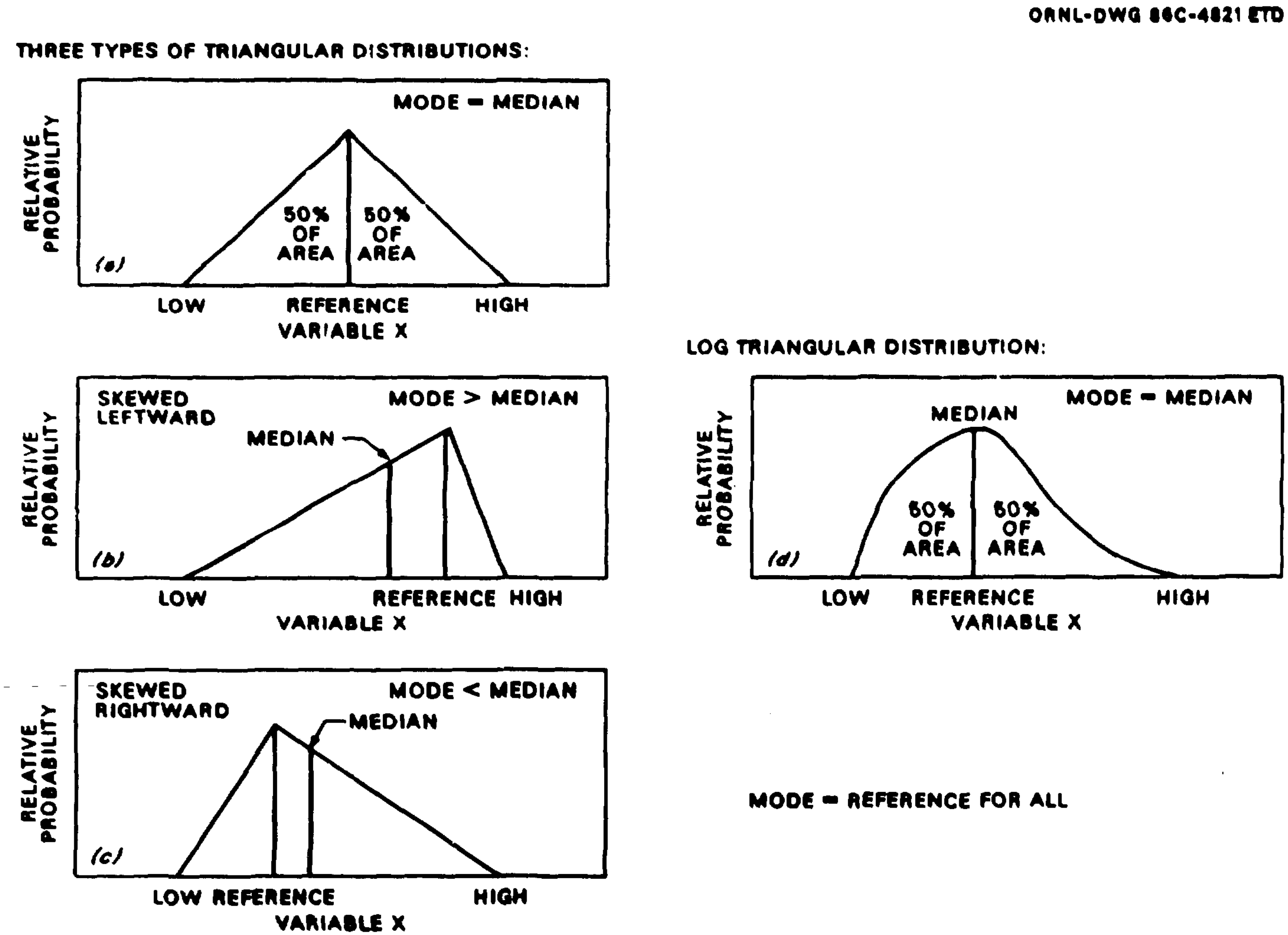

Fig. B.1. Probability distributions definable by low, mode, and high values.

variables for which simulating long tails (such as the high end of the overnight capital investment cost) without significantly distorting the median probability point is desired. For leftward-skewed triangular distributions the log-triangle modification is not applicable. These cases are better defined by histograms, as are several variables in this study. Figure B.1 shows the appearance of a typical log-triangular distribution.

Appendix C

DESCRIPTIONS OF THE TEN REGIONS

For the reader to better understand the results of this study, it is necessary that the authors provide a short discussion of each particular region's attributes that affect the energy-related economics of either power generation option. The regional breakdown corresponds to that used by the Energy Information Administration (EIA) in its forecasting system.

The states within each region are shown on the map in Fig. 2.2. The power generation fuel mix for each region is given below for the first quarter of CY-1986 (second quarter, FY-86) and is calculated from data in the EIA's *Electric Power Quarterly: Jan-Mar 1985*.[1] Note that the category "other" includes geothermal, wind, wood, waste, and solar-power generation.

Region I (New England)

Region I includes the states of Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island, and Vermont. This region has no indigenous fossil fuel resources and relies heavily on imported oil and, to a lesser degree, coal transported a considerable distance from northern Appalachian coal fields. For these reasons, nuclear power gained early acceptance among the utilities in the 1960s and 1970s, and several of these early power plants continue to provide a significant percentage of the region's electric power needs. Small hydro and imported Canadian hydro provide a small percentage. The breakdown of power production methods (by power produced rather than capacity in places) in the first quarter of 1986 is coal fired — 18.6%, hydroelectric — 5.5%, gas fired — 0.3%, nuclear — 26.8%, oil fired — 48.6%, and other — 0.2%.

Region II (New York and New Jersey)

This heavily populated and heavily industrialized region has very small indigenous fossil fuel resources. Transportation costs for coal are less than for the New England region because of the closer proximity of the Appalachian coal fields (see Fig. C.1 for locations of coal fields in the contiguous 48 states); thus, coal-fired electric generation is more competitive than in Region I. The fact that many power plants are located in heavily populated areas forces some utilities to burn gas and oil to comply with air-quality regulations. New York has been obtaining an increasing amount of its power from hydroelectric resources in both the United States and Canada. Nuclear units in these two states provide an amount of electricity comparable to oil-fired units alone. The breakdown of power production methods is coal fired — 16.9%, hydroelectric — 19.7% (does not include Canadian imports), gas fired — 7.3%, nuclear — 27.5%, oil fired — 28.6%, and other — 0.0%.

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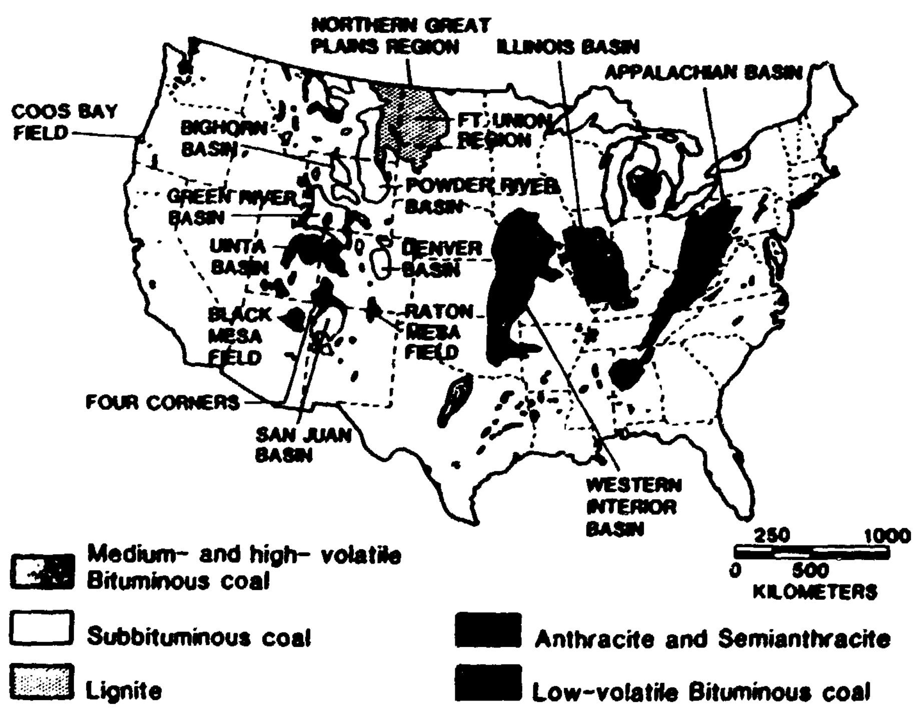

Fig. C.1. Coal fields of the conterminous United States. *Source*: P. Averitt, *Coal Reserves of the United States, January 1, 1974*, U.S. Geological Survey Bulletin 1412, U.S. Government Printing Office, Washington, D.C., 1975.

Region III (Mid Atlantic)

This mixed agricultural/industrial region includes the states of Delaware, Maryland, Pennsylvania, Virginia, and West Virginia. Three of these five states (Pennsylvania, Virginia, and West Virginia) are major coal-producing states; thus, coal transportation costs are lower than in Regions I and II. Some of the coal is of the medium- or high-sulfur grade and at times is not suitable for use in the heavily populated areas of the eastern seaboard; thus, a small amount of oil-fired capacity exists. The region also has a significant commitment to nuclear power with much of it brought on-line during the 1970s. The breakdown for power production is coal fired — 72.1%, hydroelectric — 1.7%, gas fired — 0.1%, nuclear — 22.6%, oil fired — 3.5%, and other — <<0.1%.

Region IV (South Atlantic)

This mixed agricultural/industrial region includes most of the Southeastern states of Alabama, Florida, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, and Tennessee. The Appalachian states in this group are major producers of coal and also have significant hydroelectric production capability. Coal is by far the largest producer of electric power. With the exception of heavily populated southern Florida and the Gulf Coast, transportation costs for coal are relatively low. Nuclear power will supply a growing percentage of power in Region IV as the Tennessee Valley Authority's nuclear operating and construction problems are resolved. Much of the small amount of switchable gas/oil capacity is located in south Florida. The breakdown for power production for this region is coal fired — 69.7%, hydroelectric — 4.4%, gas fired — 3.3%, nuclear — 19.7%, oil fired — 2.9%, and other — 0.0%.

Region V (Midwest)

Proximity of this region (Illinois, Indiana, Michigan, Minnesota, Ohio, and Wisconsin) to the Appalachian and north central coal fields, plus indigenous coal resources in Illinois, Indiana, and Ohio, makes coal-fired plants the primary electric power source. Nuclear power plays a significant role with some utilities, such as Commonwealth Edison in Illinois, heavily committed to nuclear power. Less than 1% of the power in this region is contributed by the burning of oil or gas.

The breakdown for this region is coal fired — 82.0%, hydroelectric — 0.9%, gas fired — 0.2%, nuclear — 16.5%, oil fired — 0.3%, and other — 0.1%.

Region VI (Southwest)

This region (Arkansas, Louisiana, Oklahoma, New Mexico, and Texas) includes the two states that provide almost two-thirds of the natural gas available in the United States; therefore, it is not surprising that this clean and easily transportable fuel supplies a fraction of power production that is much higher than in any other region. Coal is the major electric-power fuel source with significant amounts available from indigenous resources in Texas and New Mexico. Nuclear, hydro, and oil provide only small fractions in this region. The breakdown is coal fired — 53.1%, hydroelectric — 2.1%, gas fired — 38.4%, nuclear — 6.2%, oil fired — 0.1%, and other — 0.1%.

Region VII (Central)

This primarily agricultural region includes Iowa, Kansas, Missouri, and Nebraska. The presence of some indigenous coal and its proximity to low-cost coal from Regions VIII and V account for the fact that nearly three-quarters of that region's power is generated by coal. At >21%, nuclear power is playing an increasing role. The breakdown is coal fired — 74.5%, hydroelectric — 3.3%, gas fired — 0.7%, nuclear — 21.3%, and oil fired — 0.2%.

Region VIII (North Central)

This sparsely populated region includes Colorado, Montana, North Dakota, South Dakota, Utah, and Wyoming. Most of these states are coal producers, with much of the coal being low cost, strip mined, low sulfur, and sub-bituminous. This region has the largest coal generation fraction, ~83%, of all the regions. Hydroelectric capacity, some of it imported from the Pacific Northwest, provides nearly all of the remaining power. This is the region in which there is the smallest nuclear electric power generation capacity (i.e., one plant, Fort St. Vrain, in Colorado). The breakdown of power actually produced in CY-1986, first quarter, is coal fired — 83.1%, hydroelectric — 16.3%, gas fired — 0.3%, nuclear — 0.0%, oil fired — 0.1%, and other — 0.2%.

Region IX (West)

This region includes Arizona, California, and Nevada, all hydroelectric producers. Thus, along with hydro imports from Region X and Canada, hydro accounts for the largest fraction in Region IX. Small indigenous coal resources, plus coal from neighboring regions, make coal second at >21% (California has no coal-burning plants, however). Coastal California relies heavily on oil- and gas-fired capacity, especially because of air-quality problems in Southern California. Nuclear power is playing an increasing role in this region as new plants in California have come on-line. This region is the only one to utilize a significant fraction of generation resources in the category called "other." These include several wind-farm, geothermal, and solar projects. The breakdown is coal fired — 21.4%, hydroelectric — 32.7%, gas fired — 20.8%, nuclear — 14.3%, oil fired — 5.0%, and other — 5.8%.

Region X (Northwest)

The three states of Idaho, Oregon, and Washington compose Region X. The Columbia River and its tributaries provide a tremendous, low-cost, hydroelectric capacity that accounts for ~85% of this region's power generation. Nuclear power accounts for most of the balance. This region has the lowest dependence on coal at only ~3%. The breakdown is coal fired — 3.1%, hydroelectric — 84.8%, gas fired — 2.0%, nuclear — 9.8%, oil fired — 0.2%, and other — 0.1%.

Other Observations

The present relatively low prices for residual fuel oil and natural gas are causing some utilities to increase the fraction of this fuel in their power generation mix. It is unlikely, however, that significant new oil-fired capacity will be added. Coal and nuclear account for ~74% of the power generation in the continental United States and will account for an even greater fraction of any new capacity brought on-line in the next 20 years. For these reasons, this report will deal only with coal and nuclear power generation costs.

REFERENCE

1. *Electr. Power Q.: Jan-Mar 1985*, DOE/EIA-0397(86/1Q), Energy Information Administration; Washington, D.C., April 1986.

Appendix D

REVENUE REQUIREMENTS AND CASH-FLOW TABLES FOR REFERENCE PLANTS (MIDWEST REGION)

Table D.1. Annual revenue requirements (BE nuclear plant located in region 5: capital components)

INITIAL INVESTMENT = $ 3687.

TAX DEDUCTIBLE FRACTION OF INITIAL INVESTMENT = 0.7103

YEAR	RATE BASE	RETURN ON CAPITAL	BOOK DEPR	TAX DEPR	INCOME TAXES CURRENT	INCOME TAXES DEFERRED	PROPERTY TAXES	INTERIM REPL	REVENUE REQR. NOMINAL $	REVENUE REQR. 1986 $	CENTS/KWH NOMNL $	CENTS/KWH 1986 $
2000	3477.9	394.2	92.2	209.5	165.4	69.4	73.7	19.4	814.4	391.7	12.07	5.81
2001	3321.6	376.5	92.2	366.7	80.3	145.1	73.7	20.3	788.2	361.1	11.68	5.35
2002	3089.6	350.2	92.2	314.3	91.5	119.8	73.7	21.3	748.9	326.7	11.10	4.84
2003	2882.8	326.8	92.2	261.9	104.3	94.6	73.7	22.4	714.0	296.7	10.59	4.40
2004	2701.2	306.2	92.2	261.9	93.3	94.6	73.7	23.5	683.6	270.5	10.13	4.01
2005	2519.7	285.6	92.2	261.9	82.[illegible]	94.6	73.7	24.7	653.2	246.2	9.68	3.65
2006	2338.1	265.0	92.2	235.7	84.0	82.0	73.7	25.9	622.9	223.6	9.23	3.31
2007	2169.2	245.9	92.2	235.7	73.8	82.0	73.7	27.2	594.9	203.4	8.82	3.01
2008	2000.2	226.7	92.2	235.7	63.6	82.0	73.7	28.6	566.9	184.6	8.40	2.74
2009	1831.3	207.6	92.2	235.7	53.4	82.0	73.7	30.0	538.9	167.1	7.99	2.48
2010	1662.4	188.4	92.2	0.0	156.7	-31.5	73.7	31.5	511.1	150.9	7.58	2.24
2011	1607.0	182.2	92.2	0.0	153.4	-31.5	73.7	33.1	503.0	141.5	7.46	2.10
2012	1551.5	175.9	92.2	0.0	150.0	-31.5	73.7	34.8	495.1	132.6	7.34	1.97
2013	1496.1	169.6	92.2	0.0	146.7	-31.5	73.7	36.5	487.2	124.3	7.22	1.84
2014	1440.7	163.3	92.2	0.0	143.3	-31.5	73.7	38.3	479.4	116.5	7.11	1.73
2015	1385.3	157.0	92.2	0.0	140.0	-31.5	73.7	40.2	471.7	109.1	6.99	1.62
2016	1329.9	150.8	92.2	0.0	136.7	-31.5	73.7	42.3	464.1	102.3	6.88	1.52
2017	1274.5	144.5	92.2	0.0	133.3	-31.5	73.7	44.4	456.5	95.8	6.77	1.42
2018	1219.1	138.2	92.2	0.0	130.0	-31.5	73.7	46.6	449.1	89.8	6.66	1.33
2019	1163.7	131.9	92.2	0.0	126.6	-31.5	73.7	48.9	441.8	84.1	6.55	1.25
2020	1108.2	125.6	92.2	0.0	123.3	-31.5	73.7	51.4	434.7	78.8	6.44	1.17
2021	1052.8	119.3	92.2	0.0	119.9	-31.5	73.7	53.9	427.6	73.8	6.34	1.09
2022	997.4	113.1	92.2	0.0	116.6	-31.5	73.7	56.6	420.7	69.2	6.24	1.03
2023	942.0	106.8	92.2	0.0	113.2	-31.5	73.7	59.5	413.9	64.8	6.14	0.96
2024	886.6	100.5	92.2	0.0	109.9	-31.5	73.7	62.4	407.2	60.7	6.04	0.90
2025	831.2	94.2	92.2	0.0	106.5	-31.5	73.7	65.6	400.7	56.9	5.94	0.84
2026	775.8	87.9	92.2	0.0	103.2	-31.5	73.7	68.8	394.4	53.4	5.85	0.79
2027	720.4	81.7	92.2	0.0	99.8	-31.5	73.7	72.3	388.2	50.0	5.75	0.74
2028	664.9	75.4	92.2	0.0	96.5	-31.5	73.7	75.9	382.2	46.9	5.67	0.70
2029	609.5	69.1	92.2	0.0	93.2	-31.5	73.7	79.7	376.3	44.0	5.58	0.65

SUM OF THE PRESENT WORTH OF THE REVENUE REQUIREMENTS TO STARTUP = 6229.7

Table D.2. Annual revenue requirements (BE nuclear plant located in region 5: all cost components)

YEAR	ANN COSTS IN NOMINAL $M: CAPITAL	FUEL	O&M	DECOMM	TOTAL	ANN COSTS IN 1986. CONST $M: CAPITAL	FUEL	O&M	DECOMM	TOTAL
2000	814.4	108.9	102.4	8.4	1034.1	391.7	52.4	49.2	4.0	497.4
2001	788.2	88.7	107.5	8.8	993.2	361.1	40.6	49.2	4.0	455.0
2002	748.9	85.0	112.9	9.3	956.0	326.7	37.1	49.2	4.0	417.1
2003	714.0	89.0	118.5	9.7	931.3	296.7	37.0	49.2	4.0	387.0
2004	683.6	97.2	124.4	10.2	915.4	270.5	38.5	49.2	4.0	362.3
2005	653.2	108.3	130.6	10.7	903.0	246.2	40.8	49.2	4.0	340.3
2006	622.9	117.9	137.2	11.3	889.3	223.6	42.3	49.2	4.0	319.2
2007	594.9	125.8	144.0	11.8	876.6	203.4	43.0	49.2	4.0	299.7
2008	566.9	133.5	151.2	12.4	864.0	184.6	43.5	49.2	4.0	281.3
2009	538.9	140.9	158.8	13.1	851.7	167.1	43.7	49.2	4.0	264.1
2010	511.1	148.8	166.7	13.7	840.3	150.9	43.9	49.2	4.0	248.1
2011	503.0	157.0	175.1	14.4	849.5	141.5	44.1	49.2	4.0	238.9
2012	495.1	165.5	183.8	15.1	859.6	132.6	44.3	49.2	4.0	230.2
2013	487.2	174.6	193.0	15.9	870.7	124.3	44.5	49.2	4.0	222.1
2014	479.4	184.1	202.7	16.7	882.9	116.5	44.7	49.2	4.0	214.5
2015	471.7	195.0	212.8	17.5	897.0	109.1	45.1	49.2	4.0	207.6
2016	464.1	205.8	223.4	18.4	911.6	102.3	45.3	49.2	4.0	200.9
2017	456.5	217.1	234.6	19.3	927.5	95.8	45.6	49.2	4.0	194.7
2018	449.1	229.0	246.3	20.2	944.7	89.8	45.8	49.2	4.0	188.8
2019	441.8	241.6	258.7	21.3	963.4	84.1	46.0	49.2	4.0	183.4
2020	434.7	254.9	271.6	22.3	983.5	78.8	46.2	49.2	4.0	178.3
2021	427.6	268.9	285.2	23.4	1005.1	73.8	46.4	49.2	4.0	173.5
2022	420.7	283.7	299.4	24.6	1028.4	69.2	46.7	49.2	4.0	169.1
2023	413.9	299.3	314.4	25.8	1053.4	64.8	46.9	49.2	4.0	165.0
2024	407.2	315.8	330.1	27.1	1080.3	60.7	47.1	49.2	4.0	161.1
2025	400.7	333.2	346.6	28.5	1109.0	56.9	47.3	49.2	4.0	157.5
2026	394.4	351.5	364.0	29.9	1139.8	53.4	47.6	49.2	4.0	154.2
2027	388.2	370.9	382.2	31.4	1172.6	50.0	47.8	49.2	4.0	151.1
2028	382.2	391.3	401.3	33.0	1207.7	46.9	48.0	49.2	4.0	148.2
2029	376.3	412.9	421.3	34.6	1245.1	44.0	48.2	49.2	4.0	145.5

Table D.3. Annual revenue requirements (BE nuclear plant located in region 5: all unit cost components)

	ANN COSTS IN NOMINAL CTS/KWH					ANN COSTS IN 1986. CONST CTS/KWH				
YEAR	CAPITAL	FUEL	O&M	DECOMM	TOTAL	CAPITAL	FUEL	O&M	DECOMM	TOTAL
2000	12.07	1.69	1.52	0.12	15.40	5.81	0.81	0.73	0.06	7.41
2001	11.68	1.37	1.59	0.13	14.78	5.35	0.63	0.73	0.06	6.77
2002	11.10	1.32	1.67	0.14	14.23	4.84	0.57	0.73	0.06	6.21
2003	10.59	1.38	1.76	0.14	13.86	4.40	0.57	0.73	0.06	5.76
2004	10.13	1.50	1.84	0.15	13.64	4.01	0.60	0.73	0.06	5.40
2005	9.68	1.68	1.94	0.16	13.46	3.65	0.63	0.73	0.06	5.07
2006	9.23	1.83	2.03	0.17	13.26	3.31	0.66	0.73	0.06	4.76
2007	8.82	1.95	2.14	0.18	13.08	3.01	0.67	0.73	0.06	4.47
2008	8.40	2.07	2.24	0.18	12.90	2.74	0.67	0.73	0.06	4.20
2009	7.99	2.18	2.35	0.19	12.72	2.48	0.68	0.73	0.06	3.94
2010	7.58	2.30	2.47	0.20	12.55	2.24	0.68	0.73	0.06	3.71
2011	7.46	2.43	2.60	0.21	12.70	2.10	0.68	0.73	0.06	3.57
2012	7.34	2.56	2.73	0.22	12.85	1.97	0.69	0.73	0.06	3.44
2013	7.22	2.70	2.86	0.24	13.02	1.84	0.69	0.73	0.06	3.32
2014	7.11	2.85	3.00	0.25	13.21	1.73	0.69	0.73	0.06	3.21
2015	6.99	3.02	3.15	0.26	13.43	1.62	0.70	0.73	0.06	3.11
2016	6.88	3.18	3.31	0.27	13.65	1.52	0.70	0.73	0.06	3.01
2017	6.77	3.36	3.48	0.29	13.99	1.42	0.71	0.73	0.06	2.92
2018	6.66	3.54	3.65	0.30	14.16	1.33	0.71	0.73	0.06	2.83
2019	6.55	3.74	3.83	0.32	14.44	1.25	0.71	0.73	0.06	2.75
2020	6.44	3.95	4.03	0.33	14.75	1.17	0.72	0.73	0.06	2.67
2021	6.34	4.16	4.23	0.35	15.08	1.09	0.72	0.73	0.06	2.60
2022	6.24	4.39	4.44	0.36	15.43	1.03	0.72	0.73	0.06	2.54
2023	6.14	4.63	4.66	0.38	15.81	0.96	0.73	0.73	0.06	2.48
2024	6.04	4.89	4.89	0.40	16.22	0.90	0.73	0.73	0.06	2.42
2025	5.94	5.15	5.14	0.42	16.68	0.84	0.73	0.73	0.06	2.36
2026	5.85	5.44	5.40	0.44	17.12	0.79	0.73	0.73	0.06	2.31
2027	5.75	5.74	5.67	0.47	17.62	0.74	0.74	0.73	0.06	2.27
2028	5.67	6.05	5.95	0.49	[illegible]	0.70	0.74	0.73	0.06	2.22
2029	5.58	6.39	6.25	0.51	[illegible]	0.65	0.74	0.73	0.06	2.18

Table D.4. Annual revenue requirements (coal-fired plant located in region 5: capital components)

INITIAL INVESTMENT = $ 2862.

TAX DEDUCTIBLE FRACTION OF INITIAL INVESTMENT = 0.7935

YEAR	RATE BASE	RETURN ON CAPITAL	BOOK DEPR	TAX DEPR	INCOME TAXES CURRENT	INCOME TAXES DEFERRED	PROPERTY TAXES	INTERIM REPL	REVENUE REQR. NOMINAL $	REVENUE REQR. 1986 $	CENTS/KWH NOMNL $	CENTS/KWH 1986 $
2000	2680.6	303.9	71.6	113.6	148.3	27.3	57.2	15.0	623.3	299.8	9.24	4.44
2001	2586.2	293.2	71.6	227.1	87.9	82.0	57.2	15.8	607.6	278.4	9.01	4.13
2002	2437.2	276.3	71.6	204.4	89.8	71.1	57.2	16.6	582.5	254.2	8.64	3.77
2003	2299.1	260.6	71.6	181.7	92.4	60.2	57.2	17.4	559.4	232.4	8.29	3.45
2004	[illegible]71.9	246.2	71.6	159.0	95.7	49.2	57.2	18.3	538.1	213.0	7.98	3.16
2005	2055.7	233.0	71.6	159.0	88.6	49.2	57.2	19.2	518.9	195.6	7.69	2.90
2006	1939.4	219.8	71.6	136.3	92.6	38.3	57.2	20.1	499.6	179.3	7.41	2.66
2007	1834.1	207.9	71.6	136.3	86.2	38.3	57.2	21.1	482.3	164.9	7.13	2.44
2008	1728.8	196.0	71.6	136.3	79.8	38.3	57.2	22.2	465.1	151.4	6.90	2.24
2009	1623.5	184.0	71.6	136.3	73.5	38.3	57.2	23.3	447.9	138.9	6.64	2.06
2010	1518.2	172.1	71.6	136.3	67.1	38.3	57.2	24.5	430.8	127.2	6.39	1.89
2011	1412.9	160.2	71.6	136.3	60.8	38.3	57.2	25.7	413.7	116.4	6.13	1.73
2012	1307.6	148.2	71.6	136.3	54.4	38.3	57.2	27.0	396.7	106.3	5.88	1.58
2013	1202.4	136.3	71.6	136.3	48.1	38.3	57.2	28.3	379.8	96.9	5.63	1.44
2014	1097.1	124.4	71.6	136.3	41.7	38.3	57.2	29.8	362.9	88.2	5.38	1.31
2015	991.8	112.4	71.6	0.0	101.0	-27.3	57.2	31.2	346.1	80.1	5.13	1.19
2016	952.1	107.9	71.6	0.0	98.6	-27.3	57.2	32.8	340.8	75.1	5.05	1.11
2017	912.4	103.4	71.6	0.0	96.2	-27.3	57.2	34.4	335.5	70.4	4.97	1.04
2018	872.7	98.9	71.6	0.0	93.8	-27.3	57.2	36.2	330.3	66.0	4.90	0.98
2019	833.1	94.4	71.6	0.0	91.4	-27.3	57.2	38.0	325.2	61.9	4.82	0.92
2020	793.4	89.9	71.6	0.0	89.0	-27.3	57.2	39.9	320.2	58.1	4.75	0.86
2021	753.7	85.4	71.6	0.0	86.5	-27.3	57.2	41.9	315.4	54.4	4.68	0.81
2022	714.1	80.9	71.6	0.0	84.2	-27.3	57.2	44.0	310.6	51.1	4.60	0.76
2023	674.4	76.4	71.6	0.0	81.8	-27.3	57.2	46.2	305.9	47.9	4.53	0.71
2024	634.7	71.9	71.6	0.0	79.4	-27.3	57.2	48.5	301.3	44.9	4.47	0.67
2025	595.1	67.5	71.6	0.0	77.0	-27.3	57.2	50.9	296.8	42.2	4.40	0.63
2026	555.4	63.0	71.6	0.0	74.6	-27.3	57.2	53.4	292.5	39.6	4.34	0.59
2027	515.7	58.5	71.6	0.0	72.2	-27.3	57.2	56.1	288.2	37.1	4.27	0.55
2028	476.0	54.0	71.6	0.0	69.8	-27.3	57.2	58.9	284.1	34.9	4.21	0.52
2029	436.4	49.5	71.6	0.0	67.4	-27.3	57.2	61.9	280.2	32.7	4.15	0.49

SUM OF THE PRESENT WORTH OF THE REVENUE REQUIREMENTS TO STARTUP = 4869.9

Table D.5. Annual revenue requirements (coal-fired plant located in region 5: all cost components)

	ANN COSTS IN NOMINAL $M					ANN COSTS IN 1986. CONST $M				
YEAR	CAPITAL	FUEL	O&M	DECOMM	TOTAL	CAPITAL	FUEL	O&M	DECOMM	TOTAL
2000	623.3	290.9	82.7	1.4	998.3	299.8	139.9	39.8	0.7	480.2
2001	607.6	305.4	86.9	1.5	1001.4	278.4	139.9	39.8	0.7	458.8
2002	582.5	320.7	91.2	1.5	996.0	254.2	139.9	39.8	0.7	434.6
2003	559.4	336.7	95.8	1.6	993.5	232.4	139.9	39.8	0.7	412.8
2004	538.1	353.6	100.6	1.7	994.0	213.0	139.9	39.8	0.7	393.4
2005	518.9	371.2	105.6	1.8	997.5	195.6	139.9	39.8	0.7	375.9
2006	499.6	389.8	110.9	1.9	1002.2	179.3	139.9	39.8	0.7	359.7
2007	482.3	409.3	116.4	2.0	1010.0	164.9	139.9	39.8	0.7	345.3
2008	465.1	429.8	122.2	2.1	1019.2	151.4	139.9	39.8	0.7	331.8
2009	447.9	451.3	128.3	2.2	1029.7	138.9	139.9	39.8	0.7	319.3
2010	430.8	473.8	134.8	2.3	1041.6	127.2	139.9	39.8	0.7	307.6
2011	413.7	497.5	141.5	2.4	1055.1	116.4	139.9	39.8	0.7	296.7
2012	396.7	522.4	148.6	2.5	1070.2	106.3	139.9	39.8	0.7	286.7
2013	379.8	548.5	156.0	2.6	1086.9	96.9	139.9	39.8	0.7	277.3
2014	362.9	575.9	163.8	2.8	1105.4	88.2	139.9	39.8	0.7	268.6
2015	346.1	604.7	172.0	2.9	1125.7	80.1	139.9	39.8	0.7	260.5
2016	340.8	635.0	180.6	3.1	1159.4	75.1	139.9	39.8	0.7	255.5
2017	335.5	666.7	189.6	3.2	1195.0	70.4	139.9	39.8	0.7	250.8
2018	330.3	700.0	199.1	3.4	1232.8	66.0	139.9	39.8	0.7	246.4
2019	325.2	735.0	209.1	3.5	1272.9	61.9	139.9	39.8	0.7	242.3
2020	320.2	771.8	219.5	3.7	1315.3	58.1	139.9	39.8	0.7	238.5
2021	315.4	810.4	230.5	3.9	1360.1	54.4	139.9	39.8	0.7	234.8
2022	310.6	850.9	242.0	4.1	1407.5	51.1	139.9	39.8	0.7	231.5
2023	305.9	893.4	254.1	4.3	1457.7	47.9	139.9	39.8	0.7	228.3
2024	301.3	938.1	266.8	4.5	1510.7	44.9	139.9	39.8	0.7	225.3
2025	296.8	985.0	280.2	4.7	1566.7	42.2	139.9	39.8	0.7	222.6
2026	292.5	1034.3	294.2	5.0	1625.9	39.6	139.9	39.8	0.7	220.0
2027	288.2	1086.0	308.9	5.2	1688.3	37.1	139.9	39.8	0.7	217.5
2028	284.1	1140.3	324.3	5.5	1754.2	34.9	139.9	39.8	0.7	215.3
2029	280.2	1197.3	340.5	5.8	1823.8	32.7	139.9	39.8	0.7	213.1

Table D.6. Annual revenue requirements (coal-fired plant located in region 5: all unit cost components)

YEAR	ANN COSTS IN NOMINAL CTS/KWH: CAPITAL	FUEL	O&M	DECOMM	TOTAL	ANN COSTS IN 1986. CONST CTS/KWH: CAPITAL	FUEL	O&M	DECOMM	TOTAL
2000	9.24	4.31	1.23	0.02	14.80	4.44	2.07	0.59	0.01	7.12
2001	9.01	4.53	1.29	0.02	14.85	4.13	2.07	0.59	0.01	6.80
2002	8.64	4.75	1.35	0.02	14.77	3.77	2.07	0.59	0.01	6.44
2003	8.29	4.99	1.42	0.02	14.73	3.45	2.07	0.59	0.01	6.12
2004	7.98	5.24	1.49	0.03	14.74	3.16	2.07	0.59	0.01	5.83
2005	7.69	5.50	1.57	0.03	14.79	2.90	2.07	0.59	0.01	5.57
2006	7.41	5.78	1.64	0.03	14.86	2.66	2.07	0.59	0.01	5.33
2007	7.15	6.07	1.73	0.03	14.97	2.44	2.07	0.59	0.01	5.12
2008	6.90	6.37	1.81	0.03	15.11	2.24	2.07	0.59	0.01	4.92
2009	6.64	6.69	1.90	0.03	15.27	2.06	2.07	0.59	0.01	4.73
2010	6.39	7.02	2.00	0.03	15.44	1.89	2.07	0.59	0.01	4.56
2011	6.13	7.38	2.10	0.04	15.64	1.73	2.07	0.59	0.01	4.40
2012	5.88	7.74	2.20	0.04	15.87	1.58	2.07	0.59	0.01	4.25
2013	5.63	8.13	2.31	0.04	16.11	1.44	2.07	0.59	0.01	4.11
2014	5.38	8.54	2.43	0.04	16.39	1.31	2.07	0.59	0.01	3.98
2015	5.13	8.97	2.55	0.04	16.69	1.19	2.07	0.59	0.01	3.86
2016	5.05	9.41	2.68	0.05	17.19	1.11	2.07	0.59	0.01	3.79
2017	4.97	9.88	2.81	0.05	17.72	1.04	2.07	0.59	0.01	3.72
2018	4.90	10.38	2.95	0.05	18.28	0.98	2.07	0.59	0.01	3.65
2019	4.82	10.90	3.10	0.05	18.87	0.92	2.07	0.59	0.01	3.59
2020	4.75	11.44	3.25	0.06	19.50	0.86	2.07	0.59	0.01	3.54
2021	4.68	12.01	3.42	0.06	20.16	0.81	2.07	0.59	0.01	3.48
2022	4.60	12.61	3.59	0.06	20.87	0.76	2.07	0.59	0.01	3.43
2023	4.53	13.25	3.77	0.06	21.61	0.71	2.07	0.59	0.01	3.38
2024	4.47	13.91	3.96	0.07	22.40	0.67	2.07	0.59	0.01	3.34
2025	4.40	14.60	4.15	0.07	23.23	0.63	2.07	0.59	0.01	3.30
2026	4.34	15.33	4.36	0.07	24.10	0.59	2.07	0.59	0.01	3.26
2027	4.27	16.10	4.58	0.08	25.03	0.55	2.07	0.59	0.01	3.22
2028	4.21	16.90	4.81	0.08	26.01	0.52	2.07	0.59	0.01	3.19
2029	4.15	17.75	5.05	0.09	27.04	0.49	2.07	0.59	0.01	3.16

Table D.7. Annual cash flows (BE nuclear plant located in region 5)

INVESTMENT TAX CREDIT FRACTION = 0.0800

YEAR	CAPITAL INV	CURRENT TAXES	INTERIM REPL	PROP TAXES	DECOMMISS FUND	DIVID INT.PD.	TOT.CAP. REV.	CAP CSH FLOW	FUEL CSH FLOW	TOT CSH FLOW
1992.0	113.9	0.0	0.0	0.0	0.0	0.0	0.0	-113.9	0.0	-113.9
1993.0	127.4	0.0	0.0	0.0	0.0	0.0	0.0	-127.4	0.0	-127.4
1994.0	407.3	0.0	0.0	0.0	0.0	0.0	0.0	-407.3	0.0	-407.3
1995.0	565.3	0.0	0.0	0.0	0.0	0.0	0.0	-565.3	0.0	-565.3
1996.0	653.4	0.0	0.0	0.0	0.0	0.0	0.0	-653.4	0.0	-653.4
1997.0	649.9	0.0	0.0	0.0	0.0	0.0	0.0	-649.9	0.0	-649.9
1998.0	547.7	0.0	0.0	0.0	0.0	0.0	0.0	-547.7	-80.1	-627.8
1999.0	357.1	-273.0	0.0	0.0	0.0	0.0	0.0	-83.4	-106.0	-189.4
2000.0	0.0	165.4	19.4	73.7	8.4	316.8	822.8	239.0	16.0	254.9
2001.0	0.0	80.3	20.3	73.7	8.8	302.6	797.0	311.2	-8.4	302.8
2002.0	0.0	91.5	21.3	73.7	9.3	281.5	758.1	280.8	-18.4	262.4
2003.0	0.0	104.3	22.4	73.7	9.7	262.6	723.8	250.9	-21.3	229.6
2004.0	0.0	93.3	23.5	73.7	10.2	246.1	693.8	246.9	-21.0	225.9
2005.0	0.0	82.4	24.7	73.7	10.7	229.5	664.0	242.9	-18.3	224.6
2006.0	0.0	84.0	25.9	73.7	11.3	213.0	634.2	226.2	25.9	252.1
2007.0	0.0	73.8	27.2	73.7	11.8	197.6	606.7	222.5	-2.6	219.0
2008.0	0.0	63.6	28.6	73.7	12.4	182.2	579.3	218.7	-14.5	204.2
2009.0	0.0	53.4	30.0	73.7	13.1	166.8	552.0	214.9	-15.6	199.4
2010.0	0.0	156.7	31.5	73.7	13.7	151.4	524.8	97.6	9.2	106.9
2011.0	0.0	153.4	33.1	73.7	14.4	146.4	517.4	96.4	-16.7	79.7
2012.0	0.0	150.0	34.8	73.7	15.1	141.3	510.2	95.2	-18.1	77.1
2013.0	0.0	146.7	36.5	73.7	15.9	136.3	503.1	93.9	-19.6	74.3
2014.0	0.0	143.3	38.3	73.7	16.7	131.2	496.0	92.7	-16.6	76.1
2015.0	0.0	140.0	40.2	73.7	17.5	126.2	489.2	91.5	-22.1	69.4
2016.0	0.0	136.7	42.3	73.7	18.4	121.2	482.4	90.2	-23.9	66.4
2017.0	0.0	133.3	44.4	73.7	19.3	116.1	475.8	89.0	-25.7	63.3
2018.0	0.0	130.0	46.6	73.7	20.2	111.1	469.4	87.8	-27.7	60.1
2019.0	0.0	126.6	48.9	73.7	21.3	106.0	463.1	86.5	-29.9	56.7
2020.0	0.0	123.3	51.4	73.7	22.3	101.0	457.0	85.3	-32.2	53.1
2021.0	0.0	119.9	53.9	73.7	23.4	95.9	451.0	84.1	68.5	152.6
2022.0	0.0	116.6	56.6	73.7	24.6	90.9	445.3	82.8	-6.5	76.3
2023.0	0.0	113.2	59.5	73.7	25.8	85.8	439.7	81.6	-32.5	49.1
2024.0	0.0	109.9	62.4	73.7	27.1	80.8	434.3	80.4	-35.1	45.2
2025.0	0.0	106.5	65.6	73.7	28.5	75.7	429.2	79.1	15.9	95.0
2026.0	0.0	103.2	68.8	73.7	29.9	70.7	424.3	77.9	-38.4	39.5
2027.0	0.0	99.8	72.3	73.7	31.4	65.6	419.6	76.7	-41.6	35.1
2028.0	0.0	96.5	75.9	73.7	33.0	60.6	415.1	75.4	-45.0	30.4
2029.0	0.0	93.2	79.7	73.7	34.6	55.5	411.0	74.2	-39.1	35.1

Table D.8. Annual cash flows (coal-fired plant located in region 5)

INVESTMENT TAX CREDIT FRACTION = 0.0800

YEAR	CAPITAL INV	CURRENT TAXES	INTERIM REPL	PROP TAXES	DECOMMISS FUND	DIV.PD.	TOTAL REV	CASH FLOW
1994.0	58.9	0.0	0.0	0.0	0.0	0.0	0.0	-58.9
1995.0	139.4	0.0	0.0	0.0	0.0	0.0	0.0	-139.4
1996.0	576.4	0.0	0.0	0.0	0.0	0.0	0.0	-576.4
1997.0	790.0	0.0	0.0	0.0	0.0	0.0	0.0	-790.0
1998.0	736.7	0.0	0.0	0.0	0.0	0.0	0.0	-736.7
1999.0	413.9	-217.2	0.0	0.0	0.0	0.0	0.0	-196.7
2000.0	0.0	148.3	15.0	57.2	1.4	244.2	624.7	158.6
2001.0	0.0	87.9	15.8	57.2	1.5	235.6	609.1	211.1
2002.0	0.0	89.8	16.6	57.2	1.5	222.0	584.1	196.9
2003.0	0.0	92.4	17.4	57.2	1.6	209.4	561.0	182.9
2004.0	0.0	95.7	18.3	57.2	1.7	197.9	539.9	169.1
2005.0	0.0	88.6	19.2	57.2	1.8	187.3	520.7	166.5
2006.0	0.0	92.6	20.1	57.2	1.9	176.7	501.5	153.0
2007.0	0.0	86.2	21.1	57.2	2.0	167.1	484.3	150.7
2008.0	0.0	79.8	22.2	57.2	2.1	157.5	467.2	148.3
2009.0	0.0	73.5	23.3	57.2	2.2	147.9	450.1	146.0
2010.0	0.0	67.1	24.5	57.2	2.3	138.3	433.1	143.6
2011.0	0.0	60.8	25.7	57.2	2.4	128.7	416.1	141.3
2012.0	0.0	54.4	27.0	57.2	2.5	119.1	399.2	138.9
2013.0	0.0	48.1	28.3	57.2	2.6	109.5	382.4	136.6
2014.0	0.0	41.7	29.8	57.2	2.8	99.9	365.7	134.3
2015.0	0.0	101.0	31.2	57.2	2.9	90.3	349.0	66.3
2016.0	0.0	98.6	32.8	57.2	3.1	86.7	343.8	65.4
2017.0	0.0	96.2	34.4	57.2	3.2	83.1	338.7	64.5
2018.0	0.0	93.8	36.2	57.2	3.4	79.5	333.7	63.6
2019.0	0.0	91.4	38.0	57.2	3.5	75.9	328.8	62.8
2020.0	0.0	89.0	39.9	57.2	3.7	72.3	324.0	61.9
2021.0	0.0	86.6	41.9	57.2	3.9	68.7	319.3	61.0
2022.0	0.0	84.2	44.0	57.2	4.1	65.1	314.7	60.1
2023.0	0.0	81.8	46.2	57.2	4.3	61.4	310.2	59.2
2024.0	0.0	79.4	48.5	57.2	4.5	57.8	305.8	58.3
2025.0	0.0	77.0	50.9	57.2	4.7	54.2	301.6	57.5
2026.0	0.0	74.6	53.4	57.2	5.0	50.6	297.4	56.6
2027.0	0.0	72.2	56.1	57.2	5.2	47.0	293.5	55.7
2028.0	0.0	69.8	58.9	57.2	5.5	43.4	289.6	54.8
2029.0	0.0	67.4	61.9	57.2	5.8	39.8	286.0	53.9

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