COMPARATIVE COSTS OF COAL AND NUCLEAR-GENERATED ELECTRICITY IN THE UNITED STATES

W. W. BRANDFON, Sargent & Lundy
55 East Monroe Street
Chicago, Illinois 60603
(312) 269-3140

ABSTRACT

This paper compares the future first-year operating costs and lifetime levelized costs of producing baseload coal- and nuclear-generated electricity under schedules shorter than those recently experienced at U.S. plants. Nuclear appears to have a clear economic advantage. Coal is favorable only when it is assumed that the units will operate at very low capacity factors and/or when the capital cost differential between nuclear and coal is increased far above the recent historical level. Nuclear is therefore a cost-competitive electric energy option for utilities and should be considered as an alternative to coal when large baseload capacity is required.

INTRODUCTION

The American nuclear program has been halted by a confluence of unfortunate circumstances that include unpredictable regulation, overcapacity, an uncertain economic outlook, and various financial constraints. These problems have been exacerbated by the public opposition and fear that followed in the wake of the accidents at Three Mile Island in 1979 and at Chernobyl 7 years later.

A resurgence in electricity demand and an increased concern over the environmental effects of burning coal are expected to occur in America and elsewhere. Accompanying these events will continue considerable interest in the relative economics of coal-generated and nuclear-generated electricity. These are the logical sources of energy for the long-range supply of bulk electric power.

This paper describes the methodology, assumptions, and results of a study of the first-year costs and lifetime costs of generating electricity from yet-to-be-constructed coal-fired and uranium-fueled electric plants, using schedules actually followed in the United States for "custom designed" plants. Lifetime generating costs are also developed in this paper for plants with achievable, shorter-than-current lead times and demonstrably efficient plant design, construction, and operation. Such conditions have been experienced recently in many nations throughout the world as well as in the United States in spite of a difficult regulatory environment. Other assumptions, which are used as the basis for the study discussed in this paper, as well as cost projections and evaluation procedures relating to construction materials, labor, services, nuclear and coal fuels, operation, maintenance, and decommissioning, conform to the most up-to-date U.S. practice. The most important of these assumptions are listed in Table 1.

METHODOLOGY

Thirty-year lifetime generating costs were developed for two 1200-MWe PWR nuclear units, four 600-MW high-sulfur coal-fired units, and four 600-MW low-sulfur coal-fired units. Midwestern U.S. installation was assumed, since both types of coal have been used in this area and since reliable historical cost information upon which to base the cost estimates is available.

In developing lifetime costs of power generation, the conventional U.S. practice is to add the major elements - capital investment, fuel, and other operation and maintenance expenses - and divide the sum of their costs by the average annual electrical production in kilowatt hours (kWh). This yields a total cost expressed in cents per kWh, the usual criterion of economic choice.

Preoperational capital investment expenditures must be added to the annual fuel and other costs that are incurred after operation starts. To do this, a "fixed charge rate" is developed. This is a factor that converts the investment into a stream of annual "fixed charges," which can then be added to the annual fuel and other production costs.

Table 1. Comparative costs of coal-generated and nuclear-generated electricity in the United States.

Principal Assumptions

Number and Size of Units	
Nuclear	Two at 1200 MW (nominal)
Coal	Four at 600 MW (nominal)
Location	Midwest U.S.A.
Service Life, All Units	30 years
Project Schedules	See Figure 1
Capacity Factor	65%
Inflation Rate	4.1%/yr
Real Rate of Escalation After Startup	0%/yr
Capital Structure	
Common Stock	45% at 14.0%
Preferred	10% at 8.55%
Debt	45% at 8.55%
Composite Cost	11.0%/yr
Federal Tax Rate	34%
Discount Rate (After Tax)	9.69%/yr
Financing (AFUDC) Rate	11.0%/yr
Levelized Fixed Charge Rate[1]	
Nuclear	13.4%/yr
Coal	13.8%/yr
Inventory Carrying Charge Rate[1]	15.0%/yr
Tax Depreciation (150% Declining Balance, Switch to Straight Line)	
Nuclear	15 yr
Coal	20 yr

Fuel Data		Jan. 1986 Price Levels Delivered Price in Jan. 1986	Jan. 2000
Nuclear			
U308 ($/lb)		28	35
Conversion ($/kg of uranium)		7	7
Enrichment ($/separative work unit, SWU)		119	100
Fabrication ($/kg of uranium)		200	200
Disposal (mills/kWh)		1	1
Refueling Outage	80 days		
Cycle Length	12 months		
Discharge Burnup	48,000 MW-days/ metric ton of uranium		
Coal			
High-Sulfur ($/ton)		36.09	36.96
Low-Sulfur ($/ton)		63.55	44.74
Inventory Level	60 days		

Reagent Quantities Consumed and Solid Waste Discharged for Each 600-MW Coal Unit

Coal Type	Heating Value[5] (Btu/lb)	Sulfur Content[5] (%)	Ash Content[5] (%)	Requirements at 65% Capacity Factor (tons/day) Lime	Sludge	Ash
High-Sulfur	10,900	2.8	9.7	216	1346	78
Low-Sulfur	9,500	0.5	6.6	39	475	64

Operating and Maintenance Data (Costs in 1987 Dollars)

Reactant Costs	
Lime	$80.00/ton
Escalation Rate[4]	5.5%/yr
Sludge Disposal Cost (10-Mile Radius)	$6.00/ton
Ash Disposal (10-Mile Radius)	$6.00/ton
Escalation Rates (Disposal Costs)[4]	5.5%/yr
Nonfuel-Related Operation and Maintenance Costs	
Labor Rates[2]	
Coal Units	$20.12/man-hour
Nuclear Units	$23.05/man-hour
Escalation Rates[4]	
Labor	5.2%/yr
Maintenance Materials	5.2%/yr
Supplies and Expenses	5.5%/yr

System Parameters[3]	Pulverized Coal High-Sulfur	Low-Sulfur	Nuclear
Nominal Output (MW)	600	600	1,200
Sulfur Removed (%)	90	70	-
FGD System Type of Reagent	Wet lime	Dry lime	-
Net Plant Heat Rate (Btu/kWh)	9,488	9,901	10,224
Total Labor Requirements (number of persons)			
Unit 1, 600 MW	234	216	-
Unit 2, 600 MW	295	269	-
Unit 3, 600 MW	368	334	-
Unit 4, 600 MW	440	398	-
Unit 1, 1200 MW	-	-	417
Unit 2, 1200 MW	-	-	564
Maintenance Materials (% of maintenance labor)			
Fixed	62	55	75
Variable (at 65% capacity factor)	16	15	20
Supplies and Expenses			
Fixed ($/yr-unit) x 1,000,000	$2.500	$2.500	$5.500
Variable ($/MW-hr)	0.137	0.137	0.113
Administrative and General (% of total O&M)	30	30	30

Notes:
1 No state or property taxes.
2 Includes fringe benefits, supervisory overheads, and skill premiums.
3 Parameter values represent single units.
4 Escalation applied up to January 1998. Subsequently, escalation considered at 4.1%/yr.
5 Source: U.S. Department of Energy.

C1126-3
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PROJECT SCHEDULES

To develop a pattern for preoperational expenditures of capital, it is necessary to first postulate a project schedule. This sets out the major activities involved in design, procurement of equipment, construction, testing, and the myriad of other activities involved in bringing a large project to fruition.

Two such schedules have been projected, with their durations, start, and finish dates illustrated in Figure 1. Both these schedules contemplate a need for 2400 MWe of electric power on line between 1997 and 2000, with units entering service 1 year apart.

The first schedule is called a "Custom Design Schedule." It contemplates a 10-1/4 year project duration (authorization to operation) for the initial nuclear unit, including a 67-month construction period from site excavation to receipt of an operating license from the U.S. Nuclear Regulatory Commission (U.S. NRC). The duplicate follow-on nuclear unit can then be operational in about 6 years since many of the front-end activities, such as design and licensing, will have been accomplished on the first unit.

The first of the four "Custom Design" coal units is expected to take 6-1/4 years from authorization to operation. This schedule includes 30 months for licensing and 45 months for construction. The three duplicate coal units should take about 53 months from authorization to operation, since the licensing and design will already have been accomplished.

To test the impact of shortened project durations, a "Reference Design Schedule" was developed, based on the utilization of preapproved sites and adjudicated, preapproved designs. The initial nuclear unit is predicated upon a 26-month licensing process (from initiation of the preliminary safety analysis report to the U.S. NRC's issuance of the construction permit) and a 62-month period of construction. The overall project duration is 8 years. The duplicate follow-on nuclear unit has a project duration of only 6 years since licensing and design will have been accomplished previously.

The project duration of the initial "Reference Design" coal unit is 63 months (5-1/4 years) since the design and licensing will already have been accomplished. About 45 months are allowed for construction of both the initial and duplicate follow-on coal units, but the add-

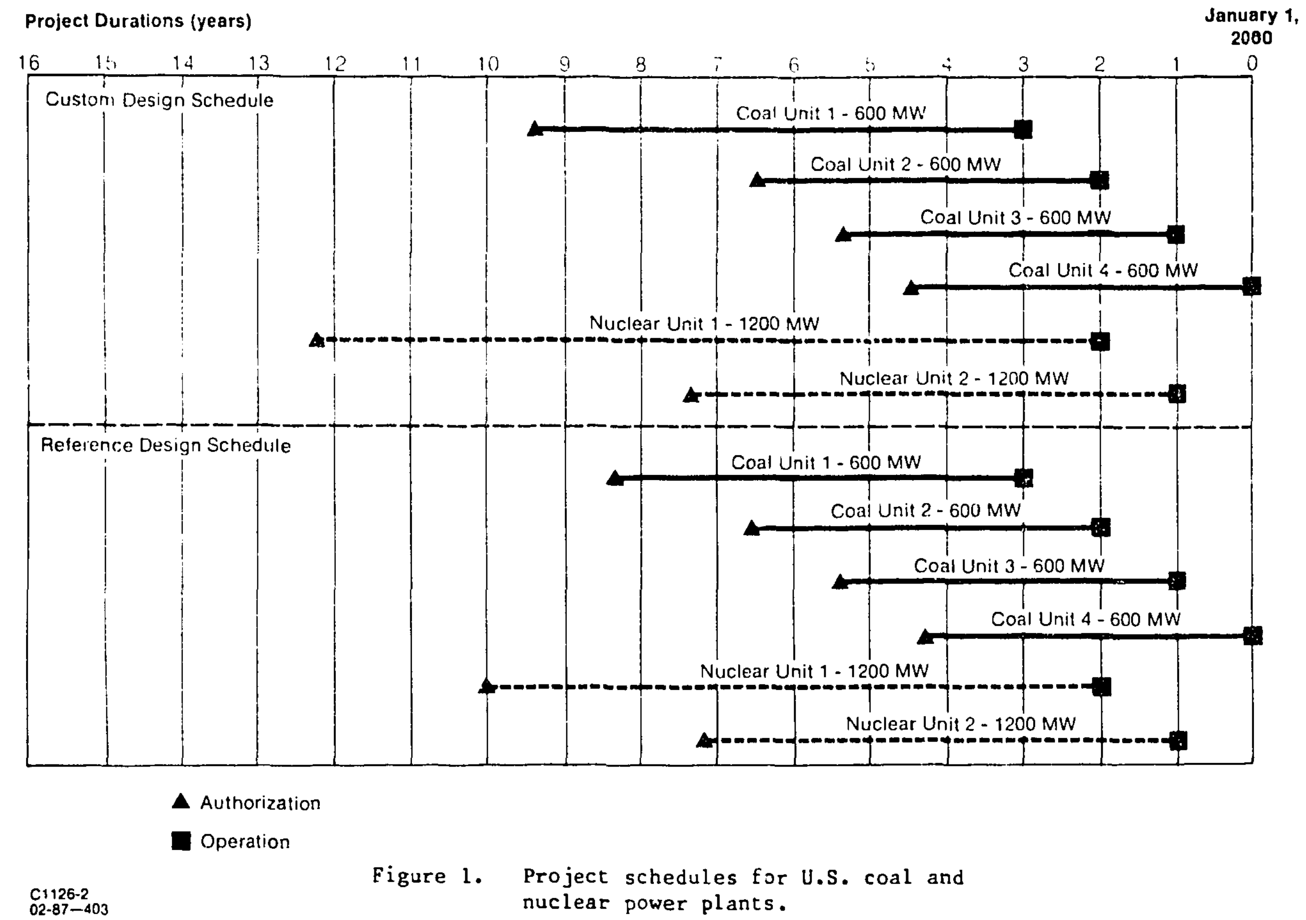

Figure 1. Project schedules for U.S. coal and nuclear power plants.

on units have a shorter overall schedule of 54 months (4-1/2 years) since detail design is assumed to have been accomplished and equipment procurement lead times are reduced.

These schedules are considerably shorter than those experienced recently at U.S. plants. For example, the average project duration of seven nuclear units commissioned in the United States in 1985 was 173 months, almost 14-1/2 years. Most of the delays that contributed to this time span were attributable to regulatory problems (some resulting from the 1979 accident at Three Mile Island), economic and financial constraints, labor and weather problems, lower-than-forecasted load growth, and public opposition. Studies have shown these delays to be extremely costly. "Shorter-than-experienced" schedules, however, are not without precedent. In the United States, several nuclear units have been completed in under 8 years within the past 4 years despite a difficult regulatory environment. Also, in France, Japan, Sweden, Switzerland, Taiwan of China, Canada, and the United Kingdom, many nuclear units have been commissioned recently in less than 8 years.

A study by the U.S. Electric Power Research Institute (EPRI) of coal plant lead times in the United States found only a small increase in project durations between 1965 and 1980, even though pollution control requirements were significantly increased during that time. The EPRI study also showed that about two-thirds of the construction delays in coal units were deliberately instigated by the owner for various reasons, such as less than originally predicted load growth.

In 1983, EPRI postulated a typical coal project duration of 6 years from start of preliminary engineering to operation; the 5-1/4-year coal schedules analyzed in this study are currently being proposed for future U.S. installations.

INVESTMENT COSTS

Capital investment costs were estimated in great detail for two 1200-MW nuclear units and four 600-MW coal units. The nuclear units were based upon the last PWR unit bid in the United States, modified to include later regulatory requirements (some resulting from lessons learned at Three Mile Island) and more recent design enhancements. The coal units were developed from a reference design established by Sargent & Lundy. Unit sizes were selected as desirable for large utility systems to take advantage of the economies of scale.

A large body of design and estimating experience is available to back up the cost projections for these large units. The costs listed in Table 2 are summaries of the major accounts. They represent detailed cost estimates comprising approximately 2000 line items for each of the nuclear and coal units. The total investment for the "Custom Design" nuclear plant, including financing and escalation, was found to be 1.39 times that of the less costly of the high- or low-sulfur coal plant alternatives. A sensitivity study indicated that, in order for the generating costs to break even (i.e., for the coal-fired plant to become more economical than the nuclear plant on a ¢/kWh basis), the capital cost of the nuclear plant would have to increase by about 20%. This would raise the capital cost of the nuclear plant to $2,785/kW or almost $6.7 billion. The average cost of the seven U.S. nuclear units entering service in 1985 was less than $2,400/kW. Under the more disciplined schedules upon which this study is based, it is unlikely that investment costs would exceed the 1985 experience.

NUCLEAR FUEL COSTS

The costs and escalation rates of coal and nuclear fuels, along with capital investment costs, are vital in any comparison of the two technologies. The nuclear fuel costs assumed for the study are based on operation under a once-through fuel cycle, wherein spent nuclear fuel is turned over to the U.S. Government for disposal under the 1982 Nuclear Waste Policy Act. The fee imposed by the Government for disposing of nuclear waste is 0.1¢/kWh generated. Nuclear fuel revenue requirements include expenditures for uranium, conversion of U308 to uranium hexafloride, enrichment by the U.S. Department of Energy (DOE), private fabrication of fuel assemblies, and spent fuel disposal by the Government. Uranium prices were obtained from a DOE study that covered world uranium supply and demand. The prices were determined for the year 2000 and escalated thereafter at 4.1% per year, a rate equivalent to the coal fuel escalation rate. This assumption biases the study against nuclear power, since delivered coal prices have historically escalated much more rapidly than has the price of uranium.

Suppliers of nuclear fuel enrichment services are operating below full capacity. Existing production capacity is sufficient to meet world demand well into the 1990s. As a consequence, an enrichment market has emerged in which market forces and technology advancements will establish future enrichment prices. The enrichment price projected for the latter part of this century is based on the competitive nature of the market and the introduction of advanced enrichment technology such as the atomic vapor laser isotope separation process. A number of studies have projected the cost of enrichment, which is listed in Table 1 with other nuclear fuel cycle costs. While enrichment costs can be expected to decline throughout the introductory phase, when the production capacity of the advanced technology is increasing, the price of enrichment in this

Table 2. Investment and operating costs of U.S. power-generating stations based on Custom Design and Reference Design Schedules.

	Two 1200-MW Units Nuclear PWR	Four 600-MW Units High-Sulfur Coal Midwest U.S. Site	Four 600-MW Units Low-Sulfur Coal Midwest U.S. Site
Investment Costs (thousands of 1987 dollars)			
Direct Costs			
Structures and Improvements	475,552	234,636	347,993
Reactor Boiler Plant	449,540	1,136,128	1,122,295
Turbine Plant	919,514	422,792	422,792
Electrical Plant	231,293	150,838	153,043
Miscellaneous Plant Equipment	34,695	25,010	25,010
Substation Structures	958	196	196
Substation Equipment	10,027	9,560	9,560
Nuclear Other	84,665	--	--
Total Direct Costs	2,206,264	1,979,160	2,080,890
Indirect Costs			
Owner Costs	204,418	161,634	161,634
Engineering	262,987	73,244	73,244
Construction Management	212,002	34,886	34,886
Total Indirect Costs	679,407	269,764	269,764
Total "Overnight" Investment Costs	2,885,671	2,248,924	2,350,654
Year 2000 Operating Costs (thousands of dollars)			
Fuel Costs	206,720	401,640	582,120
Operation and Maintenance Costs	171,870	201,210	118,810
Custom Design Schedule			
Project Duration of First Unit	10-1/4 yr	6-1/4 yr	6-1/4 yr
Project Duration of Subsequent Units	6 yr	4-1/2 yr	4-1/2 yr
Escalation	1,120,746	1,001,641	1,047,271
Allowance for Funds Used During Construction	1,564,852	745,465	778,496
Total Investment	5,571,269	3,996,030	4,176,421
$/kW	2,321	1,665	1,740
Ratio, Nuclear to Best Coal		1.39	
30-Year Levelized (¢/kWh)			
Capital	3.73	2.79	2.91
Fuel	0.97	2.55	3.70
O&M	1.09	1.28	0.76
Other*	0.54	0.45	0.48
Total	6.33	7.07	7.85
Nuclear Advantage Over Best Coal		10.5%	
Reference Design Schedule (Preapproved Sites and Designs)			
Project Duration of First Unit	8 yr	5-1/4 yr	5-1/4 yr
Project Duration of Subsequent Units	6 yr	4-1/2 yr	4-1/2 yr
Escalation	1,169,180	1,003,801	1,049,431
Allowance for Funds Used During Construction	1,373,708	737,771	770,804
Total Investment	5,428,559	3,990,496	4,170,889
$/kW	2,262	1,663	1,738
30-Year Levelized (¢/kWh) from January 1987			
Capital	3.63	2.78	2.91
Fuel	0.97	2.55	3.70
O&M	1.09	1.28	0.76
Other*	0.54	0.45	0.48
Total	6.23	7.06	7.85
Nuclear Advantage Over Best Coal		11.8%	

*Other includes backfitting, decommissioning, carrying charges on coal inventory.

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study is assumed to be no less than $100 per separative work unit (SWU).

The nuclear fuel cost analysis is based upon an advanced core design that permits up to 18 months between refuelings, with discharge burnups close to 50,000 MW per day per metric tonne of uranium. As a measure of conservatism, this study has assumed a cycle length of 12 months. Performance at higher levels (which would lower nuclear fuel cycle costs) has been verified by extensive testing programs conducted by DOE, fuel vendors, utilities, EPRI, and other research facilities.

COAL FUEL COSTS

Fuel costs at various coal-fired plants differ principally because of the characteristics of the coal, the distance from the coal mine to the plant, and the cost of coal transportation. For plant sites in the Midwest, high-sulfur coal is assumed to originate from the abundant resources of the Illinois Coal Basin, which would minimize transportation costs to those plants. Low-sulfur coal is assumed to come from Wyoming and Montana; therefore, a large component of its delivered price to Midwestern power plants includes transportation costs. Coal prices at the mine are those reported by mine owners to the DOE. Coal transportation costs through the year 2000 were based on a DOE economic model that develops costs for coal movements between supply regions and demand regions as a function of distance, terrain, rail congestion, and competition. After the year 2000, the cost of both coal at the mine itself and its transportation component are assumed to escalate at the base inflation rate used in this study, 4.1% per year. The assumed inflation rate represents a consensus of about 50 U.S. economic forecasting organizations.

This study assumes that nuclear and coal fuels will escalate at the same rate after 2000, which is the approximate date of commercial operation of the plants under study. Surveys of electric utilities operating both coal- and nuclear-fueled power plants show that the cost of coal burned in their boilers between 1980 and 1985 rose from 1.5¢ to 1.9¢/kWh. Nuclear fuel costs moved at a lower level between 0.5¢ and 0.7¢/kWh over the same period.

OTHER COSTS

Nonfuel Operation and Maintenance Expenses

These expenses include costs for the plant staff, maintenance materials, supplies, and offsite support services, and administrative and general expenses. Additionally, U.S. NRC inspection fees and nuclear insurance expenses for the nuclear units, and reactant costs for the coal alternatives, are also considered in the estimates. The methodology used in developing these costs is based upon surveys and procedures developed by a national laboratory in the United States and includes flue-gas desulfurization (FGD) systems for the coal units. The systems used as a basis were wet lime throwaway systems for units that use high-sulfur coal and dry lime/spray drying FGD systems for units using low-sulfur coal. FGD expenses include costs for lime reactant and for ash and sludge disposal as listed in Table 1.

Decommissioning Costs

Decommissioning costs for both coal and nuclear facilities have been included. The reliability of these projections, which are for largely untried procedures to be accomplished more than 50 years in the future, is perhaps more speculative than any of the other factors considered in the study. Nevertheless, detailed estimates have been made by knowledgeable industry authorities and entered into the calculations. The present and levelized values of these expenditures to be made in the distant future are very small, however, and have a negligible impact on the results.

Backfitting Costs

A more significant factor in the evaluation involves capitalized expenditures to be added to both nuclear and coal plant accounts after commercial operation of the units. Studies based on capital additions reported to DOE form the basis for the development of these costs. Included are plant equipment, materials, and services associated with the replacement of and the refurbishment, enhancement, and regulatory backfitting work to the original installations. These interim capital additions, or backfitting charges, were escalated; related annual carrying charges were developed; and the aggregate was added to the other annual costs of generation.

PERFORMANCE

Plant capacity factor is the performance measure most commonly used in economic studies of this type. It is the ratio of the actual electricity production during a given period divided by the electricity that could have been produced if the plant had run continuously at its maximum rating. When the annual plant capacity factor is multiplied by the plant's maximum possible energy generation, the result provides the output over which annual costs are spread. For most of the 5-year period ending in 1985, coal and nuclear capacity factors have generally been comparable, with nuclear units operating at slightly higher capacity factors during most of this period. This is principally a result of preferential loading because of nuclear units' lower fuel costs.

The mass of statistical data indicates long-term equality of operating performance for coal and nuclear plants. The 65% capacity factor used in this study is considered a reasonable level for the future, considering the performance of many U.S. and non-U.S. plants is more favorable now than it was previously. Operation at higher capacity factors will favor the nuclear units because the fixed charges on their larger required capital investment will be spread over a larger kilowatt-hour base, yielding lower costs per kilowatt hour. The opposite is true at lower capacity factors.

In fact, 65% may indeed be a conservative capacity factor given good operating management. PWRs in five countries in Europe have lifetime capacity factors in excess of 75%, as do six units in the United States.

To test the sensitivity of the generating costs to lower capacity factors, additional computer analyses were performed for both nuclear and coal plants operating at lower energy outputs. It was found that the capacity factor at which both the "Custom Design" nuclear and high-sulfur coal plants would have to operate before coal generating costs became more favorable than nuclear generating costs was 45%. This capacity factor is far below the historical world average of 62.64% in 1985.

CONCLUSIONS

Table 2 shows that for both the Custom and Reference Design Schedules, nuclear power is clearly the economical choice by over 10%. The 10-1/4 year nuclear Custom Design Schedule is only 0.1¢/kWh more costly than the 8-year nuclear Reference Design Schedule. This is because most of the total investment cost differential is experienced before the large expenditures, which are incurred during and after construction. Also, the follow-on nuclear units are assumed to have the same schedule, thus dampening the cost differential.

In summary, this analysis has compared future baseload coal and nuclear alternatives with project schedules shorter than those recently experienced in the United States. Coal appears to have an economic advantage only when it is assumed that the units will operate at very low capacity factors and/or when the capital cost differential between nuclear and coal is increased far above the historical level.

This conclusion conflicts with recent historical data. Annual surveys taken by the U.S. Atomic Industrial Forum show that for units operating since 1970, nuclear units had a generating cost advantage until 1983, after which coal-fired units became more economical. This turnaround was due to the impact of the previous decade's nuclear construction stretch-outs, high interest rates, inflation, and the escalation of regulatory requirements, all of which affected nuclear plants to a greater extent than coal plants. As these high-cost nuclear plants depreciate, their generating costs should decrease to the level of future coal plants, for which the full impact of pollution control restrictions (for acid rain, toxic wastes, etc.) is yet to be felt.

This study shows that from an economic standpoint, nuclear is a cost-competitive electric-energy option for utilities. It should be considered as an alternative to coal when large baseload capacity is required. Project durations are expected to be shorter and more predictable than those that have occurred in the recent past. Shorter lead times have been and can be achieved in the United States and throughout the world. They will come about with a more stable licensing environment, safe operation, continued economic recovery, and a more favorable public perception of the need for adequate electric power, produced efficiently with both coal and uranium fuels.