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AND THE CONSTRUCTION COST
OF COAL-BURNING GENERATING UNITS

By

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ABSTRACT

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The construction cost of a baseload coal-fired generating unit should depend, in general, on the engineering attributes of the unit. Previous studies generally found that there are scale economies in average construction costs over the entire range of observed unit sizes. However, these studies failed to include reliability as an attribute or characteristic of the units. Larger generating units tend to be considerably less reliable than smaller units. Thus, an important unanswered question is whether large generating units have lower average construction costs per KW of capacity because of economies of scale or because of poor quality. The implication is that omitting unit reliability will bias the estimates of the construction cost function. To analyze this question, we develop an ex ante long-run unit reliability and construction cost model. Both unit reliability and construction cost were expressed as functions of the dominant design characteristics of the generating unit. Furthermore, a simultaneous relationship between construction cost and reliability was assumed. The simultaneous-equation model was estimated with a data set that contained observations on 84 coal-fired units that entered commercial operation during the period 1964-1974. The regression estimates were used to evaluate how capital costs per KW and capital costs per KWH responded to

variations in unit size and reliability. Both measures of capital costs were found to be characterized by economies of scale at low levels of reliability and diseconomies at high levels of reliability. The cost minimizing level of reliability for each measure was also found to decrease as unit size increased. Capital cost per KWH generated are found to be lowest for units in the 300-400 MW range with equivalent availabilities of 85 to 90 percent.

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CHAPTER 1

INTRODUCTION

In this dissertation we show that the existence of economies of scale with respect to the construction costs of coal-fired generating units depends on the interaction of the size and reliability of the unit. The costs of building coal-fired units is characterized by economies of scale at low levels of unit reliability, constant returns at higher levels of reliability, and diseconomies at very high levels of reliability. This result is in sharp contrast to the conclusions reached by all other researchers and is of interest for a number of other reasons. First, our results are derived by explicitly taking into account that reliability, as measured by equivalent availability,[1] is an attribute of coal-fired units and in general is inversely related to the size of the unit. Second, we recognize the simultaneous nature of the choice of the attributes of a generation unit and its construction cost. Third, the Federal Energy Regulatory Commission (FERC) has proposed changes in policy which could substantially deregulate the generation of electricity. The proposals deal with competitive bidding for new generation capacity, independent power producers, and the administrative determination of avoided costs. A major concern under all-source bidding is how to evaluate and weigh the price and nonprice characteristics of each proposal when ranking the bids. An important nonprice attribute to include when evaluating a bid for baseload generation capacity is the reliability or availability of the unit. Each of these reasons will be examined in greater detail below.

The Cost of Poor Unit Reliability

A general result of previous studies is that there are scale economies in construction costs over the entire range of observed unit sizes.[2] These studies ignore the ex ante design process in which reliability is a key parameter. As a result, these studies overlook the possibility that a relatively inexpensive baseload coal-fired unit to build may not be so inexpensive to operate if it is frequently out of service due to forced outages or necessary maintenance.

The key issue here is the intensity with which a unit is used. Baseload units are meant to be operated at maximum capacity continuously. The capital intensive nature of baseload coal-fired generation means that the average total generation costs of a unit can be significantly reduced if the unit is used intensively.

Electric utilities consistently increased the average size of new generating units until the mid-1970's.[3] This trend was based on a number of widely held propositions: construction costs per kilowatt of capacity fell as unit size increased;[4] operation and maintenance costs per kilowatt-hour (kwh) could be reduced by building larger units; and that new, larger units historically had lower heat rates.

In general, however, there is a negative relationship between the size and reliability of a generating unit (see Table 1-1). There are a number of reasons for this inverse relationship. One is that the movement to larger units was accompanied by a movement to higher steam pressure conditions. Previous studies generally have found that increases in steam pressure conditions have been associated with higher forced outage rates.[5] Second, similar types of outages are generally

Table 1-1. Average Equivalent Availability Factors in the United States, 1971-1980

Technology - Unit Capacity	Average Equivalent Availability Factor
All fossil-fueled steam	79.61
100 - 199 MW	83.05
200 - 299 MW	80.32
300 - 399 MW	73.88
400 - 599 MW	72.02
600 - 799 MW	69.33
800 MW and above	68.49

Source: Joskow and Schmalensee, 1983

longer for larger units than for smaller units. This is due to the larger area and parts that have to be repaired. And third, more materials and equipment simply create more opportunities for breakdown.[6]

The reliability of a utility system is defined as the ability of the system to meet the demand for power at any given point in time. Individual generating unit reliability is one of the primary determinants of system reliability. The more frequent a generating unit breaks down, the lower the reliability of the system. Thus, the lower average reliability of larger units adds to a utility's total system costs because additional capacity must be built if a given level of system reliability is to be maintained.

Our primary concern is with total per-kwh generation costs at the level of the individual unit. The annual total generation costs of a unit consist of fuel expenses, capital-related costs, and labor expenses. In general these account for 50%, 40%, and 10%, respectively, of total generation costs. Annual capital-related costs are by definition fixed and are the product of the total construction costs of the unit and the annual fixed charge rate for the utility. The fixed charge rate basically consists of property taxes assessed on the unit and the cost of stocks and bonds issued by the utility to finance construction of the unit. A poor level of reliability means that the capital-related costs of a generating unit are spread over a lower level of output than if the unit is used more intensively. Thus, poor unit reliability results in higher average generation costs for the unit.

Poor reliability can also reduce the thermal efficiency of a generating unit.[7] Good heat rate performance is related in general to a high level of utilization because heat loss is fairly constant at any load. So heat loss is relatively larger at low load than at a high load. Deratings also increase heat rates, because restarting a unit means that heat energy must be expended to reheat the boiler and other components. As a result, frequent deratings of a unit due to outages can be expected to increase the unit's average fuel costs. The heat rates of large units are more likely to be adversely affected by frequent deratings because large units, in general, are more prone to outages.

Relationship Between Unit Attributes and Construction Costs

The decision to build a baseload coal-fired unit means that the utility is purchasing a piece of capital equipment with various engineering attributes. Therefore, when comparing different generating units (or any type of capital equipment for that matter), one should make adjustments for any differences in key attributes of the units. The basic concept is that the cost of a generating unit should depend on the attributes of the unit. A number of key design decisions that significantly affect the costs of building a baseload coal-fired unit have been identified in the engineering and economic literature.[8] These are: the size of the unit, unit order and replication, coal type, steam pressure conditions (subcritical or supercritical), pollution control strategies, cooling method, and reliability.

Previous studies generally found that there are scale economies in construction costs over the entire range of observed unit sizes. However, these studies failed to include reliability as an attribute or characteristic of the units. Larger generating units tend to be considerably less reliable than smaller units. So one has to wonder whether large generating units have lower average construction costs per kw of capacity because of economies of scale or because of poor quality. The implication is that omitting unit reliability will bias the estimates of the construction cost function.

A unit's attributes and construction costs are determined simultaneously. A utility might be expected to modify its choice of unit attributes if it knows something about the error term it faces in the construction cost function. This means that the choice of attributes will be correlated with the error term. This will result in ordinary least squares (OLS) estimates of the cost function being biased. (OLS is the most widely used estimation technique in previous studies.) If a complete model involves the simultaneous determination of attributes and cost, then simultaneous estimation techniques are necessary.

Note that simultaneous equation error will occur only if the utility has some conception of the error term it faces. But it would seem to be unreasonable to assume that the utility is totally unaware of the direction and size of the error. After all, each major utility in the nation has considerable experience participating in the construction of different types of generating units. Also, a utility that is considering building a generating unit can draw on the experience of other utilities that have recently built similar types of units.

The Changing Electric Utility Environment

Three controversial notices of proposed rule makings (NOPRs) were recently issued by the FERC. The NOPRs deal with competitve bidding for new generation capacity, independent power producers (IPPs), and the administrative determination of avoided costs. The most controversial aspect of the NOPRs is that they would include IPPs as potential sources of new generation capacity under any competitive bidding programs.

A major concern under any all-source bidding program is, how to evaluate and weigh the price and nonprice characteristics of each proposal when ranking the bids.[9] An important attribute to include when evaluating a bid for baseload generation capacity is the reliability or availability of the unit. Baseload units are meant to be operated at maximum capacity whenever they are available. Each generating unit design is likely to have a different level of reliability. Also, each design can enhance reliability by adding redundancy to key components and/or by specifying the use of more reliable but more costly materials and equipment. Thus, it is extremely important to determine the consistency between the design of the unit, its construction cost, and its reliability.

Numerous states also have implemented or proposed performance standards for individual generating units.[10] The two most common criteria used to measure unit performance are equivalent availability and heat rate. Utilities operating units that are found to be efficient are financially rewarded, while utilities with units that fail to meet specified minimum performance levels are penalized. One possible problem is that imposing minimum standards for a narrow range of performance criteria can create perverse incentives for the utility. For example, the utility might be willing to incur excessive costs in areas outside the incentive program so as to improve performance in the targeted areas. In this context, it is important to understand the extent to which there is a tradeoff between the reliability and the construction costs of a generating unit. The existence of such a tradeoff would call for regulatory policies focused on a utility's design and construction decisions. If, on the other hand, unit performance is a random variable or a function of utility maintenance policies, then different regulatory policies would be necessary.

Methodology

When comparing pieces of capital equipment it is necessary to control for all relevent engineering characteristics. Most previous studies have treated the capital embodied in generating units as if it was homogeneous. Other studies have disaggregated the attributes of generating units along the dimensions of unit size and steam pressure conditions (or heat rate). These studies ignored the ex ante design and construction process in which reliability is a key parameter. As a result, these studies overlooked the possibility that a relatively inexpensive coal-fired unit to build may not be so inexpensive to operate if it is frequently forced out of service due to mechanical failures. This is especially relevant given the capital intensive nature of baseload electric power generation which means that average total generation costs can be significantly reduced through intensive utilization of the unit.

The central feature of the model developed here is that the cost of a generating unit depends on the engineering characteristics of the unit. Thus, emphasis will be placed on a multidimensional description of capital equipment that includes reliability as an attribute. We argue in Chapter 3 that the traditional neoclassical production model is inappropriate when capital has multiple attributes. Therefore, we have developed an engineering cost function that is flexible enough to allow all major engineering characteristics to be included.

A critical review of the literature is presented in Chapter 2. This is followed by a presentation of the theoretical basis for the structure of our model in Chapter 3. There we argue that minimizing a unit's annual total per-kwh generation costs can be approximated by minimizing its annual capital cost per-kwh. This is based on the concept that intensive utilization of a unit not only spreads its annual capital-related costs over a higher level of output, but average per-kwh fuel costs are also reduced. We have developed an engineering construction cost function which includes reliability as one of the characteristics of a generating unit. This model enabled us to determine the cost minimizing combination of unit size and reliability while accounting for other important engineering attributes.

Chapter 3 also includes a specification of the construction cost model and a discussion of error structure and estimation technique. It concludes with econometric estimates of the construction cost function and an examination of the elasticity of per-kw construction cost with respect to unit reliability. In Chapter 4, we show (assuming that whenever a unit is available it is used) how annual capital costs per-kwh change for various combinations of unit size and reliability.

Chapter 5 provides a summary of our results and ideas for further research.

CHAPTER 2

SURVEY AND CRITIQUE OF THE LITERATURE

The electric generating industry has been the subject of a large number of econometric studies of its production process. This is a result of the capital intensive nature of the generation process, the rapid technological advancement embodied in the generation equipment, and the abundance of detailed data at the plant and firm levels due to federal and state regulation of the electric utility industry.

This review concentrates on that part of the literature which examines the capital cost of steam electric generating units. Emphasis is placed on the methodologies and data used in the studies that are reviewed. Particular attention is placed on the fact that few studies have properly addressed the heterogeneity of capital equipment and its role as a channel for technological advancement in the electric generation process.

The Basic Production Process and Technological Change

Electricity is generated by a process that involves transforming energy from one physical state to another. The technology for transforming fossil fuel into electricity using steam turbines is well developed. Fossil fuel is burned in a furnace to generate heat. Pressurized high-temperature steam is created by transferring the heat to water circulating within an enclosed boiler. The pressurized steam is expanded through a turbine which turns a generator to produce electricity. The steam is then cooled in the condenser and returned to the boiler to repeat the cycle. Thus, the energy transformation process can be divided into four stages--fuel combustion, steam generation, steam expansion, and power generation.[11]

Each stage of the production process is represented by a different piece of capital equipment. It is here that capital heterogeneity is introduced. The furnace is linked to combustion, the boiler to the creation of steam, the turbine to steam expansion, and the generator to the production of electricity. Each piece of capital equipment is purchased with numerous engineering characteristics which are substituted for one another at the design stage of the construction project. This causes heterogeneity at the individual component level, but heterogeneity is also created at the generating unit level by the physical linking of the components. As a result, a generating unit "represents a series of individual and joint optimizations that are reflected in the designs" of the individual components and the unit as a whole.[12]

Another source of capital heterogeneity is the innovation process itself. Traditionally the manufacturers of electrical equipment have played a key role in the development of technological innovations in electric power generation. This means that the vast majority of technological innovations have been capital-embodied.[13] Electric utilities participated in the innovation process by being among the first to purchase the equipment and use it under actual operating conditions. As the innovation proves itself technically and economically it is gradually implemented by other utilities. As a result, a number of technologies can and do coexist at any given time in the industry.

It is also important to note that technological innovation and average unit size are positively correlated over time.[14] The primary goal of technological innovation has been to improve the thermal efficiency of the production process. The desire for increased thermal efficiency led to continued efforts to increase steam pressure and temperature conditions. Table 2-1 shows the steam pressure conditions of all coal-fired units placed into commercial operation between 1950 and 1982. This table shows that the movement to higher pressure (more technologically advanced) units occurred only gradually. Table 2-2 shows the size distribution of the corresponding units. Table 2-2 shows that average unit size increased rapidly until the early 1970's. Together the tables show that the movement to higher pressure (more technologically advanced) units was accompanied by a movement to larger sized units.

Table 2-1. Capacity Additions by Technological Group and Year: 1950-1982 (% of New Capacity)

Period	Turbine Throttle Pressure Groups (psi)				
	1600 or Less	1800	2000	2400	3500
1950-1954	39	45	13	2	0
1955-1959	10	32	36	20	1
1960-1964	2	21	20	45	12
1965-1969	2	8	1	46	42
1970-1974	0+	5	0+	32	62
1975-1980	0	6	1	62	31
1981-1982	0	2	4	88	6

Source: Joskow and Rose, 1985

Table 2-2. Size Distribution of New Coal Capacity
Year: 1950-1982 (Mwe)

Period	Mean	Minimum	Maximum	Number of New Units Installed
1950-1954	124	100	175	99
1955-1959	168	100	335	175
1960-1964	242	100	704	104
1965-1969	407	103	950	100
1970-1974	591	115	1300	109
1975-1980	545	114	1300	127
1981-1982	517	110	891	41

Source: Joskow and Rose, 1985

The main point is that the use of vintages to define periods of technologically homogeneous capital in the electric generation industry is likely to be inadequate. Tables 2-1 and 2-2 indicate that there are a number of technologies in use at any point in time, and that unit size and advanced technology are closely related. Thus, failure to adequately control for technology and size is likely to bias any parameter estimates.

As a result, the studies reviewed here are classified into two groups--those studies that explicitly take into account or somehow control for capital heterogeneity when estimating the construction cost function parameters and those studies that do not.

Models Which Fail to Properly Control for Capital Heterogeneity

Komiya (1962) studied the ex ante production function for steam electric generation and sought to explain shifts in the production function due to technological change. His sample consisted of 235 new plants built between 1938 and 1956. The plants included both single and multiple units. The sample was divided into eight vintage-fuel type groups. Each fuel type, coal and noncoal, was divided into four technological vintage periods: 1938-45, 1946-50, 1951-53, and 1954-56. The idea was that each plant that entered commercial operation in a particular period embodied the best technology available at the time. Any differences in the production function across vintages would be evidence of technological change.

Komiya estimated a Cobb-Douglas production function within each cell, but he concluded that the technology did not allow input substitution when the function performed poorly. He then estimated a Leontief type, or fixed proportion, model within each cell.

$$Y_F = A_F + B_F X_1$$

$$Y_C = A_C + B_C X_1 + B_N X_2$$

$$Y_L = A_L + B_L X_1 + B_N X_2$$

Where,

Y_F = natural log of fuel input, total BTU's, per generating unit when operated at full capacity,

Y_C = natural log of average equipment cost per generating unit in constant dollars (Note that the cost of structures and land were excluded.),

Y_L = natural log of the annual average number of employees per generating unit,

X_1 = natural log of the average size of the generating unit in megawatts,

X_2 = natural log of the number of generating units in the plant.

Komiya found that economies of scale at both the unit and plant levels were important factors in declining input requirements over time. Scale elasticities at the plant level for fuel and capital were estimated to range between .80 and .85. The scale elasticity with respect to labor was estimated to range between .50 and .60. Technical change was found to have little impact on capital or fuel input requirements. The effect of technological change was to reduce labor input by 46 percent from vintage 1938-45 to vintage 1954-56 for coal plants of a given size. There was also a significant difference in capital equipment requirements of equal sized coal and noncoal plants.

The major weakness in Komiya's study is the use of vintage cells to characterize periods of homogeneous technology.[15] As noted earlier, a number of technologies coexist at any given time in the industry. Also, improvements in technology are associated with increases in average unit size. This could cause his capacity parameter estimates to be biased.

Barzel (1964) estimated log-linear input demand functions for fuel, labor, and capital. His sample consisted of 220 plants that entered commercial operation between 1941 and 1959. Each plant's annual data was observed from its first full year of operation until 1960 or until there was a major change in the plant.

The capital input demand equation is:

$$\log P_k = \sum_{i=1}^{4} b_i \log X_i + \sum_{i=5}^{18} b_i X_i$$

Where,

P_K = total undeflated value of plant including equipment, structure, and land,

X_1 = plant size measured in kilowatts,

X_2 = labor price observed in first full year of operation,

X_3 = fuel price observed in first full year of operation,

X_4 = plant factor in first full year of operation,

$X_{5\text{-}18}$ = vintage dummies.

Barzel includes the ex post plant factor as a proxy for the desired rate of utilization of the plant. He appears to be the first to recognize that plants with higher levels of desired utilization must have components which can handle the added stress, thus requiring more capital investment.[16]

Barzel finds that the coefficient of the size variable is .815. He concludes that there are economies of scale in the capital cost of the plant since the coefficient is significantly smaller than unity. He also estimated that the elasticity of plant investment with respect to the plant factor was .117. As a result, he concludes that quality is an important determinant of the costs of capital equipment.

A major shortcoming of Barzels' study is the use of vintage dummy variables. The dummy variables were included to shift the intercept over time in response to technological change, but there are at least two problems with this methodology. First, the shifts are partly due to inflation since Barzel used the total undeflated value of the plant as the dependent variable.[17] Second, the period of time covered by his sample was one of considerable technological change and, given the deliberate pace of innovation in the industry, there is likely to be a number of technologies in use at any given time. Again, technological change and the size of plants or units is correlated so that poor treatment of technological change can seriously bias the econometric results.

Another problem with Barzels' study is that the ex post plant factor observed in the first full year of operation is likely to be a poor proxy for the level of desired utilization for two reasons. First, availability and unit size are inversely related, while unit size and desired utilization generally are positively correlated. Thus, the ex post plant factor may understate the level of desired utilization due to the declining availability of larger units.[18] Second, generating units may go through a break-in period the first year or two of commercial operation. The break-in period may be characterized by high forced-outage rates and derating or cycling of units meant for baseload operation.[19]

Galatin (1968) estimated input requirement functions for fuel, labor, and capital. His sample included 158 plants which entered commercial operation from 1920 to 1953. Only plants with units of the same vintage and size were included in the sample. The sample was divided into 12 vintage-fuel subsamples so that the effects of scale and technological change could be examined across the vintage cells. The six vintages were 1920-24, 1925-29, 1930-39, 1940-44, 1945-50, and 1951-53.

Galatin postulated the capital cost of a generating unit is a function of the size of the unit and the number of units in the plant. The functional form was specified as:

$$CT/N \text{ or } CE/N = A_1N + A_2N^2 + A_3N^3 + A_4X_K$$

Where,

CT = total undeflated capital cost of a plant including land, structures, and equipment,

CE = total undeflated equipment cost of a plant,

N = number of units in the plant,

X_K = size of each unit in megawatts.

The capital cost function was estimated with data covering the vintage fuel-type cells 1945-50 and 1951-53, so that costs for land, structures, and equipment "may be assumed to relate to approximately the same period."[20] Galatin found that total capital cost and equipment cost per generating unit increased with the size of the unit. He also found that total capital cost and equipment cost per generating unit for coal-fired plants in the 1945-50 vintage fell as the number of units in the plant increased from one to three units, and increased as the number of units at the plant increased beyond three. Average costs per generating unit for mixed fuel-type plants of 1945-50 vintage and noncoal plants of 1951-53 vintage also fell as the number of units in the plant increased from one to two units, and then rose as the number of units increased beyond two.[21]

There are a number of problems with Galatin's study. One is that the analysis of capital input is only applicable to plants composed of units of the same size, vintage, and fuel type. Secondly, the sample includes plants with units ranging in size from 4 MW to 150 MW. However, Galatin fails to recognize that desired utilization generally increases with unit size, and that the desired level of utilization, independent of unit size, is an important determinant of plant capital costs.[22] Thirdly, Galatin used vintages in an effort to control for the effects of changing technology.

The primary objective of Huettner's study (1974) is to examine the effects of technological change and plant capacity on the average investment required per unit of capacity. Huettner's sample consisted of 391 plants divided into 13 vintage time periods from 1923-1968. Within each of the vintage cells he estimated an average capacity cost equation which included fuel type dummies and the reciprocal of the size of the plant as the primary explanatory variables. Huettner used stepwise regression analysis due to a conflict between the number of explanatory variables and the number of observations within each vintage cell.

Huettner did some preliminary testing of the model on a subsample in order to reduce the number of explanatory variables to be considered when using stepwise regression analysis for the entire sample. The subsample consisted of 185 subcritical, coal-fired plants of full indoor construction. The subsample ranged from 5 observations to 30 observations per vintage period and averaged 14 observations per period. Due to the small number of observations in some of the vintage cells, Huettner included only three explanatory variables in the average capacity cost equation estimated with the subsample. The three variables chosen were the number of units in the plant, the fuel consumption of the plant, and the reciprocal of plant capacity.

Huettner included the fuel consumption variable, as measured by the plants average heat rate, to test whether load type has an effect on average capacity cost. He noted,

> Generating plants may also be classified as base-load plants, cycling plants, and peak-load plants. Base-load plants are designed to operate at maximum fuel efficiency without being shut down for long periods of time. This may increase unit capacity costs (UCC) above that of cycling plants which are designed to operate at the highest fuel efficiency consistent with rapid warm-up and cool-down during frequent shutdowns. Cycling plants might tend to have lower UCC due to looser tolerances on equipment, as for example on the turbine blades.[23]

Huettner found the fuel consumption variable was generally of the appropriate sign, but statistically significant in only 2 of 13 vintage periods. He noted there was a high degree of correlation between plant heat rate and plant capacity which meant that multicollinearity was likely to be a problem. As a result, Huettner excluded the fuel consumption variable from the stepwise regression analysis of the full sample.

The number of units variable was included by Huettner because "some studies argue that quantity discounts are a significant factor affecting equipment costs in generation plants; hence, one would expect UCC to decline as the number of units increased."[24] Huettner found that plants with multiple units had lower average capacity costs in 10 of the 13 vintage periods, but the coefficient was statistically significant in only 3 of these 10 periods. It should be noted that this variable was dropped from the remainder of the analysis due to its poor performance. As a result, Huettner's study analyzes plant-level economies instead of unit-level economies.

Huettner found that average capacity costs generally declined as the size of the plant increased. The capacity variable coefficient was positive in 9 of the 13 vintage periods and statistically significant in 7 of these periods. Based on the performance of the capacity variable, it became the primary variable of interest in the stepwise regression analysis of the full data set.

Plant characteristics used as explanatory variables in the capacity cost equation for the full sample included fuel-type dummies, a full-indoor construction dummy, a supercritical dummy, and the reciprocal of plant capacity. Huettner found that plant fuel-type is a significant determinant of the average capacity costs of generating plants. Coal-fired plants were more expensive to build than oil-fired plants, and oil-fired plants were more costly than gas-fired plants. Supercritical plants were represented in only the 1959-60, 1963-65, and 1966-68 vintage periods, but were significantly more expensive than subcritical plants in 2 of the 3 periods. Huettner also found that average capacity cost declined with increased plant capacity in every vintage period since 1940.

There are a number of problems with Huettner's study. First is the use of vintages to define periods of homogeneous technology. Second, Huettner recognized that baseload and non-baseload plants have significantly different design characteristics due to differences in desired utilization, and that baseload operation and plant size are highly correlated. But the estimated plant size coefficients will be biased by his failure to control for differences in desired utilization, and the mixing of baseload and non-baseload plants in the sample. Third, Huettner recognized that the reliability of a generating unit is inversely related to its size and "that the lower reliability of large units reduces their economic attractiveness."[25] But he fails to include reliability as an explanatory variable so the parameter estimates may be biased. As a result, it is impossible to determine whether large units cost less to build due to economies of scale or poorer quality as reflected by lower reliability.

Wills (1978) recognized the non-homogenous nature of capital equipment in the steam-electric generating industry and noted the construction cost of a plant will be a function of its attributes. Thus, Wills estimated an hedonic cost function for steam electric plants. His sample included 156 plants which entered commercial operation between 1947 and 1970. The observations were divided into eight vintage cells.

The attributes initially considered by Wills were plant capacity, average unit capacity, unit fuel efficiency, and the average number of employees that worked in the plant. He also noted that plants could be divided into groups based on construction-type, fuel-type, and whether the plant contained a single unit or multiple units. However, Wills concluded from a preliminary analysis of the sample that the effects of the dummy variables could be restricted to an interaction with the capacity variable. He also excluded the fuel efficiency variables because they were collinear with the size variable.

As a result, the hedonic capital cost equation was of the following form:

$$\text{PRICE} = \alpha_o + \{\alpha_1 + \beta_i + \gamma_j + \delta_k + N_c\}\text{Cap} + \alpha_2\text{CAP}^2$$

Where,

PRICE = total nominal cost of the plant,

CAP = plant capacity,

β_i = one if the plant is of full-indoor construction, zero otherwise;

Y_j = one if the plant has only one unit, zero otherwise;

δ_k = one if the plant burns coal, zero otherwise;

N_c = dummy variables that represent the vintage of the plant.

The model was normalized by plant size in order to remove a problem with heteroskedasticity. The model became:

$$\text{Price/Cap} = \alpha_o(1/\text{Cap}) + (\alpha_1 + \beta_i + Y_j + \delta_k + N_i)\ (\text{Cap/Cap}) + \alpha_2(\text{Cap}^2/\text{Cap})$$

Wills argued that all of the explanatory variables were exogenous except the capacity variables. He believed it likely that plant size was correlated with the error term. Thus, he used instruments for unit size multiplied by the number of units in the plant as instruments for plant size. The instruments for plant size included the "expected absolute growth in demand for electricity from the utility times the number of units, the price of fuel times the number of units, the price of fuel squared times the number of units, and expected demand growth times the price of fuel times the number of units."[26]

The hedonic cost function was estimated using random components instrumental variable estimation and random components estimation. Wills found that economies of scale in plant cost per unit of capacity are essentially exhausted at plant capacities of about 100 megawatts. He also found that vintage effects were not important determinants of plant cost per unit of capacity.

There are a number of problems with Wills' study. Once again there is the problem of using vintages to define periods of homogenous technology. Also, there is the problem of mixing baseload and non-baseload plants in the sample. The sample includes plants that range in size from 5 MW to 950 MW. Unit size and desired utilization intensity are correlated but each, independent of the other, is an important determinant of the cost of building a generating unit. Thus, failure to control for desired utilization and mixing baseload and non-baseload plants in the sample will bias the coefficient estimates.

Models Which Avoid the Vintage Problem[27]

Stewart (1979) is concerned with the relative importance of capacity utilization and size of plant in determining the average cost of generating electricity. He adopts a quasi-engineering approach by incorporating technical information on the characteristics of the capital equipment and production process. A quasi-engineering approach is used because the investment decision of the utility "will encompass determining both the segment of total demand the new plant will serve and the configuration of the new plant." The load increment for which the new plant is designed and built is "defined by an instantaneous rate" (the size of the new plant), K, and the number of yearly hours the plant will produce at that rate (or duration).[28] Stewart defined the expected cumulative output of the plant as:

$$Q = 8760bK$$

Where,

8760 = number of hours in a year,

b = expected plant factor,

K = capacity of the plant measured in megawatts.

Stewart assumed that the range of technology available to the utility could be fully defined by the size and thermal efficiency of the generating unit. So the average capacity cost (cost per KW) function was written as:

$$P_k = P_k(\alpha, k)$$

The average capacity cost of a plant was expected to increase at an increasing rate with the fuel efficiency, α, of the plant. Stewart also expected the average capacity cost of a plant to decrease over some range of plant size. As a result, the utility was faced with the problem of choosing the cost minimizing level of fuel efficiency for a unit designed to meet an expected load increment defined by b and K. The cost minimizing heat rate was given as:

$$\alpha^* = g(K, b, P_F, r)$$

Where,

α^* = cost minimizing heat rate (BTU/kwh),

P_F = price per BTU of fuel,

r = cost of capital.

Ex ante total generation costs are derived by substituting α^* into the following cost function.

$$TC^*(K, b, P_F, r) = g(K, b, P_F, r)8760bKP_F +$$

$$rP_K(g(K, b, P_F, r), K)K$$

Where the first part of the total cost function represents ex ante fuel costs and the second part represents ex ante capital cost.

The estimated plant cost function was combined with the plant's size, load factor, and factor prices to compute the cost minimizing heat rate and the average total cost per Kwh for each plant. Stewart found that plant utilization intensity was the dominant factor in reducing average generation costs, while plant size was found to have relatively little impact.

Our primary attention will be on Stewart's plant cost function. He estimated a translog specification of the cost of plant function:

$$\ln P_K = A + \gamma_\alpha \ln(\alpha - \bar{\alpha}) + \gamma_{\alpha\alpha} (\ln(\alpha - \bar{\alpha}))^2$$
$$+ \gamma_K \ln(K) + \gamma_{KK}(\ln(K))^2 \quad + \gamma_{\alpha K}\ln(K)\ln(\alpha - \bar{\alpha})$$
$$+ \sum_i \gamma_i X_i + u$$

Where,

P_K = nominal land and equipment cost per KW of the generating unit (excluding structures),

α = average heat rate of the unit (BTU's/Kwh),

$\bar{\alpha}$ = asymptotic heat rate (6000 BTU/Kwh),

K = capacity of the unit (Kw),

X_i = regional dummies and natural log of the number of units in a given plant.

The plant cost function was estimated using a sample of 58 plants which entered commercial operation between 1970 and 1971. The sample included plants with single units or multiple identical units. The sample consisted of 19 steam electric plants and 39 gas turbine plants.

Stewart estimated two forms of the cost-of-plant function. One included only a dummy variable to differentiate between the two types of generating plants. Thus, the coefficients of the size and heat rate variables were restricted to be equal for each type of plant. The second specification allowed the plant type dummy variable to interact with the size and heat rate variables and their interaction variable.

The plant type dummy was not allowed to interact with the squared size or squared heat rate variables.

Stewart found plant equipment cost fell at a decreasing rate as heat rate increased (thermal efficiency decreased) for both types of plants. He also found plant size had very little impact on the cost of equipment for either type of unit. Plant costs of gas turbines at the mean heat rate declined with unit size only for units smaller than 70 MW. Average equipment cost for steam plants was found to increase at a "relatively modest rate" over most of the reasonable range of unit sizes and fuel efficiencies.

We believe there are a number of flaws in Stewart's study. One involves the estimation of a single quadratic function to approximate both technologies. Steam-electric and gas-turbine technologies are quite different so there is little reason to believe that scale economies will be at all similar for the two technologies.[29] A second problem involves the mixing of baseload and non-baseload plants in the sample. The steam electric plants range in size from 200 MW to 800 MW and the gas turbines range from 20 MW to 187 MW. Failure to control for different levels of desired utilization means the size coefficient will be biased.

Another problem relates to Stewart's failure to include reliability as an attribute of a generating unit in the cost of plant function. He is interested in the relative importance of capacity utilization and plant size in determining the cost of generating electricity. However, he fails to recognize that utilization depends on availability and that availability is an attribute of a unit.

Komanoff (1982) estimated a log linear average construction cost equation. The sample consisted of all U.S. coal-fired units, 100 megawatts or larger, which entered commercial operation from January 1972 through December 1977. The units ranged in size from 114 MW to 1300 MW and averaged 608 MW. Fifteen of the units had flue gas desulfurization devices or scrubbers.

Real capital costs per kilowatt, excluding AFUDC, was regressed on a number of explanatory variables using ordinary least square (OLS). Unfortunately, Komanoff shows the econometric results for only the statistically significant variables. All other variables were excluded from the final regression equation and were simply listed as having been tried in alternative specifications of the regression equation. Insignificant variables included the presence of cooling towers, supercritical boilers, and unit size.

Komanoff found the presence of scrubbers added 26 percent to the capital cost of a generating unit. He also found that units which share a plant site with an identical unit have lower capital costs than non-multiple units. Capital costs were found to increase approximately 4 percent for each later year that the unit entered commercial operation. Other significant explanatory variables were regional dummies, which probably reflected regional variations in construction-type, and the cost of labor. Units built in the Midwest or Northeast are more likely to be of full-indoor design than units built in the Southwest or Southeast.

Interestingly, Komanoff found capital costs to be significantly correlated with ownership by two large utility holding companies: the

Southern Company and American Electric Power (AEP). Generating units built by AEP were found to be 18 percent more costly than other comparable units, while Southern Company's units were 15 percent less costly to build than other Southeast units. Komanoff argued these differences were probably due to the two utilities' unit design and operation philosophies. AEP has a reputation for building highly reliable and efficient units, while Southern Company tends to build units with below-average reliability and fuel efficiency. As a result, Komanoff concluded unit reliability is a significant determinant of a units' capacity costs.[30]

One problem with Komonoff's study has to do with mixing baseload and non-baseload units in the sample. That this may be a problem is indicated by the inclusion of units as small as 114MW in the sample. Baseload and non-baseload units have different levels of desired utilization and, thus, different engineering characteristics which are likely to effect the capital costs of each type of unit. Failure to account for desired utilization can seriously bias the parameter estimates since unit size and desired utilization are generally correlated.

Another problem arises from Komanoff's failure to properly account for unit reliability in the capital cost equation. It is necessary to control for different levels of desired utilization and to include a reliability variable. This prevents the size coefficient from being biased since size and reliability are inversely related. Komanoff also implicitly recognizes the simultaneous nature of the relationship between unit reliability and capital costs. He notes that higher initial capital cost due to conservative design philosophy and, thus, higher unit reliability may result in lower total costs over time. The endogenous nature of unit reliability means simultaneous estimation techniques are necessary for unbiased parameter estimates.

Perl (1982) is concerned with calculating the levelized cost of electricity from coal-fired plants. "Levelized costs are a constant annual charge for electricity which yield the same present value as actual annual charges over the life of a plant."[31] Current accounting practices and the capital intensive nature of coal-fired plants causes high front end costs. Levelized costs, he argues, better reflect life time electricity costs.

Perl's methodology involves econometrically estimating capital costs, non-fuel operating and maintenance costs, availability factors, and heat rates for coal-fired units. These were regressed on the engineering characteristics of the units using OLS. His sample included 245 coal-fired units which entered commercial operation between 1965 and 1980. These components of cost and performance were combined in the following model to produce the levelized cost of electricity:

$$\frac{\sum_{i=1}^{N} RR_i(1 + \varepsilon)^i}{\sum_{i=1}^{N} G_i(1 + \varepsilon)^i/(1 + r)^i} * \frac{1}{(1 + r)^m}$$

Where,

RR_i = revenue requirement in year i,

G_i = generation in year i,

N = book life of the plant,

M = number of years from current date to start of commercial operation,

δ = nominal discount rate,

r = inflation rate.

Perl assumed that plant life was 30 years, 1985 to 2014. He also assumed when forecasting capital and O & M expenses per kilowatt-hour that a unit is used if it is available.

We will focus our attention on Perl's average capital cost and equivalent availability equations. The dependent variable in the equivalent availability equation is the logit transformation of the equivalent availability factor. This transformation restricts the estimated variable to the interval from zero to one. The sample used to estimate the equation consisted of annual observations of equivalent availability for "a large sample of coal units operating from 1969 through 1977."[32] Observations for the first full year of commercial operation of a unit were excluded to avoid any bias due to break-in problems. Explanatory variables included the year the unit entered commercial operation to represent vintage, the age of the unit, the reciprocal of unit size, and numerous dummy variables. The dummies indicated a supercritical boiler, a balanced draft boiler, a cyclone boiler, boiler manufacturer, turbogenerator manufacturer, and whether the unit was built by the particular architect-engineer (A-E) or utility represented.

Perl found equivalent availability tended to decline with increased age and larger unit size. Subcritical units were also substantially more reliable than comparable supercritical units. Perl also noted that there appeared to be significant differences in the availability of units built by particular A-Es and utilities.

Perl estimated a log linear specification of the capital cost equation. The dependent variable is the natural log of real capital cost per kilowatt excluding AFUDC. The sample consisted of 245 coal-fired units built between 1965 and 1980. Explanatory variables included unit size, regional wages, the date the unit entered commercial operation, and dummy variables indicating supercritical boilers, scrubbers, and whether the unit was designed and built by a particular A-E or utility.

Perl found average capital costs were significantly related to unit size, the presence of scrubbers, and regional wages of construction labor. Supercritical units were found to be considerably more costly than comparable subcritical units. He also found average capital costs varied depending on which A-E or utility built the unit. Perl argued that this indicated the more experience the A-E had designing and building generating units, the lower the capital cost of a unit.

Perl concluded that economies of scale are very limited for subcritical coal-fired units. The higher average construction costs of smaller units are offset by their higher equivalent availability. Thus, the cost of electricity from subcritical units is basically constant when unit size is beyond 200 megawatts. In contrast, Perl finds that supercritical units are characterized by economies of scale. Average capital costs fall with increases in size while availability remains roughly constant. As a result, Perl concluded that subcritical units are cheaper to build and operate than supercritical units when unit size is less than 800 MW, and that the reverse is true when unit size increases beyond 800 MW.

We believe there are a number of problems with Perl's study. One problem relates to the use of A-E dummy variables and Perl's conclusion, when these dummies prove to be statistically significant, that A-E experience is a significant determinant of the capital cost of a unit. A variable measuring experience must be included in the construction cost equation to separate the effects of experience and any attributes of particular A-Es. Characteristics of particular A-Es, such as design philosophy, choice of vendors for major components, and the quality of the units, may be correlated with experience. So both experience and A-E specific characteristics must be included to avoid biased parameter estimates.

Another problem relates to Perl's failure to include availability in the capital cost equation even though he recognizes that unit size and equivalent availability are inversely related. This will cause the parameter estimates to be biased and makes it difficult to determine whether large units cost less to build due to economies of scale or poorer quality.

Houldsworth (1985) examined the relative importance of capacity utilization and plant size in determining the average cost of generating electricity. He adopted the same quasi-engineering approach used by Stewart,[33] except for how the level of utilization is included in the model. Recall that Stewart defined the expected cumulative output of a generating plant as:

$$Q = 8760bk$$

Where,

8760 = number of hours in a year,

b = expected plant factor,

k = capacity of the plant measured in megawatts.

It is also important to recall that Stewart's sample consisted of a mixture of baseload and non-baseload plants which entered commercial operation during the period 1970-71. He used the plant factor observed in 1972 for each plant as a proxy for the expected plant factor.

Houldsworth recognized the desired level of utilization is a significant determinant of generating plant construction costs. He also recognized that the ex post plant factor will probably understate the level of desired utilization. Plant size is positively correlated with desired utilization intensity, while equivalent availability is negatively correlated with unit size. Houldsworth also recognized that mixing baseload and non-baseload plants in the same sample is inappropriate since they have different levels of desired utilization.

Houldsworth avoided these mistakes by restricting his sample to 32 coal-fired baseload plants which began commercial operation in the period 1972-1978. He also defined the level of utilization by the expected availability, a (k), since each unit was assumed to serve baseload demand. This meant that the expected cumulative output relationship became:

$$Q = 8760a(k)K$$

Houldsworth combined the estimated plant cost function with the plant size, equivalent availability, and factor prices to compute the cost minimizing heat rate and the average total cost per kwh for each plant. The simulations conducted by Houldsworth indicated average total cost per kwh reached a minimum between 150 and 250 MW, and increased moderately for larger sized units. Thus, Houldsworth concluded that declining availability offset the benefits of any reductions in heat rate and/or average construction cost per kw associated with units larger than 250 megawatts.

Our primary concern lies with Houldsworth's use of availability data published regularly by the North American Electric Reliability Council (NERC). These reports provide availability data that are cumulative over a ten-year period and are averaged over many types of units. The NERC data mixes units in the same size range even though they have considerable differences that significantly affect their reliability. Units within the same NERC size categories vary with respect to fuel-type (gas, oil, or coal), desired level of utilization (baseload or non-baseload), and in steam conditions (high or low steam pressure and termperature). "The reliability data given are, therefore, average figures that reflect 'average' hypothetical units."[34]

Joskow and Rose (1985) are interested in determining what impact unit size, differences in technology, tightened environmental restrictions, and the experience of utilities and A-Es has on the costs of building coal-fired generating units. They specify the construction cost model:

$$LAC = \sum_{t=1960}^{1979} A_t T_t + b_1 LSIZE + b_2 RWAGE + b_3 FIRST +$$

$$b_4 SCRUBBER + b_5 COOLTWR + b_6 UNCONV + b_7 EXPERAE +$$

$$b_8 EXPERU + b_9 EXPERI + S + U.$$

Where,

LAC = natural log of real cost per KW of a unit, net of AFUDC;

T_t = one if the unit entered commercial operation in year t, and zero otherwise;

LSIZE = natural log of unit size in megawatts;

RWAGE = regional average union wage for construction workers in 1976;

FIRST = one if the unit is the first unit on the plant site, zero otherwise;

SCRUBBER = one if unit was built with a scrubber, zero otherwise;

COOLTWR = one if the unit was built with a cooling tower, zero otherwise;

UNCONV = one if the unit is not of full-indoor construction, zero otherwise;

EXPERAE = the cumulative number of "like" units designed by the A-E being observed that entered commercial operation between 1950 and year t;

EXPERU = utility experience since 1950;

EXPERI = total industry experience since 1950;

S = a seperate intercept term for each A-E.

The data set consisted of 411 coal-fired generating units which entered commercial operation between 1960 and 1980. The units were divided into four turbine throttle pressure groups: 1800, 2000, 2400, and 3500 PSI. Subcritical units have steam pressures less than 3206 PSI, while supercritical units have steam pressure in excess of 3206 PSI. The units ranged in size from 100 megawatts to 1300 megawatts.

Joskow and Rose treat this data set as a panel with individual generating units as observations over time on a cross section of A-Es. They believe there are A-E specific design characteristics common to units designed by a particular firm so they use fixed effects estimation to control for these effects. Fixed effects means estimating a separate intercept for each A-E.

It should be noted that Joskow and Rose specify a Cobb-Douglas relationship between cost and unit size. This forces the cost function to have a constant elasticity of unit cost with respect to size. Additional flexibility is added by allowing the size coefficient to take on a different value for each pressure group. The intercept is also allowed to vary across pressure groups.

Joskow and Rose found significant differences between the cost characteristics of subcritical and supercritical units. Supercritical units are more costly to build than subcritical units except for large unit sizes. Only when unit size increases beyond 600 megawatts do supercritical units become cheaper to build than subcritical units. As a result, they conclude there "is no simple static tradeoff between unit size and construction cost: full exploitation of economies of scale in construction costs can only be achieved by moving from one technology to another. It would be wrong to think of static economies of scale independently of choice of technology."[35]

They also found scrubbers and cooling towers added 15% and 6%, respectively, to the construction cost of coal-fired units. Experience was found to be numerically and statistically significant for supercritical units only. Average construction cost for a supercritical unit fell approximately 15% when the architect-engineer's experience with that type of unit increased from zero to the average level of experience in the sample.

We believe there are a number of problems with the Joskow and Rose study. One is the likelihood that baseload and non-baseload units, and their different levels of desired utilization, were mixed in the sample.

Again, the level of desired utilization, independent of unit size, is an important determinant of the cost of building a generating unit. Failure to control for desired utilization and mixing baseload and non-baseload units in the sample will bias the parameter estimates since the level of desired utilization generally increases with unit size.

Joskow and Rose also note large units generally have lower equivalent availabilities than small units and that "especially poor performance is exhibited by the larger supercritical units."[36] However, they fail to treat reliability as an attribute of generating units and thus exclude it from the construction cost function. As a result, it is difficult to determine whether large units cost less because of economies of scale or because of poorer quality.

Schmalensee and Joskow (1986) were concerned with how the construction cost of a coal-fired generating unit varied with the quality of the facility. The two indices of quality were the units' heat rate and equivalent availability. They used a two-stage estimation process. The first stage was concerned with obtaining estimates of unit-specific quality attributes from data on actual unit performance and operating characteristics that affect performance over time. A fixed effects model was used to obtain estimates of each of the two quality attributes which are supposed to enter the second stage of the process, estimation of a construction cost function. The sample used by Schmalensee and Joskow consisted of observations on 71 subcritical coal-fired units which entered commercial operation between 1960 and 1969. The units ranged in size from 218 MW to 709 MW. The sample also contained operating performance data, heat rate and equivalent availability, for these units, for the years 1969 through 1977.

The first stage consisted of two performance equations of the following form:

$$REL = D\delta_1 + W\gamma_1 + V_1$$

$$EFF = D\delta_2 + W\gamma_2 + V_2$$

Where

REL = -ln(1 - equivalent availability),

EFF = -ln[(gross heat rate - 6000)/6000].

The W's are matrices of exogenous variables that should affect intra-unit variations in performance over time. The variables included in W are:

CAPU = deviation in output factor [=100X generation/(capacity x hours in service)] from the sample mean for all units, a measure of relative capacity utilization,

AGE = unit age (calendar year - year unit entered commercial operation) minus three,

BTU (MOIST, ASH, SULPH) = deviation of BTU's per pound (percentage of moisture, ash, sulpher) of the coal burned from the sample mean for the observed unit.

Age entered each equation quadratically to allow for the possibility that performance improves when a unit first enters commercial operation, and then decreases as the unit ages beyond some point. The D's are matrices of unit--specific dummy variables that take on a value of one for a unit when the observations are associated with that unit and zero otherwise. Thus, the coefficients δ_1 and δ_2 are the estimates of unit specific quality attributes used as explanatory variables in the construction cost equation.

Schmalensee and Joskow found unit performance deteriorated as units aged after a short break-in period. Reliability peaked after a year or less of operation (note that age is measured as actual age minus three) and then fell, while fuel efficiency declined from the start of operations. Also, the coal characteristics variables were never statistically significant. Thus, intra-unit variation in coal characteristics appeared to have little effect on unit performance.

Schamalensee and Joskow rejected the null hypothesis that unit qualities are identical. The estimated unit-specific coefficients of REL (the estimated elements of δ_1) correspond to equivalent availabilities ranging from .6 to .97 and a mean of .84. The estimated unit-specific coefficients of EFF (the estimated elements of δ_2) correspond to heat rates ranging from 7,700 to 10,800 BTU/KWH and a mean of 9,000.

The second stage consisted of estimating a construction cost equation of the form:

AVCOST = f(SIZE, WAGE, BTU, TIME, EFF, REL).

Where,

AVCOST = natural log of unit capital cost in 1965 dollars per KW of capacity,

SIZE = natural log of nameplate capacity in megawatts,

BTU = natural log of unit-specific mean of BTU's per pound of coal burned,

WAGE = natural log of regional construction wage in 1965,

EFF = design thermal efficiency of the unit (the estimated unit-specific coefficients, δ_2, as defined in the first stage),

REL = design reliability of the unit (the estimated unit-specific coefficients, δ_1, as defined in the first stage).

Schmalensee and Joskow estimated two specifications of the construction cost equation. The first specification was linear in the variables, except time which was entered as a quadratic. The second specification allowed the effects of reliability and fuel efficiency to interact with the quality of the coal burned variable (BTU).

Each specification was estimated three different ways. One ordinary least squares (OLS) estimate was obtained by using unit-specific averages of observed heat rates and equivalent availabilities as the quality variables rather than the values (coefficients) estimated in the first stage. The second set of OLS estimates was provided by using the values (coefficients) estimated in the first stage. The third set of estimates was provided by an adjusted least squares technique developed by Schmalensee and Joskow.

Schmalensee and Joskow found the quality attributes, EFF and REL, were statistically insignificant, and frequently had implausible signs and magnitudes. All six equations implied that increasing fuel efficiency reduced construction costs per unit of capacity. The adjusted least square estimates indicated REL had a positive impact on costs, but that it was never close to statistical significance. In the linear and interactive specifications estimated using OLS, REL had a negative insignificant coefficient.

Schmalensee and Joskow found the size coefficients were statistically significant in the OLS estimates, but statistically insignificant in the adjusted least squares estimates. The magnitude of the estimated size coefficients did not differ very much and implied that doubling unit capacity would reduce average construction cost per unit of capacity by between 10 and 12 percent.

Schmalensee and Joskow are the first to include quality variables for both fuel efficiency and equivalent availability, but there are still a number of problems with their study. One problem relates to their inability to include a size variable in the first stage regressions, since it would be perfectly collinear with the unit-specific dummy variables.[37] Other things equal, equivalent availability falls as unit size increases. Unit size is also negatively correlated with construction cost per unit of capacity. Thus, use in the construction cost equation of an equivalent availability variable that fails to control for unit size may cause the parameter estimates to be biased. They also recognize there may be architect-engineer (A-E) specific variations in ex post performance given the level of construction costs and design performance levels, but cannot capture these effects explicitly due to a conflict between sample size and the number of explanatory variables.[38] Again, these effects will be reflected in the fixed-effects estimates of the unit-specific quality variables of the first stage.

Summary

A review of the literature reveals that unit size, technological vintage, and fuel type have been viewed as the primary determinants of the construction cost per KW of capacity of a generating unit. A general conclusion of these studies is that there are economies of scale with respect to construction costs.

But this review also shows few previous studies have properly accounted for the desired utilization intensity of a generating unit. A majority of the studies mix baseload and non-baseload units in the sample and also fail to include the mode of operation (baseload or non-baseload) as an explanatory variable, so the estimated size coefficients are likely to be biased. Given that unit size and desired utilization intensity are positively correlated, it's likely the estimated size coefficients are picking up the affect of moving from non-baseload to baseload operation, and not just the impact of unit size.

Also, the vast majority of these studies fail to include reliability as an attribute or characteristic of generating units. They ignore the ex ante design process in which reliability is a key parameter. But the key issue is the intensity with which a unit is used. A poor level of reliability, especially for baseload units, means the capital-related costs of a unit are spread over a lower level of output than if a unit is used more intensively. Thus, these studies fail to recognize that an inexpensive unit to build may not be so inexpensive to operate.

The studies by Perl, Houldsworth, and Schmalensee and Joskow (1986) are the only studies that include in their analysis the effects of unit reliability. Unfortunantly, each of these studies was flawed. Both Perl and Houldsworth fail to include availability in the capital cost equation even though they recognize that unit size and equivalent availability are inversely related. This causes their parameter estimates to be biased and makes it difficult to determine whether large units cost less to build due to economies of scale or poorer quality.

Schmalensee and Joskow (1986) were the only researchers to include equivalent availability as an explanatory variable in the construction cost equation. However, they used an estimate of equivalent availability that did not control for unit size. This is a significant problem since unit size and equivalent availability are, in general, negatively correlated. Thus, use of their equivalent availability variable in the construction cost equation may bias the estimated coefficient since it may be picking up the negative size effect.

This review indicates a construction cost model must recognize the ex ante design and construction process in which reliability is a key parameter. Not only must the construction cost function include reliability as one of the attributes of a generating unit, but the model should also recognize that unit reliability is a function of numerous factors. The development of such a model is the subject of the next chapter.

CHAPTER 3

DEVELOPMENT OF A GENERATING UNIT CONSTRUCTION COST AND RELIABILITY MODEL

Introduction

In this chapter we develop a model of the steam electric generation process that recognizes the multidimensional nature of capital embodied in baseload coal-fired generating units. The first section, the Heterogenous Nature of Capital, emphasizes how a utility's choice of unit characteristics at the ex ante or design stage determines the ex post production relationships. Thus, the fuel-output relationship is fixed once the unit is built and it is fairly insensitive to the rate of generation. In the second section, the Model, we develop a model that highlights the capital-intensive nature of baseload coal-fired generation and the importance of intensive utilization if a unit's average total generation costs are to be minimized. In the third section, Specification of the Construction Cost and Reliability Model, we develop a simultaneous equation model of unit construction cost per KW of capacity where average construction cost and reliability are endogenous variables. In the fourth section, Empirical Analysis, the data employed in the study is discussed and the estimation results are presented.

THE HETEROGENEOUS NATURE OF CAPITAL

The Two-Dimensional Nature of Output

The cyclical nature of the demand for electricity has important implications for the nature of capital in the electric generating industry. The output of a generating unit can be thought of as having at least two dimensions. Power, the first dimension, is the instantaneous rate of output and is measured in kilowatts (KW). The second dimension is energy, measured in kilowatt hours (KWH). Energy is the product of a power level and the period of time (measured in hours) over which the unit operates at that level. Thus, energy is the cumulative level of output over a period of time.

The demand for electricity fluctuates in a cyclical pattern over a day, week, or season. Generally, however, electric power is non-storable, so the supply of electricity must equal the demand for electricity at all times. Thus, a utility must install sufficient capacity to satisfy the maximum demand expected over the cycle. Given that the demand for electricity varies more quickly than generation capacity, a portion of the utility's generation facilities will not be operated at maximum capacity at all times. As a result, generating units with the same maximum capacity may have different levels of cumulative output and units with the same levels of cumulative output may have different maximum capacities. In this environment it is reasonable to expect a utility that is building a new generating unit to consider both dimensions of output when making choices at the <u>ex ante</u> or blueprint stage. Thus, the utility must decide what portion of the total demand for electricity the unit will serve. This decision will then affect the size and desired thermal efficiency of the planned unit.

The Unit Design Process and Ex Post Production

A utility faces a wide range of production possibilities at the blueprint stage. Each blueprint represents a generating unit with different engineering characteristics such as unit size, unit type (baseload and non-baseload), reliability requirements, fuel type and quality, steam pressure conditions (an ex ante measure of thermal efficiency[39]), pollution control techniques, unit life, expected capital cost, expected operation and maintenance costs, and numerous other characteristics. But once the generating unit is built, the fuel-output and labor-output relationships are fixed. Thus, the utility faces a set of *ex ante* production possibilities from which various engineering attributes are selected which shape the *ex post* production relationship.[40]

Labor is heavily dependent on the design of the unit and thus exhibits very little response to variations in output. The operational labor requirements are affected by the number and size of units in operation at a site. The choice of fuel also affects the number of operational personnel needed, since it determines the fuel handling requirements. In particular, coal requires more labor input than does either oil or natural gas. The number of maintenance personnel also depends on the number and size of units and the schedule of routine maintenance, rather than the level of output. Routine maintenance is scheduled on an annual basis and is geared to unit size, unit type, and the presence of pollution abatement technologies such as scrubbers.[41]

The relationship between the flow of fuel and output also depends on the design characteristics of the generating unit. Thermal efficiency increases (heat rate falls) with the temperature and pressure of the steam, the thermal efficiency of the boiler, the efficiency of the turbine, and the size of the boiler and the turbine. Once the unit is built, marginal fuel use, or the incremental heat rate, is related to the capacity utilization of the unit. According to Bushe (1981, Chapter 4) there are a number of alternatives for the form of the incremental heat rate function for a single generating unit (see Figure 3-1). He notes that, it is likely that the form depends on the design of the unit and large baseload units may have forms like (d) or (e) of Figure 3-1, while peaker units may have forms like (c). Since we are concerned only with baseload units in this study, we will assume that the relevant forms are (d) or (e). This assumption means the incremental heat rate is fairly insensitive to changes in load within the normal operating range of a baseload unit. As a result, the amount of fuel required is proportional to the rate at which the unit produces electricity.[42]

Thus, the fuel-output and labor-output relationships are conditional upon the design characteristics of the generating unit. Once the unit is built there is very little opportunity for substitution among the inputs, so the technology for generating electricity is putty-clay.

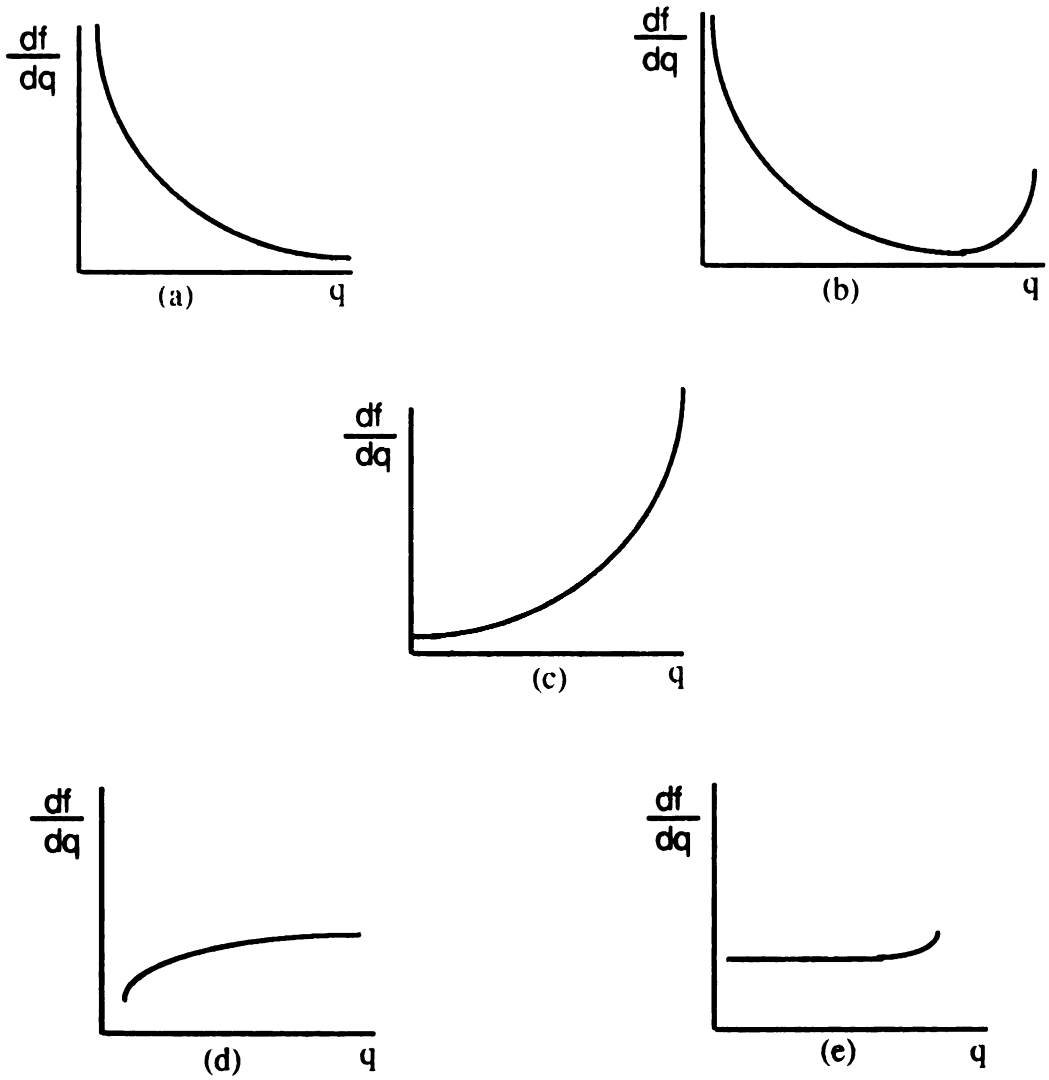

Figure 3.1. Possible Forms for the Incremental Heat Rate

df/dq = incremental heat rate
q = load

Source: Bushe (1981), Chapter 4

THE MODEL

General

The traditional neoclassical production model assumes that input capital is homogeneous (i.e., one unit of capital services is equal to any other unit of capital services). This assumption implies that a unit of capital can be represented by a scalar measure such as size or the dollar value of the capital equipment. We believe, however, that the heterogeneous nature of capital means the electric generation process cannot be accurately summarized by the traditional neoclassical production function. The fuel-output and labor-output relationships are too dependent on the characteristics of the capital equipment to be ignored.[43] Therefore, we developed a model that explicitly recognizes the heterogeneous nature of capital in the electric generating industry.

Our concern is with the investment decision of the utility since the characteristics of the capital equipment restrict the variable input-output relationships or, in other words, the associated short-run production possibility sets. The utility must decide what portion of total demand the new unit will serve and the associated engineering attributes of the unit.

We assume that the utility wants to serve an exogenous baseload and will choose the engineering characteristics of a coal-fired unit to minimize the expected total cost of meeting the load. A key issue here is the intensity with which a unit is used. The capital intensive nature of baseload coal-fired generation means that the average total generation costs of a unit can be significantly reduced if the unit is used intensively. Baseload units are meant to be operated at maximum capacity continuously so that the level of utilization is dependent on the expected availability of the unit. Thus, the expected output of the unit is defined as:

$$Q = 8760*A(X)*K,$$

Where,

Q = expected output, measured in kilowatt hours,

$A(X)$ = expected availability of the unit,

X = unit attributes that affect availability,

K = size of the unit measured in kilowatts.

The Expected Ex Post Cost Function

As noted earlier, electric generating technology is putty-clay. The thermal efficiency of a unit is variable at the design stage and dependent on the utility's choice of steam pressure conditions. But once a unit has been built, the fuel-output relationship is fixed.[44] Thus, the total cost of generating electricity is a function of the level of output, the price of fuel on a BTU basis, the thermal efficiency of the unit, construction costs per KW of capacity, and the annual fixed charge rate.[45] The fixed charge rate is the annual cost of money capital including depreciation, property taxes, and other expenses proportional to capital costs. As a result, expected *ex post* total generation costs are:

$$SRTC(P_F, P_K, r, \alpha, K) = \alpha 8760\ A(X_0)K_0$$
$$\cdot P_F + rP_K(Z_0)K_0,$$

Where,

α = the unit's heat rate (BTU's/KWH),

P_F = price per BTU of fuel,

$P_k(Z)$ = unit construction costs per KW of capacity,

Z = unit attributes which affect construction costs,

r = the annual fixed charge rate.

Ex Ante Costs and the Investment Decision

Given that the technology is putty-clay, the utility is faced with the task of choosing unit attributes that minimize the expected total costs of serving a baseload demand for electricity at the blueprint stage. The primary unit attributes to be chosen are unit size, steam pressure conditions (an ex ante measure of thermal efficiency), and the reliability of the unit. The average construction cost of a coal-fired unit is also assumed to vary with the choice of these engineering characteristics. Briefly, it is reasonable to expect a movement from subcritical to supercritical steam pressure conditions to increase average construction cost. Higher pressure conditions improve thermal efficiency,[46] but necessitate the use of costly materials capable of handling the extreme pressure. It is reasonable to expect that $\partial P_k/\partial K$ will take on positive, negative, or zero values depending on the size of the unit. We expect that $\partial P_k/\partial K$ will take on negative values at low unit sizes and possibly become positive at large unit sizes. We also expect that the average construction cost will increase with the reliability of the unit, $\partial P_k/\partial A>0$. Finally, we expect average construction cost to increase at an increasing rate as availability approaches the limit of 100 percent, $\partial^2 P_k/\partial A^2>0$.[47]

As noted earlier, a unit's fuel costs per KWH are relatively insensitive to the rate of generation.[48] But the capital intensive nature of baseload coal-fired generating units means that intensive utilization of a unit spreads annual capital costs (which are fixed once a unit is built) over a greater level of output than if a unit is used less intensively. Thus, the _ex ante_ total costs per KWH generated by a coal-fired baseload unit are in large part determined by the availability, or reliability, of the unit:

$$TC(P_f,r,\alpha,K) + \alpha 8760KA(X)P_f+rP_k(Z)K_0.$$

This implies that the total generating costs per KWH of a subcritical or supercritical unit can be approximated by minimizing the unit's annual capital cost per KWH produced:

$$\text{Capital Cost per KWH} = \frac{(\text{Total Capital Cost x Annual Fixed Charge Rate})}{Q}$$

Since Q = 8760 A(X)K,

$$\text{Capital Cost per KWH} = \frac{\text{Capital Cost per KW * AFCR}}{8760 * A(X)}$$

This indicates that the ratio of average capital cost to unit availability determines capital cost per KWH generated. In general, both availability and capital cost decline with increased unit size for both subcritical and supercritical technologies. Thus, minimum total generation costs per KWH can be approximated for a given type of unit (subcritical or supercritical) by selecting the level of reliability and unit size such that the ratio of average capital cost to availability is the least.

SPECIFICATION OF THE CONSTRUCTION COST AN RELIABILITY MODEL

The Determinants of Unit Construction Cost

The construction cost of a coal-fired generating unit depends on the cost of inputs and a number of unit-specific attributes. Attributes commonly thought to influence the construction cost per KW of capacity include unit size, unit order, steam pressure conditions, reliability, and cooling method.

Reliability, measured by equivalent availability, is not the result of a single design or construction decision. Rather, reliability encompasses a large number of design and construction decisions ranging from the number and sizing of various types of equipment to the quality of the inputs used to manufacture or assemble the various components of the unit. Above all, redundancy of critical components is necessary to maintain a high level of unit reliability. A unit can continue in operation when a critical component fails, or needs regular maintenance, only if the component has a backup.[49] As a result, one would expect that increasing the level of reliability, everything else constant, requires additional capital investment which means $\partial P_k/\partial A>0$. We also expect that increasing reliability beyond some point will cause costs to increase at an increasing rate. Thus, we expect $\partial^2 P_k/\partial A^2>0$.

According to engineering literature, construction costs increase less than proportionately with the size of the unit. As unit size increases, the amount of material and labor per KW of capacity decreases. For example, a 600 MW unit uses only twice the piping and steel necessary to build a 200 MW unit.[50] But it would also seem reasonable to expect average construction costs to increase as unit size increases beyond some point. Extremely large unit size might require the use of additional structural reinforcement, special materials or construction methods. Thus, we expect that $\partial P_k/\partial k$ will take on negative values at low unit sizes and possibly become positive at very large unit sizes.

The primary technological frontier with respect to the thermal efficiency of coal-fired units built since 1960 has been in steam pressure conditions.[51] These units fall into two major technological classes--subcritical units with steam pressures below 3206 PSI and supercritical units with pressures greater than 3206 PSI. Subcritical units fall into three pressure classes around 1800 PSI, 2000 PSI, and 2400 PSI. These units require no technological changes as steam pressure in increased. But the higher pressures do require thicker casings for components and materials that can handle the higher pressures. Supercritical units represent an entire different technology since there is no real boiling process and steam is produced continuously as the temperature of the water increases. The need for some equipment associated with a conventional boiling process is removed, but the large increase in pressure necessitates considerable expenditure on special materials capable of withstanding these pressures. Thus, we will use the design steam pressure condition as an <u>ex ante</u> measure of thermal efficiency, and we expect supercritical units to be more costly to build than subcritical units.

The majority of individual generating units are part of multiunit sites, and the order in which the units are built has considerable impact on their individual construction costs. The first unit at a multiunit site is usually built with sufficient waste disposal facilities, transportation facilities, fuel-handling facilities, and other common facilities to support the operation of all other units scheduled to be built on the site at a later date. Thus, we expect the first unit at a site to be more costly than follow-on units.

A couple of previous studies have examined the effects of utility and architect-engineer (A-E) experience on the construction costs of generating units. Joskow and Rose (1985) found that there are important learning or experience effects as the number of units built by a given A-E increases. However, they also found that the experience effects were limited to the building of supercritical units. In order to account for the presence of any experience effects, we include a variable which measures each A-E's cumulative experience since 1950 with a specific technology. We broadly define all subcritical units as falling into one technology group, and all supercritical units as following into another technology group.

In addition to the variables mentioned above, we also include a number of dummy variables. First, it is possible that there are regional cost differences which might arise for a number of reasons. But the primary reason is that the market for construction labor is generally regional and wages can vary considerably across regions. These variations may be due to differences in the degree of unionization and the tightness of the regional labor market.

Second, we include a dummy variable to indicate whether the unit is of full-indoor design. In colder climates, boilers and turbine-generators are usually fully enclosed in protective structures. But these facilities are often only partially enclosed or fully outdoors in warmer parts of the United States. Thus, one would expect units of a full-indoor design to be more costly to build.

Third, we include a dummy variable for each A-E so as to reduce or eliminate any potential omitted variable bias. There are likely to be unobserved A-E specific design characteristics common to units designed by a particular firm. These unmeasured attributes may be correlated with experience or unit reliability which means that failing the account for them could cause the parameter estimates to be biased. Also, the inclusion of A-E dummy variables allows us to assess any differences between specific A-E firms.[52]

A translog specification of the construction cost function will be estimated. The primary reason for using this specification is that it is flexible enough to allow all size-reliability effects to occur. The basic construction cost relationship is:

$$\begin{aligned} \ln P_K = {} & B_o + B_1 \ln(MW) + B_2(\ln(MW))^2 + B_3(-\ln(1-EA)) + \\ & B_4(-\ln(1-EA))^2 + B_5(-\ln(1-EA))\ln(MW) + \\ & B_6 {*} PRESSURE + B_7(PRESSURE * \ln(MW)) + B_8(PRESSURE * (-\ln(1-EA))) + \\ & B_9 \ln(1 + EXPERAE) + B_{10} LN(YEAR) + \\ & \Sigma B_i X_i + e_t. \end{aligned}$$

Where,

P_K = the real dollar cost per KW of a generating unit net of capitalized interest costs,

MW = the capacity of the unit in megawatts (MW),

EA = a three year average of a unit's observed equivalent availability (The observations covered each unit's second through fourth year of commercial operation.),

PRESSURE = a dummy variable which indicates whether the unit is supercritical,

YEAR = the year the unit entered commercial operation minus 1900,

EXPERAE = the cumulative experience since 1950 of the A-E with the technology of the observed unit (If a unit enters commercial operation in the year t the total experience of the A-E is measured as the total number of units of the same technology designed by the A-E that entered commercial operation before year t.),

x = dummy variable indicating regionality, the presence of cooling towers, the first unit at a multiunit site, and the other variables discussed above,

e_t = the error term.

The Determinants of Unit Reliability

The engineering and economic literatures indicate that a number of design and operational characteristics have a systematic effect on unit availability. Among these are unit size, steam pressure conditions, unit age, vintage, mode of operation, and the degree of redundancy of key components.

Some engineering and economic studies assume that availability is independent of unit size,[53] but several studies that examine the size-availability relationship conclude that size and reliability are inversely related.[54] One explanation for the inverse relationship is that similar types of outages are generally longer for large units than for smaller units due to the larger area and parts that have to be repaired. Also, large unit size means more material and equipment which simply creates more opportunities for things to break down. Thus, we expect $\partial Rel/\partial K<0$. To explore more fully the relationship between availability and unit size, we allow size to enter with a quadratic specification.

Previous studies have generally found that higher steam pressure conditions have been associated with higher forced outage rates. In particular, supercritical units have been found to be considerably less reliable than similar sized subcritical units.[55] Thus, we expect supercritical units, everything else equal, to be less reliable than subcritical units.

Availability also varies with the age of the unit. The engineering literature assumes that the availability of a unit will improve the first two or three years of commercial operation due to a process of debugging and learning by plant operators. Unit availability is then expected to remain fairly constant for a number of years before starting a process of slow decay as the unit ages. Econometric studies find evidence of, at most, a one-year break-in period.[56] These studies also find that unit availability peaks after a year or less of operation and then steadily declines. We control for the effects of aging by using unit-specific averages of equivalent availability observed at the same stage of the unit life cycle. The observed equivalent availability data covered each unit's second through fourth year of commercial operation. This avoids or minimizes any possible bias due to break-in periods while also minimizing variations due to differences in utility-specific maintenance behavior.

Another reliability factor is the mode of operation. One would expect that load-following with a generating unit will reduce availability relative to that which would be obtained with baseload operation. Load-following or cycling places a considerable amount of wear and tear on a unit and thus increases the likelihood that the unit will break down.[57] We control for the mode of operation by including only units that are 300 MW or larger. New generating units with capacities of at least 300 MW are almost certainly baseload units.

As mentioned earlier, the engineering literature indicates that unit reliability is a function of numerous design and construction factors. These factors range from a 'conservative' design philosophy (which includes a high level of redundancy of key components) to the quality of the materials used to make various components of the unit and a careful inspection process during the construction phase. We are unable to observe these factors directly, so we are forced to use a proxy. We believe that construction cost per KW is a good proxy since all these factors can be expected to increase construction costs.

We also include the experience of the A-E with the given technology. Designing and building a baseload generating unit is an immensely complicated task, so it seems reasonable that A-E's go through a learning process associated with the repetitive design and construction of technologically-similar generating units.

In addition to the variables mentioned above, we also include dummy variables to control for any reliability factors that may be associated with the different manufacturers of key subcomponents, such as boilers and turbine-generators, and any omitted A-E specific effects which may bias the parameter estimates.

First, we include dummy variables to indicate the manufacturers of the boilers and turbine-generators. It is reasonable to expect that availability varies among the manufacturers of these key subcomponents due to differences in the design of the equipment, the production process, and the quality of the inputs used in the production process.

We also include a dummy variable for each A-E (except one to avoid perfect multicollinearity) in an effort to reduce or eliminate any potential omitted variable bias. Again, there are likely to be unobserved A-E specific characteristics which may be correlated with explanatory variables, such as the choice of boiler or turbine-generator manufacturers. As a result, failure to control for these unobserved A-E specific characteristics may bias the estimates of the parameter vector. This also allows us to assess any differences between specific A-E firms.

The basic reliability relationship is:

$$-\ln(1-EA) = A_0 + A_1\ln(P_K) + A_2\ln(MW) +$$
$$A_3(\ln(P_K)*\ln(MW)) + A_4 PRESSURE + A_5(PRESSURE*\ln(MW)) +$$
$$A_6\ln(1 + EXPERAE) + A_7\ln(YEAR) +$$
$$\Sigma A_i X_i + e_t$$

Where,

X = dummy variables indicating the first unit at a multiunit site, manufacturers of boilers and turbine generators, and the other variables discussed above.

The reliability variable was specified so that the variable becomes infinite as availability approaches the highest levels that are theoretically possible.[58]

<u>The Need for a Simultaneous-Equations Model</u>

As we have argued above, unit engineering attributes are determined at the same time as unit construction cost. If the utility has some conception of the error term it faces in the construction cost function, the utility might be expected to modify its choice of unit attributes. This means that the choice of unit attributes may be correlated with the error term. As a result, ordinary least squares estimates of the unit attribute coefficients in the cost function will be biased.

This estimation error will occur only if the utility has some knowledge of the error term it faces. However, it would seem unreasonable to assume that the utility or A-E is totally unaware of the direction and size of the error term. After all, every major utility or A-E has considerable experience participating in the construction and/or operation of different types of generating units. Also, a utility or A-E considering building a generating unit can draw on the experience of other utilities that have recently built similar units.

The endogenous nature of unit reliability in the cost function has been hinted at by previous researchers. Komanoff (1976) notes that higher initial construction cost due to a conservative design philosophy and, thus, higher unit reliability may result in lower total generation costs over time. Schmalensee and Joskow (1986) argue that it is only "logical to assume that construction costs will vary with the 'quality' of the facility," and that one measure of quality is the reliability of the unit. Engineering case studies indicate that improved unit reliability requires additional capital expenditures. High availability requires that critical components have spares so that if one component fails or service is required, the unit can continue in operation. Thus, high availability necessitates redundancy, and redundancy means higher capital costs.[59]

Also, the reliability variable, EA, is the realized reliability which consists of the <u>ex ante</u> level of reliability and a measurement error. It is the <u>ex ante</u> level of reliability which determines cost of construction. To ignore the fact that we can measure ex ante reliability only with some error from actual performance data would cause OLS estimation of the cost function to be biased.[60] In this situation, an instrumental variables estimator, such as two-stage least squares (2SLS), is consistent.[61]

As a result, the construction cost and reliability equations are treated as a simultaneous equations system:

$$\begin{aligned}\ln P_k = {} & B_0 + B_1\ln(MW) + B_2(\ln(MW))^2 + B_3(-\ln(1-EA)) + \\ & B_4(-\ln(1-EA))^2 + B_5(-\ln(1-EA))\ln(MW) + \\ & B_6{*}PRESSURE + B_7(PRESSURE * \ln(MW)) + \\ & B_8(PRESSURE * (-\ln(1-EA))) + B_9\ln(1+EXPSUB) + \\ & B_{10}\ln(1+EXPSUP) + B_{11}\ln(YEAR) + B_{12}FIRST + \\ & B_{13}TOWER + B_{14}FULLIN + \Sigma B_i REGION_i + \\ & \Sigma B_j AEDUM_j + e_1\end{aligned}$$

$$\begin{aligned}-\ln(1-EA) = {} & A_0 + A_1\ln(P_k) + A_2\ln(MW) + \\ & A_3(\ln(P_k)*\ln(MW)) + A_4 PRESSURE + A_5(PRESSURE * \ln(MW) + \\ & A_6\ln(1 + EXPSUB) + A_7\ln(1 + EXPSUP) + A_8\ln(YEAR) + \\ & A_9 FIRST + \Sigma A_i BOILER\ MANU_i + \Sigma A_j TURBINE\ MANU_j + \\ & \Sigma A_k AEDUM_k + e_2\end{aligned}$$

Where,

FIRST = one if the unit is the first unit on the plant site, zero otherwise,

TOWER = one if the unit was built with any type of cooling tower,

FULLIN = one if the unit was a full indoor design, zero otherwise,

REGION = a regional dummy variable,

AEDUM = one if built by a particular architect-engineer. All other variables are as previously defined.

Boiler and turbine manufacturer dummy variables are included in the reliability equation but excluded from the cost equation. This was done because a review of the literature found that differences in component design across manufacturers could affect reliability while having no systematic affect on unit construction costs. The Tower and Fullin variables are included in the cost equation but excluded from the reliability equation. The presence of a cooling tower and a fully enclosed boiler increases the number of structures to be built which means higher construction costs; however, a review of the engineering literature found no reason why the presence of either design attribute should affect unit reliability. Finally, regional dummy variables were included in the cost equation and excluded from the reliability equation. Construction cost might vary regionally because construction labor is hired in regional markets, across which wages vary considerably. There is little reason to believe that unit reliability varies on a regional basis.

The constant term, unit order, regional, and time effects are assumed to be exogenous in the construction cost equation. The effects of unit size, steam pressure conditions, cooling method, full-indoor design, choice of architect-engineers, and experience are assumed to be exogenous, since there seems to be no direct way that unit construction cost can affect the choice of these attributes and/or information regarding possible instruments is unavailable.

The situation with respect to the reliability equation is quite similar to that of the cost equation. The constant term, time, and unit order effects are assumed to be exogenous in the reliability equation, while the effects of size, pressure, experience, choice of A-E, and choice of boiler and turbine manufacturers are assumed to be exogenous because there is no obvious way that reliability can affect a utility's choice of these attributes and/or information regarding possible instruments is not available.

Estimation of the Simultaneous-Equations Model

The construction cost and reliability equations are linear in the parameters but nonlinear in the endogenous variables. The variables $(-\ln(1\text{-EA}))^2$, $(-\ln(1\text{-EA}))*\ln(\text{MW})$, $\text{Pressure}*(-\ln(1\text{-EA}))$, and $\ln(P_K)*\ln(\text{MW})$ are all nonlinear endogenous variables, since $(-\ln(1\text{-EA})$ and $\ln(P_K)$ are endogenous variables. Drawing on the procedure developed by Kelejian (1971) and used by Farber (1981) and Martin (1979), we derive first-stage estimates of the endogenous variables by including as instrumental variables the squares of all non-dummy exogenous variables. Thus, the reduced form equations are approximated by a second-order polynomial of the exogenous variables. The predicted values from the first stage were then used to estimate the structural equations. This procedure leads to consistent estimates of the parameter vectors using two-stage least squares. Both structural equations are identified using the criteria derived by Kelejian for nonlinear models.[62]

EMPIRICAL ANALYSIS

The Data

We estimated the above equations on a sample of 84 coal-fired units that entered commercial operation between 1960 and 1974. The sample consisted of 40 supercritical units and 44 subcritical units. The supercritical units range in size from 359 MW to 1,300 MW and the subcritical units range from 310 MW to 745 MW.

Total construction costs per generating unit were derived from the U.S. Department of Energy's Steam-Electric Plant Construction Cost and Annual Production Expenses (DOE). However, these cost data are reported in nominal dollars and include interest charges capitalized during construction. Therefore, we use a procedure implemented by Joskow and Rose (1985) and Zimmerman (1982) to deflate for input price changes and to remove the capitalized interest charges.

The deflation process is complicated by a number of problems. First, not only do the reported construction costs include interest charges, but they reflect the summation of nominal dollars spent over a number of years. Second, construction times and construction cash flow profiles are not reported for individual units. So we are forced to use a typical cash flow profile for units built in the early 1970's. This standard cash flow profile is combined with a price index and historical interest rates to derive real construction costs net of interest charges.[63]

We used the Handy Whitman Index of Public Utility Construction Costs to deflate the nominal construction costs to constant 1973 dollars.[64] The index is a proprietary seven-region index of steam-generating unit construction costs.

It should be noted that time is not a measure of the impact of technological change on unit construction cost in this study. As noted in Chapter 2, the primary goal of technological innovation has been to improve the thermal efficiency of the generation process. The desire for increased thermal efficiency has led to continued efforts to increase steam pressure and temperature conditions. However, the movement to higher pressure (more technologically advanced) units occurred only gradually; thus, a number of technologies are in use at any point in time. This means that the use of vintages or time to define periods of technologically homogeneous capital is likely to be inadequate.[65]

Furthermore, the primary technological frontier with respect to baseload coal-fired units built since 1960 has been in the steam pressure conditions. These units fall into two major technological classes--subcritical units with steam pressures below 3206 PSI and supercritical units with pressures greater that 3206 PSI. Supercritical technology is the primary technological innovation with respect to thermal efficiency since 1960.[66] Thus, we include a supercritical technology dummy variable to measure the impact of technological change on unit construction cost.

The equivalent availability variable was derived from data collected by the National Electric Reliability Council (NERC).[67] The NERC data contained annual observations of equivalent availability for a large number of large (300 MW through 1300 MW) coal-fired units covering the period 1965 to 1977. Unfortunately, the units were observed at different points in the unit life cycle. As a result, some units were observed from their first year of commercial operation; others were not observed until they had been in operation for a number of years. In order to observe the units at the same point in the life cycle, we included only those units for which we had observations covering their second through fourth year of commercial operation. The three annual unit-specific equivalent availabilities were then averaged to derive our reliability variable.[68]

Cooling tower information was obtained from the Department of Energy's Generating Unit Reference File (GURF). Architect-engineer information for coal-fired units built since 1950 was obtained from annual survey's in Power. Information on boiler and turbine manufacturers was also obtained from Power. All other data was obtained from DOE.

Regression Results

In order to show the importance of simultaneous equation bias and/or measurement error we use both OLS and 2SLS to estimate the cost and reliability equations. Four variations of the construction cost function are estimated using both regression techniques. One form of the cost function includes $\ln(MW)$, $(\ln(MW))^2$, $-\ln(1-EA)$, $(-\ln(1-EA))^2$, and an interaction term, ln(MW)*(-ln(1-EA)). The second form of the cost equation adds the interaction variable Pressure*ln(MW). The third form eliminates the Pressure*ln(MW) variable and adds the Pressure*(-ln(1-EA)) variable. The fourth cost function form estimated includes both the Pressure*(-ln(1-EA)) and Pressure*ln(MW) variables.

Following Joskow and Rose (1985), we initially estimate the cost function using ordinary least squares while excluding the reliability variables and including dummy variables for all A-E's except one (Stone & Webster). This leaves us with only two specifications of the cost function. One specification includes the size variables ln(MW) and $(\ln(MW))^2$, while the other specification adds the interaction term Pressure*ln(MW).[69] Thus, the first specification forces the scale terms for subcritical and supercritical units to be the same while the intercepts for the two technologies are allowed to be different. The introduction of the interaction term, Pressure*ln(MW), in the second specification allows both the intercepts and scale effects to differ across the two technologies.

The first-unit variable has a positive coefficient that is significant at the 1% level in both estimates.[70] This is consistent with the fact that utilities have strong incentives to assign as much of the common costs of multiunit sites as possible to the first unit at the site. Also, the time trend variable, ln(Year), has a positive coefficient that is significant at the 1% level in both estimates. This would seem to indicate that units which entered commercial operation at later dates cost more to build than similar units which entered commercial operation earlier.

The A-E effects are jointly significant at the 5% level [F(15,54) = 2.24] and 10% level [F(15,53) = 1.91], respectively. This indicates there are significant unobserved architect-engineer specific attributes. The unit size variables are jointly significant at the 5% level in both estimates [(F(2,54) = 4.48 and F(3,53) = 3.16, respectively]. Finally, the null hypothesis that the intercept and scale terms for subcritical and supercritical units are the same (F(2,53) = .35) cannot be rejected (see Table A-5).

Next, we use OLS to estimate four specifications of the cost equation when the reliability variables are added as mentioned above. The estimated parameter values are presented in Tables 3-1 through 3-4.

An examination of the cost function parameter estimates reveals several things of interest. The first-unit variable has a positive coefficient and is significant at the 1% level in all four estimates. The time trend variable, ln(Year), always has a positive coefficient and is statistically significant at the 1% level in all four estimates. It is interesting to note that the reliability variables are never jointly significant. This occurs despite the -ln(1-EA) term being individually significant in three of the four estimates and the interaction term, ln(MW) * (-ln(1-EA)), being significant in two of the four estimates. Finally, we are unable to reject the null hypothesis that the intercept, scale, and reliability terms for subcritical and supercritical units are the same for the estimates reported in Tables 3-2 through 3-4 [F(2,50) = .27, F(2,50) = .2, and F(3,49) = .42, respectively].

Table 3-1. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	-1.835	12.808
PRESSURE DUMMY	- .148	.325
LN(MW)	-1.205	3.215
$(LN(MW))^2$	.001	.230
-LN(1-EQUIV. AVAIL.)	-4.591	2.555-
$(-LN(1\text{-}EQUIV.\ AVAIL.))^2$	.237	.142
LN(MW)(-LN(1-EQUIV. AVAIL.))	.614	.353-
FIRST-UNIT DUMMY	.285	.055*
LN(YEAR)	3.509	.870*
COOLING TOWER DUMMY	.084	.064
FULL-INDOOR DESIGN DUMMY	.030	.085
A-E SUBCRITICAL UNIT EXPERIENCE	- .038	.059
A-E SUPERCRITICAL UNIT EXPERIENCE	- .076	.098
MIDDLE ATLANTIC DUMMY	.004	.114
WEST NORTH CENTRAL DUMMY	- .020	.149
EAST NORTH CENTRAL DUMMY	.293	.259
ROCKY MOUNTAIN DUMMY	- .080	.166
SOUTH ATLANTIC DUMMY	- .168	.096-
SOUTHERN SERVICES CO. DUMMY	- .286	.122+
TVA CO. DUMMY	.074	.160
DUKE CO. DUMMY	- .176	.162
AEP CO. DUMMY	.202	.215
STEARNS & ROGER CO. DUMMY	- .245	.244
BECHTEL CO. DUMMY	- .109	.136
EBASCO CO. DUMMY	- .195	.104-
SARGENT & LUNDY CO. DUMMY	- .148	.103
BROWN & ROOT CO. DUMMY	- .210	.302
FLUOR CO. DUMMY	- .569	.185*
BLACK & VETCH CO. DUMMY	- .337	.170-
GILBERT CO. DUMMY	- .168	.132
GC CO. DUMMY	- .039	.153
UNITED CO. DUMMY	- .318	.262
COMMON CO. DUMMY	- .212	.147

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
R^2 = .739
Adjusted R^2 = .575
F(32, 52) = 4.505

Table 3-2. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	- .254	13.186
PRESSURE DUMMY	- .875	1.816
LN(MW)	-1.962	3.496
$(LN(MW))^2$	.073	.263
PRESSURE*LN(MW)	- .164	.286
-LN(1-EQUIV. AVAIL.)	-4.217	2.653
$(-LN(1-EQUIV. AVAIL.))^2$	.232	.143
LN(MW)(-LN(1-EQUIV. AVAIL.))	.554	.370
FIRST-UNIT DUMMY	.284	.056*
LN(YEAR)	3.587	.887*
COOLING TOWER DUMMY	.081	.065
FULL-INDOOR DESIGN DUMMY	.029	.086
A-E SUBCRITICAL UNIT EXPERIENCE	- .019	.068
A-E SUPERCRITICAL UNIT EXPERIENCE	- .072	.099
MIDDLE ATLANTIC DUMMY	.010	.115
WEST NORTH CENTRAL DUMMY	- .021	.150
EAST NORTH CENTRAL DUMMY	.277	.262
ROCKY MOUNTAIN DUMMY	- .061	.171
SOUTH ATLANTIC DUMMY	- .165	.097-
SOUTHERN SERVICES CO. DUMMY	- .280	.123+
TVA CO. DUMMY	.070	.161
DUKE CO. DUMMY	- .159	.166
AEP CO. DUMMY	.210	.217
STEARNS & ROGER CO. DUMMY	- .242	.246
BECHTEL CO. DUMMY	- .123	.139
EBASCO CO. DUMMY	- .189	.105-
SARGENT & LUNDY CO. DUMMY	- .150	.104
BROWN & ROOT CO. DUMMY	- .211	.305
FLUOR CO. DUMMY	- .551	.189*
BLACK & VETCH CO. DUMMY	- .318	.174-
GILBERT CO. DUMMY	- .175	.134
GC CO. DUMMY	- .031	.155
COMMON CO. DUMMY	- .208	.148
UNITED CO. DUMMY	- .309	.264

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
R^2 = .74
Adjusted R^2 = .569
F(33, 51) = 4.321

Table 3-3. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	.247	13.867
PRESSURE DUMMY	- .054	.399
LN(MW)	-1.662	3.426
$(LN(MW))^2$	.026	.240
-LN(1-EQUIV. AVAIL.)*PRESSURE	- .096	.234
-LN(1-EQUIV. AVAIL.)	-5.172	2.937-
$(-LN(1-EQUIV.\ AVAIL.))^2$	.234	.143
LN(MW)(-LN(1-EQUIV. AVAIL.))	.711	.427
FIRST-UNIT DUMMY	.285	.056*
LN(YEAR)	3.464	.884*
COOLING TOWER DUMMY	.081	.065
FULL-INDOOR DESIGN DUMMY	.028	.086
A-E SUBCRITICAL UNIT EXPERIENCE	- .041	.060
A-E SUPERCRITICAL UNIT EXPERIENCE	- .086	.102
MIDDLE ATLANTIC DUMMY	- .008	.118
WEST NORTH CENTRAL DUMMY	- .033	.153
EAST NORTH CENTRAL DUMMY	.293	.261
ROCKY MOUNTAIN DUMMY	- .098	.173
SOUTH ATLANTIC DUMMY	- .181	.102-
SOUTHERN SERVICES CO. DUMMY	- .295	.124*
TVA CO. DUMMY	.065	.163
DUKE CO. DUMMY	- .168	.164
AEP CO. DUMMY	.190	.219
STEARNS & ROGER CO. DUMMY	- .259	.248
BECHTEL CO. DUMMY	- .108	.137
EBASCO CO. DUMMY	- .198	.105-
SARGENT & LUNDY CO. DUMMY	- .155	.106
BROWN & ROOT CO. DUMMY	- .238	.312
FLUOR CO. DUMMY	- .595	.197*
BLACK & VETCH CO. DUMMY	- .363	.182-
GILBERT CO. DUMMY	- .174	.134
GC CO. DUMMY	- .054	.158
COMMON CO. DUMMY	- .242	.165
UNITED CO. DUMMY	- .340	.269

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
R^2 = .74
Adjusted R^2 = .568
F(33, 51) = 4.303

Table 3-4. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	6.237	15.304
PRESSURE DUMMY	2.047	2.292
LN(MW)	-3.765	4.107
$(LN(MW))^2$	.200	.304
-LN(1-EQUIV. AVAIL.)	-5.277	2.943-
$(-LN(1-EQUIV. AVAIL.))^2$	.223	.144
LN(MW)(-LN(1-EQUIV. AVAIL.))	.736	.429-
-LN(1-EQUIV. AVAIL.)*PRESSURE	- .233	.276
PRESSURE*LN(MW)	- .315	.338
FIRST-UNIT DUMMY	.282	.056*
LN(YEAR)	3.551	.890*
COOLING TOWER DUMMY	.071	.066
FULL-INDOOR DESIGN DUMMY	.025	.086
A-E SUBCRITICAL UNIT EXPERIENCE	- .009	.069
A-E SUPERCRITICAL UNIT EXPERIENCE	- .093	.103
MIDDLE ATLANTIC DUMMY	- .016	.119
WEST NORTH CENTRAL DUMMY	- .053	.155
EAST NORTH CENTRAL DUMMY	.261	.263
ROCKY MOUNTAIN DUMMY	- .087	.174
SOUTH ATLANTIC DUMMY	- .196	.104-
SOUTHERN SERVICES CO. DUMMY	- .295	.125+
TVA CO. DUMMY	.043	.165
DUKE CO. DUMMY	- .123	.172
AEP CO. DUMMY	.187	.220
STEARNS & ROGER CO. DUMMY	- .272	.249
BECHTEL CO. DUMMY	- .134	.140
EBASCO CO. DUMMY	- .190	.105-
SARGENT & LUNDY CO. DUMMY	- .169	.107
BROWN & ROOT CO. DUMMY	- .279	.316
FLUOR CO. DUMMY	- .597	.197*
BLACK & VETCH CO. DUMMY	- .361	.182-
GILBERT CO. DUMMY	- .195	.136
GC CO. DUMMY	- .057	.158
COMMON CO. DUMMY	- .275	.169
UNITED CO. DUMMY	- .354	.270

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
$R^2 = .744$
Adjusted $R^2 = .567$
$F(34, 50) = 4.191$

The OLS estimate of the parameter values of the reliability equation are reported in Table 3-5.[71] The architect-engineer specific effects are jointly significant at the 1% level ($F(15,55)=2.83$). The unit size variable, ln(MW), has a negative and statistically significant coefficient. There is also a negative and significant coefficient of the unit construction cost variable. The interaction between unit size and unit construction cost has a positive and significant coefficient. Finally, it is curious that the first-unit dummy has a positive and significant coefficient.

The results reported in Tables 3-1 through 3-5 may be biased due to the simultaneous nature of our model and/or measurement error associated with the use of the realized level of reliability instead of the ex ante level of reliability. Two-stage least squares estimates are consistent under these circumstances and appear in Tables 3-6 through 3-10.

A review of the 2SLS estimates of the four specifications of the cost equation reveals a number of differences when compared to the corresponding OLS parameter estimates.[72] The 2SLS estimates of the coefficient of $-\ln(1-EA)$ are always negative and reach some level of statistical significance in three of four specifications. The coefficient of $(-\ln(1-EA))^2$ is positive and significant at the 5% level in all four 2SLS estimates of the cost equation. These results imply that the elasticity of average construction cost with respect to unit reliability varies depending on the level of reliability. The interaction term, $\ln(MW)*(-\ln(1-EA))$, always has a positive coefficient and is significant at the 5% level in two of the four 2SLS estimates. It is important to note that the 2SLS estimates of the coefficients of $-\ln(1-EA)$, $(-\ln(1-EA))^2$, and $\ln(MW)*(-\ln(1-EA))$ are generally

Table 3-5. Ordinary Least Squares Estimate of the Reliability Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	35.278	13.249+
LN(PER KW CONSTRUCTION COSTS)	- 7.14	2.782+
LN(MW)	- 6.062	1.995*
LN(MW)*LN(PER KW CONST. COSTS)	1.071	.436+
LN(YEAR)	1.379	1.349
FIRST UNIT DUMMY	.210	.093+
PRESSURE DUMMY	- 1.180	1.743
PRESSURE*LN(MW)	.150	.271
BOILER MANU. COMBUSTION ENG.	.173	.118
TURBINE MANU. GENERAL ELEC.	.376	.252
TURBINE MANU. WESTINGHOUSE	.079	.250
BOILER MANU. BABCOCK & WILCOX	.216	.142
A-E SUBCRITICAL UNIT EXP.	.036	.087
A-E SUPERCRITICAL UNIT EXP.	- .030	.136
SOUTHERN SERVICES CO. DUMMY	- .114	.172
AEP CO. DUMMY	.474	.291
DUKE CO. DUMMY	.420	.182+
TVA CO. DUMMY	.262	.288
STEARN & ROGER CO. DUMMY	- .494	.293-
BECHTEL CO. DUMMY	- .161	.144
EBASCO CO. DUMMY	- .139	.136
SARGENT & LUNDY CO. DUMMY	- .087	.151
BROWN & ROOT CO. DUMMY	- .025	.421
FLUOR CO. DUMMY	- .773	.268*
BLACK & VETCH CO. DUMMY	- .203	.238
GILBERT CO. DUMMY	- .060	.168
COMMON CO. DUMMY	- .306	.204
UNITED CO. DUMMY	- .546	.293-
GC CO. DUMMY	.425	.221-

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
$R^2 = .8$
Adjusted $R^2 = .697$
$F(28, 56) = 7.808$

Table 3-6. Two-Stage Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	29.877	19.462
PRESSURE DUMMY	- .124	.412
LN(MW)	-8.283	4.646-
$(LN(MW))^2$	.425	.323
-LN(1-EQUIV. AVAIL.)	-14.260	4.478*
$(-LN(1-EQUIV. AVAIL.))^2$	.712	.282+
LN(MW)(-LN(1-EQUIV. AVAIL.))	1.953	.623*
FIRST UNIT DUMMY	.288	.063*
LN(YEAR)	2.784	1.197+
COOLING TOWER DUMMY	.133	.081
FULL-INDOOR DESIGN DUMMY	.013	.101
A-E SUBCRITICAL UNIT EXPERIENCE	- .105	.120
A-E SUPERCRITICAL UNIT EXPERIENCE	- .071	.077
MIDDLE ATLANTIC DUMMY	- .015	.139
WEST NORTH CENTRAL DUMMY	.040	.217
EAST NORTH CENTRAL DUMMY	.365	.311
ROCKY MOUNTAIN DUMMY	- .036	.203
SOUTH ATLANTIC DUMMY	- .170	.115
SOUTHERN SERVICES CO. DUMMY	- .296	.144+
TVA CO. DUMMY	.179	.192
DUKE CO. DUMMY	- .381	.240
AEP CO. DUMMY	- .211	.322
STEARNS & ROGER CO. DUMMY	- .446	.314
BECHTEL CO. DUMMY	- .168	.167
EBASCO CO. DUMMY	- .260	.137-
SARGENT & LUNDY CO. DUMMY	- .129	.125
BROWN & ROOT CO. DUMMY	- .375	.373
FLUOR CO. DUMMY	- .560	.252+
BLACK & VETCH CO. DUMMY	- .380	.201-
GILBERT CO. DUMMY	- .199	.153
GC CO. DUMMY	- .048	.188
COMMON CO. DUMMY	- .303	.189
UNITED CO. DUMMY	- .495	.331

* = Significant at 1 Percent
\+ = Significant at 5 Percent
\- = Significant at 10 Percent
$R^2 = .6996$
Adjusted $R^2 = .5112$
$F(32, 52) = 3.712$

Table 3-7. Two-Stage Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	32.867	21.485
PRESSURE DUMMY	- 2.121	3.320
LN(MW)	- 7.978	5.018
$(LN(MW))^2$	.364	.361
PRESSURE*LN(MW)	.315	.519
-LN(1-EQUIV. AVAIL.)	-16.005	5.606+
$(-LN(1-EQUIV. AVAIL))^2$	.692	.304+
LN(MW)(-LN(1-EQUIV. AVAIL.))	2.255	.833*
FIRST UNIT DUMMY	.291	.068*
LN(YEAR)	2.186	1.620
COOLING TOWER DUMMY	.163	.099
FULL-INDOOR DESIGN DUMMY	.014	.109
A-E SUBCRITICAL UNIT EXP.	- .129	.135
A-E SUPERCRITICAL UNIT EXP.	- .121	.117
MIDDLE ATLANTIC DUMMY	- .040	.155
WEST NORTH CENTRAL DUMMY	.098	.252
EAST NORTH CENTRAL DUMMY	.407	.341
ROCKY MOUNTAIN DUMMY	- .063	.223
SOUTH ATLANTIC DUMMY	- .195	.131
SOUTHERN SERVICES CO. DUMMY	- .333	.166-
TVA CO. DUMMY	.173	.207
DUKE CO. DUMMY	- .443	.277
AEP CO. DUMMY	- .368	.433
STEARN & ROGER CO. DUMMY	- .501	.349
BECHTEL CO. DUMMY	- .184	.181
EBASCO CO. DUMMY	- .319	.176-
SARGENT & LUNDY CO. DUMMY	- .150	.139
BROWN & ROOT CO. DUMMY	- .435	.412
FLUOR CO. DUMMY	- .616	.285+
BLACK & VETCH CO. DUMMY	- .455	.249-
GILBERT CO. DUMMY	- .205	.165
GC CO. DUMMY	- .055	.202
COMMON CO. DUMMY	- .341	.213
UNITED CO. DUMMY	- .601	.397

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
R^2 = .6738
Adjusted R^2 = .4584
F(33, 51) = 3.129

Table 3-8. Two-Stage Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	32.048	34.596
PRESSURE DUMMY	- .061	.915
LN(MW)	-8.720	7.411
$(LN(MW))^2$	.450	.467
-LN(1-EQUIV. AVAIL.)*PRESSURE	- .065	.845
-LN(1-EQUIV. AVAIL.)	-14.804	8.448-
$(-LN(1-EQUIV. AVAIL))^2$	.705	.302+
LN(MW)(-LN(1-EQUIV. AVAIL))	2.049	1.403
FIRST UNIT DUMMY	.288	.065*
LN(YEAR)	2.679	1.835
COOLING TOWER DUMMY	.135	.087
FULL-INDOOR DESIGN DUMMY	.013	.103
A-E SUBCRITICAL UNIT EXP.	- .114	.168
A-E SUPERCRITICAL UNIT EXP.	- .076	.106
MIDDLE ATLANTIC DUMMY	- .025	.190
WEST NORTH CENTRAL DUMMY	.045	.230
EAST NORTH CENTRAL DUMMY	.369	.320
ROCKY MOUNTAIN DUMMY	- .045	.235
SOUTH ATLANTIC DUMMY	- .183	.201
SOUTHERN SERVICES CO. DUMMY	- .306	.200
TVA CO. DUMMY	.170	.228
DUKE CO. DUMMY	- .384	.246
AEP CO. DUMMY	- .244	.550
STEARNS & ROGERS CO. DUMMY	- .460	.365
BECHTEL CO. DUMMY	- .176	.196
EBASCO CO. DUMMY	- .271	.202
SARGENT & LUNDY CO. DUMMY	- .139	.179
BROWN & ROOT CO. DUMMY	- .402	.510
FLUOR CO. DUMMY	- .578	.345-
BLACK & VETCH CO. DUMMY	- .403	.370
GILBERT CO. DUMMY	- .206	.181
GC CO. DUMMY	- .057	.228
COMMON CO. DUMMY	- .326	.354
UNITED CO. DUMMY	- .528	.549

* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent
R^2 = .6974
Adjusted R^2 = .4977
F(33, 51) = 3.492

Table 3-9. Two-Stage Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	20.391	40.221
PRESSURE DUMMY	-3.431	4.877
LN(MW)	-5.052	9.422
$(LN(MW))^2$	.174	.632
-LN(1-EQUIV. AVAIL.)	-13.332	9.194
$(-LN(1-EQUIV. AVAIL))^2$	.730	.322+
LN(MW)(-LN(1-EQUIV. AVAIL))	1.783	1.534
-LN(1-EQUIV. AVAIL.)*PRESSURE	.412	1.122
PRESSURE*LN(MW)	.459	.651
FIRST UNIT DUMMY	.295	.069*
LN(YEAR)	2.582	1.950
COOLING TOWER DUMMY	.161	.100
FULL-INDOOR DESIGN DUMMY	.015	.109
A-E SUBCRITICAL UNIT EXP.	- .083	.184
A-E SUPERCRITICAL UNIT EXP.	- .109	.121
MIDDLE ATLANTIC DUMMY	.011	.208
WEST NORTH CENTRAL DUMMY	.092	.253
EAST NORTH CENTRAL DUMMY	.401	.342
ROCKY MOUNTAIN DUMMY	- .021	.251
SOUTH ATLANTIC DUMMY	- .127	.227
SOUTHERN SERVICES CO. DUMMY	- .283	.215
TVA CO. DUMMY	.227	.255
DUKE CO. DUMMY	- .454	.280
AEP CO. DUMMY	- .225	.584
STEARN & ROGER CO. DUMMY	- .439	.388
BECHTEL CO. DUMMY	- .143	.213
EBASCO CO. DUMMY	- .275	.214
SARGENT & LUNDY CO. DUMMY	- .098	.199
BROWN & ROOT CO. DUMMY	- .295	.561
FLUOR CO. DUMMY	- .528	.372
BLACK & VETCH CO. DUMMY	- .338	.402
GILBERT CO. DUMMY	- .164	.201
GC CO. DUMMY	.002	.256
COMMON CO. DUMMY	- .214	.407
UNITED CO. DUMMY	- .439	.596

* = Significant at 1 Percent
\+ = Significant at 5 Percent
\- = Significant at 10 Percent
R^2 = .6778
Adjusted R^2 = .4543
F(34, 50) = 3.032

Table 3-10. Two-Stage Least Squares Estimate of the Reliability Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	52.189	27.700-
LN(PER KW CONSTRUCTION COSTS)	-12.142	6.236-
LN(MW)	-9.472	4.442+
LN(MW)*LN (PER KW CONST. COSTS)	1.806	.974-
LN(YEAR)	2.868	1.730-
FIRST UNIT DUMMY	.288	.113+
PRESSURE DUMMY	- .162	1.947
PRESSURE*LN(MW)	.008	.299
BOILER MANU. COMBUSTION ENG.	.173	.131
TURBINE MANU. GENERAL ELEC.	.317	.293
TURBINE MANU. WESTINGHOUSE	- .004	.281
BOILER MANU. BABCOCK & WILCOX	.190	.164
A-E SUBCRITICAL UNIT EXP.	- .011	.152
A-E SUPERCRITICAL UNIT EXP.	.007	.096
SOUTHERN SERVICES CO. DUMMY	- .153	.184
AEP CO. DUMMY	.400	.360
DUKE CO. DUMMY	.383	.196-
TVA CO. DUMMY	.237	.314
STEARN & ROGER CO. DUMMY	- .262	.422
BECHTEL CO. DUMMY	- .127	.158
EBASCO CO. DUMMY	- .167	.144
SARGENT & LUNDY CO. DUMMY	- .082	.159
BROWN & ROOT CO. DUMMY	.009	.454
FLUOR CO. DUMMY	- .831	.304*
BLACK & VETCH CO. DUMMY	- .283	.259
GILBERT CO. DUMMY	- .024	.179
COMMON CO. DUMMY	- .285	.222
UNITED CO. DUMMY	- .594	.310-
GC CO. DUMMY	.523	.246+

* = Significant at 1 Percent
\+ = Significant at 5 Percent
\- = Significant at 10 Percent
R^2 = .7819
Adjusted R^2 = .6709
F(28, 56) = 7.043

considerably larger in absolute value and have a higher level of statistical significance than the OLS estimates of the coefficients.

The coefficient of the size variable, ln(MW), has the expected negative sign, but it is statistically significant in only one of the four 2SLS estimates. The other size variable, $(\ln(MW))^2$, has the expected positive sign, but it is never statistically significant. In general, the 2SLS estimates of the coefficients of ln(MW) and $(\ln(MW))^2$ are much larger in absolute value and are somewhat more significant than their OLS counterparts.

The time trend variable, ln(Year), always has a positive coefficient and is significant in one of the four 2SLS estimates. The corresponding OLS estimates of the time trend coefficient are larger in absolute value and have a higher level of significance.

The first-unit variable has a positive coefficient that is significant at the 1% level in all four 2SLS estimates. However, the first-unit coefficients are quite close to their values and significance levels found in the OLS estimates. Also, several of the A-E dummy variables reach some level of significance and are quite similar to the OLS parameter estimates.

Notice that the squared terms and interaction variables cause the unit cost elasticities with respect to reliability and size to vary for different locations in the sample. Unit cost elasticities with respect to size for the four 2SLS estimates are given in Tables 3-11 through 3-16. Unit cost elasticities with respect to relaibility for the four 2SLS estimates are given in Tables 3-17 through 3-22.[73]

Table 3-11. Plant Cost Elasticities with Respect to Size for a Generic Unit**

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	-1.645+	-1.400*	-1.211*	-1.056*	- .925*	- .811*	- .711+	- .622+	- .541	-.467	-.399
T STAT	-2.543	-2.913	-3.313	-3.629	-3.630	-3.211	-2.592	-2.014	-1.552	-1.198	-.926
65%	-1.385+	-1.140+	- .950*	- .795*	- .664*	- .551+	- .451	- .361	- .280	- .206	-.138
T STAT	-2.326	-2.652	-2.994	-3.170	-2.895	-2.254	-1.610	-1.116	- .758	- .497	-.301
70%	-1.084-	- .840+	- .650+	- .495+	- .364	- .250	- .150	- .061	.020	.094	.162
T STAT	-1.987	-2.179	-2.296	-2.107	-1.542	- .932	- .477	- .166	.049	.204	.320
75%	- .729	- .484	- .294	- .139	- .008	.105	.205	.295	.376	.450	.518
T STAT	-1.444	-1.347	-1.044	- .528	- .029	.316	.535	.676	.773	.841	.893
80%	- .293	- .049	.141	.296	.427	.540	.640	.730	.811	.885	.953
T STAT	- .603	- .130	.418	.845	1.096	1.230	1.303	1.344	1.368	1.383	1.393
85%	.268	.512	.702	.857-	.988-	1.101-	1.201-	1.291-	1.372-	1.446-	1.514-
T STAT	.515	1.111	1.514	1.722	1.813	1.846	1.854	1.849	1.840	1.828	1.816
90%	1.058	1.303-	1.492+	1.647+	1.778+	1.892+	1.992+	2.082+	2.163+	2.237+	2.305+
T STAT	1.619	2.005	2.186	2.257	2.276	2.270	2.255	2.235	2.214	2.194	2.174
95%	2.410+	2.654+	2.844+	2.999+	3.130+	3.244+	3.344+	3.433+	3.514+	3.588+	3.656+
T STAT	2.422	2.558	2.606	2.615	2.606	2.590	2.571	2.551	2.531	2.511	2.493

** Based on regression results reported in Table 3-6
 * = Significant at 1 percent
 + = Significant at 5 percent
 - = Significant at 10 percent

	Mean	Minimum	Maximum
MW	621	310	1300
EA	71%	43%	93%

Table 3-12. Plant Cost Elasticities with Respect to Size for a Subcritical Unit**

	MEGAWATTS					
	300	400	500	600	700	800
Equiv. Avail.						
60%	-1.761+	-1.552*	-1.390*	-1.257*	-1.145+	-1.047+
T STAT	-2.439	-2.697	-2.818	-2.744	-2.506	-2.194
65%	-1.460+	-1.251+	-1.088+	- .956+	- .843+	- .746-
T STAT	-2.236	-2.507	-2.635	-2.507	-2.171	-1.779
70%	-1.113-	- .903+	- .741+	- .608-	- .496	- .399
T STAT	-1.886	-2.101	-2.159	-1.907	-1.462	-1.040
75%	- .702	- .492	- .330	- .197	- .085	.012
T STAT	-1.286	-1.264	-1.054	- .647	- .250	.032
80%	- .198	.011	.174	.306	.418	.516
T STAT	- .363	.027	.470	.806	.991	1.080
85%	.450	.660	.822	.955-	1.067-	1.164-
T STAT	.710	1.196	1.532	1.706	1.774	1.789
90%	1.365	1.574-	1.737+	1.869+	1.982+	2.079+
T STAT	1.583	1.904	2.080	2.164	2.194	2.197
95%	2.928+	3.137+	3.300+	3.432+	3.545+	3.642+
T STAT	2.149	2.300	2.378	2.417	2.435	2.439

** Based on regression results reported in Table 3-7
* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent

	Mean	Minimum	Maximum
MW	483	310	745
EA	75%	47%	93%

Table 3-13. **Plant Cost Elasticities with Respect to Size for a Supercritical Unit ****

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	-1.446-	-1.237+	-1.075+	- .942+	- .830+	- .732+	- .647+	- .570	- .501	- .437	- .379
T STAT	-1.881	-2.118	-2.366	-2.565	-2.603	-2.405	-2.040	-1.648	-1.306	-1.030	- .812
65%	-1.145	- .936	- .773-	- .641-	- .528	- .431	- .346	- .269	- .199	- .136	- .078
T STAT	-1.523	-1.635	-1.718	-1.717	-1.575	-1.302	- .987	- .703	- .473	- .294	- .154
70%	- .798	- .588	- .426	- .293	- .181	- .084	.002	.079	.148	.212	.270
T STAT	-1.060	-1.004	- .889	- .700	- .457	- .209	.005	.173	.300	.396	.469
75%	- .387	- .177	- .015	.118	.230	.327	.413	.490	.559	.623	.681
T STAT	- .495	- .279	- .027	.232	.460	.640	.770	.861	.925	.970	1.002
80%	.117	.326	.489	.621	.733	.831	.916	.993	1.063	1.126	1.184
T STAT	.137	.443	.723	.951	1.120	1.238	1.316	1.367	1.399	1.419	1.430
85%	.765	.975	1.137	1.270	1.382	1.479	1.565-	1.642-	1.711-	1.775-	1.833-
T STAT	.774	1.076	1.307	1.472	1.585	1.660	1.708	1.737	1.755	1.764	1.767
90%	1.680	1.889	2.052-	2.184-	2.297-	2.394-	2.479-	2.556+	2.626+	2.689+	2.747+
T STAT	1.359	1.592	1.750	1.855	1.925	1.971	2.001	2.019	2.029	2.035	2.036
95%	3.243-	3.452+	3.615+	3.747+	3.860+	3.957+	4.043+	4.119+	4.189+	4.252+	4.310+
T STAT	1.873	2.012	2.101	2.159	2.197	2.223	2.241	2.252	2.259	2.263	2.265

** Based on regression results reported in Table 3-7
 * = Significant at 1 percent
 + = Significant at 5 percent
 - = Significant at 10 percent

	Mean	Minimum	Maximum
MW	773	359	1300
EA	66%	43%	82%

Table 3-14. **Plant Cost Elasticities with Respect to Size for a Generic Unit ****

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	-1.708-	-1.449-	-1.248+	-1.084+	- .946*	- .825*	- .719+	- .625-	- .539	- .461	-0.388
T STAT	-1.675	-1.893	-2.160	-2.472	-2.754	-2.800	-2.463	-1.933	-1.449	-1.076	-0.800
65%	-1.434	-1.176-	- .975+	- .811+	- .672*	- .552+	- .446	- .351	- .265	- .187	-0.115
T STAT	-1.666	-1.931	-2.285	-2.668	-2.703	-2.103	-1.403	- .906	- .577	- .353	-0.192
70%	-1.118	- .860-	- .659+	- .495-	- .356	- .236	- .130	- .035	.051	.129	0.201
T STAT	-1.606	-1.881	-2.153	-1.955	-1.226	- .641	- .286	- .065	.082	.186	0.264
75%	- .745	- .486	- .285	- .121	.018	.138	.244	.339	.425	.503	0.575
T STAT	-1.354	-1.308	- .860	- .311	.037	.239	.363	.447	.506	.549	0.584
80%	- .287	- .028	.172	.337	.475	.595	.702	.796	.882	.960	1.032
T STAT	- .567	- .059	.311	.510	.619	.685	.728	.758	.780	.797	0.810
85%	.303	.561	.762	.926	1.065	1.185	1.291	1.386	1.472	1.550	1.622
T STAT	.433	.704	.826	.886	.920	.940	.953	.962	.969	.974	0.977
90%	1.134	1.393	1.593	1.758	1.896	2.016	2.122	2.217	2.303	2.381	2.453
T STAT	.971	1.049	1.081	1.096	1.104	1.107	1.109	1.109	1.109	1.109	1.108
95%	2.555	2.814	3.014	3.178	3.317	3.437	3.543	3.638	3.724	3.802	3.874
T STAT	1.223	1.235	1.238	1.238	1.236	1.233	1.231	1.228	1.226	1.223	1.221

** Based on regression results reported in Table 3-8
* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent

	Mean	Minimum	Maximum
MW	621	310	1300
EA	71%	43%	93%

Table 3-15. Plant Cost Elasticities with Respect to Size for a Subcritical Unit **

	MEGAWATTS					
	300	400	500	600	700	800
Equiv. Avail.						
60%	-1.433	-1.333	-1.256+	-1.192+	-1.138+	-1.092+
T STAT	-1.251	-1.612	-2.044	-2.409	-2.452	-2.177
65%	-1.195	-1.095	-1.017+	- .954+	- .900+	- .854
T STAT	-1.231	-1.673	-2.215	-2.452	-2.101	-1.634
70%	- .920	- .820-	- .743+	- .679-	- .626	- .579
T STAT	-1.169	-1.682	-2.114	-1.767	-1.248	- .913
75%	- .595	- .495	- .418	- .354	- .300	- .254
T STAT	- .964	-1.251	-1.031	- .660	- .436	- .304
80%	- .197	- .097	- .020	.044	.097	.144
T STAT	- .359	- .187	- .030	.053	.099	.127
85%	.315	.416	.493	.557	.610	.657
T STAT	.426	.476	.468	.453	.439	.427
90%	1.038	1.139	1.216	1.280	1.333	1.380
T STAT	.833	.782	.735	.698	.669	.646
95%	2.274	2.374	2.452	2.516	2.569	2.616
T STAT	1.011	.952	.907	.873	.845	.823

** Based on regression results reported in Table 3-9
* = Significant at 1 percent
+ = Significant at 5 percent
- = Significant at 10 percent

	Mean	Minimum	Maximum
MW	483	310	745
EA	75%	47%	93%

Table 3-16. Plant Cost Elasticities with Respect to Size for a Supercritical Unit **

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	- .974	- .874	- .797	- .733	- .679	- .633	- .592	- .555	- .522	- .492	-.464
T STAT	- .652	- .764	- .906	-1.088	-1.314	-1.549	-1.671	-1.565	-1.318	-1.072	-.875
65%	- .736	- .636	- .558	- .495	- .441	- .395	- .354	- .317	- .284	- .254	-.226
T STAT	- .549	- .640	- .759	- .911	-1.071	-1.127	- .988	- .767	- .580	- .443	-.344
70%	- .461	- .361	- .284	- .220	- .167	- .120	- .079	- .042	- .009	.021	.049
T STAT	- .391	- .426	- .462	- .474	- .414	- .286	- .163	- .074	- .014	.028	.058
75%	- .136	- .036	.041	.105	.159	.205	.246	.283	.316	.346	.374
T STAT	- .132	- .049	.072	.203	.291	.331	.345	.349	.349	.347	.344
80%	.262	.362	.439	.503	.556	.603	.644	.681	.714	.744	.772
T STAT	.279	.486	.633	.684	.678	.654	.628	.603	.583	.565	.550
85%	.774	.875	.952	1.016	1.069	1.116	1.157	1.193	1.227	1.257	1.285
T STAT	.781	.920	.941	.912	.871	.832	.798	.769	.744	.722	.703
90%	1.497	1.598	1.675	1.739	1.792	1.839	1.880	1.916	1.950	1.980	2.008
T STAT	1.120	1.113	1.070	1.023	.981	.944	.913	.886	.863	.843	.825
95%	2.733	2.833	2.911	2.975	3.028	3.075	3.116	3.152	3.185	3.216	3.244
T STAT	1.227	1.174	1.126	1.087	1.053	1.025	1.001	.980	.962	.946	.931

** Based on regression results reported in Table 3-9
 * = Significant at 1 percent
 + = Significant at 5 percent
 - = Significant at 10 percent

	Mean	Minimum	Maximum
MW	773	359	1300
EA	66%	43%	82%

Table 3-17. **Plant Cost Elasticities with Respect to Reliability for a Generic Unit ****

	MEGAWATTS 300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	-1.833*	-1.272*	- .837+	- .481	- .181	.080	.309	.515	.701	.870-	1.027+
T STAT	-3.161	-2.925	-2.424	-1.598	- .613	.255	.894	1.338	1.646	1.866	2.028
65%	-1.643*	-1.082*	- .647+	- .291	.010	.270	.500	.705-	.891-	1.061+	1.217+
T STAT	-3.193	-2.913	-2.234	-1.115	.035	.872	1.409	1.754	1.985	2.147	2.266
70%	-1.423*	- .862*	- .427-	- .072	.229	.489	.719-	.925+	1.110+	1.280+	1.436+
T STAT	-3.212	-2.828	-1.790	- .302	.833	1.494	1.877	2.114	2.272	2.383	2.466
75%	-1.164*	- .603+	- .167	.188	.489	.749-	.979+	1.184+	1.370+	1.540+	1.696+
T STAT	-3.169	-2.478	- .792	.759	1.579	1.999	2.238	2.389	2.491	2.564	2.620
80%	- .846*	- .285	.150	.506	.806+	1.067+	1.297+	1.502+	1.688+	1.857*	2.014*
T STAT	-2.847	-1.321	.623	1.628	2.089	2.331	2.476	2.572	2.639	2.688	2.727
85%	- .436	.125	.560	.916+	1.216+	1.476+	1.706+	1.912+	2.097*	2.267*	2.423*
T STAT	-1.594	.450	1.600	2.108	2.365	2.513	2.609	2.675	2.723	2.760	2.789
90%	.141	.702	1.137+	1.493+	1.793+	2.054+	2.284+	2.489*	2.675*	2.845*	3.001*
T STAT	.371	1.537	2.069	2.339	2.496	2.597	2.667	2.717	2.756	2.787	2.811
95%	1.128	1.689+	2.124+	2.480+	2.781+	3.041+	3.271+	3.476*	3.662*	3.832*	3.988*
T STAT	1.585	2.055	2.303	2.452	2.551	2.621	2.673	2.713	2.745	2.771	2.793

** Based on regression results reported in Table 3-6
 * = Significant at 1 percent
 + = Significant at 5 percent
 - = Significant at 10 percent

	Mean	Minimum	Maximum
MW	621	310	1300
EA	71%	43%	93%

Table 3-18. **Plant Cost Elasticities with Respect to Reliability for a Generic Unit ****

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	-1.880*	-1.231+	- .728-	- .317	.031	.332	.598	.835	1.050	1.246	1.427-
T STAT	-2.982	-2.632	-1.823	- .786	.069	.650	1.034	1.295	1.480	1.616	1.721
65%	-1.695*	-1.046+	- .543	- .132	.216	.517	.782	1.020	1.235-	1.431-	1.612-
T STAT	-3.013	-2.625	-1.597	- .364	.506	1.031	1.356	1.569	1.717	1.826	1.908
70%	-1.482*	- .833+	- .330	.081	.429	.730	.996-	1.233-	1.448-	1.644+	1.825+
T STAT	-3.027	-2.557	-1.154	.242	1.024	1.442	1.687	1.845	1.954	2.034	2.095
75%	-1.229*	- .581+	- .077	.334	.681	.982-	1.248-	1.486+	1.701+	1.897+	2.077+
T STAT	-2.969	-2.253	- .306	.991	1.558	1.839	2.001	2.105	2.178	2.231	2.272
80%	- .921+	- .272	.231	.643	.990-	1.291+	1.557+	1.794+	2.009+	2.206+	2.386+
T STAT	-2.640	-1.199	.839	1.672	2.004	2.169	2.265	2.328	2.372	2.405	2.430
85%	- .522	.126	.630	1.041+	1.388+	1.689+	1.955+	2.193+	2.408+	2.604+	2.784+
T STAT	-1.564	.430	1.647	2.098	2.293	2.394	2.455	2.495	2.523	2.544	2.559
90%	.039	.688	1.191+	1.602+	1.949+	2.251+	2.516+	2.754+	2.969+	3.165+	3.345+
T STAT	.086	1.404	2.016	2.291	2.430	2.510	2.560	2.593	2.617	2.634	2.647
95%	.998	1.647-	2.150+	2.561+	2.909+	3.210+	3.475+	3.713+	3.928+	4.124+	4.305+
T STAT	1.250	1.860	2.175	2.352	2.459	2.530	2.579	2.614	2.641	2.661	2.677

** Based on regression results reported in Table 3-7
 * = Significant at 1 percent
 + = Significant at 5 percent
 - = Significant at 10 percent

	Mean	Minimum	Maximum
MW	621	310	1300
EA	71%	43%	93%

Table 3-19. Plant Cost Elasticities with Respect to Reliability for a Subcritical Unit

	MEGAWATTS					
	300	400	500	600	700	800
EQUIV. AVAIL.						
60%	-1.819*	-1.230+	- .772	- .398	- .082	.191
T STAT	-2.987	-2.529	-1.294	- .514	- .086	.171
65%	-1.631*	-1.041+	- .584	- .210	.106	.380
T STAT	-2.948	-2.498	-1.074	- .286	.115	.348
70%	-1.414*	- .824+	- .366	.007	.323	.597
T STAT	-2.842	-2.402	- .746	.010	.362	.559
75%	-1.157+	- .567+	- .109	.264	.580	.854
T STAT	-2.584	-2.089	- .245	.395	.666	.812
80%	- .842+	- .252	.205	.579	.895	1.169
T STAT	-2.009	-1.098	.482	.881	1.036	1.117
85%	- .436	.153	.611	.985	1.301	1.574
T STAT	- .982	.545	1.327	1.443	1.470	1.480
90%	.135	.725	1.183-	1.556-	1.872-	2.146-
T STAT	.236	1.549	1.979	1.984	1.936	1.891
95%	1.113	1.702-	2.160+	2.534+	2.850+	3.123+
T STAT	1.217	1.985	2.299	2.364	2.346	2.307

** Based on regression results reported in Table 3-8
* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent

	Mean	Minimum	Maximum
MW	483	310	745
EA	75%	47%	93%

Table 3-20. Plant Cost Elasticities with Respect to Reliability for a Supercritical Unit **

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	-1.884	-1.295	- .837	- .463	- .147	.126	.368	.584	.779	.958	1.122
T STAT	-1.622	-1.663	-1.663	-1.392	- .485	.324	.718	.914	1.026	1.097	1.145
65%	-1.696	-1.106	- .649	- .275	.041	.315	.556	.772	.968	1.146	1.310
T STAT	-1.472	-1.444	-1.335	- .891	.147	.845	1.112	1.226	1.286	1.321	1.344
70%	-1.479	- .889	- .431	- .058	.258	.532	.774	.989	1.185	1.363	1.527
T STAT	-1.287	-1.166	- .894	- .189	.928	1.426	1.541	1.566	1.570	1.567	1.563
75%	-1.222	- .632	- .174	.199	.515	.789-	1.031-	1.247-	1.442-	1.620-	1.784-
T STAT	-1.058	- .818	- .348	.592	1.636	1.958	1.960	1.913	1.867	1.829	1.799
80%	- .907	- .317	.140	.514	.830+	1.104+	1.345+	1.561+	1.757+	1.935+	2.099+
T STAT	- .772	- .394	.253	1.243	2.082	2.333	2.309	2.232	2.159	2.097	2.047
85%	- .501	.088	.546	.920-	1.236+	1.509+	1.751+	1.967+	2.162+	2.341+	2.505+
T STAT	- .410	.101	.832	1.682	2.297	2.528	2.543	2.487	2.417	2.351	2.294
90%	.070	.660	1.118	1.491-	1.807+	2.081+	2.323+	2.539+	2.734+	2.912+	3.076+
T STAT	.053	.646	1.327	1.956	2.382	2.589	2.653	2.646	2.610	2.564	2.517
95%	1.048	1.637	2.095-	2.469+	2.785+	3.058+	3.300+	3.516*	3.711*	3.890*	4.054*
T STAT	.663	1.225	1.732	2.131	2.403	2.568	2.656	2.695	2.705	2.698	2.681

** Based on regression results reported in Table 3-8
* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent

	Mean	Minimum	Maximum
MW	773	359	1300
EA	66%	43%	82%

Table 3-21. Plant Cost Elasticities with Respect to Reliability for a Subcritical Unit **

	MEGAWATTS 300	400	500	600	700	800
Equiv. Avail.						
60%	-1.822*	-1.309+	- .912	- .586	- .312	- .074
T STAT	-2.825	-2.488	-1.378	- .681	- .294	- .059
65%	-1.627*	-1.114+	- .717	- .392	- .117	.121
T STAT	-2.778	-2.464	-1.186	- .478	- .114	.100
70%	-1.402+	- .889+	- .492	- .166	.108	.346
T STAT	-2.663	-2.384	- .897	- .214	.109	.292
75%	-1.136+	- .623+	- .225	.100	.375	.613
T STAT	-2.396	-2.107	- .452	.134	.387	.526
80%	- .810-	- .297	.100	.426	.700	.938
T STAT	-1.820	-1.198	.212	.584	.734	.813
85%	- .390	.123	.520	.846	1.120	1.358
T STAT	- .823	.410	1.037	1.131	1.155	1.164
90%	.202	.715	1.112-	1.437-	1.712	1.950
T STAT	.327	1.444	1.740	1.698	1.634	1.582
95%	1.214	1.727-	2.124+	2.449+	2.724+	2.962+
T STAT	1.240	1.899	2.133	2.147	2.099	2.041

** Based on regression results reported in Table 3-9
* = Significant at 1 percent
\+ = Significant at 5 percent
\- = Significant at 10 percent

	Mean	Minimum	Maximum
MW	483	310	745
EA	75%	47%	93%

Table 3-22. Plant Cost Elasticities with Respect to Reliability for a Supercritical Unit **

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60	-1.410	- .897	- .500	- .174	.100	.338	.548	.736	.906	1.061	1.204
T STAT	-1.005	- .898	- .696	- .322	.210	.662	.913	1.036	1.099	1.133	1.153
65	-1.215	- .702	- .305	.020	.295	.533	.743	.931	1.101	1.256	1.399
T STAT	- .869	- .707	- .429	.038	.632	1.062	1.254	1.322	1.344	1.347	1.345
70	- .990	- .477	- .080	.246	.520	.758	.968	1.156	1.326	1.481	1.624
T STAT	- .707	- .479	- .111	.456	1.096	1.488	1.615	1.629	1.608	1.581	1.555
75	- .724	- .211	.187	.512	.787	1.025-	1.235-	1.423-	1.592-	1.748-	1.890-
T STAT	- .513	- .208	.253	.899	1.543	1.889	1.966	1.938	1.883	1.829	1.781
80	- .398	.115	.512	.838	1.112-	1.350+	1.560+	1.748+	1.918+	2.073+	2.216+
T STAT	- .277	.109	.649	1.319	1.910	2.208	2.266	2.221	2.151	2.080	2.017
85	.022	.535	.932	1.258	1.532+	1.770+	1.980+	2.168+	2.338+	2.493+	2.636+
T STAT	.014	.475	1.052	1.671	2.162	2.414	2.479	2.449	2.386	2.316	2.250
90	.614	1.127	1.524	1.849-	2.124+	2.362+	2.572+	2.760+	2.930+	3.085+	3.228+
T STAT	.382	.888	1.434	1.937	2.305	2.511	2.590	2.594	2.561	2.512	2.459
95	1.626	2.139	2.536-	2.861+	3.136+	3.374+	3.584+	3.772+	3.942+	4.097+	4.240+
T STAT	.872	1.348	1.777	2.121	2.366	2.519	2.602	2.639	2.645	2.633	2.611

** Based on regression results reported in Table 3-9
 * = Significant at 1 percent
 + = Significant at 5 percent
 - = Significant at 10 percent

	Mean	Minimum	Maximum
MW	773	359	1300
EA	66%	43%	82%

An examination of the unit cost elasticities with respect to size reveals several things of interest. First, the largest degree of statistical significance occurs at low levels of reliability. Also, the elasticities are always negative at low levels of reliability and they diminish in absolute value as unit size increases. The elasticities are always positive at higher levels of reliability and increase as unit size increases. This suggests that per KW construction costs can be reduced if unit size is increased at a low level of reliability, but that maintaining a high level of reliability as unit size is increased will cause higher per KW construction cost.

The unit cost elasticities with respect to reliability are unexpectedly negative and take on some level of significance for the smaller sized units. As unit size increases, the elasticities are negative only at low levels of reliability. Generally, the elasticities for units beyond 600 MW or 700 MW are all positive and take on a fairly high level of significance. Notice for any particuluar level of reliability that the elasticities tend to increase as the units get larger. This suggests that the impact of reliability on unit construction cost is stronger for large generating units regardless of whether they are of subcritical or supercritical technology.

An examination of the 2SLS estimate of the values for the reliability equation (see Table 3-10) reveals several things of interest.[74] First, the time trend variable, ln(year), has a positive and statistically significant coefficient. This seems to indicate that units that entered commercial operation later in the observed period had higher levels of reliability than similar units that entered commercial operation earlier. The 2SLS estimate of the time trend coefficient is twice as large and has a higher level of significance than the OLS estimate.

The unit-size variable, ln(MW), has a negative and statistically significant coefficient. Interestingly, there is a negative and significant coefficient for the average construction cost variable. Also, the interaction between unit size and average construction cost has a positive and significant coefficient. It is important to note that the OLS estimate of these coefficients is considerably smaller in absolute value than the 2SLS estimates. However, the OLS estimate of each of the coefficients has a higher level of statistical significance than the 2SLS estimate.

Several of the A-E dummy variables reach some level of statistical significance and are similar to the OLS parameter estimates. Again, it is curious that the first-unit dummy variable has a positive and significant coefficient.

Summary

The purpose of this chapter has been to develop a model that recognizes reliability as an endogenous attribute of baseload coal-fired generation. The capital-intensive nature of baseload coal-fired generation means that intensive utilization can significantly reduce average capital cost per KWH generated and thus average total generation costs per KWH generated.

We began this chapter by noting that the cyclical demand for electricity means that generating units will be designed for different modes of operation. For example, baseload units are designed for continuous operation at maximum capacity whenever they are available while, at the other extreme, peakers are designed for rapid starts and shutdowns and are operated only during periods of peak demand. In order to avoid the problem of mixing units designed for different modes of operation, we restricted ourselves to an analysis of the generation costs of coal-fired baseload units.

An examination of the unit design process revealed that the fuel-output relationship (we ignore labor) is fixed once the unit is built and is fairly insensitive to the level of generation. Thus, the utility is faced at the design stage with choosing unit engineering attributes, such as size, thermal efficiency (as measured by steam pressure conditions), and reliability so as to minimize the expected total cost of meeting the expected load.

Given the capital-intensive nature of baseload generation and the putty-clay nature of the technology, an important determinant of a unit's total generation cost per KWH is the intensity with which it is used. Supercritical units are slightly more fuel efficient than subcritical units with steam pressures of 2400 PSI, but they are also generally more costly to build and less reliable. So we concentrated on developing a unit average construction cost model that would allow us to examine how capital cost per KW varies for the two technologies given various combinations of unit size and reliability.

The result was a simultaneous-equations model where construction cost per KW and reliability are endogenous variables. A translog form of the construction cost function was estimated with unit size, reliability (as measured by equivalent availability), steam pressure conditions (subcritical or supercritical), first unit at a multiunit site, and A-E experience with the technology as the primary explanatory variables. The reliability equation was estimated with unit size, steam pressure conditions, and the quality of the facility as measured by capital cost per KW as the primary explanatory variables.

The chapter concluded with a review of OLS and 2SLS estimates of the average construction cost and unit reliability functions. The above results suggest that the potential bias from ignoring the simultaneous nature of the model and/or ignoring the measurement error associated with the use of realized reliability instead of the <u>ex ante</u> level of reliability may be important factors in the estimation of generating unit construction cost-unit reliability relationships.

In Chapter 4, we will show, assuming that whenever a unit is available it is used, how annual capital costs per KWH change for various combinations of unit size and reliability for both subcritical and supercritical technologies.

CHAPTER 4

AVERAGE CAPITAL COSTS AND THE UNIT SIZE-RELIABILITY TRADEOFF

Introduction

In Chapter 3, we developed and estimated a simultaneous-equation model with construction cost per KW and reliability being treated as endogenous variables. We will use that model in this chapter to show how capital costs per KW and capital costs per KWH respond to various combinations of unit size and reliability for both subcritical and supercritical generation technologies. These results are interesting in light of a number of existing and proposed programs aimed at improving the performance of the electric utility industry.

The cost-plus nature of electric utility regulation has long been suspected of reducing incentives to make efficient investment and operating decisions by utility management.[75] So, in an effort to improve the efficiency of utility operations, a number of state regulatory commissions have implemented incentive programs which condition financial rewards or penalties on some measure of a utility's performance. A popular incentive program involves setting generating unit performance targets. The most common criteria used to measure unit performance is equivalent availability. But setting minimum standards for a narrow range of performance criteria can create perverse incentives for utility management. For example, utility management might be willing to incur excessive costs in areas outside the incentive program so as to improve performance in the targeted areas. Thus, it is important to understand the extent to which there is a trade-off between the reliability and the construction costs of a generating unit.

The Federal Energy Regulatory Commission (FERC) has recently proposed all-source bidding programs for new generating capacity in an effort to improve the efficiency of utility investment decisions. A major concern under any all-source bidding program is how to evaluate and weigh the price and nonprice characteristics of each proposal when ranking the bids. An important attribute to include when evaluating a bid for baseload generation capacity is the availability or reliability of the proposed unit. Each unit design is likely to have a different level of reliability. Thus, it is important to determine the consistency between the units' design, projected construction costs, and expected availability.

The Behavior of Average Capital Costs

Our primary purpose at this stage is to evaluate how capital costs per KW and capital costs per KWH respond to variations in unit size and reliability. An examination of both is necessary because the cost-minimizing level of reliability for a given sized unit often differs between the two measures of capital costs. This analysis will be done by using the average construction cost function estimates given in Tables 3-6 through 3-9 in Chapter 3. In order to derive estimates of capital costs per KWH, we must make the assumption that a generating unit is used whenever it is available. This is a reasonable assumption given that all units in our data set are baseload in nature.

The results of this exercise are presented in Tables 4-1 through 4-14. The odd-numbered tables (4-1, 4-3, etc.) show how capital costs per KWH respond to variations in unit size and reliability, while the even-numbered tables (4-2, 4-4, etc.) show how capital costs per KW respond. Each table was derived by assuming a unit was either subcritical or supercritical, the architect-engineer had previously designed and built five generation units with the given technology, the presence of a cooling tower, a full-indoor design, the unit is not the first unit at the plant site, an annual fixed charge rate of 15 percent, and that the unit entered commercial operation in 1970.

A general result for each measure of capital costs is that the cost-minimizing level of reliability falls as unit size increases. This is consistent with the observation in Chapter 3 that high levels of reliability are more expensive to attain for large units regardless of whether the unit is subcritical or supercritical in technology.

It is also interesting to note that the level of availability, which minimizes capital costs per KW for a given sized unit, is frequently lower than the level of availability which minimizes capital costs per KWH for the unit. In fact, the level of availability that minimizes capital costs per KWH for a given sized unit is always greater-than or equal-to the level of availability that minimizes capital costs per KW for the same unit. Thus, minimizing capital costs per KW does not assure minimum capital costs per KWH for a given sized unit.

Table 4-1. Capital Cost Per KWH for a Subcritical Unit *

	MEGAWATTS										
	300	350	400	450	500	550	600	650	700	750	800
Equiv. Avail.											
60%	1.136	.891	.733	.625	.548	.490	.446	.411	.383	.360	.341
65%	.832	.679	.578	.509	.458	.420	.391	.368	.349	.334	.322
70%	.610	.521	.462	.421	.392	.370	.353	.340	.330	.323	.317
75%	.450	.406	.378	.359	.346	.338	.333	.330	.329	.330	.331
80%	.337	.325	.321	.321	.324	.330	.337	.346	.356	.368	.380
85%	.264	.278	.295	.315	.338	.362	.389	.418	.449	.481	.516
90%	.235	.279	.329	.386	.450	.521	.599	.685	.780	.884	.997
95%	.345	.505	.715	.983	1.320	1.738	2.249	2.867	3.607	4.485	5.520

* Based on regression results reported in Chapter 3, Table 3-6
Note: All figures are in cents per KWH.

Table 4-2. Capital Cost Per KW for a Subcritical Unit *

	MEGAWATTS										
	300	350	400	450	500	550	600	650	700	750	800
Equiv. Avail.											
60%	398.18	312.13	256.94	219.15	192.00	171.73	156.16	143.89	134.05	126.02	119.38
65%	315.72	257.63	219.58	193.12	173.89	159.45	148.31	139.54	132.53	126.84	122.20
70%	249.27	213.05	189.02	172.24	160.08	151.05	144.22	139.00	134.99	131.91	129.56
75%	196.91	177.78	165.40	157.16	151.64	148.02	145.76	144.54	144.11	144.32	145.05
80%	157.36	151.93	149.81	149.83	151.35	153.99	157.50	161.71	166.52	171.84	177.62
85%	130.87	137.76	146.40	156.42	167.63	179.92	193.22	207.50	222.74	238.94	256.08
90%	123.27	146.59	173.12	203.03	236.48	273.69	314.86	360.22	410.00	464.47	523.86
95%	191.40	280.33	396.57	545.33	732.40	964.16	1247.62	1590.44	2000.99	2488.35	3062.37

* Based on regression results reported in Chapter 3, Table 3-6
Note: All figures are in dollars per KW.

Table 4-3. Capital Cost Per KWH for a Subcritical Unit *

	MEGAWATTS										
	300	350	400	450	500	550	600	650	700	750	800
Equiv. Avail.											
60%	1.347	1.036	.837	.701	.603	.530	.474	.430	.394	.365	.341
65%	.980	.789	.664	.576	.511	.463	.425	.394	.370	.350	.333
70%	.712	.605	.533	.482	.444	.415	.393	.375	.361	.349	.340
75%	.519	.470	.437	.415	.399	.388	.381	.376	.373	.371	.371
80%	.383	.375	.373	.375	.381	.388	.398	.409	.421	.434	.448
85%	.293	.317	.344	.373	.405	.440	.477	.516	.558	.601	.647
90%	.251	.312	.383	.463	.554	.656	.769	.896	1.036	1.190	1.358
95%	.340	.538	.813	1.183	1.668	2.293	3.083	4.068	5.280	6.756	8.534

* Based on regression results reported in Chapter 3, Table 3-7
Note: All figures are in cents per KWH.

Table 4-4. Capital Cost Per KW for a Subcritical Unit *

	MEGAWATTS										
Equiv. Avail.	300	350	400	450	500	550	600	650	700	750	800
60%	472.13	363.10	293.31	245.60	211.34	185.78	166.10	150.58	138.08	127.83	119.31
65%	371.86	299.58	251.92	218.56	194.14	175.62	161.19	149.69	140.36	132.68	126.26
70%	291.08	247.41	217.94	196.98	181.49	169.71	160.55	153.31	147.50	142.81	138.99
75%	227.32	205.86	191.57	181.74	174.86	170.05	166.73	164.53	163.20	162.55	162.46
80%	178.82	174.99	174.17	175.32	177.87	181.47	185.89	190.98	196.63	202.77	209.34
85%	145.28	157.12	170.53	185.28	201.28	218.45	236.77	256.21	276.78	298.49	321.34
90%	131.66	163.95	201.05	243.29	291.02	344.60	404.42	470.87	544.34	625.25	714.03
95%	188.46	298.62	451.17	656.32	925.62	1272.13	1710.46	2256.89	2929.46	3748.06	4734.55

* Based on regression results reported in Chapter 3, Table 3-7
Note: All figures are in dollars per KW.

Table 4-5. Capital Cost Per KWH for a Supercritical Unit *

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	.988	.672	.519	.432	.377	.340	.314	.294	.280	.268	.260
65%	.718	.533	.440	.387	.354	.332	.317	.307	.301	.296	.294
70%	.522	.428	.382	.358	.345	.339	.338	.339	.343	.349	.356
75%	.380	.351	.344	.347	.357	.370	.387	.406	.427	.449	.474
80%	.281	.299	.328	.363	.403	.447	.496	.549	.605	.666	.730
85%	.215	.276	.349	.435	.534	.646	.774	.916	1.075	1.251	1.446
90%	.184	.307	.477	.702	.992	1.357	1.808	2.358	3.018	3.804	4.730
95%	.249	.653	1.437	2.812	5.055	8.521	13.652	20.990	31.192	45.040	63.458

* Based on regression results reported in Chapter 3, Table 3-7
Note: All figures are in cents per KWH.

Table 4-6. Capital Cost Per KW for a Supercritical Unit *

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	346.13	235.43	181.99	151.49	132.20	119.14	109.87	103.07	97.96	94.06	91.06
65%	272.62	202.21	167.18	147.01	134.38	126.08	120.47	116.66	114.10	112.47	111.53
70%	213.40	174.93	156.29	146.43	141.22	138.78	138.15	138.77	140.31	142.54	145.34
75%	166.66	153.77	150.58	152.06	156.25	162.22	169.49	177.79	186.94	196.84	207.41
80%	131.10	139.80	153.17	169.54	188.25	209.03	231.74	256.32	282.75	311.05	341.23
85%	106.51	136.88	173.33	215.93	264.99	320.87	383.97	454.74	533.63	621.12	717.71
90%	96.53	161.38	250.60	368.84	521.15	712.98	950.20	1239.13	1586.51	1999.54	2485.91
95%	138.17	362.14	797.07	1559.98	2804.66	4727.58	7574.14	11645.43	17305.33	24988.13	35206.50

* Based on regression results reported in Chapter 3, Table 3-7
Note: All figures are in dollars per KW.

Table 4-7. Capital Cost Per KWH for a Subcritical Unit *

	MEGAWATTS										
Equiv. Avail.	300	350	400	450	500	550	600	650	700	750	800
60%	1.194	.928	.758	.643	.561	.500	.453	.417	.388	.364	.344
65%	.875	.709	.601	.527	.473	.433	.402	.378	.358	.343	.330
70%	.643	.547	.483	.440	.408	.385	.367	.354	.344	.336	.330
75%	.474	.427	.397	.378	.364	.356	.351	.349	.348	.349	.352
80%	.356	.344	.340	.341	.345	.352	.361	.372	.385	.398	.413
85%	.278	.295	.315	.339	.365	.394	.426	.460	.496	.535	.577
90%	.247	.298	.355	.421	.496	.579	.672	.776	.891	1.017	1.156
95%	.361	.540	.780	1.093	1.493	1.998	2.624	3.394	4.328	5.451	6.791

* Based on regression results reported in Chapter 3, Table 3-8
Note: All figures are in cents per KWH.

Table 4-8. Capital Cost Per KW for a Subcritical Unit *

	MEGAWATTS										
	300	350	400	450	500	550	600	650	700	750	800
Equiv. Avail.											
60%	418.52	325.04	265.67	225.36	196.58	175.23	158.90	146.10	135.86	127.55	120.70
65%	332.33	269.22	228.24	199.95	179.51	164.24	152.52	143.34	136.03	130.14	125.34
70%	262.75	223.47	197.62	179.68	166.78	157.25	150.10	144.68	140.55	137.43	135.09
75%	207.80	187.22	174.02	165.35	159.64	155.97	153.80	152.74	152.55	153.05	154.12
80%	166.21	160.68	158.76	159.19	161.27	164.59	168.88	173.97	179.74	186.11	193.02
85%	138.22	146.34	156.43	168.13	181.25	195.67	211.33	228.22	246.32	265.64	286.18
90%	129.95	156.38	186.77	221.38	260.49	304.38	353.40	407.88	468.19	534.69	607.77
95%	200.05	299.65	432.63	606.17	828.36	1108.26	1456.00	1882.78	2401.01	3024.33	3767.70

* Based on regression results reported in Chapter 3, Table 3-8
Note: All figures are in dollars per KW.

Table 4-9. Capital Cost Per KWH for a Supercritical Unit *

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	1.126	.714	.529	.427	.365	.325	.296	.276	.261	.250	.242
65%	.818	.562	.442	.375	.335	.308	.291	.279	.271	.265	.262
70%	.594	.447	.377	.340	.318	.306	.299	.296	.297	.299	.303
75%	.434	.363	.333	.321	.318	.322	.329	.339	.352	.366	.382
80%	.320	.306	.311	.326	.347	.372	.402	.435	.471	.510	.552
85%	.246	.279	.323	.376	.439	.510	.590	.679	.778	.887	1.007
90%	.213	.306	.427	.579	.767	.996	1.270	1.596	1.979	2.426	2.944
95%	.297	.642	1.229	2.160	3.563	5.590	8.430	12.303	17.468	24.229	32.936

* Based on regression results reported in Chapter 3, Table 3-8
Note: All figures are in cents per KWH.

Table 4-10. Capital Cost Per KW for a Supercritical Unit *

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	394.38	250.35	185.24	149.73	128.03	113.74	103.83	96.73	91.50	87.60	84.67
65%	310.46	213.22	167.70	142.48	127.08	117.09	110.40	105.85	102.78	100.77	99.55
70%	243.01	182.77	154.25	138.83	129.99	124.94	122.26	121.19	121.27	122.21	123.83
75%	189.93	159.05	145.90	140.57	139.43	140.86	144.04	148.51	154.00	160.32	167.37
80%	149.72	143.01	145.28	152.13	161.92	173.88	187.65	203.02	219.89	238.21	257.95
85%	122.21	138.30	160.24	186.85	217.78	253.02	292.68	336.95	386.04	440.21	499.73
90%	111.91	160.84	224.31	304.33	403.17	523.37	667.65	838.94	1040.38	1275.30	1547.27
95%	164.68	356.14	681.90	1198.57	1976.49	3101.55	4677.01	6825.56	9691.38	13442.40	18272.65

* Based on regression results reported in Chapter 3, Table 3-8
Note: All figures are in dollars per KW.

Table 4-11. Capital Cost Per KWH for a Subcritical Unit *

	MEGAWATTS										
	300	350	400	450	500	550	600	650	700	750	800
Equiv. Avail.											
60%	1.111	.895	.746	.639	.559	.497	.447	.407	.374	.346	.322
65%	.815	.680	.586	.516	.463	.421	.387	.359	.335	.315	.298
70%	.599	.522	.466	.424	.392	.366	.344	.326	.311	.298	.287
75%	.444	.406	.379	.359	.342	.330	.319	.311	.303	.298	.292
80%	.335	.326	.321	.318	.317	.317	.317	.319	.321	.323	.326
85%	.265	.279	.294	.310	.326	.342	.359	.375	.392	.410	.427
90%	.241	.280	.329	.378	.428	.482	.538	.597	.658	.722	.789
95%	.373	.531	.727	.964	1.246	1.577	1.960	2.400	2.901	3.466	4.101

* Based on regresstion results reported in Chapter 3, Table 3-9
Note: All figures are in cents per KWH.

Table 4-12. Capital Cost Per KW for a Subcritical Unit *

	MEGAWATTS										
	300	350	400	450	500	550	600	650	700	750	800
Equiv. Avail.											
60%	389.38	313.48	261.55	224.08	195.94	174.11	156.75	142.64	130.98	121.18	112.85
65%	309.28	258.30	222.47	196.02	175.75	159.76	146.84	136.20	127.28	119.72	113.22
70%	244.87	213.36	190.63	173.49	160.13	149.42	140.66	133.37	127.20	121.93	117.37
75%	194.28	177.98	166.08	157.04	150.00	144.37	139.81	136.05	132.93	130.31	128.10
80%	156.35	152.30	149.86	148.51	147.92	147.88	148.24	148.93	149.87	151.00	152.30
85%	131.55	138.68	146.14	153.84	161.74	169.79	177.98	186.30	194.73	203.28	211.93
90%	126.61	149.21	173.17	198.50	225.20	253.28	282.74	313.58	345.82	379.45	414.49
95%	206.77	294.82	403.55	535.06	691.46	874.89	1087.52	1331.58	1609.31	1923.00	2274.98

* Based on regression results reported in Chapter 3, Table 3-9
Note: All figures are in dollars per KW.

Table 4-13. Capital Cost Per KWH for a Supercritical Unit *

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	.690	.529	.439	.382	.343	.314	.292	.275	.261	.250	.240
65%	.535	.439	.384	.349	.325	.307	.294	.284	.276	.269	.264
70%	.419	.372	.346	.331	.321	.315	.311	.309	.308	.309	.310
75%	.334	.326	.326	.331	.338	.346	.355	.365	.376	.387	.398
80%	.277	.302	.331	.360	.391	.423	.455	.488	.521	.555	.590
85%	.247	.313	.383	.459	.538	.623	.712	.806	.905	1.008	1.116
90%	.265	.413	.596	.813	1.067	1.360	1.693	2.068	2.486	2.950	3.460
95%	.545	1.214	2.305	3.942	6.261	9.410	13.549	18.850	25.496	33.684	43.620

* Based on regression results reported in Chapter 3, Table 3-9
Note: All figures are in cents per KWH.

Table 4-14. Capital Cost Per KW for a Supercritical Unit *

	MEGAWATTS										
	300	400	500	600	700	800	900	1000	1100	1200	1300
Equiv. Avail.											
60%	241.84	185.37	153.85	133.82	120.02	109.95	102.29	96.29	91.47	87.53	84.24
65%	202.95	166.59	145.80	132.45	123.23	116.54	111.51	107.64	104.59	102.18	100.23
70%	171.22	152.11	141.55	135.20	131.23	128.74	127.24	126.43	126.11	126.18	126.53
75%	146.44	142.86	142.94	144.86	147.83	151.46	155.54	159.93	164.56	169.37	174.32
80%	129.21	141.32	154.53	168.39	182.71	197.42	212.46	227.81	243.46	259.40	275.62
85%	122.39	155.15	190.23	227.61	267.29	309.28	353.57	400.17	449.09	500.33	553.90
90%	139.21	217.28	313.04	427.32	560.98	714.88	889.89	1086.90	1306.77	1550.40	1818.66
95%	302.49	673.70	1278.84	2186.91	3473.44	5220.56	7516.93	10457.86	14145.26	18687.75	24200.64

* Based on regression results reported in Chapter 3, Table 3-9
Note: All figures are in dollars per KW.

Another general result of our research is that capital costs per KW for both generation technologies fall continuously as unit size increases, but only at low levels of equivalent availability (60-70%). At high levels of equivalent availability (85-95%), capital costs per KW increase with unit capacity. Capital costs per KW follow a U-shaped pattern as unit size increases at intermediate levels of availability (75-80%). These relationships are clearly seen in Figure 4-1, which plots capital cost per KW as unit size increases while equivalent availability is maintained at levels of 60, 75, and 90 percent. Capital costs per KWH follow very similar patterns for the various combinations of unit size and availability (see Figure 4-2). These results are in sharp contrast to those obtained by previous researchers, who generally found that capital costs per KW fall as unit size increases; however, they failed to treat reliability as an attribute of a generating unit.

To the extent that the goal of regulators is to minimize capital costs per KWH, there are two broad groups of size-reliability combinations that appear to generally satisfy this goal. One group consists of units in the 300 to 500 MW range with equivalent availabilities of 80 to 90 percent. The second group consists of very large units (800 MW and larger) with equivalent availabilities ranging from 60 to 70 percent. It is interesting to note that capital costs per KWH are almost always lowest for units in the 300-400 MW range with equivalent availabilities of 85 to 90 percent.

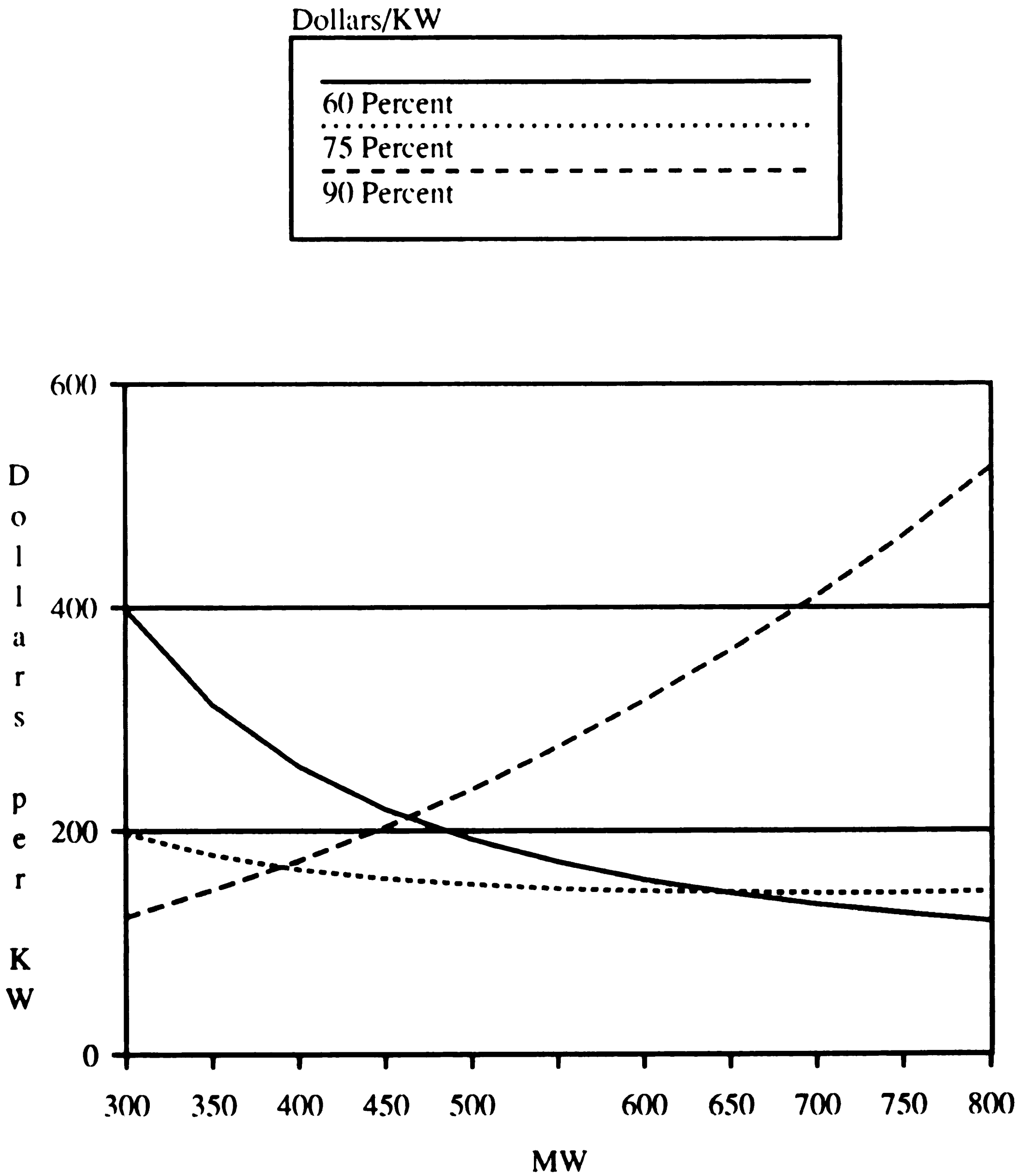

Figure 4.1 Capital Cost Per KW

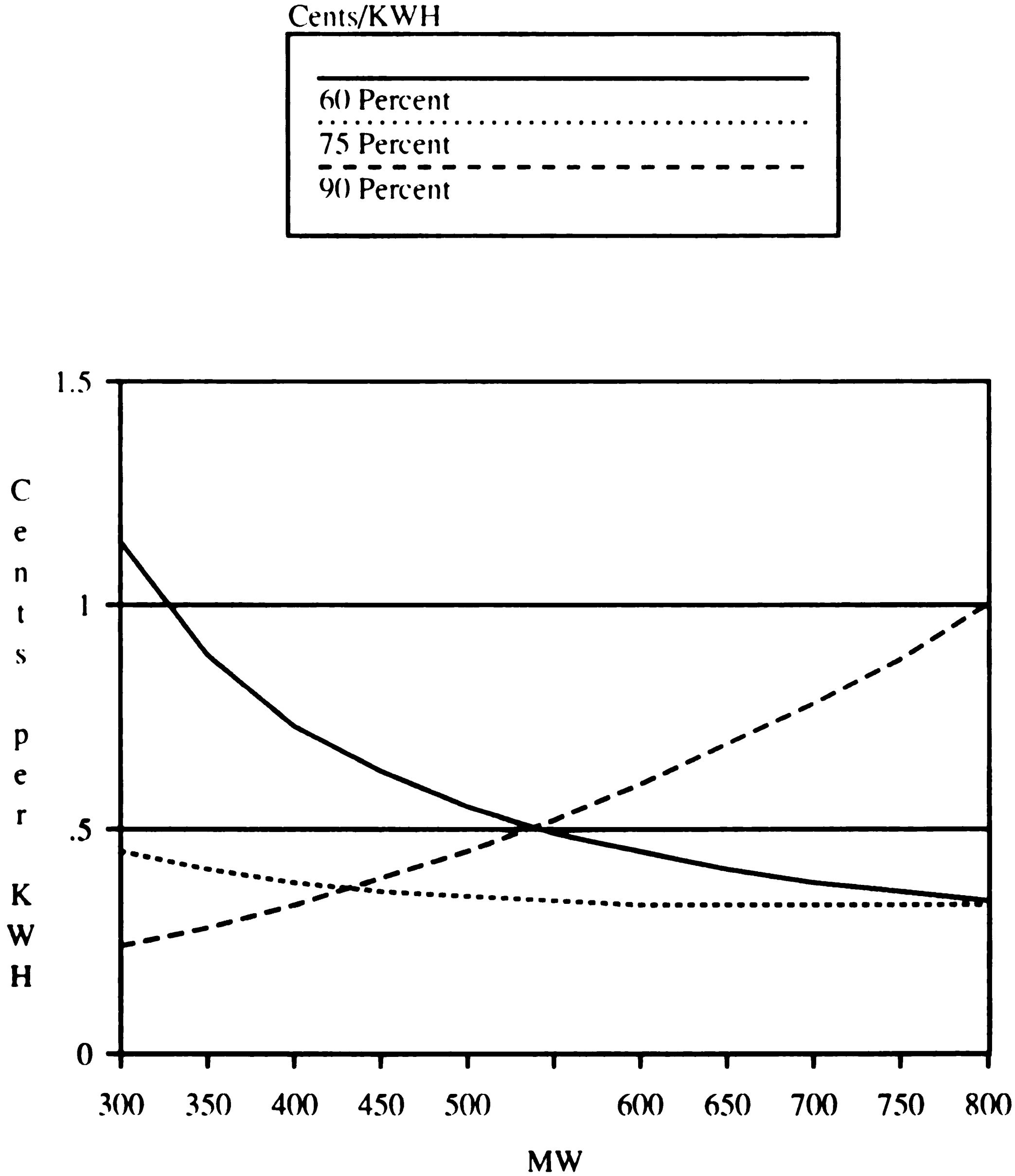

Figure 4.2 Capital Cost Per KWH

Efforts to Improve Utility Performance and the Size-Reliability Tradeoff

Poor reliability means that the capital-related costs of a baseload generating unit are spread over a lower level of output than if the unit is used more intensively. Poor reliability also reduces the thermal efficiency of a generating unit in two ways. First, frequent deratings of a unit due to outages means that heat energy must be expended to reheat the boiler and other components. Second, heat loss is relatively larger at low load than at high load, given that the absolute amount of heat loss is fairly constant. Thus, poor unit reliability means higher average costs per KWH generated.

As a result, a number of state utility commissions have initiated incentive programs aimed at improving the equivalent availability of a utility's baseload generation facilities.[76] The idea is to encourage the utility to keep a unit running as much as is economically reasonable. One approach is to tie a utility's return on equity to the level of plant availability. For example, a normal range of plant availability may be set between 70 and 80 percent. Performance below 70 percent causes the return on equity to be reduced by .25%, while performance greater that 80 percent is rewarded by allowing the return on equity to increase by .25%.

However, setting minimum standards for a narrow range of performance criteria can create perverse incentives for a utility.[77] A utility might be willing to incur excessive costs in areas outside the incentive program so as to improve performance in the targeted areas. For example, a utility might spend excessively on maintenance and, thus, partially or even totally offset the benefits to rate payers of higher unit availability.

The results given above and in Chapter 3 reveal that there is a relationship (or connection), everything else equal, between the construction costs and reliability of a generating unit. These results indicate that there is an optimum level of reliability depending on generation technology and unit-size which minimizes capital costs per KWH and/or capital costs per KW. An examination of Tables 4-1 through 4-14 also reveals that capital costs can increase significantly if the desired level of equivalent availability is either higher or lower than the cost-minimizing level of reliability for a given sized unit. Thus, to the extent that a utility has an incentive to increase the reliability of a unit under construction beyond the cost-minimizing level for a given unit-size due to an incentive program, the additional capital costs may more than offset any potential benefits to ratepayers. As a result, state regulators should also develop policies that focus on unit design and the construction process.

Traditionally, however, state utility commissions have relied on prudence tests to help offset the disincentive effects of cost-plus regulation on utility capital spending. The disincentive problem is accentuated by the fact that regulators generally have less information than utility management regarding utility investment decisions and the efficiency of the generating unit design and construction process. The prudence test is an imperfect tool to improve utility performance, because it can only be used to punish especially bad and costly outcomes.

Thus, the FERC has proposed all-source bidding programs for new generation capacity in an effort to improve the efficiency of utility investment and construction decisions.[78] The idea is that a competitive solicitation for new generation capacity from all sources will promote the construction of the least cost facilities.

The general nature of an all-source bidding program that may result from the FERC proposal can be seen from the broad characteristics of a number of state bidding programs that currently exist.[79] Under all-source competitive bidding, a utility would forecast its need for additional generation capacity and set the long-run avoided cost cap for the new electricity. The cost cap would be set equal to the utility's projected cost of supplying the additional electricity itself. At this point, the utility would request proposals for generation capacity from other sources. If alternative generation sources are inadequate to meet the utility's needs or the utility's own offer is deemed best in terms of cost and reliability, then the utility would be permitted to build the needed generation facilities. If the utility spends more than the avoided cost cap, only the amount stated in the cap would be added to the rate base. Should the utility spend less than the cap, it would earn a higher rate of return, since the total cap amount would be included in the rate base.

However, at least two issues must be settled before any type of bidding program can be implemented. First, to what extent should generating capacity choices be made on the basis of price? Second, to the extent that noncost factors are included in the bid evaluation process, what are the appropriate noneconomic factors to be included and how are they to be evaluated?

Current state bidding programs generally utilize some type of ranking system to evaluate and compare bids. A common practice is to divide the ranking criteria into two broad categories--economic and noneconomic. The economic factors usually receive the greatest weight in the ranking process and are primarily limited to the bid price of the electricity. Noneconomic factors typically include the following: (1) project schedule and milestones, (2) project financing, (3) project team and experience, (4) fuel type, (5) generation technology, (6) engineering design, and (7) reliability.[80]

It is important to obtain a balance between price and nonprice considerations and to conduct a thorough evaluation of a bid to determine whether the proposed price of electricity is consistent with the noneconomic factors of the bid. This is necessary because the "noneconomic" factors of a proposed generating facility can have a significant impact on the "economic" factors. For example, the econometric analysis in Chapter 3 highlighted the simultaneous nature of the relationship between the reliability (a common noncost factor) and construction costs of a generating unit. But the ability to make simple and straightforward checks on the consistency between the economic and noneconomic factors of a bid and to compare the characteristics of alternative bids remains to be seen.

One way that utilities are coping with this uncertainty is by inserting a number of conditions into contracts with independent bidders for new generation capacity. These conditions are aimed at reducing the uncertainty that utilities have regarding whether independent suppliers will prove to be reliable sources of generation capacity. Among the conditions being contractually required by some utilities are: (1) large security deposits, (2) warranties from engineers and equipment manufacturers, (3) site inspections, (4) financial audits, and (5) supervision of maintenance.[81]

State utility commissions and purchasing utilities are also requiring independent suppliers to satisfy performance guarantees in order to avoid paying penalties. A fairly typical standard requires the owner of an independent generation facility to pay a capacity penalty if the facility fails to maintain an annual average availability factor greater-than or equal-to the lesser of the purchasing utility's prior year's weighted average of equivalent availability for its non-nuclear units or a cap of 80 percent for solid fuel facilities.[82]

However, to the extent that state regulators seek high levels of unit reliability (defined as 80% and higher) and reasonable capital costs, it would seem desirable to encourage the construction of baseload coal-fired units in the 300-450 MW range. An examination of the above tables reveals that both capital costs per KWH and capital costs per KW increase as unit size increases beyond 450 MW while maintaining an 80% level of equivalent availability. At levels of equivalent availability greater than 80%, both measures of capital costs increase as unit size increases beyond 300 MW.

Summary

In this chapter we have reviewed how capital costs per KW and capital costs per KWH respond to variations in unit size and reliability. A general result is that the level of reliability which minimizes capital costs per KWH is always greater than or equal to the level of reliability which minimizes capital costs per KW for a given sized unit. Another general result is that the level of reliability which minimizes each measure of capital costs falls as unit size increases. Finally, both measures of capital costs either fall, rise, or follow a U-shaped pattern as unit size increases beyond 300 MW while maintaining, respectively, low (60-70%), high (85-95%), or intermediate (75-80%) levels of equivalent availability.

We also used these results to briefly review and evaluate two regulatory reforms aimed at improving incentives for efficiency in the electric utility industry. Maintaining a high level of unit reliability was the primary objective of one program and an important objective of the other program. Each program sought to promote high levels of unit reliability by tying some combination of financial rewards and/or penalties to the average annual equivalent availabilities of specified units.

Our results indicate, however, that if state and federal regulatory agencies desire high levels of unit reliability and reasonable capital costs, then they should promote the construction of coal-fired baseload units in the 300-450 MW range with equivalent availabilities of 80 to 90 percent. In fact, capital costs per KWH generated are almost always lowest for units in the 300-400 MW range with equivalent availabilities of 85-90 percent.

CHAPTER 5

CONCLUSIONS

Summary

The primary objective of this study was to develop a construction cost function for coal-fired steam-electric generating units which explicitly recognized that unit size and reliability are inversely related. The basic concept was that the construction cost of a generating unit, or any other type of capital equipment, should depend on the various engineering attributes of the facility. Most previous studies have treated generating units as if they were homogeneous pieces of capital equipment that could be represented by a scalar aggregate measure like unit size. Other studies have generally disaggregated the engineering attributes of generating units along the dimensions of size and steam pressure conditions (or heat rate). But the failure to include reliability as an engineering attribute has meant that it is impossible to determine whether large units cost less to build because of economies of scale or because of poorer quality.

To begin our analysis, we noted that the cyclical demand for electricity means that generating units will be designed for different modes of operation. Baseload units are designed for high thermal efficiency and continuous operation at maximum capacity whenever they are available. At the other extreme, peakers are designed for rapid starts and shutdowns, lower thermal efficiency, and operation only during periods of peak demand. A utility's decision as to what portion of the total demand for electricity the unit would serve was seen as having a significant effect on the desired engineering characteristics of the unit. Thus, we assumed for the remainder of our analysis that we were dealing exclusively with coal-fired, baseload units.

Another important feature of our analysis was an examination of how the unit design process and, thus, the choice of engineering characteristics shaped the ex post production relationship. Both the labor-output and fuel-output relationships were found to be conditional upon the design characteristics of the generating unit. Once a unit is built, there is very little opportunity for substitution among the inputs so the technology for steam-electric generation was seen to be of a putty-clay nature.

As a result, a utility was viewed as being faced with the task, at the blueprint stage, of choosing unit attributes that minimize the expected total costs of serving a baseload demand for electricity. The capital intensive nature of baseload, coal-fired generation means that the average total generation costs of a unit can be reduced significantly if it is used intensively. However, baseload units are meant to be operated at maximum capacity whenever they are available, so the primary determinant of the intensity with which a baseload unit is utilized and, thus, an important engineering attribute is the reliability of the unit.

On the basis of these observations, we developed an ex ante long-run unit reliability and construction cost model. Both unit reliability and construction costs were expressed as functions of the dominant design characteristics of the generating unit. We further noted that a utility can be expected to modify its choice of unit attributes if it has some conception of the magnitude and sign of the disturbance term in the construction cost function. Such an event was deemed reasonable given the substantial experience major utilities have building and operating a variety of generating units. So a simultaneous relationship between construction costs and reliability was assumed.

The simultaneous-equation model was estimated with a data set that contained observations on 84 coal-fired units that entered commercial operation during the period 1964-1974. We then used regression estimates to evaluate how capital costs per KW and capital costs per KWH responded to variations in unit size and reliability.

One interesting result was that units that entered commercial operation later in the observed period were more reliable than similar units that entered commercial operation earlier. We also found that unit size and reliability are inversely related.

Both measures of capital costs were found to be characterized by economies of scale at low levels of reliability and diseconomies at high levels of reliability. Both capital cost measures followed a U-shaped pattern as unit size increased at intermediate levels of reliability. The cost-minimizing level of reliability for each measure was also found to decrease as unit size increased. These results indicate that high levels of reliability are expensive for large units to attain, given the general size-reliability tradeoff noted earlier.

We also learned that focusing on minimizing capital costs per KW is inappropriate if utilities and regulators desire to minimize average total generation costs for a baseload unit. The level of reliability that minimizes capital costs per KWH was found to be greater-than or equal-to the level of reliability that minimizes capital costs per KW for a given sized unit. The reason for this result is, the relative increase in construction costs caused by the higher level of reliability is less-than or equal-to the relative increase in potential KWH generated.

Capital costs per KWH were found to be minimized by units that fell into two broad-size reliability groups. One group consisted of units in the 300-500 MW range with equivalent availabilities of 80-90 percent. The second group consisted of units 800 MW and larger with equivalent availabilities of only 60-70 percent.

It is important to remember that we limited our analysis to the impact the size-reliability tradeoff has on the average generation costs of an individual baseload unit. Any consideration given to building extremely large units with low levels of reliability would be put into a less favorable light if we were to expand our analysis to include the impact on system-wide costs and reliability. The lower average reliability of larger units adds to a utility's total system costs, because additional capacity must be built if a specified level of system reliability is to be maintained.

Perhaps the most important conclusion drawn from this study is that the size-reliability tradeoff, which seems to characterize the coal-fired baseload generation technologies, cannot be ignored if regulatory authorities desire both high levels of reliability and reasonable capital costs. Current policies promoting improved reliability by tying financial rewards and/or penalities to the average annual equivalent availabilities of specified units are inadequate, because they create perverse incentives for a utility. In general, regulatory agencies need to develop policies that focus on unit design and the construction process. Regulatory authorities, to be more specific, should promote the construction of coal-fired baseload units in the 300-450 MW range with equivalent availabilities of 80-90 percent.

Suggestions for Future Research

There were two significant limitations placed on the scope of our analysis which provide interesting areas for future research. First, we excluded from our analysis nuclear units. Nuclear units are definitely baseload facilities and have low fuel costs but very high capital costs. In fact, nuclear units are considerably more capital-cost intensive than coal-fired units. Thus, the existence of any size-reliability tradeoff for nuclear units can have a significant impact on their average total generation costs.

The second area of future research was touched on earlier. Our primary concern in this study was an analysis of how the size-reliability tradeoff affected construction cost economies at the level of the individual unit. However, one of the primary determinants of system reliability is the reliability of the systems' individual generating units. The more frequent a generating unit is broken down, everything else equal, the lower the reliability of the utility system and/or the higher are system-wide production costs. Thus, an interesting area of future research involves analyzing how movement to relatively small (300-450 MW), reliable, baseload, coal-fired units affects system-wide reliability and costs.

APPENDICES

APPENDIX A

APPENDIX A

THE DEFLATION PROCESS

The following formula was used to deflate the nominal construction cost of a unit and to net out interest charges:

Construction cost in constant dollars net of interest charges =

$$\frac{\text{Reported Nominal Cost}}{\sum_{t=i}^{s} S_t \cdot \left[\prod_{i=1}^{t} (i + p(i)) \cdot \prod_{j=t}^{s} (1 + r(j))\right]}$$

Where,

S_t = the share of actual construction costs in year t (taken from a typical cash flow curve reported in Power Plant Capital Costs, Current Trends and Sensitivity to Economic Parameters, U.S. Atomic Energy Commission, WASH-1345, October 1974, Figure 5. This gives annual cash flows for a 5-year construction period.),

P(i) = the percentage change in input prices in year i (taken from the Handy-Whitman Public Utility Construction Cost Index),

r(j) = the average allowance for funds used during construction [rate from the DOE's Statistics of Privately-Owned Utilities in the United States (various years)].

APPENDIX B

APPENDIX B

ESTIMATION OF A COBB-DOUGLAS SPECIFICATION OF THE COST FUNCTION

Below we specify the relationship between average construction cost and unit size to be Cobb-Douglas, as was done by Joskow and Rose (1985). We estimate three variations of this basic construction cost relationship. We initially estimate the cost function using OLS while excluding the reliability variables and including architect-engineer dummy variables (see Table B-1). This is similar to the basic cost function specification estimated by Joskow and Rose. Several of our results are similar to their findings. We obtain a very large and precise estimate of the first-unit effect, which implies that such units are in the range of 25% more costly than follow-on units. We also find that real costs per KW, net of input price changes, have increased over time. The coefficient on the time trend variable, ln(year), is positive and statistically significant at the 1% level. We also found that the architect-engineer (A-E) dummy variables are jointly significant at the 5% level ($F(15,54) = 2.15$).

A couple of our results are also different from Joskow and Rose's findings. We find that the coefficients of the A-E experience variables have the expected signs but are not statistically significant. Joskow and Rose found the experience effects for the supercritical technology to be fairly large and statistically significant. Finally, we are unable to reject the null hypothesis that the intercept and scale terms for subcritical and supercritical units are the same ($F(2,54) = 1.23$).

Table B-1. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	-10.269	3.139
PRESSURE DUMMY	1.798	1.234
LN(MW)	-.138	.140
LN(MW)*PRESSURE	-.303	.195
FIRST UNIT DUMMY	.275	.055*
LN(YEAR)	3.770	.789*
COOLING TOWER DUMMY	.070	.061
FULL-INDOOR DESIGN DUMMY	.054	.084
A-E SUBCRITICAL UNIT EXPERIENCE	-.011	.060
A-E SUPERCRITICAL UNIT EXPERIENCE	-.046	.096
MIDDLE ATLANTIC DUMMY	.031	.111
WEST NORTH CENTRAL DUMMY	.034	.135
EAST NORTH CENTRAL DUMMY	.273	.257
ROCKY MOUNTAIN DUMMY	-.033	.166
SOUTH ATLANTIC DUMMY	-.167	.095-
SOUTHERN SERVICES CO. DUMMY	-.285	.121+
TVA CO. DUMMY	-.014	.148
DUKE CO. DUMMY	-.126	.147
AEP CO. DUMMY	.280	.163-
STEARNS & ROGER CO. DUMMY	-.108	.226
BECHTEL CO. DUMMY	-.133	.138
EBASCO CO. DUMMY	-.189	.098-
SARGENT & LUNDY CO. DUMMY	-.178	.102-
BROWN & ROOT CO. DUMMY	-.106	.292
FLUOR CO. DUMMY	-.500	.174*
BLACK & VETCH CO. DUMMY	-.296	.168-
GILBERT CO. DUMMY	-.170	.133
GC CO. DUMMY	-.042	.150
COMMON CO. DUMMY	-.145	.138
UNITED CO. DUMMY	-.291	.252

* = Significant at 1 Percent
+ = Significant at 5 Percent
\- = Significant at 10 Percent
R^2 = .72
Adjusted R^2 = .57
F(30, 54) = 4.795

Joskow and Rose found supercritical units to be characterized by a higher level of costs and larger estimated scale effects than subcritical units.

As done in Chapter 3, we now use OLS to estimate the cost function when our basic reliability variables are added to the cost equation (see Table B-2). The first unit effects are once more positive and significant at the 1% level. Again, the time trend variable has a positive and significant coefficient (at the 1% level). The size variable, ln(MW), has a considerably larger coefficient in absolute value than before and is now significant at the 10% level. Finally, the reliability variables are not jointly significant ($F(3,51) = 1.31$). These results are similar to those reported in Chapter 3.

We will now use 2SLS to estimate the cost function, which includes the basic reliability variables (see Table B-3).[83] The 2SLS estimate of the coefficient of -ln(1-EA) is negative and statistically significant at the 1% level. The coefficient of $(-\ln(1-EA))^2$ is positive and significant at the 5% level. The interaction term, ln(MW)*(-ln(1-EA)), has a positive coefficient that is significant at the 5% level. It is important to note that the 2SLS estimate of these coefficients is much larger in absolute value and has a higher level of statistical significance than the OLS parameter estimates presented in Table B-2.

The coefficient on the size variable, ln(MW), has a negative sign and is significant at the 1% level. The 2SLS estimate of the size effect is quite larger in absolute value and has a higher level of significance than the OLS estimate. The time trend variable has the expected positive coefficient, but it is not significant. The OLS

Table B-2. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	-3.539	5.664
PRESSURE DUMMY	.644	1.597
LN(MW)	-1.007	.542-
PRESSURE*LN(MW)	-.126	.249
-LN(1-EQUIV. AVAIL.)	-3.958	2.460
$(-LN(1-EQUIV. AVAIL.))^2$	.220	.135
LN(MW)(-LN(1-EQUIV. AVAIL.))	.520	.344
FIRST UNIT DUMMY	.285	.055*
LN(YEAR)	3.618	.872*
COOLING TOWER DUMMY	.078	.064
FULL-INDOOR DESIGN DUMMY	.029	.085
A-E SUBCRITICAL UNIT EXP.	-.024	.065
A-E SUPERCRITICAL UNIT EXP.	-.072	.098
MIDDLE ATLANTIC DUMMY	.013	.113
WEST NORTH CENTRAL DUMMY	-.014	.147
EAST NORTH CENTRAL DUMMY	.284	.258
ROCKY MOUNTAIN DUMMY	-.061	.169
SOUTH ATLANTIC DUMMY	-.166	.096-
SOUTHERN SERVICES CO. DUMMY	-.280	.122+
TVA CO. DUMMY	.080	.156
DUKE CO. DUMMY	-.159	.164
AEP CO. DUMMY	.236	.194
STEARN & ROGER CO. DUMMY	-.232	.241
BECHTEL CO. DUMMY	-.123	.138
EBASCO CO. DUMMY	-.193	.103-
SARGENT & LUNDY CO. DUMMY	-.151	.103
BROWN & ROOT CO. DUMMY	-.205	.301
FLUOR CO. DUMMY	-.547	.187*
BLACK & VETCH CO. DUMMY	-.323	.172-
GILBERT CO. DUMMY	-.173	.132
GC CO. DUMMY	-.036	.152
COMMON CO. DUMMY	-.202	.145
UNITED CO. DUMMY	-.317	.260

* = Significant at 1 Percent
\+ = Significant at 5 Percent
\- = Significant at 10 Percent
R^2 = .74
Adjusted R^2 = .577
F(33, 51) = 4.536

Table B-3. Two-Stage Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	15.084	12.090
PRESSURE DUMMY	-2.964	3.175
LN(MW)	-3.053	1.104*
PRESSURE*LN(MW)	.461	.492
-LN(1-EQUIV. AVAIL.)	-14.273	5.273*
$(-LN(1-EQUIV.\ AVAIL))^2$	.617	.292+
LN(MW)(-LN(1-EQUIV. AVAIL))	2.027	.793+
FIRST UNIT DUMMY	.290	.067*
LN(YEAR)	2.396	1.588
COOLING TOWER DUMMY	.151	.098
FULL-INDOOR DESIGN DUMMY	.026	.107
A-E SUBCRITICAL UNIT EXP.	-.150	.112
A-E SUPERCRITICAL UNIT EXP.	-.116	.132
MIDDLE ATLANTIC DUMMY	-.011	.150
WEST NORTH CENTRAL DUMMY	.169	.239
EAST NORTH CENTRAL DUMMY	.463	.333
ROCKY MOUNTAIN DUMMY	-.041	.219
SOUTH ATLANTIC DUMMY	-.196	.129
SOUTHERN SERVICES CO. DUMMY	-.336	.164+
TVA CO. DUMMY	.207	.202
DUKE CO. DUMMY	-.471	.273-
AEP CO. DUMMY	-.249	.411
STEARNS & ROGERS CO. DUMMY	-.402	.331
BECHTEL CO. DUMMY	-.191	.179
EBASCO CO. DUMMY	-.342	.173-
SARGENT & LUNDY CO. DUMMY	-.159	.137
BROWN & ROOT CO. DUMMY	-.362	.401
FLUOR CO. DUMMY	-.559	.277+
BLACK & VETCH CO. DUMMY	-.471	.245-
GILBERT CO. DUMMY	-.196	.163
GC CO. DUMMY	-.097	.196
COMMON CO. DUMMY	-.286	.203
UNITED CO. DUMMY	-.656	.389-

* = Significant at 1 Percent
+ = Significant at 5 Percent
- = Significant at 10 Percent
$R^2 = .672$
Adjusted $R^2 = .467$
$F(33, 51) = 3.271$

estimate of the time effect is larger in absolute value and has a higher level of significance.

These results are basically the same as those reported in Chapter 3. They suggest that the potential bias from ignoring the simultaneous nature of the model and/or ignoring the measurement error associated with the use of realized reliability instead of the *ex ante* level of reliability may be important factors in the estimation of generating unit construction cost/unit reliability relationships.

Table B-4. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	-19.789	7.660
PRESSURE DUMMY	-.091	.316
LN(MW)	2.980	2.226
$(LN(MW))^2$	-.259	.176
FIRST UNIT DUMMY	.280	.055*
LN(YEAR)	3.807	.791*
COOLING TOWER DUMMY	.065	.062
FULL-INDOOR DESIGN DUMMY	.052	.085
A-E SUBCRITICAL UNIT EXPERIENCE	-.043	.057
A-E SUPERCRITICAL UNIT EXPERIENCE	-.050	.096
MIDDLE ATLANTIC DUMMY	.031	.111
WEST NORTH CENTRAL DUMMY	.031	.135
EAST NORTH CENTRAL DUMMY	.305	.257
ROCKY MOUNTAIN DUMMY	-.063	.164
SOUTH ATLANTIC DUMMY	-.168	.095-
SOUTHERN SERVICES CO. DUMMY	-.289	.121+
TVA CO. DUMMY	.021	.157
DUKE CO. DUMMY	-.140	.147
AEP CO. DUMMY	.353	.174+
STEARNS & ROGER CO. DUMMY	-.095	.225
BECHTEL CO. DUMMY	-.105	.133
EBASCO CO. DUMMY	-.194	.099-
SARGENT & LUNDY CO. DUMMY	-.170	.102-
BROWN & ROOT CO. DUMMY	-.092	.291
FLUOR CO. DUMMY	-.519	.174*
BLACK & VETCH CO. DUMMY	-.327	.169-
GILBERT CO. DUMMY	-.155	.132
GC CO. DUMMY	-.063	.150
COMMON CO. DUMMY	-.139	.138
UNITED CO. DUMMY	-.302	.254

* = Significant at 1 Percent
\+ = Significant at 5 Percent
\- = Significant at 10 Percent
$R^2 = .719$
Adjusted $R^2 = .568$
$F(30, 54) = 4.764$

Table B-5. Ordinary Least Squares Estimate of the Construction Cost Function

VARIABLE	COEFFICIENT	STANDARD ERROR
CONSTANT	-15.535	9.463
PRESSURE DUMMY	1.157	1.649
LN(MW)	1.566	2.890
$(LN(MW))^2$	-.139	.235
PRESSURE*LN(MW)	-.201	.261
FIRST UNIT DUMMY	.279	.056*
LN(YEAR)	3.787	.794*
COOLING TOWER DUMMY	.068	.062
FULL-INDOOR DESIGN DUMMY	.050	.085
A-E SUBCRITICAL UNIT EXP.	-.022	.063
A-E SUPERCRITICAL UNIT EXP.	-.051	.097
MIDDLE ATLANTIC DUMMY	.032	.111
WEST NORTH CENTRAL DUMMY	.039	.136
EAST NORTH CENTRAL DUMMY	.285	.259
ROCKY MOUNTAIN DUMMY	-.040	.168
SOUTH ATLANTIC DUMMY	-.170	.096-
SOUTHERN SERVICES CO. DUMMY	-.286	.121+
TVA CO. DUMMY	.016	.158
DUKE CO. DUMMY	-.126	.148
AEP CO. DUMMY	.323	.179-
STEARN & ROGER CO. DUMMY	-.110	.227
BECHTEL CO. DUMMY	-.132	.139
EBASCO CO. DUMMY	-.197	.099-
SARGENT & LUNDY CO. DUMMY	-.177	.103-
BROWN & ROOT CO. DUMMY	-.113	.294
FLUOR CO. DUMMY	-.505	.175*
BLACK & VETCH CO. DUMMY	-.311	.171-
GILBERT CO. DUMMY	-.168	.134
GC CO. DUMMY	-.049	.152
COMMON CO. DUMMY	-.145	.138
UNITED CO. DUMMY	-.310	.255

* = Significant at 1 Percent
+ = Significant at 5 Percent
- = Significant at 10 Percent
$R^2 = .721$
Adjusted $R^2 = .565$
$F(30, 53) = 4.59$

APPENDIX C

APPENDIX C

DERIVATION AND STATISTICAL SIGNIFICANCE OF NONLINEAR DERIVATIVES

If

$$\ln P_k = B_0 + B_1 \ln(MW) + B_2(\ln(MW)^2 + B_3(-\ln(1-EA) +$$
$$B_4(-\ln(1-EA))^2 + B_5(-\ln(1-EA))\ln(MW) +$$
$$B_6 Pressure + B_7(Pressure*\ln(MW)) +$$
$$B_8(Pressure*(-\ln(1-EA))) + \ldots$$

(Where the omitted variables are linear), then

$$\partial \ln P_k/\partial \ln MW = B_1 + 2B_2 \ln(MW) + B_5(-\ln(1-EA)) +$$
$$B_7 Pressure.$$

For any particular (ln(MW), -ln(1-EA), Pressure) and estimated (B_1, B_2, B_5, B_7), we obtain an estimated $\partial \ln P_k/\partial \ln MW$, with variance

$$Var(\partial \ln P_k/\partial \ln MW) = Var(B_1) + 4Var(B_2)\ (\ln(MW))^2 +$$
$$Var(B_5)\ (-\ln(1-EA))^2 + Var(B_7)\ (Pressure)^2 +$$
$$4Cov(B_1,B_2)\ (\ln MW) + 2Cov(B_1,B_5)\ (-\ln(1-EA)) +$$
$$2Cov\ (B_1,B_7)Pressure + 4Cov(B_2,B_5)\ (\ln(MW)*(-\ln(1-EA))) +$$
$$4Cov(B_2,B_7)\ (\ln(MW)*Pressure) +$$
$$2Cov(B_5,B_7)\ (-\ln(1-EA)*Pressure).$$

Var is the variance of B_i and Cov is the covariance of B_i and B_j. These are elements of the parameter variance-covariance matrix. A T-statistic under the null hypothesis that $\partial \ln P_k/\partial \ln MW$ is then

$$(\partial \ln P_k/\partial \ln MW)/SE$$

Where SE is the standard error of the estimated elasticity, or the square root of the variance.

Similar computations were done for the elasticity of unit construction cost with respect to reliability.

END NOTES

END NOTES

CHAPTER 1. INTRODUCTION

1. The National Electric Reliability Council (NERC) defines equivalent availability as the fraction of a period that a unit is available to generate power, adjusting for partial outages that reduce the effective capacity. The NERC is the source of our equivalent availability data.

2. Joskow and Rose (1985), Cowing (1974), Komanoff (1981), Perl (1982), Stewart (1979), and Wills (1978) are more recent studies of the construction cost of coal-fired generating units.

3. Joskow and Rose (1985) examined the average size of new units placed into commercial operation between 1950 and 1982. They found that average unit size increased fairly rapidly until 1975 and fell slightly over the period 1975-82.

4. This was based on the engineering rule of thumb called the "six-tenths factor" which states that the capital cost of a new generating unit increases only in proportion to the six-tenths power of the capacity of the unit.

5. See Perl (1982), Corio (1982), and Joskow and Schmalensee (1987).

6. See Komanoff (1976) and EPRI (1982).

7. See Komanoff (1976) for a nontechnical discussion of the engineering basis for this relationship. Joskow and Schmalensee (1987) present econometric results which support this relationship.

8. See DOE (1985) and Joskow and Rose (1985) for good discussions of these design characteristics.

9. See Nagelhaut (1988) for a survey of developments in those states in which bidding processes have been implemented or are under consideration.

10. See Johnson (1985) and Joskow and Schmalensee (1986).

CHAPTER 2. SURVEY AND CRITIQUE OF THE LITERATURE

11. For a more detailed discussion of steam-electric generating technology, see Ling (1964), Cowing (1974), and Bushe (1981, Ch. 2).

12. See Bushe (1981), pp. 63-65.

13. For a more detailed discussion of technological change and the innovation process, see Bushe (1981, Ch. 3) and Smith (1977).

14. See Bushe (1981, Ch. 3) and Joskow and Rose (1985) pp. 3-4.

15. The same criticism was made by Bushe (1981, p. 125).

16. Barzel (1964), p. 142.

17. This problem was noted by Barzel, pp. 142-143.

18. This criticism was also made by Houldsworth (1985).

19. Komanoff (1976) found empirical support for a break-in period for coal-fired units. But Joskow and Schmalensee (1987) found no empirical evidence of a break-in period.

20. Galatin (1968), p. 131.

21. Ibid., pp. 133-134.

22. That the desired level of utilization affects plant capital costs independent of size was noted by Houldsworth (1985) and Huettner (1964).

23. Huettner (1974), p. 47.

24. Ibid., p. 47.

25. Ibid., p. 98.

26. Wills (1978), p. 504.

27. The studies in this section generally avoid the vintage problem by using samples that contain only coal-fired units built since 1960. Joskow and Rose (1985, pp. 3-4) note that since 1960 the "primary technological frontier" has been in the steam pressure dimension. All coal-fired units built since 1960 fall into four pressure classes grouped around 1800, 2000, 2400, and 3500 PSI. Thus, an adequate control for "vintage" simply requires only a steam pressure variable or a heat rate variable.

28. Stewart (1979, p. 552).

29. The same criticism was made by Joskow and Schmalensee (1983, p. 229).

30. Komanoff (1982, pp. 215-217). Also, Komanoff (1976) found that units operated by AEP had superior capacity factor performance. Capacity factor is a power plant's actual generation as a percentage of its maximum possible generation, over a period of time.

31. Perl (1983, p. 2).

32. Ibid., p. 11.

33. Stewart, op. cit.

34. French and Haddad (1980, p. 682) provide an excellent discussion of the NERC (formerly EEI) availability data.

35. Joskow and Rose (1985, p. 20).

36. Ibid., pp. 23-24.

37. Schmalensee and Joskow (1986, p. 302) note this problem with respect to unit heat rate, but they fail to recognize that the same problem applies to the equivalent availability variable.

38. Ibid., pp. 299-300.

CHAPTER 3. DEVELOPMENT OF A GENERATING UNIT CONSTRUCTION COST AND RELIABILITY MODEL

39. As noted in more detail later in this chapter, steam pressure conditions have been the main avenue for improved thermal efficiency of coal-fired units built since 1960.

40. Cowing and Smith (1978) provide an excellent review of the econometric analyses of steam-electric generation. In their survey they conclude ". . .the physical attributes of the capital equipment appear to constrain the ability of the economic agent in ensuing allocation decisions, both those directly involving capital's services and those associated with labor and fuel."

41. For an excellent discussion of how labor inputs are more dependent on unit design characteristics than the level of output, see Bushe (1981, Ch. 4).

42. Komanoff (1976) also notes that a unit's heat rate is dependent to some extent on the level of utilization of the unit since heat loss is fairly constant at any load.

43. Stewart (1979), Cowing (1974), and Bushe (1981) provide good discussions of the need to consider unit size and thermal efficiency as characteristics of generating equipment. Houldsworth (1986) notes the need to treat reliability as another attribute of baseload units.

44. As noted on pages 4 and 5, the incremental heat rate of a generating unit is dependent on the level of generation. It was noted that there are a fairly large number of possible forms (see Figure 3-1) for the incremental heat rate. We assume the incremental heat rate form is represented by (d) or (e) and that the baseload units operate under normal load conditions. As a result, the amount of fuel required is generally proportional to the rate at which the unit generates electricity.

45. Labor costs are ignored in our anlysis. This is unlikely to bias our results for a couple of reasons. One, labor costs make up only about 10% of a unit's generation costs. Two, labor input is dependent

on the engineering characteristics of the unit. But we are restricting our analysis to baseload coal-fired units so any differences in labor input requirements are likely to be minimal.

46. Everything else equal, supercritical units are 2 to 3 percent more efficient than subcritical units with pressures of 2400 PSI [see French and Haddad (1980) and Joskow and Schmalensee (1987)]. Both studies also find that unit size has almost no impact on thermal efficiency once steam pressure conditions are considered.

47. These relationships will be discussed in more detail in the following section of this chapter.

48. See footnote 6 and pages 4 and 5 in this chapter for additional detail.

49. See DOE (1985), pp. 38-39, Komanoff (1974, Ch. 7), and Vardi and Aui-Itzhak (1981), pp. 20-21.

50. DOE (1985), pp. 30-31.

51. See Joskow and Rose (1985) and Bushe (1981, Ch. 3).

52. This was recognized as a possible source of bias by Joskow and Rose (1985).

53. Ling (1964), Bushe (1981), Wills (1978), and Cowing (1974) take no account of variations in unit reliability across unit size or steam pressure conditions.

54. See Komanoff (1974), Joskow and Schmalensee (1987), and Perl (1982).

55. See Perl (1982) and Joskow and Schmalensee (1987).

56. See Joskow and Schmalensee (1987) and Schmalensee and Joskow (1986).

57. Load-following is an intentional reduction in the level of generation (power) due to low demand for electricity.

58. A logit transformation of the reliability variable was also used for estimation. A logit transformation restricts the variable to the 0-1 interval. The results are not reported since they are virtually the same as those for the reliability transformation given above.

59. DOE (1985), pp. 38-39.

60. See Kmenta (1986), pp. 346-350.

61. See Kmenta (1986), pp. 357-361.

62. See Kelejian and Walker (1989), pp. 314-315.

63. See Appendix A for details of the deflation process. I did not amortize the construction cost of a unit over its life since it is assumed that all units have equal life expectancies. Thus, amortizing a units' construction cost would make no difference. The assumption of equal life expectancies for different types and sizes of baseload coal-fired generating units is a standard industry practice. See EPRI (1986).

64. Whitman, Requardt, and Associates, Handy-Whitman Index of Public Utility Construction Costs. Baltimore: Whitman, Requardt and Associates, 1986.

65. See Bushe (1981, Ch. 3), Smith (1977), and Joskow and Rose (1985) pp. 3-4.

66. See Joskow and Rose (1985) and Bushe (1981, Ch. 3).

67. The data was made available to us by S.M. Stoller Corp.

68. It should be noted that no units were excluded due to poor reliability. Units were excluded only if they were not observed during their second through fourth year of commercial operation.

69. Joskow and Rose (1985) specify the relationship between average construction cost and size to be Cobb-Douglas. As a result, the cost function has a constant elasticity of unit cost with respect to size. They state that more flexible specifications do not improve or change the results in a significant manner. Our results, using the Cobb-Douglas specifications, are presented in Tables B-1 through B-3 in Appendix B. We prefer to estimate more flexible specifications that allow the elasticity of average construction cost with respect to size to vary with size and to change sign.

70. These parameter estimates are presented in Tables B-4 and B-5 in Appendix B.

71. Alternative specifications of the reliability equation were estimated, but made little difference in the general estimation results. Also, introduction of other explanatory variables like a quadratic size term cause some problems with multicollinearity.

72. Compare the results in Tables 3-1 and 3-6, Tables 3-2 and 3-7, Tables 3-3 and 3-8, and Tables 3-4 and 3-9.

73. See Appendix C for details on how the unit cost elasticities and their statistical significance were calculated.

74. The same specification of the reliability equation was estimated with all four specifications of the cost function. Alternative specifications of the reliability equation were estimated, but they did not change the results in any important way.

CHAPTER 4. AVERAGE CAPITAL COSTS AND THE UNIT SIZE-RELIABILITY TRADEOFF

75. For an excellent discussion, see Trebing (1981), pp. 369-385.

76. See Joskow and Schmalensee (1986B) and Johnson (1985).

77. For a more detailed discussion, see Johnson (1985), pp. 47-48.

78. See FERC (1988).

79. Good surveys of state bidding programs are provided by Meade (1987) and Nagelhout (1988).

80. See Nagelhout (1988) and Walker (1989).

81. See Romo (1988), p. 9.

82. See Walker (1989), p. 35.

APPENDIX B

83. We used the same specification of the reliability function that was used in Chapter 3. (See the parameter estimates presented in Table 3-10.)

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