

EFFICIENT SCALE AND ASSET VALUES IN STEAM ELECTRIC POWER GENERATION

by

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EXECUTIVE SUMMARY

Regulatory reforms are promoting the development of open markets for electric power. The vertically integrated structure of the industry is giving way to one in which electricity generators compete with each other on the basis of cost. Many regulatory agencies are encouraging this development by ruling that generation companies at some point in the future will no longer operate under guaranteed rates of return on capital or automatic fuel cost adjustment clauses. As electricity generating companies compete in this new environment, they will face four key questions:

- What is our marginal production cost?
- What is the market valuation of our generation assets?
- How does our cost and asset valuation rank in the industry?
- What is the most profitable scale of operation?

This report addresses these questions by developing a cost model for fossil fuel-fired steam electric generation for 82 private utilities in the United States. We discuss the determinants of generation costs and show how they vary with changes in production and fuel prices. We estimate cost savings from additional capital investment, which is equal to a firm's implicit rate of return in a competitive market place.

The cost model also provides estimates of the least cost scale of generation, which has important implications for the number of firms that would operate if the industry were completely open and competitive. These estimates also have important implications for merger and restructuring strategies in the electric utility industry.

This study also estimates profit margins known as *spark spreads*, for a variety of cost definitions. Many generation companies buy and sell call options on spark spreads, which provide them with the right but not the obligation to take a long (buy) position in a fuel and to simultaneously sell short electricity. Using information from our cost model, we calculate the value of these spark-spread options by firm.

Unlike studies that depend upon specific assumptions concerning plant efficiencies, the methods employed in this study are based upon observed plant efficiencies and, most importantly, upon actual operational decisions by firms. Our estimates of spark spread option values differ considerably by firm and span prices paid for recently installed new generation capacity. We believe that this quantitative information will be important for future strategic decision making in the electric utility business. The report concludes with a summary of key findings and a discussion of their implications for electric utility firms.

I. INTRODUCTION

Recent policy actions at the state and federal level are promoting competition in the electric utility industry. Under the Energy Policy Act of 1992, the Federal Energy Regulatory Commission (FERC) issued FERC Order 888 in 1996, forcing utilities with transmission networks to deliver power to third parties at nondiscriminatory cost-based rates. In addition, several state public utility commissions are adopting customer choice programs and other schemes to unbundle retail prices into generation, transmission, distribution, and transition charges (Joskow, 1996). These policy initiatives recognize that while electrical transmission and distribution remain natural monopolies, competition in generation is possible with open access to transportation networks. Under these emerging regulatory regimes, generation companies will no longer operate under guaranteed rates of return on capital or automatic fuel cost adjustment clauses.

With regulatory barriers removed, generation companies will compete with each other for market share. These competitive pressures will force companies to re-evaluate their strategic position in the industry. In order to accomplish this, however, one needs to know what the industry will look like in a competitive environment. Will the industry be dominated by five or six mega-utilities? Or will competition act to increase the number of companies? To answer these questions, one must identify the efficient scale of operation. For example, if the efficient scale is 100 million-megawatt hours (mwh) and total market demand is 1500 mwh, then an efficient industry structure would include 15 firms. In this study, we determine the efficient scale of operation by estimating the relationship between cost and firm size for 82 steam electric generating companies in the U.S.

Our results reported below indicate that there likely will be a major consolidation in the industry. The number of independent firms in the industry could drop substantially as small firms are absorbed into larger entities that have lower average costs of production. There is a limit, however, to this consolidation given by the optimal efficient scale, which is the output level at which long-run average costs begin to rise. We find that most firms are much smaller than the efficient scale of operation and, therefore, are likely take-over candidates. Hence, there could be a major asset transfer within the industry.

This study also determines the prices at which these assets would be exchanged. These asset prices vary by firm and reflect the implicit rate of return on existing generating plant and equipment. Capital asset valuation in the electric utility industry is particularly difficult because rate of return regulation has distorted capital stocks. As electricity generation becomes more competitive and low cost producers gain market share, some firms may not earn a sufficient rate of return to recover prior investments. These investments in unprofitable capacity, called *stranded costs* by Baumol and Sidak (1995), have become a major issue facing many electric utility industry restructuring proposals. The existence of stranded costs in electricity generation implies that electrical generating capacity is too high.

Studies by Courville (1974), Spann (1974), and Peterson (1975) find some support for the Averch-Johnson (1962) hypothesis that utilities “overcapitalize” under rate-of-return regulation. In addition to regulation, capital stock valuation reflects technology, demand, and input prices. If the implicit rate of return earned on existing plant and equipment, known as the *shadow value* of a capital, is less than the market opportunity cost of capital, a firm will divest over time. In this case, the ratio of capital shadow values to capital costs – Tobin’s Q – will be less than one. In the long-run, a firm in a

competitive industry will employ an amount of capital with an implicit value reflecting its opportunity cost.

The conditions defining a long-run competitive equilibrium in the electric utility industry, however, will change under industry restructuring. For instance, the equilibrium price of coal may change. We do not estimate these second round-induced changes. Instead, the objective of this study is to compare actual capital stocks in the electricity generation sector with equilibrium levels that would prevail under current factor market conditions, such as the current price of fuels and current output levels. In other words, our definition of *optimal* capital is the level that would minimize cost given current electricity demand and input prices facing steam electricity generators.

This comparison is accomplished below using a short-run restricted cost model in which firms minimize short-run variable cost given output, capital, and technology. We estimate optimal capital by solving the long-run equilibrium condition in which capital shadow values equal their user costs. The empirical model uses a functional form widely used in applied economic studies that allows simple solutions for optimal capital and other related measures of cost performance.

As electricity companies navigate a deregulated environment, managing uncertainty will become paramount. In the past, electric utilities could pass on fuel price increases to their customers. In the future, an increasing number of electricity generating companies will operate as typical commodity producers in which their profit margins, known as *spark spreads*, will fluctuate with prices for fuels and electricity. Accordingly, the market value of a generation company will be affected by their ability to manage these risks. This ability, however, is constrained by the type, vintage, and operational efficiency of their generation capacity. For example, a coal-based utility will likely

have a different risk profile than a company dependent upon natural gas or oil. Hence, the cost structure of generating companies, reflecting fuel choice among other factors, affects asset values, particularly under uncertain fuel prices.

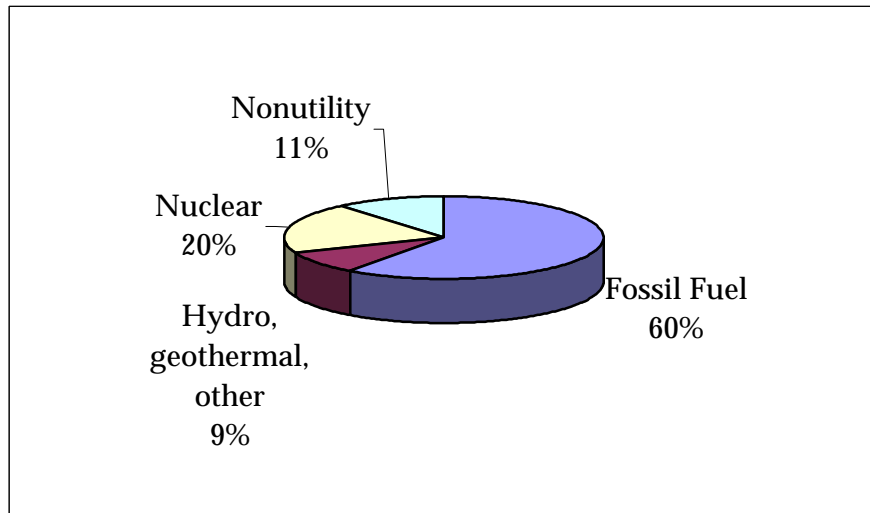
How do we consider uncertainty in the valuation of generating assets? A common approach is to view the business of generating electrical power as an option. In purchasing an electrical generating asset, a firm is exercising its option to begin production. If market conditions are not favorable, it could choose to wait and exercise this option in the future. For electricity, this option is on the spark spread. Many companies buy and sell spark-spread options as they trade electricity across geographical areas on a daily basis. Buying or selling a generating plant or a group of plants we call a firm also involves valuation of spark spread options. Since the market now determines prices for current and future delivery of electric power, firms control their profits or spark spreads by controlling their costs. In this study, we estimate the value of these spark spread options capturing the diversity of cost efficiencies observed in the industry.

In the following section, we discuss the context of our study in more detail. A heuristic description of the cost model is in section III. Measurement issues are in section IV along with an overview of the data sample. Section V presents our estimates of cost and input demand elasticities, marginal cost, and economies of scale. The spark spread option values appear in section VI. The concluding section briefly summarizes our key findings and their implications for strategic planning in the industry. The technical details supporting our data collection and computations appear in several appendices.

II. THE ELECTRIC POWER INDUSTRY

The electricity industry has undergone some profound changes over the past 20 years and is on the threshold of a new deregulated era. Figure 1 summarizes the composition of technology used in electricity generation. Fossil-fuel-fired boilers producing steam for turbine generators remain the dominant electricity generation technology in the United States, comprising 60 percent of total generation in 1996 (EIA, 1996). Of this amount, coal-fired generation comprises 84 percent, natural gas constitutes 12.7 percent, and petroleum accounts for the remaining 3.3 percent. The fastest growing source of electricity supply in recent years is nonutility generators, who now supply nearly 11 percent of total net generation using fossil-fuel-fired technologies, including conventional steam-driven turbines and combined cycle gas turbines. Many of these

Figure 1. – Composition of technology used to generate electricity



nonutility sources sell power to electric utilities at rates based upon avoided cost, which in many cases is the marginal cost of power from steam electricity generation. Hence, the marginal cost of steam electricity generation is an important issue for nonutility

generators. Even though nuclear power constitutes nearly 20 percent of total net generation, no new nuclear plants have been ordered in the United States in recent years. Economic and technological problems, including safety and waste disposal issues, may continue to limit growth prospects for nuclear power. Hydro, geothermal, and other sources of power constitute the remaining 9 percent of generation and also have limited growth prospects.

We analyze only the costs of steam electric power generation for major investor-owned utilities in the United States. The Energy Information Administration (EIA) (1996), which is the primary source of data for this study, classifies major utilities as those companies that have had sales and transmission services that exceed either one or more of the following over three consecutive years: one million megawatt hours of total annual sales, 100 mwhts of annual sales for resale, or 500 mwhts of annual wheeling or power exchanges. EIA identifies 179 major private utilities and 64 small investor-owned utilities. Together these utilities account for more than 75 percent of sales to ultimate consumers. A large number of publicly owned utilities (2,010) and cooperatives (932) and ten federal utilities supply the remaining 25 percent of total electricity sales.

Steam generation accounts for 70.6 percent of total generation by privately held public utilities in 1996. The remaining output is from nuclear plants (24 percent) and hydroelectric and other sources (5.4 percent). The technology and economics of hydroelectricity, nuclear power, and steam power are quite different. It would be unwise to aggregate these different technologies for our purposes. A focus on steam power production avoids these aggregation problems and allows us to determine the effects on estimates of scale economies, among other measures, from relaxing the

assumption that capital is in equilibrium. Cost analysis of nuclear power generation is beyond the scope of this current study.

III. THE DETERMINANTS OF GENERATION COSTS

A cost model simply describes how costs vary with production, input prices, technology, and capital stocks. The total variable cost of steam electric power generation includes expenditures on fuel, labor, and maintenance. Since firms generally pay the market price for fuels and labor, they control costs by adjusting their purchases of these variable inputs. The technology of generating plants, often represented by their thermal efficiency, also affect a firm's cost structure. These efficiencies slowly improve over time as technology advances and firms modify existing boilers. The vintage and composition of a firm's capital stock will also influence variable costs. A firm can adjust its capital stock by retiring old plants and investing in new ones.

Variable costs also vary with the level of generation. Fixed costs do not vary with production and include expenditures on debt payments, dividends, rents, and other fixed payments related to structures and equipment. Total cost is the sum of variable and fixed cost. Average variable cost is total variable cost divided by output. Marginal cost is the change in cost for a change in output and varies with the level of production. The relationship between marginal cost and output depends upon technology. For electric power generation, at low output levels, marginal cost and average cost generally decline with higher output. If marginal cost is below average cost over some range of output, the firm has economies of scale. If the reverse holds, the firm encounters diseconomies of scale and needs increasingly higher prices to justify further

expansion of output. For example, after fully utilizing its base load capacity to meet higher demand, a generating company typically uses higher cost sources of power, such as gas turbine peaking generators. At the firm level, rising marginal costs often reflects this switch from baseload to peaking plants. How a firm manages its plant mix would determine its cost and profit performance.

We measure two categories of variable costs for steam power production: fuel and an aggregate of labor and maintenance costs from data reported by the Energy Information Administration (1996) in their annual report, *Financial statistics of major U.S. investor-owned electric utilities* (see Appendix A). EIA reports these costs by firm. Fuel costs for a typical firm in our sample comprise about 80 percent of total variable generation costs, including expenditures on coal, natural gas, and petroleum products. By definition, fuel costs equal fuel consumption multiplied by fuel price. To compute fuel prices, we compute a price index for each firm using plant level data on fuel consumption and prices paid upon receipt. We use a special price index called a *divisia* that is superior to other indices of fuel prices, such as dollars per British thermal units (BTU), which imply perfect substitution between fuels. The *divisia* avoids this problem and is invariant to base year changes, unlike fixed weight indices.

We form a second input category that includes the aggregate of labor and maintenance costs because they are difficult to separately identify. The price index for this category is a weighted average of the wage rate—or total labor expense per employee company wide, and a price index for electrical supplies from the Bureau of Labor Statistics. The weights are the labor cost share of nonfuel variable costs for those utilities with entirely steam power production.

Another key measurement issue involves the capital stock. One approach is to aggregate nameplate plant generation capacity to the firm level. The problem with this approach is that companies make capital improvements that effectively increase nameplate capacity. Our method captures these enhancements by estimating a benchmark capital stock value based upon installed capacity in a base year valued at replacement cost and then updating this value each year using annual plant and equipment retirements and capital expenditures. The benchmark capital stock for each firm is a weighted average of plant capacities where the weights reflect the thermal efficiency of each plant relative to an industry-wide average efficiency rate. Replacement cost is based upon the average price of newly installed capacity. We also adjust the capacity data for joint ownership, allocating capacity based upon joint venture ownership shares. These calculations essentially translate production capacity into a dollar amount that reflects the replacement value of installed generation capacity. This method is equivalent to the market valuations that appraisers do when homeowners refinance their mortgage.

Unlike a homeowner, however, a utility company raises capital by selling bonds and equity. The prices for these financial instruments vary by firm. We develop an average user cost of capital for each firm that reflects the firm's bond rate, debt-equity ratio, and equity return. The cost of capital is also adjusted for depreciation and inflation. Firm capital payments for steam electricity generation plant and equipment equal the product of the user cost and real capital stocks.

Our cost model contains certain features that reflect the unique characteristics of the electricity generation industry. First we assume that electrical generation companies face competitive variable input prices and that rate-of-return regulation prevents capital from reaching equilibrium levels in the short run. Over the sample period used

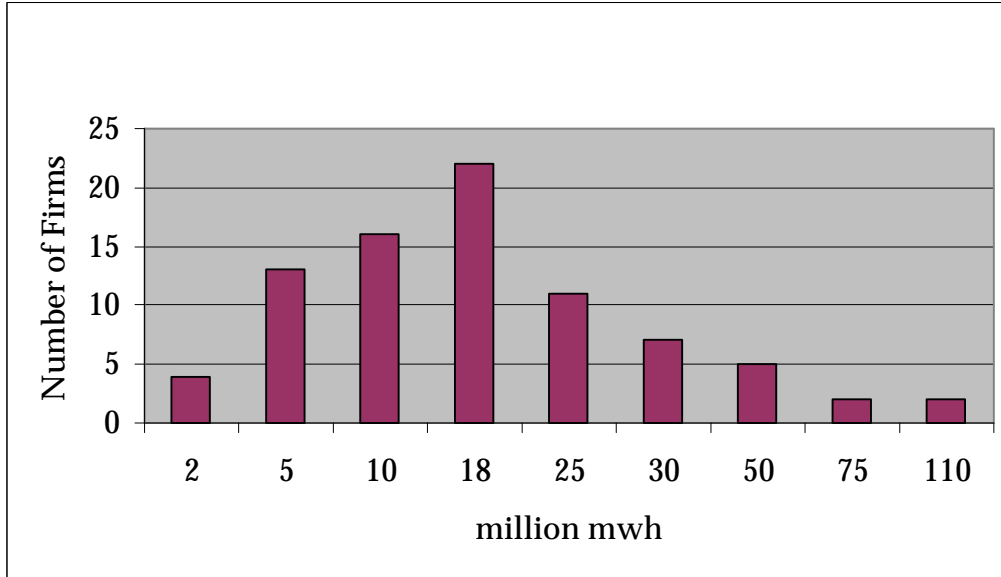
in this study, 1986 to 1996, state public utility regulations required that electric utilities must supply all electricity demanded at regulated prices. Hence, utility firms could not choose the level of production to maximize profits. Customer choice programs, wholesale power marketing, and other efforts to restructure the electricity market are intended to create a competitive market for electricity generation, which, if successful, would imply that each firm has no control over its level of production. In either world, assuming that the output level is beyond the control of the firm seems plausible. The economic decision, therefore, is to find the optimal level of inputs.

In any given year, utility firms inherit their generating capacity from the previous year. They retire old plants, modernize generating units, and occasionally build new plants, generally after a lengthy period of licensing, regulatory review, and construction. Electric utility firms have added very little new capacity in recent years. Instead, they have met any shortfalls in demand by purchasing from nonutility generators. For these reasons, assuming capital is fixed in the short run seems plausible. With this constraint, the economic decision is to find the least-cost levels of variable inputs, such as fuel, labor, and maintenance, subject to these output and capital constraints.

IV. AN OVERVIEW OF THE COST DATA

We reduce our original panel of 111 companies to 82 because many companies are subsidiaries of holding companies. Christensen and Greene (1976) show that failure to recognize holding companies results in underestimating scale economies. The distribution of average annual production for each firm from 1987 to 1996 appears in Figure 2. Nearly 60 percent of all firms produce between 10 and 25 million-megawatt hours. Average firm output over the period ranges from a low of 1.1 million mwh to

Figure 2.—Distribution of firm output



105.6 million mwh. Average production across all firms is 17 million mwh with a standard deviation of 18.6 million mwh. There are 55 firms with generation below the sample mean. Two firms have output nearly five times larger than the industry average.

In Figure 3, we present the distribution of average total observed cost or the sum of variable cost and capital charges, calculated using the user cost of capital and real capital stocks. Average total cost ranges from a low of 2.2 cents per kilowatt (kwh) to slightly under 7 cents per kwh with a mean of 3.46 cents per kwh. The standard deviation of average total cost is 0.95 cents per kwh. Notice that the distribution of average total cost is skewed with the largest number of firms producing power around 3 cents per kwh, roughly one-half cent below the mean. In addition, there is a long tail in the distribution on the high end of the cost range, which reflects the pressures within the industry to restructure and reduce cost.

Firm level detail is reported in Table 1, which reports average annual production for each firm from 1987 to 1996. Average production over the period ranges from a low of 1.1 million mwh by St. Joseph Light and Power to 105.6 million mwh by The Southern Company. The largest firms are concentrated in the south and midwest. The smallest firms are located generally in the Northeast. The largest ten firms produce 40 percent of total steam power production (see Table 1).

Figure 3.—Distribution of average total cost

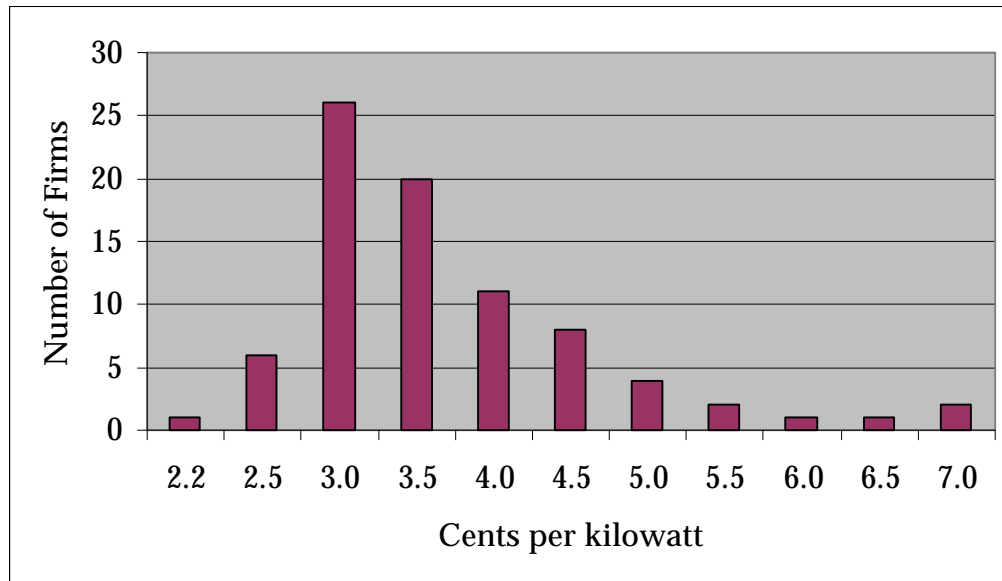


Table 2 ranks firms by their average total cost. Montana Power had the lowest generation costs of 2.17 cents per kwh, while Ohio Edison, Allegheny Power, Empire District Electric, Minnesota Power, and Kentucky Utilities also had very low average total costs. At the other end of the spectrum, Philadelphia Electric, Public Service Electric & Gas, and Commonwealth Edison had average total costs between 5 and 6 cents per kwh. San Diego Gas & Electric, Consolidated Edison Co-NY and Central Maine Power had costs averaging over 6 cents per kwh.

Table 1.—Steam electricity generation and average total cost, firm means

<u>Company</u>	Average		<u>Company</u>	Average	
	Generation <u>million mwh</u>	Total Cost <u>(cents/kwh)</u>		Generation <u>million mwh</u>	Total Cost <u>(cents/kwh)</u>
St Joseph Light & Power Co	1.06	3.03	New England Electric System	12.92	3.76
Central Maine Power Co	1.15	6.66	Indianapolis Power & Light Co	12.97	2.87
Madison Gas & Electric Co	1.49	2.98	Niagara Mohawk Power Corp	13.00	3.55
Rochester Gas & Electric Corp	1.97	4.17	Northern Indiana Pub Serv Co	13.70	3.73
Eastern Utilities Associates	2.09	3.91	Public Service Co of Colorado	14.15	2.46
Empire District Electric Co	2.28	2.43	Kentucky Utilities Co	14.23	2.44
Otter Tail Power Co	2.38	2.54	Illinois Power Co	14.24	2.65
El Paso Electric Co	3.07	3.49	Dayton Power & Light Co	14.27	3.00
Orange & Rockland Utils Inc	3.16	4.64	Baltimore Gas & Electric Co	15.17	3.33
Atlantic City Electric Co	3.23	4.41	New York State Elec & Gas Corp	15.40	2.67
Portland General Electric Co	3.31	3.98	Tampa Electric Co	16.36	3.36
Interstate Power Co	3.43	2.78	Wisconsin Electric Power Co	16.64	3.12
Sierra Pacific Power Co	3.45	3.19	Consumers Power Co	17.32	3.09
Central Hudson Gas & Elec Corp	3.94	4.02	Consolidated Edison Co-NY Inc	17.39	6.53
UtiliCorp United Inc	4.13	2.83	General Public Utilities Corp	18.51	3.35
Commonwealth Energy System	4.16	4.21	Southwestern Public Service Co	19.09	2.74
San Diego Gas & Electric Co	4.22	6.15	Potomac Electric Power Co	19.38	3.29
United Illuminating Co	5.06	3.81	Centerior Energy Corp.	19.51	3.31
Hawaiian Electric Co Inc	5.30	4.66	Commonwealth Edison Co	19.92	5.69
Southern Indiana Gas & Elec Co	5.31	3.36	Oklahoma Gas & Electric Co	20.20	3.22
Central Illinois Light Co	5.43	2.96	Florida Power Corp	20.30	3.58
Nevada Power Co	5.57	3.20	Gulf States Utilities Co	21.10	2.91
Minnesota Power & Light Co	5.78	2.43	CINergy Corporation	21.59	2.82
Central Louisiana Elec Co Inc	5.80	3.58	Union Electric Co	22.53	2.98
Public Service Co of NM	6.01	2.87	Carolina Power & Light Co	22.86	3.06
Montana Power Co	6.11	2.17	PSI Energy Inc	25.54	2.70
Kansas Gas & Electric Co	6.11	2.72	Pennsylvania Power & Light Co	27.04	3.21
Wisconsin Public Service Corp	6.82	2.89	Pacific Gas & Electric Co	27.26	4.35
Boston Edison Co	7.23	4.44	Virginia Electric & Power Co	28.27	2.87
Wisconsin Power & Light Co	7.52	2.62	Southern California Edison Co	28.32	4.48
Delmarva Power & Light Co	8.31	3.50	Duke Power Co	29.63	3.06
South Carolina Elec & Gas Co	8.91	3.11	Florida Power & Light Co	29.88	4.46
Philadelphia Electric Power Co	9.71	5.10	Entergy Corporation	30.15	3.57
Central Illinois Pub Serv Co	10.21	3.41	Allegheny Power Systems Inc.	40.94	2.40
Kansas City Power & Light Co	10.48	2.52	The Detroit Edison Co	41.31	2.95
Duquesne Light Co	10.72	2.99	Ohio Edison Co.	42.50	2.33
Northeast Utilities	10.75	4.77	Houston Lighting & Power Co	46.64	3.56
Long Island Lighting Co	10.98	4.71	Central and Southwest Corp	50.81	3.20
Louisville Gas & Electric Co	11.11	2.80	Texas Utilities Electric Co	70.32	2.88
Arizona Public Service Co	11.90	2.89	American Electric Power Co Inc	98.51	2.60
Public Service Electric & Gas	12.91	5.39	The Southern Company	105.55	3.14

Also appearing in Table 2 is a decomposition of total average costs into their fixed and variable components. On average, capital costs account for approximately one cent per kwh with a standard deviation of 0.41 cents per kwh. Kansas Gas and Electric, Montana Power, Public Service Company of New Mexico, and Centerior Energy have among the lowest capital costs in the industry. Those companies burdened with

relatively high fixed costs include Portland General Electric, Public Service Electric & Gas, Central Maine Power, Consolidated Edison Company of New York, and San Diego Gas and Electric Company. With the exception of Portland General Electric,

Table 2.—Steam electricity average total, variable, and fixed cost, firm means

Company	(cents/kwh)			Company	(cents/kwh)		
	Avg. Total Cost	Avg. Vari. Cost	Avg. Fixed Cost		Avg. Total Cost	Avg. Vari. Cost	Avg. Fixed Cost
Montana Power Co	2.17	1.76	0.41	Nevada Power Co	3.20	2.46	0.74
Ohio Edison Co.	2.33	1.78	0.54	Central and Southwest Corporation	3.20	2.22	0.98
Allegheny Power Systems Inc.	2.40	1.76	0.64	Pennsylvania Power & Light Co	3.21	2.35	0.86
Empire District Electric Co	2.43	1.53	0.90	Oklahoma Gas & Electric Co	3.22	2.18	1.04
Minnesota Power & Light Co	2.43	1.83	0.60	Potomac Electric Power Co	3.29	2.33	0.96
Kentucky Utilities Co	2.44	1.60	0.84	Centerior Energy Corp.	3.31	2.83	0.49
Public Service Co of Colorado	2.46	1.73	0.73	Baltimore Gas & Electric Co	3.33	2.37	0.96
Kansas City Power & Light Co	2.52	1.69	0.83	General Public Utilities Corp	3.35	2.25	1.10
Otter Tail Power Co	2.54	1.64	0.90	Southern Indiana Gas & Elec Co	3.36	2.09	1.27
American Electric Power Co. Inc	2.60	1.95	0.65	Tampa Electric Co	3.36	2.61	0.75
Wisconsin Power & Light Co	2.62	1.86	0.76	Central Illinois Pub Serv Co	3.41	2.43	0.99
Illinois Power Co	2.65	1.90	0.75	El Paso Electric Co	3.49	2.41	1.09
New York State Elec & Gas Corp	2.67	2.10	0.57	Delmarva Power & Light Co	3.50	2.62	0.88
PSI Energy Inc	2.70	1.83	0.87	Niagara Mohawk Power Corp	3.55	2.57	0.98
Kansas Gas & Electric Co	2.72	2.39	0.33	Houston Lighting & Power Co	3.56	2.37	1.20
Southwestern Public Service Co	2.74	1.98	0.77	Entergy Corporation	3.57	2.35	1.22
Interstate Power Co	2.78	2.15	0.63	Central Louisiana Elec Co Inc	3.58	2.16	1.42
Louisville Gas & Electric Co	2.80	1.81	0.99	Florida Power Corp	3.58	2.45	1.13
CINergy Corporation	2.82	1.91	0.91	Northern Indiana Pub Serv Co	3.73	2.47	1.26
UtiliCorp United Inc	2.83	2.00	0.83	New England Electric System	3.76	2.88	0.88
Public Service Co of NM	2.87	2.32	0.54	United Illuminating Co	3.81	3.03	0.78
Indianapolis Power & Light Co	2.87	1.60	1.28	Eastern Utilities Associates	3.91	3.30	0.61
Virginia Electric & Power Co	2.87	2.03	0.84	Portland General Electric Co	3.98	1.88	2.10
Texas Utilities Electric Co	2.88	2.18	0.70	Central Hudson Gas & Elec Corp	4.02	2.83	1.19
Arizona Public Service Co	2.89	1.94	0.94	Rochester Gas & Electric Corp	4.17	2.76	1.41
Wisconsin Public Service Corp	2.89	2.20	0.69	Commonwealth Energy System	4.21	3.07	1.14
Gulf States Utilities Co	2.91	2.31	0.60	Pacific Gas & Electric Co	4.35	3.36	0.99
The Detroit Edison Co	2.95	2.15	0.80	Atlantic City Electric Co	4.41	2.93	1.47
Central Illinois Light Co	2.96	2.24	0.72	Boston Edison Co	4.44	3.36	1.09
Madison Gas & Electric Co	2.98	2.20	0.77	Florida Power & Light Co	4.46	2.97	1.49
Union Electric Co	2.98	1.99	0.99	Southern California Edison Co	4.48	2.94	1.54
Duquesne Light Co	2.99	2.22	0.76	Orange & Rockland Utils Inc	4.64	3.31	1.34
Dayton Power & Light Co	3.00	1.90	1.10	Hawaiian Electric Co Inc	4.66	3.95	0.71
St Joseph Light & Power Co	3.03	1.72	1.31	Long Island Lighting Co	4.71	3.47	1.24
Carolina Power & Light Co	3.06	2.17	0.88	Northeast Utilities	4.77	3.39	1.38
Duke Power Co	3.06	2.05	1.01	Philadelphia Electric Power Company	5.10	3.57	1.52
Consumers Power Co	3.09	2.16	0.93	Public Service Electric & Gas	5.39	3.00	2.39
South Carolina Elec & Gas Co	3.11	1.94	1.17	Commonwealth Edison Co	5.69	4.21	1.48
Wisconsin Electric Power Co	3.12	2.07	1.06	San Diego Gas & Electric Co	6.15	3.95	2.20
The Southern Company	3.14	2.25	0.89	Consolidated Edison Co-NY Inc	6.53	4.39	2.14
Sierra Pacific Power Co	3.19	2.57	0.62	Central Maine Power Co	6.66	4.34	2.32

these companies also have high average variable costs as well. The lowest average variable cost is 1.53 cents per kwh by Empire District Electric company. Kentucky Utilities, Indianapolis Power & Light, Kansas City Power & Light, and Otter Tail Power also have very low average variable costs.

As mentioned above, the main component of variable cost is fuel. Table 3 decomposes average variable costs into fuel and the aggregate of labor and maintenance expenses. Montana Power has the lowest average fuel costs of 0.70 cents per kwh and Hawaiian Electric had the highest at 3.43 cents per kwh. On average fuel costs are 1.85 cents per kwh with a 0.51 cents per kwh standard deviation. Fuel prices vary widely by firm with coal-based utilities paying considerably less than oil and natural gas-based utilities. The four largest firms, accounting for more than 23 percent of total production in the sample, have production costs substantially below average and are largely coal-based operations. The high cost firms are generally smaller with less coal base capacity.

There are also substantial differences in labor and maintenance (L&M) costs by firm. Average L&M costs are 0.58 cents per kwh, about 31 percent of fuel costs, small but significant. These costs also vary substantially by firm due to the age and condition of generating facilities. Southwestern Public Service has the lowest average labor and maintenance cost of 0.19 cents per kwh. Many firms with low labor and maintenance costs are in the South and western regions of the US. Most of the high labor cost firms are in the Northeast.

Our estimates of capital stocks and user costs appear in Table 4. Reflecting the relative size of their generation capacity, the value of steam plant varies from a low of \$72 million to \$6.0 billion (see Table 4). Book values will be substantially different because

we value capacity at replacement cost to conform with economic theory and to provide a common basis to compare firms without variations in accounting practices obscuring the true opportunity cost of capital. The mean capital value for our 82 firm sample is slightly over \$1 billion. Capital user costs are on average about 15%, ranging from a

Table 3.—Steam electricity average variable by type, firm means

Company	(cents/kwh)			Company	(cents/kwh)		
	Avg Vari.	Avg Fuel	Avg L & M		Avg Vari.	Avg Fuel	Avg L & M
	Cost	Cost	Cost		Cost	Cost	Cost
Empire District Electric Co	1.53	1.19	0.33	The Southern Company	2.25	1.83	0.42
Indianapolis Power & Light Co	1.60	1.16	0.44	General Public Utilities Corp.	2.25	1.59	0.66
Kentucky Utilities Co	1.60	1.28	0.32	Gulf States Utilities Co	2.31	2.04	0.28
Otter Tail Power Co	1.64	1.20	0.44	Public Service Co of NM	2.32	1.77	0.56
Kansas City Power & Light Co	1.69	1.14	0.55	Potomac Electric Power Co	2.33	1.85	0.48
St Joseph Light & Power Co	1.72	1.46	0.25	Pennsylvania Power & Light Co	2.35	1.79	0.55
Public Service Co of Colorado	1.73	1.28	0.46	Entergy Corporation	2.35	2.03	0.32
Allegheny Power Systems Inc.	1.76	1.37	0.39	Houston Lighting & Power Co	2.37	1.96	0.41
Montana Power Co	1.76	0.70	1.06	Baltimore Gas & Electric Co	2.37	1.76	0.61
Ohio Edison Co.	1.78	1.33	0.46	Kansas Gas & Electric Co	2.39	1.45	0.94
Louisville Gas & Electric Co	1.81	1.24	0.57	El Paso Electric Co	2.41	1.93	0.48
PSI Energy Inc	1.83	1.49	0.34	Central Illinois Pub Serv Co	2.43	1.77	0.66
Minnesota Power & Light Co	1.83	1.46	0.38	Florida Power Corp	2.45	2.10	0.35
Wisconsin Power & Light Co	1.86	1.55	0.31	Nevada Power Co	2.46	1.67	0.79
Portland General Electric Co	1.88	1.05	0.83	Northern Indiana Pub Serv Co	2.47	1.79	0.69
Dayton Power & Light Co	1.90	1.48	0.42	Sierra Pacific Power Co	2.57	2.18	0.39
Illinois Power Co	1.90	1.49	0.41	Niagara Mohawk Power Corp	2.57	2.06	0.51
CINergy Corporation	1.91	1.48	0.43	Tampa Electric Co	2.61	2.19	0.43
Arizona Public Service Co	1.94	1.39	0.55	Delmarva Power & Light Co	2.62	2.01	0.61
South Carolina Elec & Gas Co	1.94	1.63	0.32	Rochester Gas & Electric Corp	2.76	1.84	0.92
American Electric Power Co Inc	1.95	1.53	0.42	Centerior Energy Corp.	2.83	1.74	1.08
Southwestern Public Service Co	1.98	1.79	0.19	Central Hudson Gas & Elec Corp	2.83	2.32	0.51
Union Electric Co	1.99	1.51	0.49	New England Electric System	2.88	2.17	0.71
UtiliCorp United Inc	2.00	1.52	0.48	Atlantic City Electric Co	2.93	1.89	1.05
Virginia Electric & Power Co	2.03	1.57	0.47	Southern California Edison Co	2.94	2.32	0.62
Duke Power Co	2.05	1.65	0.40	Florida Power & Light Co	2.97	2.46	0.51
Wisconsin Electric Power Co	2.07	1.47	0.60	Public Service Electric & Gas	3.00	1.83	1.17
Southern Indiana Gas & Elec Co	2.09	1.53	0.56	United Illuminating Co	3.03	2.41	0.62
New York State Elec & Gas Corp	2.10	1.59	0.51	Commonwealth Energy System	3.07	2.44	0.63
Interstate Power Co	2.15	1.80	0.35	Eastern Utilities Associates	3.30	2.58	0.73
The Detroit Edison Co	2.15	1.67	0.48	Orange & Rockland Utils Inc	3.31	2.64	0.66
Consumers Power Co	2.16	1.71	0.45	Pacific Gas & Electric Co	3.36	2.29	1.06
Central Louisiana Elec Co Inc	2.16	1.93	0.24	Boston Edison Co	3.36	2.60	0.76
Carolina Power & Light Co	2.17	1.81	0.36	Northeast Utilities	3.39	2.50	0.89
Oklahoma Gas & Electric Co	2.18	1.93	0.25	Long Island Lighting Co	3.47	2.90	0.57
Texas Utilities Electric Co	2.18	1.81	0.37	Philadelphia Electric Power Co	3.57	2.00	1.58
Wisconsin Public Service Corp	2.20	1.69	0.51	San Diego Gas & Electric Co	3.95	3.06	0.89
Madison Gas & Electric Co	2.20	1.62	0.58	Hawaiian Electric Co Inc	3.95	3.43	0.52
Central and Southwest Corp	2.22	1.98	0.24	Commonwealth Edison Co	4.21	3.13	1.08
Duquesne Light Co	2.22	1.69	0.53	Central Maine Power Co	4.34	2.83	1.51
Central Illinois Light Co	2.24	1.78	0.46	Consolidated Edison Co-NY Inc	4.39	3.04	1.35

low of just under 10% for Northern Indiana Public Service Company to nearly 19% for New England Electric System. Unlike the other components of costs, capital costs vary relatively little with a standard deviation of less than one basis point.

Table 4.—Steam electric capital stocks and cost of capital, firm means

<u>Company</u>	Capital Stock (<u>\$ millions</u>)	Cost of Capital	<u>Company</u>	Capital Stock (<u>\$ millions</u>)	Cost of Capital
Madison Gas & Electric Co	71.95	15.30%	Tampa Electric Co	749.93	16.4%
Eastern Utilities Associates	72.56	15.80%	Louisville Gas & Electric Co	755.81	15.2%
St Joseph Light & Power Co	81.53	16.70%	Illinois Power Co	819.83	12.9%
Otter Tail Power Co	123.17	16.60%	Southwestern Public Service Co	829.62	17.3%
Empire District Electric Co	140.45	14.60%	Northeast Utilities	860.85	16.5%
Kansas Gas & Electric Co	140.79	13.40%	Long Island Lighting Co	873.71	14.9%
Sierra Pacific Power Co	141.94	14.60%	Niagara Mohawk Power Corp	878.48	13.1%
Central Maine Power Co	147.77	13.40%	Consumers Power Co	932.59	16.9%
Interstate Power Co	149.08	14.40%	Philadelphia Electric Power Co	973.93	14.7%
Montana Power Co	172.91	14.20%	Indianapolis Power & Light Co	996.86	17.0%
Rochester Gas & Electric Corp	175.61	14.70%	Dayton Power & Light Co	1010.28	16.3%
Minnesota Power & Light Co	209.38	15.90%	Wisconsin Electric Power Co	1058.73	16.5%
UtiliCorp United Inc	233.34	13.90%	Baltimore Gas & Electric Co	1065.96	14.3%
Hawaiian Electric Co Inc	244.61	14.70%	Northern Indiana Pub Serv Co	1113.03	16.0%
Public Service Co of NM	248.04	12.90%	Gulf States Utilities Co	1242.03	9.8%
United Illuminating Co	253.86	14.80%	Potomac Electric Power Co	1245.69	14.8%
Central Illinois Light Co	254.17	15.20%	Oklahoma Gas & Electric Co	1251.02	16.5%
Commonwealth Energy System	258.05	16.50%	PSI Energy Inc	1257.17	17.3%
El Paso Electric Co	265.93	12.40%	Carolina Power & Light Co	1283.90	15.4%
Orange & Rockland Utils Inc	278.55	14.80%	General Public Utilities Corp	1338.06	15.1%
Central Hudson Gas & Elec Corp	285.31	15.30%	Union Electric Co	1347.44	16.3%
Nevada Power Co	294.43	14.20%	Florida Power Corp	1414.92	16.0%
Wisconsin Public Service Corp	295.32	15.90%	CINergy Corporation	1425.66	15.0%
Atlantic City Electric Co	312.81	14.90%	Pennsylvania Power & Light Co	1511.44	15.1%
Wisconsin Power & Light Co	343.48	16.40%	Ohio Edison Co.	1627.12	14.0%
Southern Indiana Gas & Elec Co	425.61	16.50%	Pacific Gas & Electric Co	1695.99	14.3%
Portland General Electric Co	435.02	14.90%	Allegheny Power Systems Inc.	1717.52	15.4%
Delmarva Power & Light Co	498.36	14.40%	Virginia Electric & Power Co	1727.31	13.7%
Boston Edison Co	513.98	13.90%	Duke Power Co	1836.77	16.0%
Central Louisiana Elec Co Inc	523.40	16.00%	Public Service Electric & Gas	1841.75	15.8%
Duquesne Light Co	537.11	15.20%	The Detroit Edison Co	1925.95	16.6%
San Diego Gas & Electric Co	551.18	16.60%	Consolidated Edison Co-NY Inc	2125.30	15.4%
Kansas City Power & Light Co	579.54	14.80%	Commonwealth Edison Co	2236.29	12.4%
New England Electric System	595.00	18.90%	Entergy Corporation	2287.00	15.8%
New York State Elec & Gas Corp	609.71	14.40%	Southern California Edison Co	2633.28	15.8%
South Carolina Elec & Gas Co	645.16	15.90%	Florida Power & Light Co	2804.01	15.7%
Public Service Co of Colorado	646.10	16.10%	Central and Southwest Corp	3209.83	15.4%
Central Illinois Pub Serv Co	651.28	15.30%	Texas Utilities Electric Co	3469.78	14.0%
Centerior Energy Corp.	673.85	13.70%	Houston Lighting & Power Co	3594.15	15.5%
Kentucky Utilities Co	707.74	16.70%	American Electric Power Co Inc	4193.68	15.3%
Arizona Public Service Co	709.68	15.50%	The Southern Company	6034.43	15.6%

V. COST FUNCTION ESTIMATES

In this section of the report, we describe the information provided by the cost model. This information falls into three categories. The first class includes measures of the responsiveness of resource use by utilities to market prices for inputs, technological change, and demand. Economists summarize these measures with elasticities. The second category identifies the shape of the production cost curve for steam electric generation, showing how production costs vary with the scale of production, which are summarized by measures of economies of scale. The optimal or least cost scale of production is important in determining the number of firms in the industry. If the optimal scale is larger than the average firm then cost driven mergers are likely, if regulators permit them. The third category is closely related to the second and involves incentives for investment. If firms are generating up to their capacity limits, they have incentives to either invest in new capacity or purchase power from a third party. If there are short-run scale diseconomies, in which marginal costs rise sharply when capital is fixed, generators will need higher prices to justify further expansions in output. Our findings reported below identify those firms that are likely to grow and those that are potential take-over targets.

Estimates of short and long-run input demand elasticities appear in Table 5. In the short-run, the demand for fuels is price inelastic. The short-run output elasticity of fuel demand is 0.91, which means that for a 10 percent increase in electricity generation, fuel demand will increase 9.1 percent. This simply reflects the close correspondence between energy consumption and steam power production. Not surprisingly, labor and maintenance use is not nearly as sensitive to generation levels with an elasticity of only 0.04. Variable inputs also respond to prices. In the short-run when capital is fixed, fuel demand is unresponsive to fuel prices, decreasing only 1 percent for each 10 percent

Table 5.—Elasticity estimates

Short run	Fuel	Labor and maintenance	Capital	Output	Technological change
Fuel	-0.110 (0.009)	0.110 (0.009)		0.906 (0.034)	-0.053 (0.005)
Labor and maintenance	0.349 (0.027)	-0.349 (0.027)		0.036 (0.096)	-0.126 (0.013)
Long-run					
Fuel	-0.353 (0.024)	0.057 (0.010)	0.296 (0.025)	0.753 (0.059)	-0.015 (0.001)
Labor and maintenance	0.159 (0.032)	-0.391 (0.029)	0.232 (0.025)	-0.084 (0.114)	-0.025 (0.002)
Capital	0.875 (0.075)	0.191 (0.020)	-1.067 (0.085)	0.551 (0.110)	0.049 (0.008)

Notes: White heteroscedastic-consistent standard errors are in parentheses. Elasticities evaluated at sample means.

increase in price. In the long-run, however, the own price elasticity of demand for fuel is -0.353, which is considerably larger. In the long-run, the demand for capital is elastic with an own-price elasticity of capital is -1.067. All inputs are substitutes and the relatively large cross-price elasticities of demand between capital and fuel suggest the greatest substitution possibilities between these two inputs.

Technological change is biased toward using capital and saving fuel and labor (see Table 5). The elasticities reported in Table 6 suggest that technological progress also shifts the cost function down over time. Christensen and Greene (1976) argue that technological change was relatively more important than scale economies in explaining absolute declines in the cost of production between 1955 and 1970. While our technological change elasticities are significant, they are relatively small, which suggests that the pace of technological progress in steam power production may have slowed during our sample. Unlike the stable energy price era from the 1950s through

the early 1970s, fuel prices are now much more volatile and are the most important factor shifting steam electricity production cost curves.

Table 6.—Estimates of other cost and scale measures

Scale economies	Percent	Technological change	Percent
Short run	0.422 (0.021)	Short run	-0.059 (0.006)
Long-run	0.276 (0.031)	Long-run	-0.029 (0.004)
Marginal cost	¢/kwh	Capital stock	Percent
Short run	1.709 (0.102)	Shadow value	0.099 (0.009)
Long-run	2.096 (0.133)	Optimal/actual	0.661 (0.058)
Average cost	¢/kwh	Capacity utilization	0.889 (0.017)
Long-run	2.894 (0.071)	Tobin's Q	0.649 (0.056)

The mean shadow value on capital, reported in Table 6, is nearly 10 percent, which is considerably below the average user cost of capital of about 15 percent. Tobin's Q is slightly less than 65 percent, implying that, on average, firms have market values less than their replacement cost. The estimated optimal capital stock as a percentage of observed capital is slightly more than 66 percent. The average rate of capacity utilization is 89 percent indicating excess capacity in the industry, also consistent with optimal capital stocks being lower than existing levels. Each of these measures tells essentially the same story—current capital stocks levels in the steam electricity generation industry are in disequilibrium.

Short-run marginal cost is estimated to be 1.71 cents per kwh at the sample mean, which increases to 2.10 cents per kwh in the long-run (see Table 6). Marginal costs vary considerably by firm (see Table 7). Ranging from a low of less than 1 cent per kwh to more than 5 cents per kwh. The two largest firms, American Electric Power and The Southern Company, have the highest short-run marginal cost. It is important to keep in mind that these are incremental costs calculated for each firm given their input prices, capital stocks, output, and technology. The firms with the highest output levels are near their capacity limits and, therefore, experience rising marginal costs. Their profitability at this margin will be examined in the next section.

Long-run marginal costs, also reported in Table 7, reflect the adjustment of capital stocks over time as firms invest in new plant and equipment. For several firms, marginal costs fall in the long-run because additional capital investment improves their efficiency, thus reducing their generation costs. The Southern Company, American Electric Power, Texas Utilities, and Ohio Edison are among some of the largest firms that experience marginal costs that are lower in the short-run than in the long-run. Other firms with excess capacity would slowly reduce their capital stock, perhaps by accelerating plant retirements. In Table 6 we found that on average firms have a positive shadow value for capital, which means that additional capital lowers production cost. Hence, for those firms with a smaller capital base in the long-run, their marginal production cost curves will shift upward.

Long-run average cost is 2.90 cents per kwh, roughly one-half cent below actual total average costs (see Table 6). Total average annual production in our sample is 1,398 million megawatts and this half-cent reduction would lower total production costs by \$7 billion. These cost savings would be achieved as the industry adjusts to equilibrium capital levels.

Table 7.—Short and long-run marginal costs, firm means

<u>Company</u>	(Cents / kwh)		<u>Company</u>	(Cents / kwh)	
	Short <u>Run</u>	Long <u>Run</u>		Short <u>Run</u>	Long <u>Run</u>
Portland General Electric Co	0.84	1.99	Duke Power Co	2.04	2.32
St Joseph Light & Power Co	0.98	1.69	Potomac Electric Power Co	2.04	2.39
Indianapolis Power & Light Co	1.10	1.83	Central Illinois Pub Serv Co	2.05	2.56
Empire District Electric Co	1.17	1.68	Duquesne Light Co	2.08	2.41
Kansas City Power & Light Co	1.30	1.70	Gulf States Utilities Co	2.10	1.84
Louisville Gas & Electric Co	1.31	1.81	Florida Power Corp	2.15	2.67
UtiliCorp United Inc	1.32	1.82	Allegheny Power Systems Inc.	2.15	1.73
Otter Tail Power Co	1.33	1.78	Niagara Mohawk Power Corp	2.23	2.70
Kentucky Utilities Co	1.34	1.63	Rochester Gas & Electric Corp	2.25	3.02
Dayton Power & Light Co	1.43	2.00	Central Hudson Gas & Elec Corp	2.27	2.95
South Carolina Elec & Gas Co	1.43	2.10	Delmarva Power & Light Co	2.28	2.72
Public Service Co of Colorado	1.45	1.65	Sierra Pacific Power Co	2.28	2.52
Wisconsin Power & Light Co	1.46	1.81	Pennsylvania Power & Light Co	2.29	2.48
Montana Power Co	1.50	1.48	Tampa Electric Co	2.31	2.52
Illinois Power Co	1.50	1.76	Entergy Corporation	2.32	2.68
Southern Indiana Gas & Elec Co	1.52	2.26	Ohio Edison Co.	2.34	1.64
CINergy Corporation	1.55	1.85	Atlantic City Electric Co	2.39	3.25
Central Louisiana Elec Co Inc	1.56	2.41	The Detroit Edison Co	2.58	2.35
Minnesota Power & Light Co	1.56	1.82	New England Electric System	2.60	2.94
Arizona Public Service Co	1.58	2.04	United Illuminating Co	2.61	3.01
Madison Gas & Electric Co	1.70	2.09	Southern California Edison Co	2.63	3.48
Wisconsin Electric Power Co	1.73	2.23	Florida Power & Light Co	2.64	3.39
Public Service Electric & Gas	1.75	3.28	Centerior Energy Corp.	2.65	2.41
Wisconsin Public Service Corp	1.77	2.09	Philadelphia Electric Power Co	2.71	3.68
PSI Energy Inc	1.78	1.87	Orange & Rockland Utils Inc	2.71	3.49
Union Electric Co	1.80	2.20	Commonwealth Energy System	2.73	3.36
Oklahoma Gas & Electric Co	1.82	2.28	Northeast Utilities	2.78	3.59
General Public Utilities Corp	1.83	2.40	Boston Edison Co	2.83	3.42
Southwestern Public Service Co	1.83	1.93	San Diego Gas & Electric Co	2.85	4.06
Interstate Power Co	1.85	2.15	Long Island Lighting Co	2.87	3.58
Central Illinois Light Co	1.87	2.21	Houston Lighting & Power Co	2.87	3.08
El Paso Electric Co	1.89	2.56	Eastern Utilities Associates	2.89	3.17
New York State Elec & Gas Corp	1.90	1.89	Central and Southwest Corp	2.89	2.77
Consumers Power Co	1.91	2.27	Central Maine Power Co	3.12	4.36
Northern Indiana Pub Serv Co	1.91	2.64	Consolidated Edison Co-NY Inc	3.32	4.67
Carolina Power & Light Co	1.98	2.23	Pacific Gas & Electric Co	3.40	3.64
Virginia Electric & Power Co	1.99	1.94	Commonwealth Edison Co	3.46	4.42
Baltimore Gas & Electric Co	2.00	2.44	Hawaiian Electric Co Inc	3.58	3.92
Public Service Co of NM	2.00	2.13	Texas Utilities Electric Co	3.71	2.50
Kansas Gas & Electric Co	2.01	1.92	American Electric Power Co Inc	4.70	2.86
Nevada Power Co	2.03	2.36	The Southern Company	5.08	3.68

In Table 8, we present the shadow value of capital and Tobin's Q ratio, which is the ratio of the shadow value of capacity to the user cost of capital. A Q-ratio greater than one indicates that a firm would invest in new capacity. Thirteen firms have Tobin Q ratios greater than one, indicating that they would invest in new capacity. The other 69 firms would shrink or perhaps even disappear if they were free to choose their optimal

capital levels in the long-run. These disparities suggest the possibility of a substantial reallocation of capital within the steam electricity generation industry.

Table 8.— Shadow Value of Capital and Tobin's Q Ratios, firm means

<u>Company</u>	Shadow Value of Capital	Tobin's Q	<u>Company</u>	Shadow Value of Capital	Tobin's Q
American Electric Power Company Inc	0.32	2.09	Arizona Public Service Co	0.08	0.52
The Southern Company	0.26	1.73	Dayton Power & Light Co	0.08	0.50
Texas Utilities Electric Co	0.24	1.81	Kansas City Power & Light Co	0.08	0.53
Ohio Edison Co.	0.23	1.66	General Public Utilities Corporation	0.08	0.52
Allegheny Power Systems Inc.	0.21	1.37	Eastern Utilities Associates	0.08	0.48
The Detroit Edison Co	0.19	1.20	Southern California Edison Co	0.08	0.50
Centerior Energy Corp.	0.18	1.32	Nevada Power Co	0.08	0.55
Central and Southwest Corporation	0.17	1.08	Louisville Gas & Electric Co	0.08	0.51
Kansas Gas & Electric Co	0.16	1.21	Hawaiian Electric Co Inc	0.08	0.52
Southwestern Public Service Co	0.16	0.89	Central Illinois Light Co	0.07	0.50
PSI Energy Inc	0.15	0.95	Central Illinois Pub Serv Co	0.07	0.46
New York State Elec & Gas Corp	0.14	1.02	Niagara Mohawk Power Corp	0.07	0.58
Montana Power Co	0.14	1.08	Interstate Power Co	0.07	0.48
Houston Lighting & Power Co	0.14	0.88	Delmarva Power & Light Co	0.07	0.50
Virginia Electric & Power Co	0.13	1.28	United Illuminating Co	0.07	0.45
Duke Power Co	0.13	0.78	Indianapolis Power & Light Co	0.06	0.38
Pennsylvania Power & Light Co	0.13	0.87	Northern Indiana Pub Serv Co	0.06	0.37
Tampa Electric Co	0.13	0.78	South Carolina Elec & Gas Co	0.05	0.33
Gulf States Utilities Co	0.12	1.29	Otter Tail Power Co	0.05	0.30
Public Service Co of Colorado	0.12	0.77	Long Island Lighting Co	0.05	0.38
Entergy Corporation	0.12	0.77	Boston Edison Co	0.05	0.44
New England Electric System	0.12	0.65	Madison Gas & Electric Co	0.05	0.34
Carolina Power & Light Co	0.12	0.80	Northeast Utilities	0.05	0.31
Kentucky Utilities Co	0.12	0.70	Commonwealth Energy System	0.04	0.27
CINergy Corporation	0.11	0.77	Commonwealth Edison Co	0.04	0.32
Consumers Power Co	0.11	0.67	UtiliCorp United Inc	0.04	0.27
Pacific Gas & Electric Co	0.11	0.91	Empire District Electric Co	0.04	0.27
Union Electric Co	0.11	0.67	Southern Indiana Gas & Elec Co	0.03	0.18
Oklahoma Gas & Electric Co	0.10	0.61	Consolidated Edison Co-NY Inc	0.03	0.20
Potomac Electric Power Co	0.10	0.73	Central Hudson Gas & Elec Corp	0.03	0.20
Florida Power Corp	0.09	0.59	Philadelphia Electric Power Company	0.02	0.16
Duquesne Light Co	0.09	0.61	Central Louisiana Elec Co Inc	0.02	0.14
Public Service Co of NM	0.09	0.89	El Paso Electric Co	0.01	0.13
Minnesota Power & Light Co	0.09	0.59	Orange & Rockland Utils Inc	0.01	0.08
Wisconsin Electric Power Co	0.09	0.55	Public Service Electric & Gas	0.01	0.05
Florida Power & Light Co	0.09	0.56	St Joseph Light & Power Co	0.01	0.04
Illinois Power Co	0.09	0.74	Atlantic City Electric Co	0.00	0.02
Wisconsin Power & Light Co	0.09	0.54	Portland General Electric Co	0.00	0.00
Wisconsin Public Service Corp	0.09	0.55	Rochester Gas & Electric Corp	0.00	0.01
Sierra Pacific Power Co	0.09	0.58	San Diego Gas & Electric Co	0.00	0.00
Baltimore Gas & Electric Co	0.08	0.58	Central Maine Power Co	0.00	0.00

The actual capital stock for the steam electricity generation segment of the electricity industry averaged nearly \$86.2 billion from 1987 to 1996. Our estimate of the optimal level for the industry is \$81.2 billion.

We also report our estimates of economies of scale in Table 9. Our measure of economies of scale is equal to the difference between average and marginal cost divided by average cost. Positive values indicate economies of scale while negative values identify diseconomies. We find substantial short-run scale economies at low output levels and large diseconomies at higher output levels. A similar picture emerges in the long-run if each firm were to attain their equilibrium levels of capital. In the long-run, average scale economies are smaller (see Table 9). Unlike the short run, long-run scale economies generally rise with output to about 50 million mwh and then drop off sharply at very high output levels.

Drawing a clear relationship between scale economies and output is difficult because marginal and average costs are a function of input prices, which vary by firm and across time. In Figure 4, we control for these differences by plotting the short- and long-run average cost curves. The short-run average total cost (SRAC) curve is defined for a particular capital stock level. We generate the SRAC curve in Figure 4 by calculating predicted average total cost for each firm's output level using the firm means for input prices and capital stocks. This curve represents the short-run average total cost incurred by the "typical" firm—at average capital stocks and facing average input prices—in generating the output levels produced by each of the 82 firms.

We calculate the long-run average total cost curve in two steps. First, we calculate optimal capital stocks for each firm given their 1996 output and the firm means for input prices. We then compute long-run average total cost using these optimal capital

stocks, holding each firm’s input prices constant. Hence, capital stocks vary along the long–run average total cost curve, which is an envelope of SRAC curves. In Figure 4, we plot one SRAC curve that corresponds to the “typical” firm. This curve is tangent

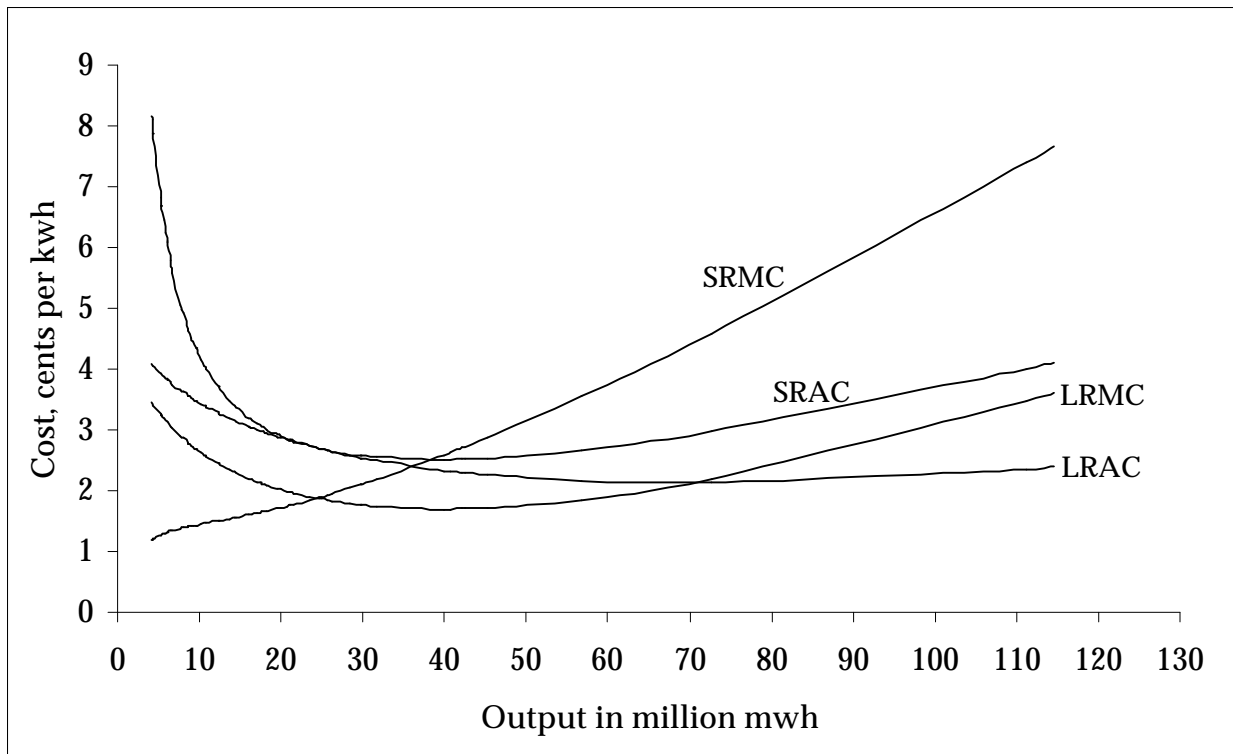
Table 9.—Estimates of capacity utilization and short and long–run scale economies

Company	Scale Economies			Company	Scale Economies		
	Short	Long	Capacity		Short	Long	Capacity
	<u>Run</u>	<u>Run</u>	<u>Utilization</u>		<u>Run</u>	<u>Run</u>	<u>Utilization</u>
Portland General Electric Co	0.78	0.22	0.44	Consumers Power Co	0.38	0.25	0.90
Public Service Electric & Gas	0.66	0.19	0.58	Commonwealth Edison Co	0.38	0.16	0.82
St Joseph Light & Power Co	0.64	0.18	0.53	Madison Gas & Electric Co	0.38	0.17	0.81
Indianapolis Power & Light Co	0.61	0.29	0.72	Potomac Electric Power Co	0.37	0.26	0.91
Central Louisiana Elec Co Inc	0.57	0.21	0.67	Wisconsin Public Service Corp	0.37	0.24	0.89
Southern Indiana Gas & Elec Co	0.54	0.21	0.69	Central Illinois Light Co	0.36	0.22	0.88
South Carolina Elec & Gas Co	0.54	0.26	0.75	Minnesota Power & Light Co	0.36	0.24	0.90
San Diego Gas & Electric Co	0.53	0.12	0.61	Commonwealth Energy System	0.36	0.15	0.81
Louisville Gas & Electric Co	0.52	0.31	0.82	Delmarva Power & Light Co	0.36	0.21	0.87
Empire District Electric Co	0.52	0.24	0.73	Entergy Corporation	0.36	0.24	0.91
UtiliCorp United Inc	0.51	0.26	0.77	Nevada Power Co	0.35	0.22	0.89
Dayton Power & Light Co	0.51	0.27	0.80	Boston Edison Co	0.35	0.18	0.85
Central Maine Power Co	0.51	0.08	0.58	Duquesne Light Co	0.34	0.22	0.90
Kansas City Power & Light Co	0.48	0.30	0.85	Carolina Power & Light Co	0.34	0.25	0.93
Northern Indiana Pub Serv Co	0.48	0.22	0.79	Southwestern Public Service Co	0.34	0.29	0.96
Otter Tail Power Co	0.47	0.21	0.75	Interstate Power Co	0.33	0.20	0.88
Atlantic City Electric Co	0.47	0.14	0.69	PSI Energy Inc	0.33	0.29	0.96
El Paso Electric Co	0.47	0.19	0.73	Duke Power Co	0.33	0.23	0.93
Rochester Gas & Electric Corp	0.46	0.13	0.67	New England Electric System	0.31	0.20	0.92
Consolidated Edison Co-NY Inc	0.46	0.15	0.73	Montana Power Co	0.31	0.31	1.00
Philadelphia Electric Power Co	0.46	0.17	0.75	United Illuminating Co	0.31	0.17	0.88
Kentucky Utilities Co	0.46	0.32	0.90	Tampa Electric Co	0.30	0.23	0.95
Arizona Public Service Co	0.46	0.26	0.84	Public Service Co of NM	0.30	0.24	0.95
General Public Utilities Corp	0.45	0.24	0.84	Virginia Electric & Power Co	0.29	0.33	1.00
Wisconsin Electric Power Co	0.44	0.25	0.85	New York State Elec & Gas Corp	0.29	0.29	1.00
Wisconsin Power & Light Co	0.43	0.27	0.86	Sierra Pacific Power Co	0.28	0.18	0.91
CINergy Corporation	0.42	0.31	0.91	Pennsylvania Power & Light Co	0.28	0.22	0.96
Central Hudson Gas & Elec Corp	0.42	0.16	0.76	Gulf States Utilities Co	0.28	0.35	1.04
Illinois Power Co	0.42	0.31	0.91	Pacific Gas & Electric Co	0.23	0.17	0.94
Oklahoma Gas & Electric Co	0.42	0.25	0.87	Hawaiian Electric Co Inc	0.23	0.14	0.92
Northeast Utilities	0.41	0.18	0.80	Kansas Gas & Electric Co	0.22	0.25	1.01
Orange & Rockland Utils Inc	0.41	0.13	0.74	Eastern Utilities Associates	0.22	0.12	0.91
Public Service Co of Colorado	0.41	0.32	0.93	Houston Lighting & Power Co	0.20	0.14	0.96
Southern California Edison Co	0.40	0.18	0.82	Centerior Energy Corp.	0.19	0.25	1.04
Central Illinois Pub Serv Co	0.40	0.22	0.84	The Detroit Edison Co	0.11	0.19	1.04
Baltimore Gas & Electric Co	0.40	0.25	0.88	Central and Southwest Corp	0.09	0.13	1.02
Florida Power Corp	0.40	0.23	0.87	Allegheny Power Systems Inc.	0.07	0.24	1.10
Union Electric Co	0.40	0.24	0.89	Ohio Edison Co.	0.00	0.27	1.14
Florida Power & Light Co	0.39	0.19	0.85	Texas Utilities Electric Co	-0.30	0.07	1.18
Long Island Lighting Co	0.38	0.18	0.83	The Southern Company	-0.64	-0.29	1.19
Niagara Mohawk Power Corp	0.38	0.23	0.87	American Electric Power Co Inc	-0.78	-0.28	1.27

with the LRAC curve around the 20 million mwh output level, the mean output level in 1996. At low output levels, short-run marginal cost (SRMC) is far below SRAC, suggesting economies of scale. Beyond the 38 million-megawatt level, short-run diseconomies of scale emerge.

The steep decent and long tail in our estimated LRAC curve in Figure 4 is similar to the average curves depicted by Christensen and Greene (1976) and suggests economies of size. In other words, the optimal size of the “typical” firm should be larger such that

Figure 4.—Cost curves for steam electric power generation in 1996



the short-run curves slide down the long-run envelope, attaining an optimal output level where LRMC intersects the minimum point of the LRAC curve. The gap between the LRAC and LRMC curves begins to close at the 50 million-megawatt level and long-

run scale diseconomies emerge beyond the 70 million-megawatt level. If the industry restructured to minimize long-run average cost, only 20 firms would be necessary to produce current average annual output.

VI. SPARK SPREAD OPTION VALUES

The shadow values on capital presented above assume that firms know generation costs and market prices for electricity with perfect certainty. Prices for natural gas, oil, coal, and electricity, however, are highly volatile, often changing abruptly with demand and supply shocks. Studies by Dixit and Pindyck (1994) and several other researchers view investments as options, showing that uncertainty profoundly affects investment decisions and the prices firms are willing to pay for capital assets. These so-called *real options* are transforming the way firms view asset valuation.

The first step in appreciating the importance of uncertainty in capital investment is to note that, in addition to deciding whether to invest, the firm has to decide *when* to invest. In other words, the firm has an *option* to invest that could be exercised now or later. Greater uncertainty increases the value of waiting so that firms do not invest until the value of a project substantially exceeds the value of the option to wait. Naturally, the value of a project affects the amount firms are willing to bid for an asset.

Most real option studies focus on generally one source of uncertainty, usually the output price. For electricity, however, fuel prices also constitute a major source of uncertainty. With futures markets for electricity, natural gas, and petroleum, electricity companies can hedge both their costs and their revenues. The spark spread between costs and revenues determines their profitability. Hence, an investment in a power plant is equivalent to an option on a spark spread. A firm deciding to invest in a power

plant must place a value on this option. If the value of the spark spread option is greater than the cost of constructing a new plant, the firm may decide to undertake the project.

Calculating the value of spark spread options is somewhat complicated for two reasons. First, there are two sources of uncertainty: costs and prices. Another complication is that many commodity prices, including electricity, have a tendency to revert to their long-run equilibrium levels. Crude oil is a good example. While the OPEC cartel may succeed in temporarily increasing prices by reducing production, these higher prices may revert to marginal extraction cost as consumption falls and new supplies from non-OPEC members become available. Electricity prices also have a tendency to revert to their long-run marginal costs of production.

Recently, Deng, Johnson, and Sogomonian (1999) incorporate these complications in their a model to value electricity options. Their method involves calculating a series of call options on spark spreads. These spreads are simply the spot electricity price less the cost of producing power, which they approximate for gas turbines with the product of the heat rate and the price of natural gas. Both ends of this spread are weighted by probabilities that depend upon the variance, covariance, and rates of mean reversion for electricity and natural gas prices.

They calculate option values for a range of heat rates and for two different sets of futures prices for electricity. Using the Palo Verde price curve on October 15, 1997, they estimate a spark spread option value of \$185 per kw for a heat rate of 9.5 million BTU per megawatt, which is within the price range for recently sold gas-fired power plants. The spark spread option values vary from a low of \$100 per kw for heat rates more than 11.5 to over \$350 per kw for heat rates as low as 7. These values also vary

with the futures price curves. For example, using the electricity and natural gas futures prices for Palo Verde as of December 31, 1998, the spark spread option value is \$437 per kw, assuming a 9.5 heat rate with the parameters used by Deng, Johnson, and Sogomonian (1999).

The product of the heat rate and natural gas price is their estimate of fuel costs. As the above discussion demonstrates, however, labor, maintenance, and capital costs are also important. Accordingly, we calculate the spark spread option values using three different measures of average cost in the short-run:

- total cost
- variable cost, and
- fuel cost.

As in Deng, et. al., we also assume a 15-year plant life and a 4.5 percent real discount rate. For the first twelve periods, the price is the corresponding futures price from the term structure reported at the end of 1998. All subsequent electricity prices escalate at 1 percent per year starting from our estimate of short-run marginal cost for each firm. Our cost model provides an estimate of short-run marginal cost, which we assume is equal to the price it receives for output at or near capacity. We estimate the rate of mean reversion for marginal costs and the three measures of average costs using the methods recently developed by Pindyck (1999). The variance and covariances between average costs and marginal costs vary with the definition of average cost in each set of calculations. In addition to average and marginal cost variations by firm, average operating rates in terms of hours per month also vary by firm.

The spark spread option values ranked by firm appear in Table 10. Using fuel costs tends to overstate the option values. Our preferred measure is average total cost, which

includes capital, labor, and maintenance expenses. We also report average variable cost because capital rental values may not accurately reflect capital charges, since they

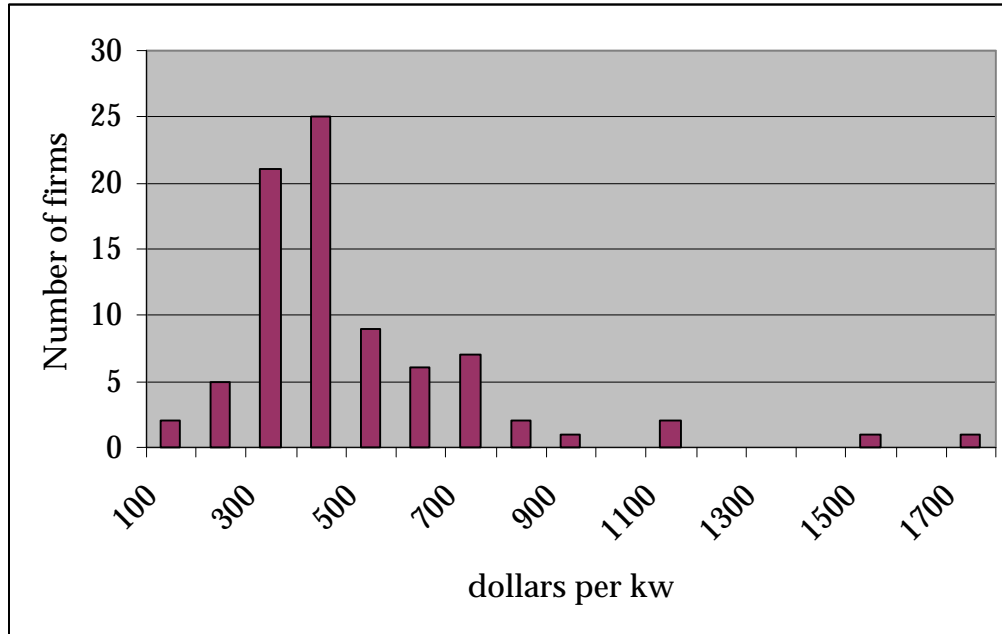
Table 10.—Estimates of spark spread option values, firm means

Company	Avg. Cost (\$/kw)			Company	Avg. Cost (\$/kw)		
	Total	Var.	Fuel		Total	Var.	Fuel
The Southern Company	1632	1654	1751	Illinois Power Co	352	341	386
American Electric Power Company	1409	1400	1512	Florida Power & Light Co	349	345	375
Texas Utilities Electric Co	1027	1007	1077	Atlantic City Electric Co	348	326	425
Hawaiian Electric Co Inc	1003	883	946	Potomac Electric Power Co	346	330	375
Ohio Edison Co.	816	782	892	General Public Utilities Corporation	342	337	405
Commonwealth Energy System	796	727	838	CINergy Corporation	335	342	380
New England Electric System	706	645	750	Wisconsin Power & Light Co	335	325	358
Centerior Energy Corp.	682	607	762	Central Maine Power Co	334	315	400
Allegheny Power Systems Inc.	656	653	716	Interstate Power Co	332	305	338
United Illuminating Co	649	587	657	Union Electric Co	326	322	375
Boston Edison Co	641	583	669	Entergy Corporation	315	310	338
Central and Southwest Corporation	612	607	639	Southern California Edison Co	312	305	346
Pennsylvania Power & Light Co	604	574	658	Oklahoma Gas & Electric Co	306	305	320
Houston Lighting & Power Co	604	599	660	Minnesota Power & Light Co	298	276	318
New York State Elec & Gas Corp	598	547	637	Consolidated Edison Co-NY Inc	292	281	335
The Detroit Edison Co	563	549	613	Madison Gas & Electric Co	291	290	322
Delmarva Power & Light Co	534	485	570	Baltimore Gas & Electric Co	281	265	314
Northeast Utilities	507	472	556	Wisconsin Electric Power Co	268	264	320
Duquesne Light Co	502	449	544	Dayton Power & Light Co	256	264	301
Montana Power Co	501	457	691	Kansas Gas & Electric Co	254	227	286
Tampa Electric Co	491	454	493	El Paso Electric Co	253	235	275
Public Service Co of NM	489	439	510	Arizona Public Service Co	251	243	297
Long Island Lighting Co	444	410	450	San Diego Gas & Electric Co	249	242	276
Central Hudson Gas & Elec Corp	434	409	456	Philadelphia Electric Power Company	248	232	312
Duke Power Co	421	417	467	Southern Indiana Gas & Elec Co	244	247	296
Consumers Power Co	420	402	460	Central Louisiana Elec Co Inc	243	244	267
Eastern Utilities Associates	417	377	416	Kentucky Utilities Co	243	243	278
Central Illinois Light Co	414	383	435	Otter Tail Power Co	235	236	285
Virginia Electric & Power Co	411	399	455	South Carolina Elec & Gas Co	234	236	265
Carolina Power & Light Co	393	379	416	Rochester Gas & Electric Corp	232	221	280
Wisconsin Public Service Corp	391	368	418	Kansas City Power & Light Co	215	213	266
Southwestern Public Service Co	380	363	385	Louisville Gas & Electric Co	208	213	260
PSI Energy Inc	377	375	418	Nevada Power Co	207	191	233
Orange & Rockland Utils Inc	374	348	393	Sierra Pacific Power Co	202	182	199
Florida Power Corp	371	358	390	Northern Indiana Pub Serv Co	192	188	224
Pacific Gas & Electric Co	364	329	402	Empire District Electric Co	188	194	225
Public Service Co of Colorado	361	351	415	Indianapolis Power & Light Co	188	207	251
Gulf States Utilities Co	360	328	351	Public Service Electric & Gas	127	133	178
Central Illinois Pub Serv Co	357	335	402	UtiliCorp United Inc	114	113	128
Niagara Mohawk Power Corp	355	324	376	St Joseph Light & Power Co	84	105	102
Commonwealth Edison Co	353	323	377	Portland General Electric Co	36	42	65

assume that firms use capital up to the point where the shadow value of capital equals the rental rate or their opportunity cost of capital. The option values based upon total average cost vary from over \$1600 per kw for The Southern Company to \$36 per kw for

Portland General Electric. The distribution of spark spread option values presented in Figure 5 shows that most option values fall between \$300 and \$600 per kw. The mean option value is \$413 and the standard deviation is \$256.

Figure 5.– Distribution of spark spread option values



The firms with above average option values are generally coal based utilities and are around the costs paid for new coal-fired capacity that began operation during 1996. For instance, according to EIA, the average cost of steam generation plants brought into operation from 1992 to 1996 was \$1,276 kw. In contrast, three gas turbine plants began operations with original plant costs in the \$225 to \$422 per kwh price range. In light of these plant cost data, our spark spread option values seem reasonable, with most falling within the range spanned by these plant costs. This comparison, however, carries a caveat that our spark spreads are averages over a ten year period while a more precise comparison would involve calculating the option values when the plant construction decision was made rather than when the plant was commissioned.

VII. IMPLICATIONS

We find evidence of over-capitalization in the steam electric power sector. Our findings also suggest that full competition in the steam electricity market may induce a substantial consolidation in this industry. Even though scale diseconomies emerge at higher output levels, the output level at which long-run average cost attains a minimum is 70 million mwh, more than three times larger than the average firm's output level. This suggests that there may be scale driven cost incentives for mergers.

At current output levels, our estimate of efficient scale implies that a competitive steam electric generating industry would accommodate about 20 independent firms. This finding does not support the view that the electricity generation sector will evolve into an industry dominated by a few industry titans, such as in the telecommunications industry. There are limits to economies of scale in electricity generation that constrain optimal firm size. Apart from regional concentrations of market power, this bodes well for the emergence of a competitive electricity market.

Our estimates of spark spread option values measure how each firm values its marginal value of capacity given uncertain prices and costs. We find that average spark spread option values for steam electric firms are slightly over \$400 per kw, ranging from over \$1600 per kw to less than \$50 per kw. The high estimates are close to recent construction costs for steam electric plants. Many utilities have option values substantially below the cost of gas-fired turbine generators. These option values may provide a good starting point to value firms as they merge to attain optimal efficient size.

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APPENDIX A—DATA SOURCES

The primary source of data for this study is from the *Financial Statistics of Major U. S. Investor-Owned Electric Utilities, EIA Form 1 (Financial Statistics)* published by the Energy Information Administration (EIA). We also used data on generation and consumption of fuels at power plants (*EIA Form 759*) and cost and quality of fuels at electric power plants (*EIA Form 423*). Recent data are available at its EIA web site. We obtained historical data directly from EIA in electronic format and appreciate their assistance.

The *Financial Statistics* contains all relevant financial and cost data for major electric utilities in the United States. The data include Statement of Income and Retained Earnings, Balance Sheet (Table 37), Statement of Cash Flows (Table 39), Electric Operating and Maintenance Expenses (Table 41), Utility Plant (Table 42), Electric Energy Account (Table 43), and financial indicators for investor-owned utilities in the U.S. (Table 44). Over the period of the sample the total number of utilities in this report ranged from 135 to 185.

EIA Form 759 (Monthly Power Plant Report) reports monthly net power generation, consumption of fossil fuels, and month-ending stocks of coal and oil at power plants in the United States. Specific data also include prime mover-type including hydro, steam, internal combustion, gas turbines, combined-cycle steam, combined-cycle gas turbine, wind, and solar; and fuel type including nuclear, oil (light and heavy), petroleum coke, coal (anthracite and bituminous), lignite, and natural gas. There are around 700 respondents to this form, including all major investor-owned utilities. Each plant is assigned a unique code, as is each utility company.

Some power plants are jointly owned by two or more electric utilities. Data on percentage ownership is available in Appendix C of the *Inventory of Power Plants*. We

identified 120 plants jointly owned from this inventory. We then extracted data from Form 759 and assigned it to the utility companies that owned the plants before reinserting them into the database. We assume the joint ownership data from 1996 represents the entire sample. The plant level data was then aggregated to the utility level. Net power generation by prime-mover type and fuel consumption and stocks at the utility level (also by prime-mover type) were extracted into another database. Specific fuel types were aggregated into three broad categories of coal, oil, and natural gas.

Form 423 (Monthly Report on Cost and Quality of Fuels of Electric Plants) provides monthly data on the quantity, quality, and cost of fuel received at power plants with a steam-electric and combined-cycle nameplate capacity of 50 megawatts or more. Data include fuel type, delivered cost per million Btu, type of purchase (spot, contract, firm, or interruptible), and quality of fuel (Btu, sulfur, and ash content). These data are based on specific spot purchases or contracts and are reported, at times more than once a month, and at times once every few months, especially for oil and natural gas. The heat content of monthly fuel receipts for three broad categories of fuels was calculated along with average annual prices, per quantity unit, and per million Btu.

The price of the energy aggregate P_t above is a Divisia price index of fuels:

$$\ln P_t - \ln P_{t-1} = \sum_{i=1}^n \frac{1}{2} (w_{it} + w_{it-1}) [\ln P_{it} - \ln P_{it-1}], \quad (\text{B1})$$

where

$$w_{it} = \frac{P_{it} Q_{it}}{\sum_{j=1}^3 P_{jt} Q_{jt}}, \quad (\text{B2})$$

and where P_{it} is the price of the i th fuel, from EIA Form 423, and Q_{it} is the joint venture corrected consumption of the same fuel from EIA Form 759. The price has also been adjusted to reflect joint ownership—parts of plants that belong to a utility but were counted as separate plants.

We compute the divisia by using the chain-linked derivation (Diewert, 1976). We define:

$$\mathbf{a}_t = \sum_{i=1}^n \frac{1}{2} (w_{it} + w_{it-1}) [\ln P_{it} - \ln P_{it-1}], \quad (\text{B3})$$

and consider the divisia in the base year, when $P_b = 1$:

$$\begin{aligned} \ln P_b &= \mathbf{a}_b + \ln P_{b-1} = 0, \\ \ln P_{b-1} &= -\mathbf{a}_b, \\ P_{b-1} &= e^{-\mathbf{a}_b}. \end{aligned} \quad (\text{B4})$$

Now consider two periods before the base year:

$$\begin{aligned} \ln P_{b-1} &= \mathbf{a}_{b-1} + \ln P_{b-2}, \\ \ln P_{b-2} &= -\mathbf{a}_b - \mathbf{a}_{b-1}, \\ P_{b-2} &= e^{-\mathbf{a}_b - \mathbf{a}_{b-1}}. \end{aligned} \quad (\text{B5})$$

A similar chain pattern emerges as one goes back in time from the base period. The derivation for periods after the base period is a mirror image. To calculate fuel quantities, we divide the steam power production fuel costs reported by firm in the *Financial Statistics* by the divisia price index for fuels.

We calculate labor and maintenance costs by subtracting these fuel costs from total steam power expenses reported in the *Financial Statistics*. Quantities of labor and maintenance equal expenditures divided by a cost share-weighted price index for labor and maintenance. The price of labor is a company-wide average wage rate. The price of maintenance and other supplies is a price index of electrical supplies from the Bureau of Labor Statistics. Cost shares equal average shares for the eleven year period for firms having only steam generation. Steam power generation by firm is from Table 43 of the *Financial Statistics*.

Our capital rental rate for each firm is the following:

$$u_{kt} = p_{kt} [r_{dt} + p] r_{et} - r_{dt} + u_t - i_t, \quad (\text{B6})$$

where p_{kt} is a price index for electrical generation plant and equipment, r_{dt} is the adjusted corporate bond rate based on Moody's ratings, p is the equity share of total capital, r_{et} is the equity rate of return computed as the ratio of net income to total primary capital, u_t is a depreciation rate assuming 30 year straight line depreciation, and i_t is the rate of change in overall wholesale prices.

As reported above, we estimate capital stocks using a perpetual inventory approach. Nameplate capacity data from the Inventory of Power Plants (EIA) is reported in EIA Form 759 along with generation and fuel use data. The generation and fuel use data were used to generate a plant efficiency measure which measured megawatts produced per million Btu. Using an industry-wide average efficiency rate, each plant capacity was adjusted (upward for more efficient plants and vice versa) to reflect its efficiency as compared to the industry average. Jointly owned plants were assigned to individual owners based on the joint ownership data.

The nameplate capacity in the base year was then valued at replacement cost using the price of new capacity in 1986:

$$K_{nt} = P_{ct} C_t, t = 1986, \quad (B7)$$

where K_{nt} is the nominal capital stock, P_{ct} is the price of new generation capacity in dollars per megawatt, and C_t is nameplate capacity also in megawatts. The Financial Statistics of Investor-Owned Utilities (EIA) reports prices for newly installed capacity since 1992. We calculated an annual average from 1992 to 1996. Values prior to 1992 are backcast using a price index for gas and steam turbine generating units from the Bureau of Labor Statistics. For subsequent years, the estimated nominal capital stock in a particular year was depreciated using straight-line depreciation for a 30-year lifetime. This was adjusted for any change in real price using the price index for electrical generating plants. Additions to steam power plant and retirements were then added and subtracted, respectively, and a nominal time series was generated:

$$K_{nt} = (1 - u) \left(\frac{K_{nt-1}}{p_{kt-1}} \right) p_{kt} + A_t - R_t, t = 1987, \dots, 1996. \quad (B8)$$

The real capital stock in the model K_t is equal to the nominal stock divided by the price index for electrical generating plant and equipment p_{kt} from the Bureau of Labor Statistics.

Bond rates in the capital user cost given by (B6) are from the Federal Reserve Board and are adjusted by firm, based upon its bond ratings by Moody's Investor Service reported by EIA. The equity rate of return is equal to net income divided by total proprietary capital. The share of equity capital is equal to total proprietary capital (TPC) divided

by the sum of TPC and TOTB, which is the total outstanding debt of the utility. The inflation rate is equal to the rate of change in the wholesale price index.

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APPENDIX B—COST MODEL AND INPUT DEMAND ELASTICITIES

This appendix presents the derivation of the cost model, the measures of economies of scale, and the short and long-run elasticities of input demand and cost. The cost model is built upon a flexible functional form that allows, among other possible shapes, U-shaped cost curves. Our model also draws the distinction between the short and the long-run, which raises the issue of disequilibrium, dynamic adjustments.

Disequilibrium is defined when static equilibrium conditions consistent with cost minimization do not hold. For example, electric generating companies may overemploy a factor of production, such as capital, under rate of return regulation.

There are a variety of approaches to model disequilibrium in factor markets. Atkinson and Halvorsen (1984) allow disequilibrium in factor markets, arguing that producers minimize cost using shadow prices, which reflect the impacts of regulation on effective input prices. They estimate the extent of disequilibrium using a constant parameter for each input. In a later paper, Atkinson and Halvorsen (1995) represent the wedge between shadow and market input prices with a function of interest rates and other proxies for adjustment costs. With energy market deregulation in the United States during the 1980s, fossil fuel prices now paid by electric utilities probably reflect competitive market levels. Past and current rate-of-return regulation, however, may have distorted capital stock levels. Brown and Christensen (1981) offer an alternative to the Atkinson and Halvorsen approach with a short-run restricted cost function in which some inputs are fixed in the short run.

Using duality theory, previous studies by Christensen and Greene (1976) and Atkinson and Halvorsen (1984) specify a translog functional form to approximate a cost function for steam electric power production. The Generalized Leontief (GL) form introduced

by Diewert (1971) also places no *a priori* restrictions on input substitution elasticities, and Caves and Christensen (1980) have shown it to be a good approximation of technology when limited input substitution possibilities exist. The GL collapses to a fixed coefficient production technology under linear parameter restrictions. Limited substitution in electric power between fuel, labor, and capital seems plausible.

Another reason we choose the Generalized Leontief form is that it facilitates analysis of short-run restricted cost functions. With a translog specification of (1), the equilibrium condition for capital is a nonlinear expression. Solving for optimal capital requires numerical methods but convergence is not guaranteed if there are convexity violations. Morrison (1988) respecifies Diewert's original GL specification in a short-run context, allowing nonconstant returns to scale and nonneutral technological change. Her respecification allows a closed-form solution for equilibrium levels for quasi-fixed inputs. Like the translog, the GL allows scale economies to vary with the level of output. This feature enables us to estimate unit cost curves that may attain the classic "U" shape. The short-run specification also allows estimation of short-run and long-run cost curves.

The studies by Nerlove (1963) and Christensen and Greene (1976) used a cross section of firms to estimate returns to scale. Christensen and Greene (1976) also compared their estimates from two cross sections using data from 1955 and 1970 to determine how scale economies changed over time. Clearly, our data from the late 1980s to mid 1990s would provide a good test for the robustness of their estimates. Furthermore, rather than comparing cross sections at several points in time, we pool data from 82 firms over 10 years so that we can estimate scale economies and technological change simultaneously.

Our empirical analysis uses the following Generalized Leontief short-run restriction cost function with non-constant returns to scale and non-neutral technological change¹:

$$\begin{aligned}
 G_t = Y_t & \left[\sum_{i=1}^2 a_{ii} + \sum_{f=1}^{81} a_{if} D_{ft} \right] P_{it} + 2a_{12} P_{1t} P_{2t} Y_t^{1/2} + \sum_{i=1}^2 d_{iy} P_{it} Y_t^{1/2} + \sum_{i=1}^2 d_{iz} P_{it} Z_t^{1/2} \\
 & + g_{kk} \sum_{i=1}^2 P_{it} K_t + Y_t \sum_{i=1}^2 P_{it} g_{yy} Y_t + 2g_{yz} Y_t^{1/2} Z_t^{1/2} + g_{zz} Z_t \\
 & + K_t Y_t^{1/2} \left[\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2} \right],
 \end{aligned} \tag{A1}$$

where \mathbf{a} , \mathbf{d} , and \mathbf{g} are unknown parameters, and D_{ft} are firm dummy variables for fixed firm effects placed on the first-order price terms in the restricted variable cost function. Taking the partial differential of (A1) with respect to input prices and using Shephard's lemma results in the following input demand functions:

$$\begin{aligned}
 \frac{Q_{it}}{Y_t} = a_{ii} + \sum_{f=1}^{81} a_{if} D_{ft} + a_{ij} \left[\frac{P_{jt}}{P_{it}} \right]^{1/2} + d_{iy} Y_t^{1/2} + d_{iz} Z_t^{1/2} + g_{yy} Y_t + 2g_{yz} Y_t^{1/2} Z_t^{1/2} + g_{zz} Z_t \\
 + \left[\frac{K_t}{Y_t} \right]^{1/2} \left[d_{ik} + g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2} \right] + g_{kk} \left[\frac{K_t}{Y_t} \right],
 \end{aligned} \tag{A2}$$

¹ Brown (1968) makes the distinction between technical change, which involves movement along an isoquant, and technological change that involves a shift in the isoquant. We adopt this distinction, noting that our cost function is dual to a production function. In this context, technological change or progress results in a shift in the cost function and factor demand functions.

for $i, j = 1$ and 2 , respectively, and where Q_{it} is quantity demanded of input i . Notice that the fixed effects; \mathbf{a}_{if} , act as intercept shifters in the input demand functions. These effects are time invariant and represent management and other factors unique to each firm. It is likely that the fixed effects are correlated with output and the other explanatory variables in the model. In this situation, a least squares with dummy variables estimator provides consistent estimates of the parameters in the absence of measurement error and endogeneity among the explanatory variables.² Our previous arguments suggest that it is reasonable to assume output, capital, and factor prices are exogenous to each firm. Our careful data collection procedures suggest the possibility of minimal measurement error.

The short-run restricted cost function (A1) and the two input-output equations (A2) constitute the empirical model. The stochastic errors for each of these equations are likely to be correlated. Consequently, we estimate the model as a system, iterating on the variance-covariance matrix, which provides maximum likelihood estimates if the disturbances are multivariate normal and identically distributed. As Morrison (1988) demonstrates, the Generalized Leontief form allows linear parameter restrictions for testing long-run constant returns to scale, $\mathbf{d}_{iy} = \mathbf{g}_{yk} = \mathbf{g}_{yz} = \mathbf{g}_{yy} = 0$. The hypothesis of neutral technological change implies the following parameter restrictions:

$\mathbf{d}_{iz} = \mathbf{g}_{yz} = \mathbf{g}_{zz} = \mathbf{g}_{zk} = 0$. We test these hypotheses below in Appendix C.

² We explored the possibility of estimating a random effects model by first estimating the model in terms of deviations from firm means. We found that the transformed input demand equations did not yield the same estimates as the untransformed model in the presence of cross equation parameter constraints. Hence, we abandoned further attempts at re-specifying the model to eliminate the need for directly estimating the firm effects.

This simple three equation model provides a wealth of information about the shape of short and long-run cost and input demand curves for electric power generation. The first measure of interest is economies of scale, or the proportionate increase in cost from an increase in the level of output. This is measured by the elasticity of cost with respect to output. In the short run, this elasticity is a function of marginal cost:

$$\begin{aligned} \frac{\partial G_t}{\partial Y_t} = & \sum_{i=1}^2 \left[a_{ii} + \sum_{f=1}^{82} a_{if} D_{fi} \right] P_{it} + 2a_{12} P_{1t} P_{2t} Y_t^{1/2} + \frac{3}{2} \sum_{i=1}^2 d_{iy} P_{it} Y_t^{1/2} + \sum_{i=1}^2 d_{iz} P_{it} Z_t^{1/2} \\ & + \sum_{i=1}^2 P_{it} \left[2g_{yy} Y_t + 3g_{yz} Y_t^{1/2} Z_t^{1/2} + g_{zz} Z_t \right] \\ & + \frac{1}{2} \left[\frac{K_t}{Y_t} \right]^{1/2} \left[\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} \left[g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2} \right] \right] \end{aligned} \quad (A3)$$

Nerlove (1963) and Christensen and Greene (1976) define scale economies as unity minus the cost-output elasticity, which in this short-run context is as follows:

$$SCE_t^{SR} = 1 - \frac{\partial \ln G_t}{\partial \ln Y_t} \Big|_{\bar{K}} = 1 - \frac{\partial \partial G_t / \partial Y_t}{\partial G_t / Y_t} \Big|_{\bar{K}} = 1 - \frac{SRMC_t}{SRAC_t}. \quad (A4)$$

Positive values for SCE_t^{SR} indicate short-run positive scale economies and negative numbers indicate short-run scale diseconomies. Long-run scale economy measures include the output-induced changes in capital stocks. Long-run marginal cost is as follows:

$$\frac{\partial C_t}{\partial Y_t} = \frac{\partial G_t^*}{\partial Y_t} + \left[\frac{\partial G_t^*}{\partial K_t} + u_{kt} \right] \frac{\partial K_t^*}{\partial Y_t}, \quad (A5)$$

where the asterisks indicate evaluation at optimal capital stocks, K_t^* . Lau (1978) and Morrison (1985a) show that in a long-run equilibrium, the shadow value of capital $SV_{kt} = -(\partial G_t^* / \partial K_t^*)$ must equal the user cost of capital u_{kt} , which implies that the bracketed term in (A5) disappears and long-run marginal costs simply equal short-run marginal costs evaluated at optimal capital stocks. A long-run scale economy measure is simply one minus the ratio of long-run marginal cost to long-run average cost.

Estimates of optimal capital levels follow from solving the capital equilibrium condition:

$$-\frac{\partial G_t}{\partial K_t} = -\frac{1}{2} \left(\frac{Y_t}{K_t} \right)^{1/2} \left[\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} (g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}) + g_{kk} \sum_{i=1}^2 P_{it} \right] = u_{kt}, \quad (A6)$$

for capital, which provides the following closed-form solution for optimal capital:

$$K_t^* = \frac{1}{4} Y_t \frac{\left[\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} (g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}) + g_{kk} \sum_{i=1}^2 P_{it} \right]}{u_{kt} + g_{kk} \sum_{i=1}^2 P_{it}}. \quad (A7)$$

The convexity conditions state that short-run variable costs decline with higher capital stocks at an increasing rate:

$$\frac{\partial G_t}{\partial K_t} = \frac{1}{2} \left(\frac{Y_t}{K_t} \right)^{1/2} \left[\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} (g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}) + g_{kk} \sum_{i=1}^2 P_{it} \right] < 0$$

$$\frac{\partial^2 G_t}{\partial K_t^2} = -\frac{1}{4} \left(\frac{Y_t}{K_t} \right)^{3/2} \left[\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} (g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}) + g_{kk} \sum_{i=1}^2 P_{it} \right] > 0. \quad (A8)$$

Morrison (1985b) also uses the shadow value on capital to define short-run average shadow cost and the following measure of capacity utilization:

$$CAPUTIL_t = \frac{SRASC_t}{SRAC_t} = \frac{SRAVC_t - \frac{\partial G_t}{\partial K_t} \frac{K_t}{Y_t}}{SRAC_t}, \quad (A9)$$

where $SRASC_t$ is the short-run average shadow cost. If the shadow value $(\partial G_t^* / \partial K_t^*)$ is negative and large, indicating that the firm should invest, the capacity utilization index will be greater than one. Another measure is Tobin's Q , which is the ratio of the shadow value on capital to the user cost of capital:

$$Q_t = \frac{Z_{kt}}{u_{kt}}. \quad (A10)$$

If this ratio is less than one, the market value of a firm's capital stock is less than its replacement cost, which implies that equilibrium capital is lower than observed capital stock levels. Values of Q greater than one suggest that the firm is undervalued and should build capital stocks.

The cost function also shifts due to technological change. The short-run elasticity of cost with respect to technological change is:

$$\frac{\partial \ln G_t}{\partial Z_t} = \frac{1}{G_t} \left[\frac{Y_t}{Z_t} \right]^{1/2} \left[\frac{1}{2} \sum_{i=1}^2 d_{iz} P_{it} + g_{yz} \sum_{i=1}^2 P_{it} Y_t + \frac{1}{2} g_{zk} \sum_{i=1}^2 P_{it} K_t^{1/2} \right] + g_{zz} \left[\frac{Y_t}{G_t} \right] \sum_{i=1}^2 P_{it}. \quad (A11)$$

The long-run cost elasticity with respect to technological change is:

$$\frac{\partial \ln C_t}{\partial Z_t} = \frac{\partial G_t^*}{\partial Z_t} + \frac{\partial G_t^*}{\partial K_t^*} + u_{kt} \frac{\partial K_t^*}{\partial Z_t} / C_t, \quad (A12)$$

where

$$\frac{\eta_{K_t^*}}{\eta_{Z_t}} = \frac{g_{zk} K_t^* \sum P_{it}}{\sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} (g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2})} \eta_{Z_t^{1/2}}. \quad (A13)$$

Long-run input demand elasticities with respect to input prices, technological change, and output also involve derivatives of optimal capital. The short-run input demand elasticities follow from partially differentiating the input demand equations (A1) with respect to input prices:

$$\begin{aligned} \frac{\eta_{\ln Q_{it}}}{\eta_{\ln P_{jt}} \Big|_{\bar{K}_t}} &= a_{12} \left[\frac{P_{jt}}{P_{it}} \right]^{1/2} \left[\frac{Y_t}{Q_{it}} \right], \quad i \neq j, \\ \frac{\eta_{\ln Q_{it}}}{\eta_{\ln P_{it}} \Big|_{\bar{K}_t}} &= -a_{12} \left[\frac{P_{jt}}{P_{it}} \right]^{1/2} \left[\frac{Y_t}{Q_{it}} \right], \quad \forall i. \end{aligned} \quad (A14)$$

The concavity conditions are satisfied if \mathbf{a} is nonnegative so that the variable input demand equations are downward sloping. The short-run input demand elasticities with respect to output are:

$$\begin{aligned} \frac{\eta_{\ln Q_{it}}}{\eta_{\ln Y_t} \Big|_{\bar{K}_t}} &= \frac{Y_t}{Q_{it}} \left[a_{ii} + \sum_{f=1}^{82} a_{if} D_{ft} + a_{12} \left[\frac{P_{jt}}{P_{it}} \right]^{1/2} + \frac{3}{2} d_{iy} Y_t^{1/2} + d_{iz} Z_t^{1/2} + 2g_{yy} Y_t \right. \\ &\quad \left. + 3g_{yz} Y_t^{1/2} Z_t^{1/2} + g_{zz} Z_t + \frac{1}{2} \left[\frac{K_t}{Y_t} \right]^{1/2} (d_{ik} + 2g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}) \right] \eta_{Z_t^{1/2}} \end{aligned} \quad (A15)$$

The short-run technological change elasticities are:

$$\frac{\eta_{\ln Q_{it}}}{\eta_{Z_t} \Big|_{\bar{K}_t}} = \frac{Y_t}{Q_{it}} \left[\frac{d_{iz}}{2Z_t^{1/2}} + g_{zz} + g_{yz} \left[\frac{Y_t}{Z_t} \right]^{1/2} + \frac{1}{2} g_{zk} \left[\frac{K_t}{Z_t Y_t} \right]^{1/2} \right] \eta_{Z_t^{1/2}}, \quad \forall i. \quad (A16)$$

To simplify the expressions for the long-run input demand elasticities, we denote the numerator and denominator of the optimal capital formula (A7) as follows:

$$N_t = \sum_{i=1}^2 d_{ik} P_{it} + \sum_{i=1}^2 P_{it} (g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}), \text{ and} \quad (\text{A17})$$

$$D_t = r_t P_{kt} + g_{kk} \sum_{i=1}^2 P_{it}.$$

The long-run price elasticities of input demand are:

$$\frac{\eta \ln Q_{it}}{\eta \ln P_{jt}} = \frac{\eta \ln Q_{it}}{\eta \ln P_{jt}} \bigg|_{\bar{K}_t} + \left(\frac{\eta \ln Q_{it}}{\eta \ln K_t^*} \right) \left(\frac{\eta \ln K_t^*}{\eta \ln P_{jt}} \right) \quad \forall i, j, \quad (\text{A18})$$

where

$$\frac{\eta \ln Q_{it}}{\eta \ln K_t^*} = \frac{1}{4} \left[\frac{Y_t N_t}{Q_{it} D_t} \right] \left[d_{ik} + g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2} + g_{kk} \frac{N_t}{D_t} + g_{kk} \frac{K_t}{Q_{it}} \right], \quad (\text{A19})$$

$$\frac{\eta \ln Q_{it}}{\eta \ln K_t^*} = \frac{1}{4} \left[\frac{Y_t N_t}{Q_{it} D_t} \right] \left[d_{ik} + g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2} + g_{kk} \frac{N_t}{D_t} + g_{kk} \frac{K_t}{Q_{it}} \right],$$

and

$$\frac{\eta \ln K_t^*}{\eta \ln P_{it}} = 2 P_{it} \left[\frac{d_{ik} + g_{yk} Y_t^{1/2} + g_{zk} Z_t^{1/2}}{N_t} - \frac{g_{kk}}{D_t} \right] \quad (\text{A20})$$

The own price elasticity of capital is:

$$\frac{\eta \ln K_t^*}{\eta \ln r_t P_{kt}} = \frac{-2 r_t P_{kt}}{D_t}. \quad (\text{A21})$$

Finally, the output elasticity for capital are as follows:

$$\frac{\eta \ln K_t^*}{\eta \ln Y_t} = 1 + \frac{0.5g_{yk} \sum_{i=1}^2 P_{it} Y_t}{N_t K_t^*}. \quad (\text{A22})$$

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APPENDIX C—ECONOMETRIC PROCEDURES

We first estimated the short-run restricted cost function (A1) and the two input demand equations (A2) as a system with the minimum distance estimator developed by Berndt, et. al. (1974) using White's (1980) heteroscedastic-consistent estimator for the standard errors. These estimates, which appear in Table C1, are equivalent to maximum likelihood (ML) if the errors are distributed normally. The fit of the model (see Table 2) is quite good but the Durbin-Watson statistics, which are essentially an average over all panels, suggest the possibility of autocorrelation.

The most common approach to correct for autocorrelation is to assume a specific order to the autoregressive error process and use feasible generalized least squares. In the context of panel data, this approach involves an additional judgement on whether each panel has a different autoregressive parameter, r . We first assumed that all firms had the same r and then adopted Berndt and Savin's (1974) specification of an interrelated autoregressive process for our three equation model, estimating nine autoregressive parameters. Unlike, the translog form, the GL does not involve a singular variance-covariance matrix so the autoregressive parameter matrix need not be constrained to ensure adding-up. We also extended their specification to include all observations by dividing the first observation for each panel's residual by $1/\sqrt{1-r_i^2}$, where r_i is the autoregressive parameter from the i th equation. This last transformation is equivalent to the maximum likelihood procedure developed by Beach and MacKinnon (1978).

The estimates from this specification, however, yield negative marginal cost for some observations and implausibly large estimates of scale economies at high output levels. Consequently, we examined our assumption of a common r for each panel by estimating a simple first order process for each firm and each equation, assuming a

Table C1.—Parameter estimates and summary fit statistics

Parameter	Maximum Likelihood			Feasible GLS			GMM		
	Estimate	St. error*	p-value	Estimate	St. error*	p-value	Estimate	St. error*	p-value
a_{12}	0.425	0.067	[.000]	0.350	0.063	[.000]	0.412	0.032	[.000]
d_{1y}	-0.215	0.143	[.132]	-0.196	0.073	[.008]	-0.297	0.062	[.000]
d_{2y}	-0.163	0.142	[.252]	-0.142	0.065	[.029]	-0.255	0.063	[.000]
d_{1z}	0.438	0.101	[.000]	0.350	0.075	[.000]	0.360	0.041	[.000]
d_{2z}	0.456	0.098	[.000]	0.362	0.077	[.000]	0.379	0.041	[.000]
g_{yy}	0.022	0.009	[.010]	0.018	0.006	[.003]	0.029	0.004	[.000]
g_{yz}	-0.005	0.002	[.008]	-0.005	0.002	[.037]	-0.006	0.001	[.000]
g_{zz}	-0.040	0.016	[.011]	-0.040	0.013	[.002]	-0.041	0.007	[.000]
d_{1k}	-0.301	0.276	[.276]	-0.492	0.151	[.001]	-0.327	0.101	[.001]
d_{2k}	0.174	0.260	[.504]	-0.075	0.111	[.498]	0.064	0.098	[.515]
g_{yk}	-0.075	0.027	[.006]	-0.027	0.014	[.066]	-0.063	0.012	[.000]
g_{zk}	-0.111	0.020	[.000]	-0.079	0.018	[.000]	-0.073	0.008	[.000]
g_{kk}	0.079	0.030	[.007]	0.098	0.020	[.000]	0.067	0.011	[.000]
<u>Equation</u>	<u>R²</u>	<u>DW</u>		<u>R²</u>	<u>DW</u>		<u>R²</u>	<u>DW</u>	
Cost	0.866	1.158		0.956	1.834		0.867	1.158	
Fuel	0.840	1.328		0.945	1.903		0.841	1.310	
L & M	0.872	0.809		0.904	0.498		0.868	0.822	
Log likelihood value			2623.16			2821.36			
Test of overidentifying restrictions							200.466		[0.193]

* Standard errors are White heteroscedastic-consistent
 We do not present the estimates of the firm effects to save space. They appear in an appendix, which is available upon request.

diagonal autocorrelation matrix. We found that r differs considerably by firm. After ensuring that $0 < |\hat{r}_i| < 1$, we then performed feasible generalized least squares (FGLS). The estimates from this procedure are presented in Table C1. Unlike the model assuming an identical r for all panels, this specification yields plausible results. In fact, the parameter estimates and elasticities are very similar to the maximum

likelihood estimates (see Table C1). Moreover, the log likelihood value is 2821.36, which is higher than the 2749.90 value obtained by assuming the same r for all firms.³

Newey and West (1987) develop a potentially more flexible approach to correcting for serial correlation, which does not require assumptions on the form of the autocorrelation. Their method is similar to White's correction for heteroscedasticity. They estimate a variance–covariance matrix using weighted inner products of the residuals and instrumental variables. We implement this approach with the generalized method of moments (GMM) estimator using the right-hand side variables in each equation as instruments. This method requires specifying the number of autocorrelation terms used in computing the covariance matrix of the orthogonality conditions. This raises the issue of whether there are unit roots in the data.

Following the studies by Quah (1994) and Levin and Lin (1993), Im, Pesaran, and Shin (1998) develop unit root tests for panel data that accommodate individual effects and different patterns of residual serial correlation. These tests essentially involve estimating conventional unit root regressions for each panel, averaging the unit root statistics, and performing a test using the critical values computed by Im, Pesaran, and Shin (1998). The tests can be performed with or without a linear trend. In our model, we have three endogenous variables, average cost (A1) and the two input-output ratios (A2), and 17 predetermined variables involving combinations of input prices, output, and capital.⁴ Since we do not have any strong prior notion on whether the variables

³ A log likelihood test is not possible because the models are not nested by parametric restrictions.

⁴ We omit those variables involving the trend term for technological change, Z_t .

contain a trend, we compute the tests both ways. Of the 20 variables tested without trend, we found 6 unit roots and 7 with trend. The power of these tests, however, is quite low for large cross sections with a relatively small number of time periods. For our sample, the numerical analysis by Im, Pesaran, and Shin (1998) suggest that the power of these tests is in the 20 to 30 percent range. Nevertheless, the tests did reveal some useful information. The optimal lag structure in the augmented Dickey-Fuller regressions was two periods for all variables tested. This provides us with some basis for assuming two autocorrelation terms in the GMM estimation.⁵

The GMM estimates appear in Table C2 and like the FGLS estimates are very similar to the ML estimates. The elasticities are also very similar. The only notable difference between the three sets of results involves the estimates of long-run scale economies at high output levels. While all three estimates indicate diminishing long-run scale economies as output expands, the ML estimates imply very small but slightly positive scale economies at the highest observed output levels, while the FGLS and GMM estimates imply long-run diseconomies of scale at high output levels. The GMM estimates of long-run scale economies are between those from the ML and FGLS estimates. This result and the absence of any strong assumptions about the autocorrelation process suggest that the GMM estimates may be the most reliable of the three. The following discussion of the empirical results, therefore, uses the GMM estimates.

⁵ The procedure developed by Newey and West (1994) provides a basis for also letting the data determine the number of lags but application of this method to panel data requires further research.

The hypothesis of constant returns cannot be accepted because the chi-squared test statistic of 21.42 is higher than the critical value of 11.1 at the 5 percent level of significance. This result is consistent with the findings by Christensen and Greene (1976). We also cannot accept the neutral technological change hypothesis, which has a chi-squared test statistic of 14.25 and the same critical value. Consequently, we base our discussion on the nonconstant returns to scale and non-neutral technological change model.

The positive and significant a_{12} indicates that substitution prevails between energy and the labor and maintenance aggregate, satisfying the concavity conditions. The convexity conditions hold for 765 of the 820 observations, more than 93 percent of the sample. The model also meets another important test. Estimates of marginal cost are positive for all observations.

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APPENDIX D—CALCULATION OF OPTION VALUES

As mentioned above, the spark spread option values for each firm is equal to the sum of monthly call option values over a 15 year time horizon:

$$V = \int_{t=1}^{180} CALL_t, \quad (D1)$$

where $CALL_t$ is the value of the call option in year t. The call option in each year is equal to the discounted probability weighted spark spread in year t:

$$CALL_t = e^{-rt} [MC_t N(d_{1t}) - AC_t N(d_{2t})] Q_t. \quad (D2)$$

where MC_t is marginal cost AC_t represents the various measures of average cost, r is a risk free rate of discount, Q_t are the number of generation hours per month, and where d_{1t} and d_{2t} are variates from the cumulative normal distribution that are a function of the implied rate of return from the spark spreads and the accumulated time path of future volatility. The normal variates are as follows:

$$d_{1t} = \frac{\ln(MC_t/AC_t) + 0.5v^2}{v} \quad (D3)$$

$$d_{2t} = d_{1t} - v, \quad (D4)$$

where the volatility term, v^2 , is defined as follows:

$$v^2 = \int_{t=0}^{180} [s_{mc,t}^2 - 2rs_{mc,t}s_{ac,t} + s_{ac,t}^2] dt. \quad (D5)$$

where the s 's denote standard deviations and r is the correlation between marginal and average cost. Note that the volatilities vary over time by the following simply exponential functions:

$$s_{it} = s_i e^{-k_i t}, \quad i = mc, ac \quad (D6)$$

We estimate the mean reversion rates, k_i , using ordinary least squares. Pindyck (1999) shows that mean reversion rates can be recovered from the following regression equation:

$$\ln MC_{it} = b_i + \sum_{f=1}^{81} b_{if} + r_i \ln MC_{it-1} + p_i z_t + p_{ii} z_t^2, \quad (D7)$$

where $k_i = \frac{1}{r_i} - 1$. We estimate similar regressions for average total, variable, and fuel costs. The fit of each regression is excellent. The detailed regression output is available upon request. The estimates of the mean reversion rates, the standard deviations, and correlations between marginal and average costs are in Table D1.

Table D1: Parameters used in option value calculations

<u>Variable</u>	<u>Mean Reversion Rates</u>	<u>Standard Deviation</u>	<u>Correlations with Marginal Cost</u>
Marginal cost	0.042	0.781	
Average cost			
Total	0.308	1.065	0.419
Variable	0.038	0.704	0.633
Fuel	0.202	0.559	0.607

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