# WHOLESALE POWER SUBSTITUTION FOR FOSSIL AND NUCLEAR FUELS BY ELECTRIC UTILITIES: A CROSS-SECTIONAL ANALYSIS

by

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# ABSTRACT

Substitution and price elasticities of fuel demand by electric utilities indicate that baseload fuels substitute for peakload fuels in the aggregated utility fuel market as a result of utilities' ability to buy and sell on the wholesale power market. This behavior reduces operating costs, and smooths aggregate demand curves without modifying consumer behavior.

This research develops a model of fuel demand by wholesale power customers to study substitution in utility fuels markets. Cross-elasticities were estimated using an econometric demand model of six utility fuel inputs solved by iterative seemingly unrelated regression. The data set is fuel demand and prices, wholesale power demand and prices, and electricity production by 82 privately owned electric utilities during 1987. In addition to wholesale power, fuel inputs include coal, natural gas, residual fuel oil, nuclear fuel, and hydroelectric power.

Results further indicate that these commodities are generally own-price sensitive and cross-price insensitive, but nonetheless, there are significant substitution dynamics to consider. Coal and wholesale power demand is the least sensitive to price of the six electric utility energy sources, while hydroelectric power, gas, oil and nuclear fuel demand is several times more responsive to own-price variation.

The estimated cross-price elasticities indicate that wholesale power does not substitute significantly for primary fuels, but cross-price elasticities do provide evidence of substitutions between functionally incompatible fuels that could not be accomplished without wholesale power transactions. This feature is especially noticeable in the substitution between oil and nuclear fuel, which appear to be mutually elastic substitutes despite the lack of technical compatibility between prime movers. In addition to the association between nuclear fuel and fuel oil, other inter-technology fuel displacement occurs between gas and nuclear fuel, oil and hydroelectric power, and to a lesser degree, between coal and nuclear power. In summary, this interfuel substitution amounts to fuels that normally supply baseload generation displacing peakload capacity.

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# Chapter 1

# INTRODUCTION

Wholesale power trade between electric utilities is an important market mechanism permitting more efficient electric generation and higher system reliability. A question which concerns the utility industry's traditional energy suppliers is: if wholesale trade increases, how will market shares of energy commodities be affected? As yet, there is no consensus about current interfuel substitution despite anecdotal evidence. In 1987, the Federal Energy Regulatory Commission (FERC) proposed expanded and less-regulated wholesale trade to provide incentive for private utilities to increase wholesale supply (FERC, 1987), an idea supported by recent research indicating that profit-based incentives will bring more wholesale power to market (Acton and Besen, 1987). Decreased market protection and mandated transmission access, it is argued, will establish a more competitive environment among electric utilities. A secondary effect of increased competition among utilities would be to realign the relative market shares now occupied by energy suppliers.

Fuel and energy expenses are the largest portion of utility operating costs and, including energy purchased in the form of wholesale power, form 60% of utility operating expense (EIA/DOE, 1989a). Fuel expenditure by utilities provide the largest revenue source to the coal and nuclear fuel industries. The prospect of increased wholesaling practice raises two questions for fuel suppliers: 1) What is interfuel substitution by electric utilities? and 2) What is the impact of wholesale power transactions on electric utility demand?

## 1.1 Problem Statement

This research proposes to measure wholesale power substitution for energy fuels by estimating substitution elasticities between fuels in the presence of wholesale power as an alternative energy source. Despite anecdotal evidence, past research regarding energy substitution has not established the direction nor magnitude of interfuel elasticity with wholesale power included as an energy source, nor measured the effect on energy markets. From the perspective of fuel suppliers, increased long-distance power transmission and proposals to deregulate historically protected utility franchises may further disrupt already depressed energy markets. The research here provides important information in this regard, particularly in the relative magnitude of fuel substitution.

## 1.2 Approach

This research develops a model of conditional input demand by potential wholesale buyers to study substitution in the utility fuels markets. Interfuel relationships will be estimated by cross-elasticities, measured using an econometric demand model of six utility fuel inputs solved by iterative seemingly unrelated regression. The data set is fuel demand and prices, wholesale power demand and prices, and electricity production by 82 privately owned electric utilities during 1987. In addition to wholesale power, energy inputs include coal, natural gas, residual fuel oil, nuclear fuel, and hydroelectric power.

## 1.3 Summary

Results indicate that baseload fuels substitute for peakload fuels in the aggregated utility fuel market. This feature of utility demand permits important economies for utilities by effectively flattening demand curves. Although wholesale power does not displace fuel consumption, wholesale power transactions permit more interfuel substitution than would otherwise be possible.

Judging from own-price elasticities, coal and wholesale power demand is least price-sensitive of the six electric utility energy sources (own-price elasticities of -0.5 and

-0.3 respectively), while hydroelectric power, gas, oil, and nuclear fuel demand is several times more responsive to price variation (own-price elasticities fall between -1.3 and -2.5). Inelastic wholesale power demand might indicate a large number of requirements-type sales in the data set. Natural gas and oil elasticities agree with previous estimates showing utility demand for these fuels to be more sensitive to price changes than manufacturing sector energy demand.

Previous research has demonstrated interfuel substitution, mostly attributed to dual-fuel boiler technology, boilers which can switch immediately from one fuel to another. This study's cross-price elasticities indicate that market-wide substitution occurs between fuel pairs such as nuclear fuel and residual fuel oil, which cannot take place in generating units that use different technologies. In addition to the association between nuclear fuel and fuel oil, other intertechnology fuel displacement occurs between gas and nuclear fuel, oil and hydroelectric power, and to a lesser extent, between coal and nuclear fuel. Wholesale power substitution coincides with all three major intertechnology substitutions, substitution which could not occur without wholesale power transactions.

Future research in fuel substitution may either increase the level of detail or expand the technique's scope and purpose. If time series were pooled with the existing cross-sectional format, regional demand effects could be interpreted. A refined version of this analysis could be included in a comprehensive, multiple-sector analysis of energy demand, or compared to utility markets simulated by dynamic-programming techniques to examine policy questions. The success of this study also suggests that the translog function could also be applied to nonenergy markets and commodity substitution.

# Chapter 2

# ELECTRIC UTILITY INDUSTRY: MARKETS AND TECHNOLOGY

## 2.1 Introduction

This chapter describes the electric utility industry demand markets, supply technology, cost structure, and wholesale markets. A description of supply and demand markets includes ownership and regulatory characteristics of electricity suppliers and the industry's technical structure. The discussion on market demand includes the electric power end-user market and the market for inter-utility bulk power sales.

## 2.2 Electric Utility Industry Market Structure

Electricity in the United States is supplied by four major ownership groups, investor-owned utilities (IOUs), Federal Power Marketing Associations (PMAs), electric cooperatives, and publicly owned local systems: municipal, county, and state power authorities. IOUs form about 8% of total utilities by number, but supply 80% of generated electricity and sales to ultimate customers (Table 2.1). Cooperative, local, and state-owned utilities form over 90% of utility organizations while providing a minor portion of supply, about 13%, of generated power.

Table 2.1 Electric Industry Structure

| Owner-Ship Group | Number of Utilities | % by Number | Energy Generated (Trillion kwh) | % of Total | % of Final Sales |
|---|---|---|---|---|---|
| IOUs | 276 | 8.5 | 2,022.3 | 79 | 77 |
| PMAs | 8 | 0.2 | 205.4 | 8 | 2 |
| Rural Co-ops | 961 | 29.7 | 258.3 | 10 | 7 |
| Public/State | 1,996 | 61.6 | 86.2 | 3 | 15 |
| Total | 3,241 | 100.0 | 2,572.2 | 100 | 100 |

Note: Percentage totals may not equal 100% due to independent rounding.

Sources: Graves, Edward, 1988, Utilities-Electric, in Industry Surveys, Standard and Poor's, October 20, 1988.

EIA/DOE, 1989, Federal Energy Regulatory Commission, Financial Statistics of Selected Electric Utilities 1987. Government Printing Office, Washington D.C.

### 2.2.1 Investor-Owned Utilities

Investor-owned utilities are privately held, publicly traded corporations. Approximately 90% of all IOUs are vertically integrated companies which own or operate generation, transmission, and distribution facilities (EIA/DOE, 1989a). Most IOUs are independent; however joint ownership and cooperation is common. Several utilities may be owned by a single, large holding company, and also, individual plants are run under joint operating agreements in which a generation plant is operated by a single utility, though generated power from these facilities is allocated to each participant. Holding companies and operating agreements allow companies to coordinate demand and generation to take advantage of excess capacity within a transmission grid.

IOUs operate as franchised monopolies under provisions which vary from state to state. State-granted franchise is justified in legal code by the stated desire to avoid duplication, improve efficiency, and minimize service area disputes. Although franchises overlap in rare instances, generally, state statutes prohibit remote utilities from servicing customers within a local utility's protected market. Franchise legislation is enacted in one of two forms: "territorial statutes," which define geographic service boundaries, and "certificates of public convenience and necessity." Both forms grant certification and assign a service area. Territorial statutes are used by 23 states, and 38 states grant certificates. In either case, competition from outside utilities is effectively prevented (Porter and Burton, 1989). In return for the privilege of protected franchises, utilities agree to serve all customers who desire service, and to adhere to state regulation enforced by state public utility commissions empowered with general operating supervision and rate regulation.

### 2.2.2 Publicly Owned Utilities

Government has been involved in electric utility ownership and operation since the late nineteenth century. Federally owned utilities are organized as PMAs, built and operated either by the Corps of Engineers or the Water and Power Resource Service. These PMAs are Bonneville, Southwestern, Southeastern, Alaskan, and Western Area. A sixth system is the Tennessee Valley Administration, the largest utility system in the country. Table 2.2 shows the relative size of the federal PMAs measured by annual sales and sales for resale (SFR), and indicates that for all but the Tennessee Valley Authority, the primary power source for federal PMAs is hydroelectric power.

The federal PMAs are a large source of hydroelectric power, and almost 80% of federal power is sold for resale to state, local, or small privately owned utilities. However, the Bonneville Power Marketing Administration, to cite an exception, sells directly to industrial customers, and the Tennessee Valley Administration sells directly to residential and commercial customers.

## 2.3 Regulation

The electric utility industry is regulated in terms of

Table 2.2 Federal Power Marketing Administrations Sales

| PMA | Total Sales (Gwh) | Sales for Resale (Gwh) | Fuel Expense (millions of $) |
|---|---|---|---|
| Alaska Power | 0.3 | 327.4 | NA |
| Bonneville | 68.9 | 46.4 | NA |
| Southeastern | 6.5 | 6.5 | NA |
| Southwestern | 5.8 | 5.8 | NA |
| Western Area | 40.9 | 34.2 | NA |
| Tennessee Valley Administration | 108.5 | 91.8 | 1,830 |
| Total | 231.1 | 185.1 | 1,830 |

Note: Gwh = gigawatt hour

Source: EIA/DOE, 1989, Financial Statistics of Selected Electric Utilities 1987, U.S. Government Printing Office, Washington, D.C.

market entry, consumer-price determination, and capacity investment decisions, as are other utilities: water, gas, railroads, and communications. Most regulated utilities are transmission industries, essentially engaged in commodity transportation businesses. Similarly, however, the power generation activity of utilities is regulated by government control over investment recovery. Government at all political levels has intervened in the electric utility market with regulated entry and cost devices, acting out of the belief that natural monopolies will inevitably develop and restrict service to charge higher prices. Several aspects of electric utility regulation impacts costs which may be passed along to customers--fuels consumed, and the prices paid or charged to other utilities for wholesale power. These regulatory policies can impact short- and long-term energy supply decisions.

Two views of regulated environments have evolved: first, that regulation is justified on empirical economies of scale exhibited by the transmission technologies and, second, that regulation serves mainly to protect the regulated industry. Superficially, both suggestions are compelling. In the case of electric utilities, transmission and generation units are both considered to have increasing economies of scale which excludes numerous small competitors forced to yield markets to a single large supplier. The regulator's objective in market intervention is to simulate competitive market supply and pricing by ensuring cost recovery and competitive financial return and by regulating prices down to marginal producer cost.

Other authors argue that utilities benefit from regulation because they are essentially granted exclusive franchises, cost-plus pricing, and guaranteed rates of return (Moorehouse, 1986). From this perspective, regulation serves mainly to protect producers from selfdestructive competition and a significant degree of business risk by avoiding circumstances where all suppliers incur redundant capital costs which could not be recovered by competitive (i.e., marginal cost) prices.

Historical capital costs allowed in the base rate are subject to regulatory approval, but, typically, the state allows the undepreciated portion of capital costs to be recovered in the rate charged to retail customers (EIA/DOE, 1989b). Until the mid-1980s, electric utility management had grown accustomed to perfunctory rate and capacity request approvals, but recently, public utility commissions have denied rate requests on the basis of the prudence principal, using the rationale that a prudent utility operator will avoid unnecessary capacity investment (Pitrolo, 1986). Retail prices are determined by estimating future capital costs and variable costs (labor and fuel) over a specified time.

In the past, the FERC and Congress, via the Public Utilities Regulatory Policies Act (PURPA), required large utilities to purchase cogenerated power from nonutilities at the hypothetical cost a utility would pay if the necessary capacity had to be purchased or recruited. The PURPA was amended in 1987 to allow utilities to accept bids from the most efficient cogeneration suppliers. Before the 1987 amendment, only qualifying suppliers could apply for cogeneration contracts with utilities, defined as sellers who owned no more than 80 megawatts production capacity. As amended, nonqualifying suppliers--inferring remote utilities with excess capacity--may bid to supply electricity to the local utility, a mechanism which should increase competition. Another legislative act which impacts utility regulation is the Powerplant and Industrial Fuel Use Act (PIFUA). This act effectively prohibited new gas-turbine capacity from 1977 to 1987, when the gas restrictions were repealed.

Industry observers interpret these recent amendments to PURPA and PIFUA as a signal of a relaxed regulatory environment, and by all accounts an even less regulated era is imminent, although total deregulation is unlikely. There is uncertainty on all sides of the regulation issue about what the proper degree of regulation should be when a post-restriction regulation philosophy is developed by the FERC. One set of proposals centers on making the existing transmission grid available to increased wholesale power transactions (Graves, 1988). Energy producers will be impacted to some degree if wholesale power becomes available to more buyers, though there is no consensus on these effects.

## 2.4 Electricity Markets and Demand Characteristics

A description of electricity markets and their demand characteristics is necessary for an understanding of the technological capabilities required by utilities to supply electricity to a broad set of customers most efficiently. This chapter briefly outlines demand markets and their demand patterns and characteristics (and limitations) of the technology intended to meet this demand.

### 2.4.1 Consumer Demand Patterns

During 1987, total electrical power demand in the United States was approximately 2.5 billion kilowatt hours (kwh), the equivalent of 7.9 quadrillion British thermal units (Btu). (One quadrillion Btu is referred to as one quad.) This electricity generation is about 11% of total U.S. energy demand by ultimate users (EIA/DOE, 1988a). Electricity demand markets are broken down by major submarkets: residential, commercial, and industrial customers. Residential customers are households and institutions that use electricity for heat, lighting, and home appliance operation. Commercial customers are primarily consumers in the service sector who use electric power to light, heat, and air condition office buildings, hospitals, warehouses, and garages. The industrial sector is less homogeneous; it includes nondurable good producers (food, textiles, publishing, petroleum products, paper, and chemicals) and durable goods (machine tooling, electronics, transportation, and metals extraction).

Among the three sectors, relative market size has realigned itself. Historically, industrial customers were the largest electric utility end market, but in 1986, residential demand exceeded industrial consumption for the first time. Commercial markets have grown rapidly as well: both sectors grew between 6% and 10% annually from the early 1970s to the early 1980s, although recently growth has slowed. In 1978, industrial demand was 40% of total demand, commercial demand was 23%, and residential demand was 33%. By 1987, the industrial sector was down to 34.5% of total demand, commercial customers consumed 27%, and at 35.6% of total demand, residential consumption was the largest electricity market (EIA/DOE, 1988a).

### 2.4.2 Consumption Characteristics

A unique characteristic of electricity consumption is that customers expect their incremental demand will be instantly satisfied. Instantaneous demand has several implications for utilities, whose residential and commercial customers are accustomed to flexible service and unlimited consumption. Electric power expenditure is about 2% of residential and commercial income, and since electric power expenditure is not perceived as a major cost, additional demand for power is made without regard to additional expense (Bureau of the Census, 1989).

Amplifying the effect of instantaneous demand is the timing of peak demand, which influences important utility decisions concerning the type of capacity to acquire. Residential and commercial customers use power for similar applications, and power demand from both groups is related to workday activities. During the summer, commercial and residential air conditioning creates a single large demand peak from about 8:00 AM to 10:00 PM of from 50% to 60% above base demand. During winter, utilities in cold climates observe two peak periods, late morning and after sundown. Figure 2.1 shows a generic daily load demand profile. Patrick (1986) details load characteristics and different generation costs in various portions of this demand curve.

A consequence of erratic demand patterns is the need for utilities to acquire specialized capacity during peak demand. To meet demand fluctuations most economically, utilities invest in a mixture of high-cost, reserve-generating capacity on hand that is under used for much of its economic life (Elgerd, 1982), and because the historical

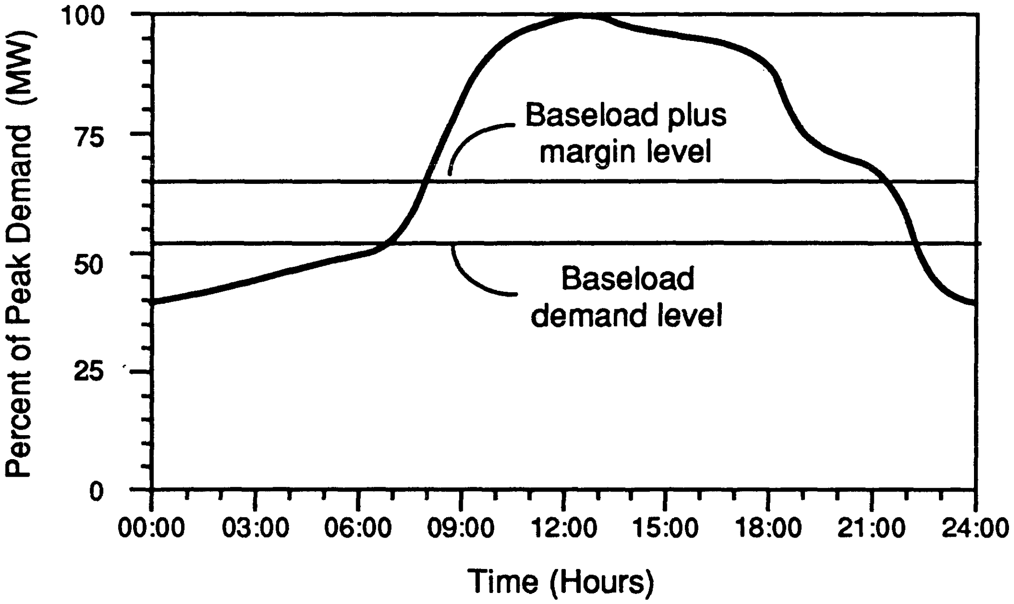

Figure 2.1 Typical Diurnal Demand Patterns

cost of this capacity is included in the capital base used for calculating customer rates, electricity prices to customers are necessarily higher by this amount.

Besides the capacity necessary to meet retail demand, utilities maintain excess capacity, referred to as margin reserve, to buffer sudden demand surges or to respond to generation or transmission failures without service disruption. Margins typically range between 15% and 25% of baseload capacity, but individual utilities may own a much higher fraction of excess capacity (Bureau of Census, 1989) unnecessary for meeting their local demand alone.

Industrial customers, whose electric expenditure is large enough to be economically managed and have more predictable usage patterns, demand large volumes at constant rates. Recent history has shown that as industrial customers leave the system, a growing majority of a utility's base comes from peak-demand customers: businesses and households. The implication for the industry is that demand peaks increase as consumption by commercial and residential sectors rise, but baseload requirements decrease as industrial demand decreases. This results in a steeper demand curve with correspondingly less efficient capacity utilization and higher generation costs. The electric utility industry is investigating pricing mechanisms intended to flatten demand curves and increase system efficiency by modifying consumer demand behavior, including time-of-use pricing and demand charges (Moore, 1986).

## 2.5 Electric Power Production Technology

Consumption characteristics influence the technologies chosen to supply demand, a selection based on the operating costs of different primary power sources as supplying utilities attempt to meet demand at minimum cost. This section will describe how certain generating units are better suited for different demand characteristics and how this preference is related to operating costs.

### 2.5.1 Electric Utility Capacity

A simple electric generation and distribution system is a prime mover (a heat or energy source) unit driving an electric generator, connected to a transmission line and an electric load. Power generation units are combined into plants where multiple units are connected in parallel to allow for planned maintenance or to serve as backup for unexpected outages.

Generating units have an maximum limit on production rate measured in megawatts, referred to as the unit's capacity. Energy capacity is the energy delivered over a given time. If a 1,000 watt generator ran for 24 hours continuously, it would produce 24,000 watt-hours or 24 kwh of energy. Typically, however, only baseload generators, such as coal, nuclear, and hydroelectric plants run for over 24 hours at a time. All plants have scheduled down-time, and generators often operate at partial output. The percentage of total electric capacity (the energy a generating unit would produce if operated at 100% capacity for 24 hours a day) a generator actually produces in one year is called the load factor. Steep, highly fluctuating demand curves contribute to low load factors.

In a simplified view, there are four functional types of generating capacity (after Elgerd, 1982):

1. Baseload units. Baseload is the demand level below which demand never falls. Coal and nuclear units are most efficiently used for stable demand patterns in order for them to maintain their thermal balance, so in practice, these prime movers supply the bulk of baseload power.
2. Intermediate units. Intermediate units must have controllable output. Hydroelectric plants are the most convenient to use when output must be regulated because they are easily adjusted by controlling water flow. Thermal units, coal and oil, are used when hydroelectric power is not

available; however, thermal unit response time is limited by a given plant's load rate, the megawatts per minute which output may increase safely.

3. Peaking units. Gas-turbine generators have high load rates, short response times, can pick up load quickly and therefore are often used for peaking purposes when system demand rises suddenly.
4. Reserve units. A system's resiliency to unexpected outages depends upon available reserves, or margin capacity. Margin capacity can consist of generators maintained at partial output or as generators standing by at various levels of readiness.

In practice, the cheapest generation resource is recruited first, and when that resource is exhausted, the next cheapest resource is fired and enters the system, and so on. Once demand has peaked and begins to decline, operators remove generators from the system in reverse order. The effect is to keep the most expensive generators operating for the minimum amount of time. Hydroelectric power is used both as a baseload and peakload source, coal and nuclear plants are used to maintain baseload and margin, and oil, gas, and internal combustion generators supply peak-demand. Table 2.3 displays estimated summer

Table 2.3 Net Summer Capacity by Prime Mover 1986

| Prime Mover | Installed Capacity (megawatts) | (%) | Generation (terawatt hours) | (%) |
|---|---|---|---|---|
| Coal | 292.6 | 43 | 1,464 | 57 |
| Gas | 118.2 | 18 | 273 | 11 |
| Oil | 76.1 | 11 | 118 | 4 |
| Nuclear | 93.6 | 14 | 455 | 18 |
| Hydroelectric | 89.6 | 14 | 249 | 10 |
| Total | 674.1 | 100 | 2,572 | 100 |

Note: Based on average all for all power plants

Source: EIA/DOE, 1988, Electric Power Annual 1987, U.S. Government Printing Office, Washington, D.C.

generating capacity by prime mover for the United States in 1986. From the generation figures in the table, it is seen that baseload units, (coal, nuclear, and to a certain extent, hydroelectric) form about 70% of installed capacity and supply about 85% of generation.

### 2.5.2 Cost Structure

Economically, the electric utility industry can be broken down into the three major activities: generation, transmission, and distribution. Generation is the conversion of mechanical energy into electric energy, transmission is long distance power delivery over high voltage power lines, and distribution includes services to commercial and residential customers: installation, administration, bill collection, and low-voltage substation maintenance.

The operating cost structure is dominated by fuel costs and purchased power, which together account for about 58% of operating expenses. Composite operating expenses for the 186 private utilities reported in the 1987 Financial Statistics of Selected Electric Utilities (FSSEU) is given as evidence, shown in Table 2.4. In the table, fuel costs include fossil and nuclear fuel costs and water purchased for hydroelectric power generation. Purchased power is predominantly wholesale power purchases, but may include transmission interchanges.

Fuel cost and purchased power are the expenses most directly associated with generation costs. Operations and maintenance costs in fact represent labor expenditure; engineering and supervision and technician labor, activities which vary little as electricity output increases. As shown, transmission and distribution expenses were relatively minor costs, distribution expense was about 6% of total expense, and transmission expense was about 2%.

Generation cost reported by the EIA/DOE in Historical Plant Operating Costs for Selected Utilities (EIA/DOE,

Table 2.4 Private Utility Expenses 1987

| Cost Element | (87 B$) | (%) |
|---|---|---|
| Fuel | 31.0 | 39.3 |
| Purchased Power | 14.7 | 18.6 |
| Administrative and General | 9.0 | 11.4 |
| Operations | 6.5 | 8.2 |
| Maintenance | 6.5 | 8.2 |
| Distribution | 5.0 | 6.3 |
| Transmission | 1.6 | 2.0 |
| Other | 4.6 | 5.8 |
| Total | 78.9 | 100.0 |

Source: EIA/DOE, 1989, Financial Statistics of Selected Electric Utilities 1987, U.S. Government Printing Office, Washington D.C.

1989b) is broken down into operation and maintenance cost, fuel cost, and capital charges. Operation and maintenance costs are recurring expenses to operate generation plants and maintain the generating and transmission facilities. This category includes operator's wages and benefits, plant maintenance, security, supervision, materials, spares, and consumables other than fuel. Combined generating costs for the five major prime movers are shown in Table 2.5.

Capital charge is the historical book value of the utility's physical plant, distributed across the electricity produced by the utility. Utilities recover capital charge

Table 2.5 Production Costs by Prime Mover
(1987 mills per kilowatt hour)

| Cost Element | Hydro | Coal | Oil | Nuclear | Gas |
|---|---|---|---|---|---|
| Operations | 1.30 | 1.53 | 1.36 | 8.21 | 5.03 |
| Maintenance | 1.05 | 2.55 | 2.43 | 5.07 | 9.46 |
| Fuel Costs | na | 16.86 | 25.78 | 7.69 | 32.71 |
| Total | 2.35 | 20.94 | 29.57 | 20.97 | 47.19 |

Source: EIA/DOE, 1989, Historical Plant Cost and Annual Production Expenses for Selected Electric Plants 1987, Government Printing Office, Washington D.C.

only during plant operation, consequently; capital charges are inversely proportional to load factor (i.e., low load factors imply high capital charge per kwh). Since capital charges are actually a regulatory mechanism for recovering fixed costs which are invariant with electric power output, capital charge has been omitted from the generation costs shown in Table 2.5.

As shown in Table 2.5, except for nuclear fuel generation, operating and maintenance costs are a minority fraction of generation cost. Oil and gas-turbine plants have higher maintenance costs per kwh, in part because load factor from these plants is comparatively low.

Along with all other consumers and producers, utilities endured volatile fuel costs between 1978 and 1987, shown in Table 2.6. Oil prices peaked in 1981, gas in 1982, and coal in 1984. However, by the beginning of 1987, oil and gas prices had declined 51% and 35% from their respective historical highs. Beginning in 1979, oil price controls were gradually removed (Ikenberry, 1988) and most natural gas was deregulated by 1987 (Mattke, 1988).

Transmission costs are a small portion of operating costs (about 2%), but transmission facility construction requires significant investment by utilities when connection to new markets or customers is desired. Most transmission lines are three-phase bare conductors on aerial transmission towers insulated by surrounding air; tower construction and conductor costs dominate transmission line investment. During 1987, the average cost per mile of installed transmission line, including underground lines, was approximately $240,000 (EIA/DOE, 1989a), but high-voltage lines can cost up to $750,000 per mile (Moore, 1986). Where population density is high, environmental concern stemming from high-voltage induced electromagnetic fields introduces legal and financial obstacles for utilities attempting to secure right of way. Public utility commissions, responding to public concern over environmental hazards and aesthetic considerations, permit fewer plants and transmission tower

Table 2.6 Fuel Cost Trends

| Year | Coal | Oil | Gas |
|---|---|---|---|
| 1986 | 1.63 | 2.47 | 2.41 |
| 1985 | 1.70 | 2.31 | 3.53 |
| 1984 | 1.72 | 4.95 | 3.69 |
| 1983 | 1.71 | 4.72 | 3.57 |
| 1982 | 1.70 | 4.97 | 3.48 |
| 1981 | 1.58 | 5.49 | 2.89 |
| 1980 | 1.39 | 4.40 | 2.27 |
| 1979 | 1.26 | 3.08 | 1.80 |
| 1978 | 1.15 | 2.19 | 1.46 |
| Percent Change | | | |
| From 1978 | +4.0 | +1.4 | +5.7 |
| From Peak | -5.0 | -51.1 | -35.0 |

Source: EIA/DOE, Annual Energy Review, 1987 and years previous, U.S. Government Printing Office, Washington D.C.

construction near population centers, and as a result, newer plants are located nearer to mine sites and tend to transmit power over longer distances than older plants.

## 2.6 Wholesale Power

This section describes the wholesale electric power market, market institutions and supply characteristics, and how information about fuel prices enters decisions to buy either fuel or wholesale power. Based on the information presented in this section, a model is developed for wholesale transactions, for later use in regression analysis.

### 2.6.1 Market Characteristics

In 1987, private electric utilities, a minor fraction of the 3,200 utilities operating in the United States, produced 40% of all electricity sales for resale (EIA/DOE, 1989a). Sales for resale include two major categories, requirements sales and coordination sales. Many smaller municipal and state-owned utilities are strictly distribution companies that own no generation capacity and rely upon nearby private utilities or federal PMAs to supply power. Sales to these companies are known as requirements sales. Larger municipalities and cooperatives sometimes own enough capacity to supply a portion of their retail demand, but satisfy the rest of their demand with wholesale power from either IOUs or federal PMAs. These customers are known as partial requirements customers. Typically, requirements and partial requirements sales are for noninterruptable power on a long-term basis.

Many requirements customers are located inside a larger utility's franchised operating area. Because they are connected to the larger utility's distribution system, small utilities are often isolated from other utilities in terms of transmission access, and therefore have a single potential partner from whom to purchase wholesale power. In such an instance, the FERC exercises price-setting controls to avoid negotiating imbalances. The price-setting process in requirements markets is similar to the rate-setting process for retail customers (Acton and Besen, 1985b).

Once retail requirements are met, system operating efficiency can be improved through coordination sales. Coordination is the practice of establishing common operating procedures, planning and sharing reserve capacity, collectively planning new capacity, coordinating operating procedures to improve efficiency and reliability, and minimizing costs subject to reliability, capacity, and demand constraints (FERC, 1981). Usually, coordination activity refers to a system of several independent utilities who have agreed upon operating principles and have interconnected transmission facilities. Coordination sales refer to wholesale power sales which displace high-cost generating capacity while allowing involved parties to meet retail demand (FERC 1981).

The FERC recognizes several categories of coordinated transactions, distinguished from one another by the relative assurance that power involved in the sale will not be interrupted: firm service, conditionally interruptable service, and unconditionally interruptable service. Firm service implies that the seller commits the capacity supplying the power in the sale as well as backup reserves. Conditionally interruptable service places conditions under which service may be interrupted and implies a degree of commitment upon capacity, but not reserves. The most important type of transaction to this research is economy interchange, a category of unconditionally interruptable service which implies no capacity commitment, making the buyer responsible for providing reliability reserves. (Moss, 1989).

Economy interchange prices and quantities purchased are not required by the FERC Form 1 report; however, sales for resale are reported. Private utilities sold 337 gigawatt hours (Gwh) for resale, and federal PMAs sold another 185

Gwh resulting in total sales for resale of 522 Gwh in 1987, making wholesale power sales equal to about 21% of electricity consumption (EIA/DOE, 1989a).

This figure does not give a direct measure of the magnitude of economy interchange; however, it may be estimated as a fraction of sales for resale sold by the 82 utilities researched for this study. Private utilities report their sales for resale on Page 310 of Form 1, separating sales to other nonassociated utilities (utilities with their own generating capacity) from sales to requirements customers (municipalities and associated utilities). Since economy interchange is a sale without claim on reserves to a utility which owns generating capacity, a portion of these sales to nonassociated utilities is economy interchange. An upper bound for economy interchange volume can be estimated by measuring the ratio of sales to nonassociated utilities to total sales for resale. As shown in Table 2.7, of the 140 Gwh sold for resale by the IOUs in the data set used for this research, 104 Gwh were sold to other utilities, or about 76% of all sales for resale in the data set.

If this ratio of nonassociated sales to requirements customers holds for the entire 337 Gwh sold for resale by the 276 utilities reported in FSSEU, 254 Gwh of electric

Table 2.7 Economy Interchange and Sales For Resale

| Category | Sales (Megawatt hours) |
|---|---|
| Thesis Data Set Sales For Resale | 140,603,534 |
| Thesis Data Set Interutility Sales | 106,181,971 |
| Fraction | 76% |
| FSSEU Sales For Resale (SFR) | 337,000,000 |
| Total Interutility Sales (0.76 X SFR) | 255,000,000 |
| Fraction of Sales to Ultimate Customers | 10.4% |

Source: EIA/DOE, Financial Statistics of Selected Electric Utilities 1987, 1989, U.S. Government Printing Office, Washington, D.C.

power was sold as either economy interchange or firm power, about 10% of all electricity consumed by ultimate consumers.

### 2.6.2 System Cost and Pricing Mechanisms

The decision to make an economy interchange purchase is based upon the difference between a buyer's projected decremental cost and all potential sellers' incremental costs. Decremental cost is the reduction in total variable cost divided by the reduction in output for a given generation decrease. Incremental cost is the increase in total variable cost divided by the increase in output for a given generation increase. If utility A can supply its retail demand with power purchased from B at a price below the cost of capacity A will temporarily withdraw from service, system efficiency increases. Whether the gains are realized by the two utilities' shareholders or retail customers is an issue which may be resolved by altering FERC regulating policy (Acton and Besen, 1985b).

Incremental costs increase as relative output (measured in percentage of name-plate capacity) increases. Since prime mover/turbine/generator assemblies are designed to work at 100% output, average cost is lowest at 100% output, but incremental cost is at a maximum. System cost is minimized at the point where the incremental cost for all units in the system are equal (FERC 1981). Baseload units, coal and nuclear, usually have the lowest incremental costs at all levels of relative output, so they are likely to be operated at nearly 100% capacity. At minimum system cost, oil-fired intermediate and gas-fired peaking units operate at output levels where their incremental cost is no higher than the incremental cost of any generator not already loaded. A cost-minimizing utility, after examining the loading of its current capacity and finding less expensive power on the wholesale spot market, will elect to substitute self-generation with wholesale power.

In this market, exchanges are usually made for one hour. Each hour, utilities communicate with one another and post projected incremental and decremental costs for the next hour. In a simple bilateral transaction for example, if cost differences justify a 100 Mw transaction between two utilities, the switch is scheduled for the next hour. Beginning at 5 minutes before the hour until 5 minutes after, the seller increases its generation by a constant rate and the buyer decreases its generation by the same amount. The seller's increased production continues for the remaining 50 minutes. Spot market sales are typical peak-demand transactions, but transactions up to weeks in duration may displace the purchaser's less efficient baseload capacity (FERC, 1981).

The fuel source providing the seller's power sold in this transaction is, in effect, substituting for the fuel which would otherwise power the buyer's displaced generation. Accepting temporarily the premise that baseload capacity for private utilities is likely to be nuclear- or coal- powered and intermediate and peaking units are typically oil- or gas-fired, in this example, the load on the nuclear or coal unit increases, increasing fuel consumption for the sale duration, while fuel consumption for the displaced unit is temporarily suspended. The effect of repeated sales on the buyer's energy account will reduce apparent year-end consumption of fuels supplying displaced capacity while increasing relative expenditure on wholesale power, and the effect on the seller will be to increase consumption in fuels supplying baseload capacity.

As mentioned earlier, municipalities, cooperatives, or other utilities whose primary service is distribution, may depend upon a single generating utility for all or a portion of their supply capacity. The FERC regulates wholesale prices paid to IOUs, and excepting recent experiments, generally allows one of two pricing formulas: a straight percentage "adder," either in terms of mills per kwh or a percentage that is added to the seller's incremental cost, or a "split savings" format where the selling utility receives 50% of the cost differential as profit and the buying utility saves 50% of its cost over the seller's. The FERC has also approved split-the-savings formulas where profit was greater than savings (Acton and Besen, 1985a).

The simple bilateral example described earlier may be complicated by the effect of loop flows on nearby utilities. Transmission flows do not generally flow direct from seller to buyer, but divide along multiple parallel paths, each having different carrying capacities in quantities proportional to the impedance of each individual path

(Moore, 1986). For example, Canadian power sales to the Northeast may flow through Midwestern systems, displacing Midwestern transmission capability. Inadvertent loop flow through noninvolved utilities creates operating and opportunity costs for those utilities. In 1988, the FERC ruled that nonparticipating utilities may be compensated for loop flow loss and that compensation may allow recovery of increased fuel costs, forgone trade opportunities, reduced wheeling capacity, and ability to respond to emergencies. Loop flow costs are over and above the selling price, and accrue to third-party utilities (Rosso, 1989).

### 2.6.3 Market Institutions

The time and effort to locate trading partners may inhibit some wholesale power sales if the cost difference between seller and buyer is small. The industry has developed public and private institutions to streamline the search for trading partners and reduce search costs. The level of organization depends in part on management control retained by utilities.

Transmission systems in North America are organized into four networks: the Hydro-Quebec System, and the Eastern, Texas, and Western Interconnection Systems. Networks are further broken down into control areas which control generation and transmission flows. Each control area has a dispatch center to monitor system generation output, frequency, and power flows in and out of the control area. The dispatch center may also monitor generation and purchases within the control area in an attempt to minimize system electric generation costs (FERC, 1981).

Power pooling is another mechanism to increase the level of transmission and generation coordination between utilities below the control area level. Formal pools are established by contractual agreement to establish management, planning, and operating criteria, sometimes enforced by penalties for noncompliance. Informal pools agree to establish common operating principles, review power supply problems and establish criteria for power supply adequacy, but compliance is voluntary. Pooling makes economy exchange easier and lowers search costs for parties interested in wholesale power trade (FERC, 1981).

Another method which achieves some coordination benefits and reduces search costs is energy brokering, as implemented by Florida utilities in the early 1980s. A computerized system pairs the lowest incremental cost seller (including transmission costs) with the highest decremental cost buyer, then the next lowest cost seller with the next highest cost buyer, and so on. Brokering systems differ from pooling arrangements in that brokered trades are bilateral agreements giving managers the option to decline a trade, while pooling arrangements are multi-lateral trades allowing managers less control. Loss of control has possibly been responsible for a decline in the number of utilities participating in pools and the fraction of U.S. generating capacity represented by utilities in pools (FERC, 1981).

### 2.6.4 An Analytical Model

The familiar criteria for efficient markets invariably demands a market populated by many well-informed buyers and sellers, none of whom retain enough market share to influence prices by their independent choice to curtail either purchases or production. Producers do not collude either explicitly or tacitly, and exit and entry from the market sets equilibrium price equal to the marginal supplier's production costs.

Superficially, the wholesale power market seems to diverge from this paradigm. Information flows are the least problematic, because there appear to be several mechanisms for communicating costs. FERC control over pricing may itself serve as evidence that competitive pricing will be inhibited by market power, but does not preclude the possibility that bilateral monopolies could develop which favor neither buyer or seller, permitting a competitive price equilibrium to be achieved without numerous firms or small market share (Acton and Besen, 1985b).

Considering the FERC treatment of price differentials and loop flow externalities, wholesale pricing would not seem to signal marginal costs of marginal suppliers. However, if in fact the pricing formulas now administered impose artificial ceilings (for instance, in the split-the-savings rule), the price treatment may have no effect on the supply of wholesale power. Acton and Besen (1985b) state that price ceilings above marginal cost will have no effect on supply.

Despite the unique aspects of wholesale power markets, there appears to be no conclusive evidence suggesting that wholesale power quantity demanded could not be treated as a quantity demanded by cost-minimizing behavior, nor that price should not be treated as a market-determined exogenous variable. In the next section, regional primary fuel markets are examined.

# Chapter 3

# U.S. DEMAND FOR ENERGY COMMODITIES AND ELECTRIC UTILITY DEMAND FOR ENERGY

## 3.1 U.S. Energy Overview

In 1987, the domestic sources supplied 64.5 quadrillion Btu, about 85% of the total U.S. consumption of 76.0 quadrillion Btu. The remainder was imported, mainly as petroleum. Relative energy supply has shifted since 1970 when the largest energy source was domestic oil and gas production; by 1987, coal had become the largest domestic energy source. On the demand side of energy markets, gas and coal demand was 23% and 24% of total consumption, respectively (EIA/DOE, 1988a).

## 3.2 Electric Utility Energy Demand

The electric utility industry produced 2,560,000 Gwh in 1987 from 27.4 quadrillion Btu of energy (about 36% of overall demand). These figures imply that, overall, utilities operated at about 32% efficiency, meaning less than one-third of the heat content in the fuel was translated into electric power, the rest was mechanical loss. Efficiency declined a small amount between 1970 and 1987.

Table 3.1 shows electric utility energy consumption of

Table 3.1 Utility Fuel Consumption, 1970 and 1987 (quadrillion Btu)

| | 1970 | % | 1987 | % | % Change |
|---|---|---|---|---|---|
| Coal | 7.2 | 44 | 15.2 | 56 | 52 |
| Gas | 4.1 | 25 | 2.9 | 11 | -37 |
| Oil | 2.1 | 13 | 1.3 | 5 | -68 |
| Nuclear | 0.2 | 2 | 4.9 | 18 | 95 |
| Other | 2.7 | 16 | 3.0 | 11 | 13 |
| Total | 16.3 | 100 | 27.4 | 100 | 40 |
| (% of U.S. Energy) | 24.5 | | 36.0 | | |

<u>Source</u>: EIA/DOE, 1988, <u>Annual Energy Review 1987</u>, U.S. Government Printing Office, Washington D.C.

coal, natural gas, oil, and nuclear fuel in the years 1970 and 1987. Table 3.2 shows energy production by fuel sources. During this period, nuclear fuel moved from the fourth-largest to the second-largest electric utility energy source, followed by gas and oil respectively. In general, power production by nuclear fuel and coal increased to the exclusion of oil and gas. Uranium oxide market share increased tenfold, coal share increased 25%, while oil and gas market share both fell dramatically.

From the perspective of coal suppliers, their demand markets became more concentrated in the utility industry,

Table 3.2 Utility Energy Production by Fuel Source, 1970 and 1987 (billion kwh)

| | 1970 | % | 1987 | % | % Change |
|---|---|---|---|---|---|
| Coal | 704 | 46 | 1,464 | 57 | 52 |
| Gas | 373 | 24 | 273 | 11 | -37 |
| Oil | 184 | 12 | 118 | 5 | -56 |
| Nuclear | 22 | 1 | 455 | 18 | 95 |
| Hydro and other | 248 | 16 | 250 | 10 | 1 |
| Total | 1,531 | 100 | 2,560 | 100 | 40 |

Source: EIA/DOE, 1988, Annual Energy Review 1987, U.S. Government Printing Office, Washington D.C.

while gas and oil exited the market. Electric utility demand for coal, oil, and gas as a fraction of total U.S. demand for each commodity by electric utilities in 1970 and 1987 is shown in Table 3.3. Over the period shown, coal consumption increased 124%, gas consumption decreased 28% (in part as a result of both increased price and regulatory restrictions). However, overall gas consumption was down, and decreased utility demand merely mirrored reduced overall gas demand, so gas concentration in electric utility markets fell only 9% relative to total U.S. consumption. Overall, U.S. oil consumption was up 17% over the period; utilities, however, cut demand by one-half.

In 1987, electric utilities spent $154 million on

Table 3.3 Electric Utility Share of Energy Products (millions of units)

| Year | Fuel | Utility Demand | Total Market | % of Market |
|---|---|---|---|---|
| 1970 | Coal (tons) | 320.2 | 523.2 | 61.2 |
| | Gas (Tcf) | 3.9 | 21.1 | 18.6 |
| | Oil (bbls) | 338.7 | 5,365.5 | 6.3 |
| | Nuclear (lbs U3O8) | NA | 21.6 | NA |
| 1987 | Coal (tons) | 718.0 | 917.0 | 78.3 |
| | Gas (Tcf) | 2.8 | 16.7 | 17.0 |
| | Oil (bbls) | 201.4 | 6,267.0 | 3.2 |
| | Nuclear (lbs U3O8) | NA | 25.3 | NA |
| % Change | Coal (%) | 124 | 75 | + 28 |
| | Gas (%) | - 28 | - 21 | -9 |
| | Oil (%) | - 41 | 17 | - 49 |
| | Nuclear (%) | NA | 17 | NA |

Source: EIA/DOE, 1988, Annual Energy Review 1987, U.S. Government Printing Office, Washington, D.C.

energy expenses. Of that amount, coal sales to the electric utility fuel market formed about two-thirds of the $37 billion electricity fuel market; gas sales were about one-fifth of the electric utility market, shown broken down by fuel type in Table 3.4. Combined petroleum product sales, including heavy and light oils and petroleum coke, were 10% of total utility energy expenditures.

Expenditure is linked to consumption through price, and in 1987, demand was not supporting high prices. Composite U.S. energy prices in 1970, 1986, and 1987 are shown in

Table 3.4 Electric Utility Energy Expenditures, 1970 and 1987 (in 1987 million dollars)

| Fuel | 1970 | % | 1987 | % |
|---|---|---|---|---|
| Coal | $6,252 | 52 | $22,785 | 62 |
| Gas | 3,217 | 27 | 6,561 | 18 |
| Oil Products | | | | |
| Heavy Oil | 2,228 | 18 | 3,439 | 9 |
| Light Oil | 224 | 2 | 362 | 1 |
| Petroleum Coke | 17 | 0 | 11 | 0 |
| Oil Subtotal | 2,465 | 20 | 3,812 | 10 |
| Nuclear Fuel | 123 | 1 | 3,486 | 10 |
| Other | 6 | 0 | 14 | 0 |
| Total | $12,063 | | $36,658 | |

Note: Heavy oil includes Grade Numbers 4, 5, 6, and residual fuel oils. Light oil includes Grade Number 2 heating oil, kerosene, and jet fuel.

Source: EIA/DOE, 1989, State Energy Price and Expenditure Report 1987, U.S. Government Printing Office, Washington, D.C.

Table 3.5 U.S. Composite Energy Prices, 1970, 1986, and 1987 (in 1987 dollars/million Btu)

| | 1970 | 1986 | 1987 | 70-87 % Chg | 86-87 % Chg |
|---|---|---|---|---|---|
| Electricity | 13.96 | 19.57 | 18.71 | 34.01 | -4.4 |
| Coal | 1.04 | 1.67 | 1.54 | 48.76 | -7.7 |
| Gas | 1.65 | 4.19 | 4.07 | 146.55 | -2.9 |
| Oil | 4.78 | 5.90 | 5.73 | 19.76 | -2.9 |
| Nuclear | 0.45 | 0.72 | 0.70 | 56.36 | -2.9 |
| U. S. Average | 4.62 | 7.56 | 7.38 | 59.86 | -2.4 |

Source: EIA/DOE, 1989, State Energy Price and Expenditure Report 1987, U.S. Government Printing Office, Washington, D.C.

Table 3.5. Between 1970 and 1987, electricity was by far the most expensive energy source, followed by composite petroleum products and gas, respectively. Nuclear fuel price is represented by prices paid for the enriched uranium heptoxide. Natural gas price rose the fastest over the period, partially a result of deregulation. All energy prices fell during 1987, reflecting soft energy markets.

There are substantial differences in energy prices paid by different sectors, shown in Table 3.6. Electric utilities paid less than 50% of the national average price for energy commodities, in part because utilities consume a higher percentage of relatively cheap coal than other sectors. Residential consumers paid the highest prices for energy followed by commercial and transportation customers. Over the long term, prices rose fastest among industrial and commercial customers, but in 1987, prices to all consumers other than transportation fell.

Table 3.6 Fuel Price to Economic Sectors, 1970, 1986, & 1987 (in 1987 dollars/million Btu)

| | 1979 | 1986 | 1987 | 70-87 % Chg | 86-87 % Chg |
|---|---|---|---|---|---|
| Electric Utils | 0.90 | 1.60 | 1.51 | 69 | -5.4 |
| Residential | 5.93 | 11.29 | 10.90 | 84 | -3.4 |
| Commercial | 5.51 | 11.68 | 11.17 | 103 | -4.3 |
| Industrial | 2.32 | 5.48 | 5.12 | 120 | -6.5 |
| Transportation | 6.49 | 6.44 | 6.60 | 2 | 2.5 |
| U. S. Average | 3.02 | 4.09 | 3.97 | 31 | -2.9 |

Source: EIA/DOE, 1989, State Energy Price and Expenditure Report 1987, U.S. Government Printing Office, Washington, D.C.

## 3.3 Regional Fuel Demand by Electric Utilities

This research recognizes regional distinctions in energy production, consumption, and attempts to explain regional preference by including regional variables in the utility's cost-minimization problem. For this purpose, states have been delineated into groups which roughly approximate geologic and geographic provinces, shown in Figure 3.1. These regions are referred to as North Atlantic, South Atlantic, Midwest, Northwest Central, Southwest Central, Mountain, and Pacific. The states which compose these regions, and the energy consumption for each state and region by energy type, are shown in Table 3.7. These regions are distinguished by the respective presence or absence of energy production capability, shown in Table 3.8.

The regions with the largest coal endowment, indicated by recent production figures, are the Midwest and Mountain states, and most oil and gas production comes from the Southwest Central and Pacific regions. The North and South Atlantic regions possess negligible fuel production capacity. Accordingly, in energy-deficient regions, fuels most cheaply transported are the most intensely consumed. National consumption patterns are presented in Table 3.9, showing that in 1987, nuclear fuel and petroleum products were consumed in proportionately higher quantities in the North and South Atlantic states, regions where nearly all fuel must be imported.

Transportation cost is a smaller component of nuclear fuel and oil cost per Btu compared to coal or gas; consequently, prices for these products are less sensitive

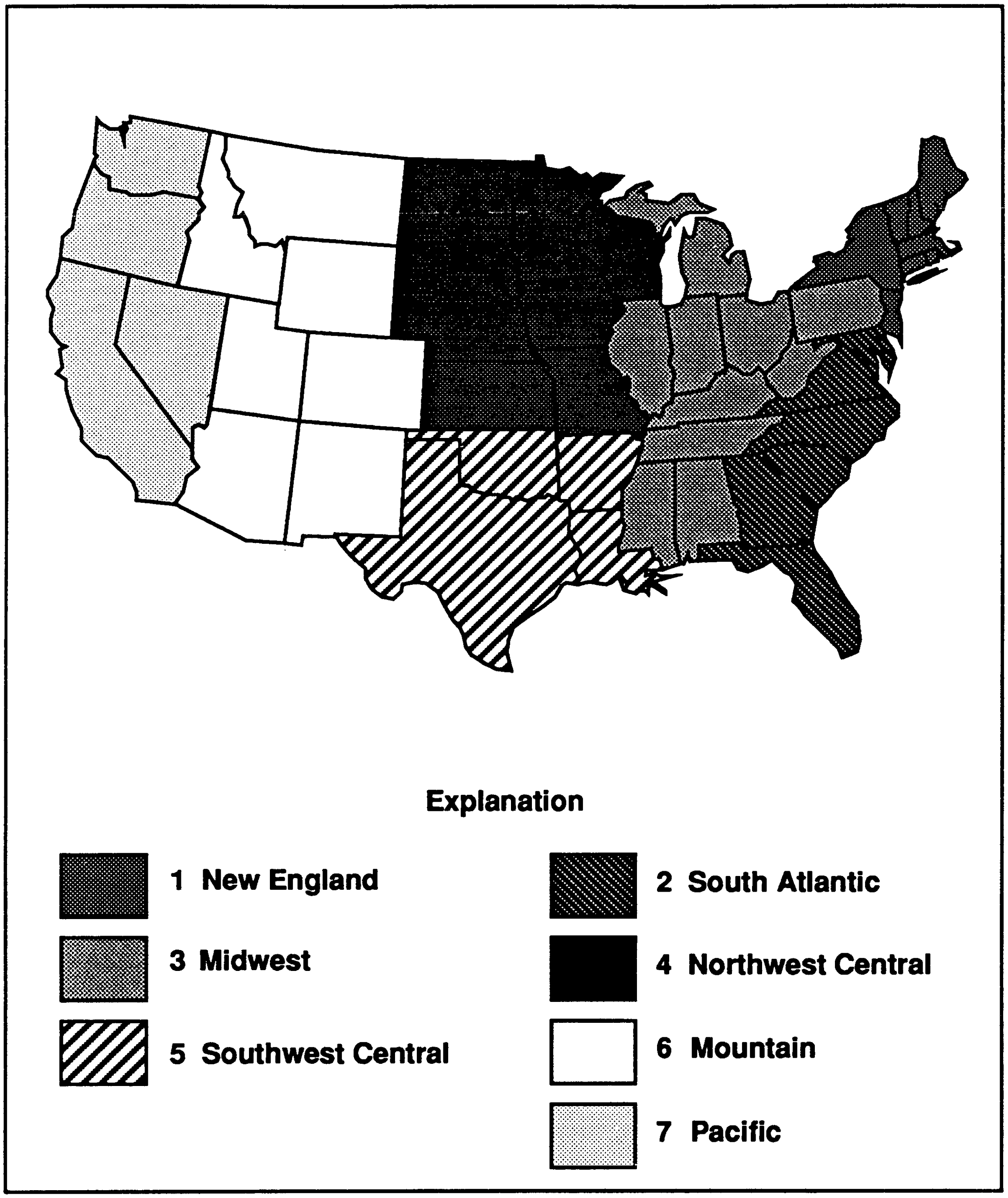

Figure 3.1 Translog Model Geographic Regions

Table 3.7 Regional Energy Provinces and Production (in teraBtus)

| Region | Coal | Gas | Oil | U3O8 | Hydro |
|---|---|---|---|---|---|
| 1 N. Atlantic | 563 | 1,559 | 4,759 | 813 | 627 |
| CT | 21 | 95 | 452 | 223 | 9 |
| ME | 7 | 3 | 217 | 44 | 66 |
| MA | 118 | 233 | 829 | 12 | 53 |
| NH | 32 | 12 | 157 | 0 | 22 |
| NJ | 91 | 432 | 1,266 | 247 | (3) |
| NY | 294 | 779 | 1,767 | 249 | 446 |
| VT | - | 5 | 71 | 38 | 34 |
| 2 S. Atlantic | 2,495 | 1,174 | 4,460 | 987 | 113 |
| DE | 70 | 37 | 126 | 0 | 0 |
| FL | 587 | 314 | 1,439 | 204 | 1 |
| GA | 711 | 311 | 792 | 166 | 33 |
| MD | 288 | 174 | 492 | 109 | 17 |
| NC | 501 | 153 | 734 | 311 | 53 |
| SC | - | 37 | 115 | - | - |
| VA | 338 | 148 | 762 | 197 | 9 |
| 3 Midwest | 8,604 | 4,306 | 7,638 | 1,368 | 228 |
| AL | 661 | 215 | 562 | 122 | 77 |
| IL | 758 | 887 | 1,183 | 545 | 1 |
| IN | 1,192 | 416 | 825 | 0 | 5 |
| KY | 747 | 178 | 488 | 0 | 30 |
| MI | 840 | 671 | 907 | 156 | 13 |
| MS | 122 | 212 | 381 | 84 | 0 |
| OH | 1,433 | 747 | 1,142 | 82 | 2 |
| PA | 1,381 | 649 | 1,297 | 380 | 12 |
| TN | 599 | 207 | 594 | (1) | 78 |
| WV | 871 | 124 | 259 | 0 | 10 |

(Continued)

Table 3.7 (Continued)

| Region | Coal | Gas | Oil | U3O8 | Hydro |
|---|---|---|---|---|---|
| 4 W-N Central | 2,175 | 1,439 | 2,706 | 505 | 177 |
| IA | 287 | 202 | 324 | 27 | 10 |
| KS | 267 | 341 | 401 | 70 | 0 |
| MN | 256 | 232 | 489 | 126 | 29 |
| MO | 528 | 234 | 612 | 66 | 15 |
| NE | 116 | 101 | 203 | 93 | 16 |
| ND | 319 | 26 | 117 | 0 | 35 |
| SD | 15 | 21 | 104 | 0 | 56 |
| WI | 387 | 282 | 456 | 123 | 16 |
| 5 W-S Central | 1,828 | 5,788 | 6,474 | 258 | 77 |
| AK | 211 | 172 | 299 | 124 | 25 |
| LA | 172 | 1,561 | 1,436 | 134 | 0 |
| OK | 241 | 618 | 413 | 0 | 30 |
| TX | 1,204 | 3,437 | 4,326 | 0 | 22 |
| 6 Mountain | 1,685 | 759 | 1,480 | 148 | 319 |
| AZ | 283 | 113 | 343 | 146 | 105 |
| CO | 297 | 210 | 338 | 2 | 19 |
| ID | 9 | 38 | 109 | 0 | 84 |
| MT | 133 | 40 | 137 | 0 | 92 |
| NM | 261 | 165 | 216 | 0 | 2 |
| UT | 274 | 107 | 206 | 0 | 9 |
| WY | 428 | 86 | 131 | 0 | 8 |
| 7 Pacific | 306 | 2,508 | 4,940 | 437 | 1,521 |
| AL | 4 | 252 | 207 | 0 | 9 |
| CA | 45 | 1,993 | 3,324 | 330 | 333 |
| HI | 2 | 3 | 229 | 0 | 1 |
| NE | 155 | 42 | 156 | 0 | 26 |
| OR | 4 | 82 | 335 | 47 | 420 |
| WA | 96 | 136 | 689 | 60 | 732 |
| Total | 17,656 | 17,533 | 32,457 | 4,516 | 3,062 |

Source: EIA/DOE, 1988, State Energy and Expenditure Report 1987, U.S. Government Printing Office, Washington, D.C.

Table 3.8 Regional Production (in thousands)

| Region | Coal (tons) | Gas (Mcf) | Oil (barrels) |
|---|---|---|---|
| 1 N. Atlantic | 0<br>(0) | 26<br>(0) | 710<br>(0) |
| 2 S. Atlantic | 44,087<br>(5) | 28<br>(0) | 8,287<br>(0) |
| 3 Midwest | 538,374<br>(60) | 968<br>(6) | 127,047<br>(4) |
| 4 W. N. Central | 30,686<br>(3) | 524<br>(3) | 109,080<br>(4) |
| 5 W. S. Central | 45,803<br>(5) | 13,395<br>(77) | 1,410,113<br>(46) |
| 6 Mountain | 226,970<br>(25) | 1,620<br>(9) | 277,375<br>(9) |
| 7 Pacific | 4,722<br>(1) | 788<br>(5) | 1,114,771<br>(37) |
| Total | 890,642<br>(100) | 17,349<br>(100) | 3,047,383<br>(100) |

Note: Coal statistics represents 1984 production, gas and oil are 1987 figures.

Mcf = thousand cubic feet.

Numbers in parentheses represent production percentages.

Sources: EIA/DOE, 1989, Petroleum Supply Annual 1988. U.S Government Printing Office, Washington, D.C.
EIA/DOE, 1989, Gas Supply Annual 1988. Ibid.
EIA/DOE, 1985, Coal Quarterly 1984. Ibid.

Table 3.9 1987 Regional Consumption Patterns
(in tera-Btu)

| | Coal | Gas | Oil | Nuclear | Hydro |
|---|---|---|---|---|---|
| 1 N. Atlantic | 563 | 1,559 | 4,759 | 813 | 627 |
| | (3) | (9) | (15) | (18) | (20) |
| 2 S. Atlantic | 2,495 | 1,174 | 4,460 | 987 | 113 |
| | (14) | (7) | (14) | (22) | (4) |
| 3 Midwest | 8,604 | 4,306 | 7,638 | 1,368 | 228 |
| | (49) | (25) | (24) | (30) | (7) |
| 4 W-N Central | 2,175 | 1,439 | 2,706 | 505 | 177 |
| | (12) | (8) | (8) | (11) | (6) |
| 5 W-S Central | 1,828 | 5,788 | 6,474 | 258 | (77 |
| | (10) | (33) | (20) | (6) | (3) |
| 6 Mountain | 1,685 | 759 | 1,480 | 148 | 319 |
| | (10) | (4) | (5) | (3) | (10) |
| 7 Pacific | 306 | 2,508 | 4,940 | 437 | 1,521 |
| | (2) | (14) | (15) | (10) | (50) |
| Total | 17,656 | 17,533 | 32,457 | 4,516 | 3,062 |
| | (100) | (100) | (100) | (100) | (100) |

Note: Numbers in parentheses represent consumption percentages

Source: EIA/DOE, 1989, State Energy Expenditure Report 1987, U.S. Government Printing Office, Washington, D.C.

to the distance delivered. For instance, because coal's Btu content per unit volume is low, freight expense makes long distance coal deliveries uneconomic, so the North Atlantic region consumes relatively less coal. Even so, while the Eastern seaboard is equally poor in oil as it is in coal, together, the North and South Atlantic regions consumed 29% of U.S. of petroleum demand. Compared to nuclear fuel and oil, gas consumption is nearly nonexistent unless pipelines are present. The Midwest region, which produces 6% of gas supply, consumed 25% of U.S. natural gas demand. The largest exporting region is the Southwest Central region, where less than 50% of production is consumed internally. The Pacific region consumes more gas then it produces, but excluding Alaska, the remaining Pacific coast states import nearly all natural gas. Gas imports, and consequently, consumption, are lowest in the North Atlantic states. A gas pipeline map of the United States, Pipeline Transportation Systems (USGS, 1974) shows a single 22-inch gas pipeline extending north from Boston to Portland, Maine, and a single 6-inch petroleum product pipeline from Portland to Bangor, Maine. This is the only connection for Maine, New Hampshire, and Vermont, and explains the relatively low gas consumption and high prices in the North Atlantic region.

Relatively higher coal consumption by coal-producing regions indicates that most coal does not leave the region where it was produced. For instance, Midwestern coal consumption is more than 80% of internal production. Mountain states also export relatively more coal than the Midwest. The major coal-importing regions are the Northwest Central and the South Atlantic, while the North Atlantic region imports small quantities.

Regional disparities in geologic occurrence and transportation distances are likewise reflected in prices. Table 3.10 shows prices and relative price levels for the three major energy commodity groups in the seven regions. South Atlantic customers pay the highest coal premiums, reflecting both the distance delivered and fuel quality. The Southwest Central and Pacific gas-producing regions receive significant discounts for gas, and the Midwest, which imports most gas, paid a 12% premium in 1987. Oil prices vary the least on a regional basis, but are lowest in the Southwest Central region, and highest in the Midwest and Mountain region.

Electric utility consumption patterns generally follow regional pricing and fuel production patterns, especially in coal use, since utilities dominate coal demand markets, seen in Table 3.11. Percentages under each commodity shown in Table 3.11 are the fraction of U.S. utility demand within

Table 3.10 1987 Regional Prices
(1987 dollars per million Btu)

| Region | Coal | % ave | Gas | % ave | Oil | % ave |
|---|---|---|---|---|---|---|
| 1 N. Atlantic | 1.71 | 10.7 | 5.16 | 26.8 | 5.83 | 1.7 |
| 2 S. Atlantic | 1.74 | 13.3 | 4.37 | 7.5 | 6.16 | 7.6 |
| 3 Midwest | 1.58 | 2.9 | 4.54 | 11.5 | 6.43 | 12.2 |
| 4 NW Central | 1.35 | -12.4 | 3.95 | -2.8 | 6.54 | 14.2 |
| 5 SW Central | 1.56 | 1.3 | 2.34 | -42.6 | 5.20 | -9.2 |
| 6 Mountain | 1.11 | -27.9 | 4.14 | 1.6 | 6.42 | 12.1 |
| 7 Pacific | 1.63 | 5.9 | 3.58 | -12.1 | 5.86 | 2.3 |
| U.S. Average | 1.54 | | 4.07 | | 5.73 | |

Source: EIA/DOE, 1989, State Energy Fuel and Expenditure Report 1987, U.S. Government Printing Office, Washington, D.C.

the respective region. For instance, 46% of electric utility coal demand is consumed in the Midwest, the region with the largest fraction of coal demand. Almost half of U.S. natural gas demand by utilities occurs in the Southwest Central region. Over 80% of oil consumption by utilities occurs west of the Mississippi River, in the North and South Atlantic, and Midwest regions. Likewise, most nuclear fuel demand is in eastern states. Over half the hydroelectric power generation occurs in the Pacific and North Atlantic.

Table 3.11 1987 Electric Utility Consumption Patterns (in tera-Btu)

| | Coal | Gas | Oil | U3O8 | Hydro |
|---|---|---|---|---|---|
| N. Atlantic | 446 | 305 | 693 | 807 | 608 |
| | (3) | (9) | (38) | (16) | (21) |
| S. Atlantic | 2,368 | 207 | 301 | 1,402 | 134 |
| | (16) | (6) | (16) | (28) | (5) |
| Midwest | 6,821 | 227 | 511 | 1,388 | 189 |
| | (46) | (7) | (28) | (28) | (7) |
| NW Central | 1,541 | 71 | (12 | 519 | 156 |
| | (10) | (2) | (1) | (10) | (5) |
| SW Central | 1,737 | 1,574 | 8 | 255 | 77 |
| | (12) | (48) | (0) | (5) | (3) |
| Mountain | 1,605 | 162 | 211 | 239 | 211 |
| | (11) | (5) | (11) | (5) | (7) |
| Pacific | 245 | 706 | 108 | 434 | 1,510 |
| | (2) | (22) | (6) | (9) | (52) |
| Total | 14,763 | 3,252 | 1,844 | 5,045 | 2,885 |
| | (100) | (100) | (100) | (100) | (100) |

Note: Numbers in parentheses represent percent of total electric utility consumption within respective regions.

Source: EIA/DOE, 1989, State Energy Data Report 1988, U.S. Government Printing Office, Washington, D.C.

# Chapter 4

# FIRM DESCRIPTION AND ELASTICITY ESTIMATION

## 4.1 Introduction

This chapter will examine conditions under which optimum fuel-input demand levels by the electric utility industry lead to profit maximization and cost minimization. This discussion of firm theory is broken down into the characteristics of production functions, related cost function characteristics, and the dual relationship between the firm's production technology and economic structure, described by its cost function. Technical characteristics of industry behavior in response to price change will be evaluated by own- and cross-price elasticities.

The approach estimates elasticities with an econometric demand model of six utility fuel inputs solved by iterative, seemingly unrelated least squares regression. The data set is fuel consumption, prices, and output by 82 investor-owned utilities during 1987. Such a short period implies that firms observe short-run profit restrictions on their production functions. Short-run assumptions imply further that fixed inputs remain unchanged during the period, eliminating the likelihood that technological improvements will change. Short-run restrictions apply to the associated cost function as well.

## 4.2 A Short-Run Production Model for Electric Utilities

Neoclassic production functions are assumed to be technologically efficient, i.e., when all inputs have been applied to the point where it is no longer possible to achieve the same output using less of one input and no more of any other input. Additional resources cannot be applied efficiently if other resources required by the technology are held constant. On the other hand, technological efficiency does imply that if one input is increased and all other inputs are held constant, output must increase. In other words, an efficient technological frontier can not be improved upon, but less efficient resource mixes are possible.

The multi-product production function takes the form:

$$\begin{aligned} Q &= (q_1, q_2, \ldots, q_s) \\ &= F(x_1, x_2, \ldots, x_n). \end{aligned} \tag{4.1}$$

The corresponding profit function is the difference between revenue, (price times output quantity), and cost components (input prices times quantities) shown below in equation (4.2).

$$\pi = \Sigma q_i p_i - \Sigma w_j x_j \qquad (4.2)$$

Mathematical forms used to describe production in competitive markets are expected to be concave functions with monotonically increasing cost functions. Cost equations are linear in inputs. These characteristics are embodied in the functional form chosen to describe the production technology that guarantee certain behavioral characteristics of competitive markets: concavity incorporates diminishing returns phenomena and downward sloping demand curves, and monotonic cost functions ensure that costs rise during price inflation. As specified in equation (4.2), both price, $p_i$, and input costs, $w_i$, are scalar (constant) quantities. Output price is postulated as a constant price because electricity price is regulated, and input prices, though supplied in competitive markets, are determined exogenously by their individual markets.

Some assumptions about market and firm behavior are implied by this profit specification. Utility output is represented by the sum of exogenously determined retail and wholesale demand. Production levels, commodity mix, and input requirements are determined endogenously, considering existing demand, the current generating technology available, and prevailing fuel prices. Furthermore, inputs are assumed to be competitively priced. In addition, commodity demand for a given observation point is interpreted as the cost-minimizing solution of the observed firm's profit-maximizing level. This assumption permits input demand to be derived from cost functions. Statistical errors in profit functions are random errors arising from deviations from cost-minimizing behavior (and includes the cumulative effects of all omitted variables).

The theoretical utility can be modeled as a short-run, profit-maximizing firm producing one output from a suite of six energy inputs transformed by a technology mix of generation equipment. Labor and capital services are not included in the short-run technology. In chapter 2, it was shown that labor costs are a minor but significant portion of generation costs. However, previous research has indicated that labor costs are not related to short-run cost-minimization. McFadden (1978), studied elasticity of substitution between labor, capital, and fuel, and although he cautioned that his test had weak explanatory power, accepted the hypothesis that fuel did not substitute for any combination of capital or labor. Fuss (1977), estimated labor, capital, and fuel substitution and concluded that the cross-elasticity of fuel substitution for labor was approximately 0.6, and for economic purposes, labor substitution for fuel was zero. These two studies indicate that labor costs may be omitted from the input demand model in this research without damaging the empirical results.

In addition to the option of producing power with self-owned generation capacity, a utility may decide to meet retail demand by purchasing power from other utilities. A unique aspect of wholesale power markets is that utilities may switch between net buying and net selling on an hourly basis, however, consumption effects of buy/sell cycles as short as one day escape detection by annual observations. Neither are load curve variables captured to account for the influence time-of-use has on input demand, such as load-shifting practices which consume more expensive capacity resources during peak demand. Consequently, wholesale power is treated the same as other energy commodities.

## 4.3 First Order Conditions

The following cost model development is taken from Henderson and Quandt (1980). A production function with s outputs and n inputs has the implicit functional form

$$F(q_1, q_2, \ldots, q_s, x_1, x_2, \ldots, x_n) = 0. \qquad (4.3)$$

The production function is assumed to possess the neoclassical production theory characteristics stated above: continuous, non-zero first and second partial derivatives; increasing output monotonicity; linear homogeneity in inputs; and regular, strict convexity over the positive input and output quadrant. At this point in model development, constant returns to scale are implied by linear homogeneity, but this restriction may be relaxed if constant elasticities of substitution are not required.

Profit is maximized subject to the available technology represented by the implicit production function, according to the objective function. That is, maximizing equation (4.2) subject to equation (4.3) results in the following Lagrangian:

$$L = \sum_{i=1}^{s} p_i q_i - \sum_{j=1}^{n} r_j x_j + \theta F(q_1, q_2, \ldots, q_s, x_1, x_2, \ldots, x_n) = 0 \qquad (4.4)$$

where θ is the Lagrangian multiplier. For an interior solution, first order conditions imply that

$$\frac{\delta \pi}{\delta q_i} = p_i + \theta F_i = 0 \quad (i = 1, 2, \ldots, s) \qquad (4.5a)$$

$$\frac{\delta \pi}{\delta x_j} = -r_j + \theta F_{s+j} = 0 \quad (j = 1, 2, \ldots, n) \qquad (4.5b)$$

?

$$\frac{\partial L}{\partial \theta}\ \frac{\delta \cancel{\pi}}{\cancel{\delta} L} = F(q_1, q_2, \ldots, q_s, x_1, x_2, \ldots, x_n) = 0 \qquad (4.5c)$$

where $F_i$ is the derivative of (4.3) with respect to $q_i$.

Equating (4.5a) to (4.5b) to solve for θ, leads to the following relationship:

$$r_j/p_k = F_{s+j}/F_k = \delta q_k/\delta \underset{j}{x_i} \qquad (j, k = 1, \ldots, s)$$

or restated,

$$r_j = p_k \delta q_k/\delta x_i \qquad (4.6)$$

reproducing the usual condition that at profit maximization, the marginal rate of product transformation for each output with respect to each input must equal the price for that input.

Another familiar production function property important to the input demand system is the relationship between inputs and their prices. Taking any two equations from (4.5b), dividing either one by the other to solve for input price, leads to the determination of marginal rate of technical substitution (MRTS):

$$\begin{aligned} w_j/w_k &= -x_k/x_j = MP_k/MP_j \\ &= -(\delta f(x^*)/\delta x_k)/(\delta f(x^*)/\delta x_j) = MRTS \qquad (4.7) \end{aligned}$$

where $f(x^*)$ is the profit-maximizing output quantity (at optimum input mix $x^*$); $w_i$ is the input price; and MP is the marginal product of $f(x)$ with respect to $x_i$.

The MRTS for every pair of inputs--holding the levels of all outputs and all other inputs constant--must equal the ratio of their prices. Thus, cost minimization implies that a firm adjusts its input mix until the MRTS among inputs equals the market-determined price ratio for these inputs. This is known as the tangency condition. Tangency occurs at the point where the slope of the cost equation is tangent to the production function, implying that an optimal solution is obtained when the marginal rate of technical substitution equals the input price ratio (Binger and Hoffman, 1988).

## 4.4 Second Order Conditions

Second order conditions for profit maximization require a negative, semi-definite bordered Hessian matrix; i.e., the second-order partial derivatives with respect to inputs prices must alternate in sign. Also, the Hessian matrix is symmetric because partial differentials are indifferent to the order of differentiation, as shown in equation (4.8)

(Varian, 1984).

$$\delta^2 f(x)/\delta x_j \delta x_i = \delta^2 f(x)/\delta x_i \delta x_j \tag{4.8}$$

## 4.5 Substitution Effects

Profit-maximizing firms adjust their output levels and input consumption in response to input price changes by varying input levels to maintain equality between the incremental cost of additional input and the incremental income accrued through its application to the production process. When more than one input is required and relative input prices change, input mix is adjusted to the point where net input cost is equal to additional income per unit sold.

If $q_i$ in equation (4.5a) were replaced by the profit-maximizing production level, $q(x^*)$, the input vector that maximizes profits at a given production level is a function of output prices and input costs, given by

$$x^* = x(p,w) \tag{4.9}$$

This results in the ordinary input demand from profit maximization of equation (4.2) subject to (4.3). The first order conditions for profit maximization, evaluated at $x^*$, would be

$$pq'(x(p,w)) - w = 0 \tag{4.10}$$

where $q'(x(p,w))$ is the first derivative of production with respect to x. If this identity were differentiated with respect to input price, the result would be

$$pq''[x(p,w)]dx(p,w)/dw - 1 = 0 \tag{4.11}$$

Maintaining the neoclassical condition that production functions have non-zero second partial derivatives, the expression becomes:

$$dx(p,w)/dw = 1/pq''[x(p,w)] \tag{4.12}$$

The righthand term of equation (4.12) is the substitution matrix, the inverted Hessian of the production function times output price. Because the substitution matrix is the inverse of a symmetrical matrix, the substitution matrix is also symmetrical as well as negative semi-definite. For profit maximization, this implies that principal minor determinants alternate in sign, and under cost minimization, the relevant Hessian determinant is negative semi-definite.

## 4.6 Cost Functions and Cost Minimization

Cost functions are the economic analogues to technological descriptions of firm behavior provided by production functions. The firm's economic and technological functions can be expressed by the system:

$$\begin{aligned} q &= f(x_1, x_2, \ldots, x_n), \\ c &= b + \Sigma x_i w_i, \\ 0 &= G(x_1, x_2, \ldots, x_n), \end{aligned} \tag{4.13}$$

where c is cost, b is the fixed cost intercept, and the input costs, w, multiplied by input quantities, x, are variable costs. This system can be reduced to a single function

$$C = C(q_1, q_2, \ldots, q_s, w_1 w_2, \ldots, w_n) \tag{4.14}$$

in which cost is stated as an explicit function of output level and input prices. To be necessary and sufficient conditions for cost minimization, the cost function should retain the characteristics of the production function: monotonically increasing in input prices and output, linear homogeneity, and concave in input prices.

## 4.7 Shephard's Lemma

Concavity in input prices is a result of a symmetrical matrix of factor demand functions constrained to possess negative own-price effects (if an input's cost increases, its consumption level decreases); and positive cross-price effects (in response to the price increase of one commodity, consumers demand more of substitute commodities). A linear cost function satisfies this property; however, concave functions allow for costs to increase at a decreasing rate as the other inputs become more important in quantitative share of production costs. As consumers substitute more competing commodities in the production process for higher priced commodities, the higher priced input forms a progressively lower fraction of the consumer's production process, and additional price increments have a successively smaller impact on total cost.

The direct effect of price change is the firm's decreased expenditure on those relatively more expensive input; indirect effects are increased consumption of relatively lower priced commodities. Assuming the firm were operating at a cost-minimizing point, any infinitesimal change will result in zero additional profits. This is consistent with the principle of monotonicity, which precludes higher profits under conditions of rising input costs.

Figure 4.1 shows a cost equation given by

$$C = w_1 x_1 + \Sigma w_i x_i \qquad (4.15)$$

and a concave cost function given by

$$C = C(w,q) \qquad (4.16)$$

The cost equation is linear in prices and input levels, while the cost function is concave in input prices. The two lines coincide at $w_1{}^*$, the cost minimization point, implying equal first derivatives, shown below:

$$\delta C/\delta w_i = x^* = \delta C(w,q)/\delta w \qquad (4.17)$$

Shephard's lemma states that optimum, cost-minimizing input levels are equal to the first derivatives of the cost function with respect to input prices and output (Fuss, 1977). Therefore equation 4.17 is the fundamental form used here to denote the input factor demand functions.

### 4.8 Elasticity of Substitution

Quantitative measures of how the production technology

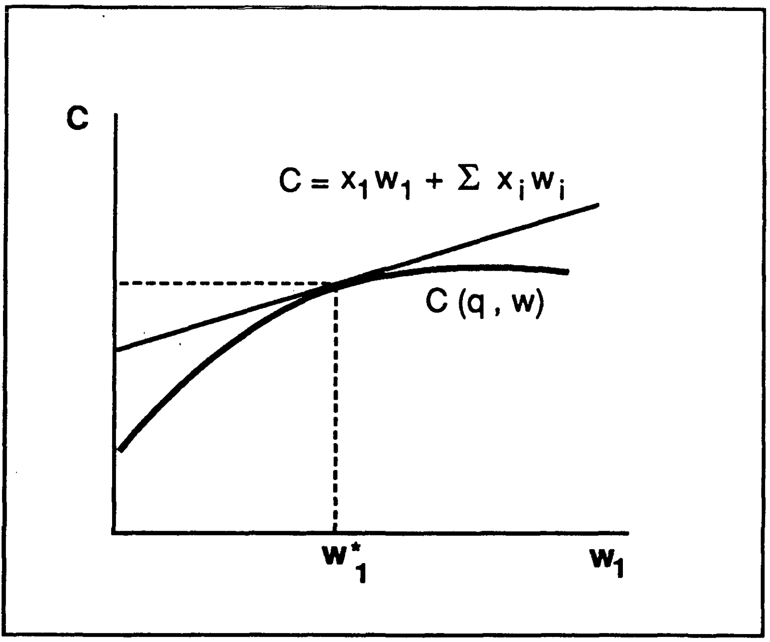

Figure 4.1 The Cost Function and Cost Equation

Source: Varian, Hal R., 1984, Microeconomic Analysis, W. W. Norton and Company, New York.

converts inputs into outputs and substitutes inputs for one another, require that relationships be defined between the economics of business activities and their technological structure. Elasticity of substitution is a common measure of substitution between inputs, and duality is a convenient approach to derive substitution elasticity relationships. The term duality describes those characteristics of mathematical production systems which relate economic effects (input price ratios) to technical solutions (relative input quantities), and allows prediction of future demand. The discussion which follows is after Varian, 1984. First order conditions for cost minimization require cost-minimizing price ratios directly proportional to the ratio of marginal products, defining the rate of profit-maximizing production change with respect to infinitesimal input demand changes (repeated below for convenience).

$$\begin{aligned} w^*_i / w^*_j &= -MP_i / MP_j \\ &= [\delta f(x^*)/\delta x_i] \ / \ [\delta f(x^*)/\delta x_j] \qquad (4.7) \end{aligned}$$

The full derivative of (4.7) results in

$$dx_j \ (x^*) \ / dx_i \ = \ - \ w_i / w_j \ . \qquad (4.18)$$

One expression of the dual relationship between production and cost functions is that the slope of the isoquant curve gives the ratio of factor prices and the isocost curve gives the ratio of the input levels, shown in Figure 4.2

The convenient aspect of duality for economic analysis is that a production technology's structure can be recovered from an econometric analysis of the cost function. As shown earlier,

$$w_1/w_2 = MP_1/MP_2 \tag{4.7}$$

at profit maximization and cost minimization optima. Allen (1938) defined the elasticity of the function y = f(x) as the rate of proportional change in y per unit proportional change in x as

$$E_y/E_x = d\ \ln(y)/d\ \ln(x) = (x/y)(dy/dx). \tag{4.19}$$

Allen elasticities of substitution are not constrained to be constant, but may vary with the value of the cost share.

To find the response of factor mix ratio to change in the factor price ratio, the equivalent expression would be

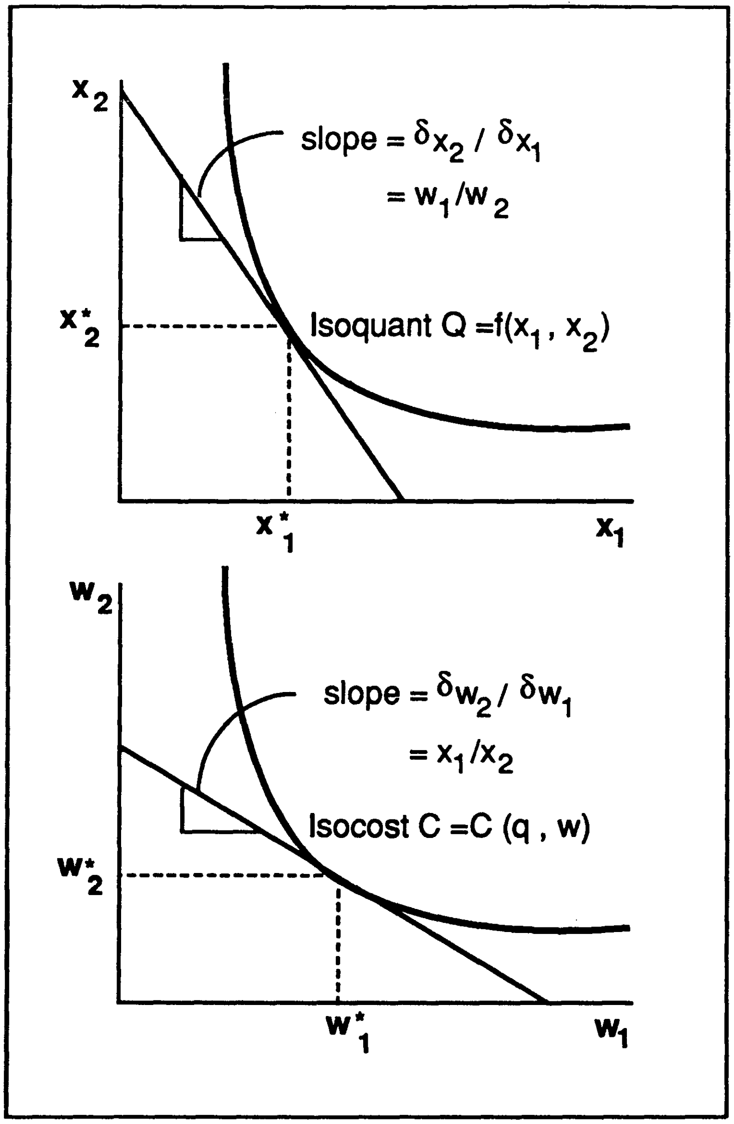

Figure 4.2 Isocost-Isoquant Duality

Source: Varian, Hal R., 1984, Microeconomic Analysis, W. W. Norton and Company, New York.

$$\sigma(q,w) = \frac{d\ \ln(x_i/x_j)}{d\ \ln(w_1/w_2)} = \frac{(w_1/w_2)\ d(x_1/x_2)}{(x_i/x_j)\ d(w_1/w_2)} \tag{4.20}$$

where $\sigma(q,w)$ is the elasticity of substitution. Using homogeneity conditions and Shephard's lemma, McFadden (1978) shows that

$$d\ \ln(x_i/x_j) = \frac{C_{ij} * C_{ij}}{C_i * C_j} * [d\ \ln(w_1/w_2)] \tag{4.21}$$

where $C_i$ equals the first partial differential of C with respect to wi.

Solving the expression for elasticity of substitution from equation 4.18, the result is shown below.

$$\begin{aligned} \sigma(q,w) &= d[\ln(x_i/x_j)]/d[\ln(w_1/w_2)] \\ &= C_{ij} * C_{ij}/C_i * C_j \end{aligned} \tag{4.22}$$

The elasticity of substitution can be reduced to a function of first and second partials of the cost function with respect to input prices.

## 4.9 Conclusions

Since demand and supply functions are derivatives of cost functions, cost function properties translate into restrictions on its derivatives: the factor demand functions given above by equation (4.17).

The first derivative of the cost function is equivalent to the factor demand function; the factor demand first derivatives are likewise the second derivatives of the cost function and equivalent to the cost function's bordered Hessian and therefore are both symmetric and negative semi-definite. Positive second partial derivatives of non-diagonal Hessian elements indicate negative semi-definiteness (McFadden, 1978). Table 4.1 summarizes implications for the factor demand functions.

The most important implications from this result are symmetrical cross-price effects and negative own-price effects, i.e., negative own-price elasticity of demand. Implications for cost equation estimation by this research are summarized in Table 4.2.

As shown, the decision to buy or sell may be motivated by either profit-maximization or cost-minimization objectives. Any time a utility purchases power below its own decremental generation costs, it demonstrates cost-minimizing behavior, and whenever the utility sells above its own incremental costs, it demonstrates profit-maximizing behavior. The next chapter presents the empirical model, and discusses regression techniques and empirical tests.

Table 4.1 Cost Function Criteria Related to Factor Demand

| Cost Function | Factor Demand Functions |
|---|---|
| Increasing in factor prices | $\delta C(q,w)/\delta w_i = x_i(q,w) > 0$ |
| $C(q,w)$ is homogeneous of degree one in in factor prices | Derivatives are homogeneous of degree zero |
| $C(q,w)$ is concave in factor prices | The matrix of 1st derivatives of factor demand functions is a symmetric negative, semi-definite matrix |

Table 4.2 Cost Function Restrictions and Implications

| Restriction | Implication |
|---|---|
| Cross-price effects are symmetric | $\frac{\delta x_i}{\delta w_j} = \frac{\delta^2 C}{\delta w_j w_i} = \frac{\delta^2 C}{\delta w_i w_j} = \frac{\delta x_j}{\delta w_i}$ |
| Own-price effects are negative | $\frac{\delta x_i}{\delta w_i} \leq 0 = \frac{\delta^2 C}{\delta^2 w_i}$ |

# Chapter 5

# TRANSCENDENTAL LOGARITHMIC FUNCTIONS AND ENERGY SUBSTITUTION

## 5.1 Introduction

To restate the objective of the current research, the intent is to determine substitution between primary fuels by electric utilities. Included in this objective is to measure substitution by utilities who have the option of fulfilling retail demand with wholesale power purchases. The approach is to model primary fuel demand by electric utilities as a cost-minimizing mix of primary fuel prices using the transcendental logarithmic function, a form which permits flexibility in returns to scale and elasticities of substitution. The data is cross-sectional consumption and prices for fuel and wholesale power by 82 utilities during 1987.

Substitution will be measured from calculations developed for the Allen-Uzawa elasticity of substitution (Allen, 1938, Uzawa, 1962) and the associated price elasticity of demand defined in chapter 4. The parameters necessary for elasticity calculation will be estimated regression parameters from a normalized cost function, the reduced form of the production system. Reduced form refers to a functional form where all explanatory variables are exogenous; i.e., factors influencing their magnitude are beyond the control of the optimizing agent.

The preferred approach might be to estimate production functions directly, but is impractical because capital service costs cannot be precisely measured and omitted variables create problems in specifying the technology ? (Denny and Pinto, 1978).

Estimating production functions by ordinary least squares (OLS) estimation is not likely to result in good estimates. The measures of output will likely correlate with unobserved variables in the error term because firm managers observe phenomena not specified by the production function, or other omitted and unmeasurable factors, such as changing consumer tastes, influencing production decisions. The classic example is a technology specification for wheat production which omits a measure for weather. A farmer's production and input level decisions (measured by explanatory variables) depend upon variations in the weather, effects of which are contained in the error term. However, a farmer might conceivably invest in additional capital (such as a water well) if rainfall is lower than anticipated. Low farm output is expected when rainfall is low, but capital expenditure will appear related with output, and lower output will be interpreted as a random deviation from optimizing behavior. The inclusion of explanatory variables (such as capital expenditure in the farming example) correlated with behavior contained in the error term violates the fundamental OLS assumption that dependent variables are uncorrelated with the error term.

In the farming example, variations in technology and other unseen effects are known to managers, but not to observers. Observed factor inputs are endogenous if random effects of technology and economic variation are known to the production unit, and exogenous if the random effects are not known by managers. A more proper method, and less susceptible to introduced errors, is to measure conditional input demand functions to infer the underlying technological structure.

## 5.2 The Transcendental Logarithmic Production Function

Production functions and their cost functions were originally described by two-input, nonlinear mathematic relationships. The Cobb-Douglas production technology is a conventional model used in early empirical studies to relate output to highly aggregated inputs of capital and labor. However, technology described by highly aggregated two-input systems are not useful for microeconomic analysis. An attractive approach would be to specify a Cobb-Douglas technology with less aggregated input factors (Berndt and Christensen, 1973), but Leontief (1947a and 1947b) has shown that multi-input Cobb-Douglas technologies imply strong separability between inputs, and that multi-factor analogues of conventional two-input models impose constant elasticities of substitution among inputs.

In the early 1970s, research focused on identifying specifications which do not require strictly separable technologies. Diewert (1971) proposed the Generalized Leontief Production Function, a quadratic form in an arbitrary number of inputs. Christensen, Jorgensen, and Lau (1973) proposed the transcendental logarithmic production function (abbreviated to translog) which permits an arbitrary number of linear and quadratic inputs. Separability can be imposed on the translog form by parametric restrictions (and tested to validate the separability assumption).

## 5.3 Separability and Implications for Functional Form

Separability is a structural property in a production technology which permits econometric analysis to be performed in terms of subsets, or input groups, of the total set of possible variables. When large numbers of inputs are measured, the unhindered ability to assume separability between inputs allows researchers to specify more flexible functional forms, and focus on a specific class of inputs (Fuss, McFadden, and Mundlak, 1978).

In terms of utility inputs, aggregated inputs may be classified into three input groups: capital services, labor, and fuel. Fuel is understood to be any energy source, including wholesale power. Subinputs within input groups are disaggregated elements within a category. Capital subinputs are equipment and structures, and correspondingly, labor may be disintegrated into management and production labor. In the present study, fuel breaks down into six subcategories: coal, nuclear, gas, oil, hydroelectric, and wholesale power.

Separability is characterized by the independence of the marginal rate of substitution (MRS) between a pair of inputs from changes in the level of a third input. If a set of inputs, N, is separated into groups $S_1$ and $S_2$, where the $S_i$'s are wholly-contained subsets of N, MRS independence is shown by the relationship:

$$\frac{\delta(f_i/f_j)}{\delta q_k} = 0 \tag{5.1}$$

where $f_i$ and $f_j$ are first differentials of the production function in $S_1$ and $S_2$ respectively, and $\delta q_k$ is marginal output with respect to a third input k, a member of a third input group, $S_3$. The ratio of marginal products (i.e., price ratios) is independent of change in a third input group.

A strongly separable function with respect to the group S implies that (5.1) holds for all disaggregated and aggregated inputs. In the electric utility industry, this premise could be interpreted to mean that in the short run, all fuel subinputs are unrelated to other input categories: equipment, and production and management labor. Weak separability refers to production functions where equation (5.1) holds for elements within an input group unrelated to other categories.

In terms of the present study, the analogous statement would be that the individual marginal rate of substitutions for fuel inputs are independent of equipment and labor input levels. Christensen, Jorgensen, and Lau (1973) use the concept of duality between cost and production to show the cost function which corresponds to a separable production function is itself separable.

The analytical penalty paid for failure to meet separability conditions is biased parameter estimates.

Individual input measurements in disaggregated technology descriptions will correlate with omitted variables whose unobserved behavior is retained in the error term. Assuming the omitted variables (capital and labor, among others) are positively correlated with electric output, the parameter estimates will err in the direction of correlation between the omitted variables and included variables.

There may be evidence to suspect that for plant-level electric production, fuel selection is somewhat dependent on equipment selection because coal and nuclear consumption is likely to be associated with large capacity plants, high production levels, and large factor share. Consequently, an expanded Cobb-Douglas model of this industry may fail to meet the strict separability requirements of the Cobb-Douglas or constant elasticities of substitution families of production functions. A specification is necessary, such as the translog function, that does not require a strictly separable technology. In the following section, a translog econometric model is developed.

## 5.4 Translog Production Function Approximation

The ensuing translog model specification development follows the method of Berndt and Christensen (1973) in their study of the substitution between equipment, structures, and labor in U.S manufacturing; and Berndt and Wood (1975) in their study of aggregated energy demand models in the U.S economy.

Second ?

The translog production function is a first-order Taylor expansion about an arbitrary point in the production function written as

$$\ln Q = \ln\alpha_0 + \alpha_A \ln A + \Sigma_i \alpha_i \ln x_i + \tfrac{1}{2}\tau_{AA}(\ln A)^2$$
$$+ \Sigma i \Sigma_j \tau_{ij} \ln x_i \ln x_j + \Sigma_i \tau_{iA} \underline{\ln x_i \ln A} \qquad (5.2)$$

where ~~V~~ Q is output, the $x_i$ are inputs, A is a technology index, the Greek letters are parameters, and $\tau_{ij} = \tau_{ji}$, (because of symmetry). If constant returns to scale apply, the following restrictions apply.

$$\Sigma_i \alpha_i = 1$$
$$\Sigma_i \tau_{ij} = 0$$
$$\Sigma_i \tau_{iA} = 0 \qquad (5.3)$$

Across the data sample, technology is assumed to be equally distributed. For instance, generation plants at all utilities have the same approximate age and operate at the same approximate heat rate. If constant returns to scale and a Hick's neutral technology is assumed, the following restrictions apply.

$$\alpha_A = 1$$

$$\tau_{AA} = 0$$

$$\tau_{iA} = 0 \tag{5.4}$$

Hicksian neutrality implies that the ratio of the marginal products of any two inputs is independent of time, and consequently, the derived demand for any two inputs is also independent of time (Lau, 1978). In the case of electric power production, this assumption implies that productivity improvements among competing technologies progresses equally. For example, turbine heat rate efficiency, which impacts marginal costs, increases for gas turbines at the same rate as for all other competing technologies.

With constant returns to scale and Hick's neutral technical change imposed, interaction terms are eliminated, and the translog production function is written in the simplified form:

$$\ln Q = \ln A + \ln\alpha_0 + \Sigma_i \alpha_i \ln x_i + \Sigma_i \Sigma_j \tau_{ij} \ln x_i \ln x_j \tag{5.5}$$

Furthermore, if the function F is defined as

$$\ln F = \ln Q - \ln A = \ln\alpha_0 + \Sigma_i \alpha_i \ln x_i + \Sigma_i \Sigma_j \tau_{ij} \ln x_i \ln x_j \qquad (5.6)$$

where Q is transformed by the relationship, V = AF; i.e., individual inputs are transformed into aggregate input F by the translog input function, and then, aggregate input F is transformed into output by the scalar technology index A. The logarithmic marginal productivity conditions on Q and F are equal and independent of A.

$$\frac{\delta \ln Q}{\delta \ln x_i} = \frac{\delta \ln F}{\delta \ln x_i} = \alpha_i + \Sigma_j \tau_{ij} \ln x_j \qquad (5.7)$$

Because the translog function has quadratic terms, it has several maxima and minima points which will satisfy optimality conditions, implying that it is not globally monotonic or convex, if at least one $\tau_{ij}$ does not equal zero. However, there are regions of input space where monotonicity and convexity will be satisfied, large enough that the translog function will provide a good representation of relevant production possibilities.

Monotonicity requires that the first partial differential of F with respect to the input factors $x_i$ is positive (i.e., increasing inputs means increased production). Since the $x_i$ and F are always positive, an equivalent set of conditions is written

$$M_i = \delta \ln F/\delta \ln x_i = (\delta F/\delta x_i)(x_i/F) > 0 \qquad (5.8)$$

where $M_i$ is the logarithmic marginal product. Assuming competitive markets, a set of necessary conditions for efficient production is

$$\frac{\delta F}{\delta x_i} = P_i \qquad (5.9)$$

where $P_i$ is the price of the ith input relative to the price of the aggregate input F. This says, in competitive markets, marginal productivity achieved through recruitment of an additional unit of input is equal to the price of that input.

Equation (5.8) can then be written as

$$M_i = (\delta F/\delta x_i)(x_i/F) = P_i x_i/F > 0 \qquad (5.10)$$

which, as shown, must be positive for monotonicity to hold. Since $P_i$ multiplied by $x_i$ is total expenditure on input $x_i$, and F is total output, the cost share of x is given by

$$P_i x_i / F \tag{5.11}$$

In other words, cost shares are equal to marginal productivity and are approximations of cost-minimizing conditions for profit-maximizing firms. Monotonicity and convexity conditions may be verified by statistical tests.

The firm's cost model is developed in the next section, a more convenient approach to cost-minimization analysis.

## 5.5 Translog Cost Function Approximation

As stated in section 5.1, dual relationships between cost and production functions expeditiously avoid typical difficulties encountered when estimating production functions directly, such as choosing (or locating) appropriate proxy variables for capital service costs and technical description. All essential structural characteristics of a production technology can be derived from the resulting cost function, the basis for all subsequent regression analysis.

Production functions for electric utility power generation are assumed to take the form

$$Q = f(q, x_c, x_o, x_g, x_n, x_h, x_w) \tag{5.12}$$

$Q = ?$

where $q$ = total retail and wholesale power sales
$x_c$ = coal consumption
$x_o$ = oil, fuel oil, and distillate consumption
$x_g$ = natural gas consumption
$x_n$ = nuclear fuel
$x_h$ = hydroelectric power production
$x_w$ = wholesale power consumption

All inputs are measured in British thermal units (or, in the case of wholesale and hydroelectric power, in Btu equivalents adjusted for thermal efficiency). The corresponding cost function for this production technology is given by

$$C = C(q, w_c, w_o, w_g, w_n, w_h, w_w) \tag{5.13}$$

where $q$ = total retail and wholesale power sales
$w_c$ = coal cost
$w_o$ = oil, fuel oil, and distillate cost
$w_g$ = natural gas cost
$w_n$ = nuclear fuel cost
$w_h$ = hydroelectric power production costs

$w_w$ = wholesale power cost

Uzawa (1964) shows that if a function possesses the following properties:

Homogeneity of degree one in factor costs

Factor cost concavity

Factor costs increasing monotonically

Cost continuity

then that function sufficiently describes the cost function of that technology. As stated, dual characteristics between cost and production allow technological structure to be determined from cost functions. The convenience obtained here allows analysis of strictly inseparable technologies in more detail possible than with more restrictive functions.

A translog cost function approximation meets these criteria. The analogous translog cost function is a first order Taylor expansion about an arbitrary point of the cost function given by equation (5.13), shown below.

$$\begin{aligned} \ln C(q,w) = {} & \ln\alpha_0 + \Sigma_i \; \alpha_i \ln w_i + \Sigma_k \; \beta q_k \\ & + \tfrac{1}{2}\Sigma_i \Sigma_j \; \tau_{j\,k} \ln w_i * \ln w_j \\ & + \tfrac{1}{2}\Sigma_i \Sigma_k \; \delta_{j\,k} \ln q * \ln w_i \\ & + \tfrac{1}{2}\Sigma_i \Sigma_k \; \theta_{j\,k} \ln q * \ln w_i \end{aligned} \tag{5.14}$$

where

$w_i$ = input price for the ith factor

$i,j$ = $w_c$, $w_o$, $w_g$, $w_n$, $w_h$, and $w_w$

$q$ = total output

at the point of expansion, ($q = 1$, $w_c = 1$, $w_o = 1$, $w_g = 1$, $w_n = 1$, $w_h = 1$, $w_w = 1$), and joint cost function parameters are equal to the first and second order derivatives of the approximation with respect to input prices.

The input demand function is determined from Shephard's lemma, restated in equation (5.15):

$$\begin{aligned} \delta C/\delta w_i &= \delta C(q,w)/\delta w_i = x^* \\ &= f(q, w_c, w_o, w_g, w_n, w_w). \end{aligned} \tag{5.15}$$

The partial derivative of the translog cost function with respect to logarithms of input price is

$$\delta(\ln C)/\delta(\ln w) = (w_i * x^*)/C = S_i \tag{5.16}$$

where $x^*$ is the consumption level of input $x_i$ at cost minimization. The term $(w_i * x^*)/C$ is interpreted as the cost share of input i ($S_i$), because $w_i x^*$ is the expenditure on input i at cost minimization for output q. C represents total cost, given by the cost equation:

$$C = b_0 + \Sigma (w_i * x_i). \qquad (5.17)$$

To summarize, the estimated system is represented by

$$\begin{aligned}\delta(\ln C)/\delta(\ln w) &= w_i \; x^*/C = S_i \\ &= \alpha_i + \Sigma_j \; \tau_{ij} \ln w_i + \Sigma_k \; \delta_{ik} \ln q_k \qquad (5.18)\end{aligned}$$

The individual conditional demand functions are

$$\begin{aligned}S_{wj} = \alpha_w &+ \tau_{ww} \ln w_w + \tau_{wc} \ln w_c + \tau_{wo} \ln w_o \\ &+ \tau_{wg} \ln w_g + \tau_{wu} \ln w_u + \tau_{wh} \ln w_h \\ &+ \delta_{wr} \ln q_w + \varnothing_{wj} \qquad (5.19a)\end{aligned}$$

$$\begin{aligned}S_{cj} = \alpha_c &+ \tau_{cw} \ln w_w + \tau_{cc} \ln w_c + \tau_{co} \ln w_o \\ &+ \tau_{cg} \ln w_g + \tau_{cu} \ln w_u + \tau_{ch} \ln w_h \\ &+ \delta_{cr} \ln q_c + \varnothing_{cj} \qquad (5.19b)\end{aligned}$$

$$\begin{aligned}S_{oj} = \alpha_o &+ \tau_{co} \ln w_w + \tau_{oc} \ln w_c + \tau_{oo} \ln w_o \\ &+ \tau_{og} \ln w_g + \tau_{ou} \ln w_u + \tau_{oh} \ln w_h \\ &+ \delta_{or} \ln q_o + \varnothing_{oj} \qquad (5.19c)\end{aligned}$$

$$\begin{aligned}S_{gj} = \alpha_g &+ \tau_{gw} \ln w_w + \tau_{gc} \ln w_c + \tau_{go} \ln w_o \\ &+ \tau_{gg} \ln w_g + \tau_{gu} \ln w_u + \tau_{gh} \ln w_h \\ &+ \delta_{gr} \ln q_g + \varnothing_{gj} \qquad (5.19d)\end{aligned}$$

$$S_{uj} = \alpha_u + \tau_{uw}\ln w_w + \tau_{uc}\ln w_c + \tau_{uo}\ln w_o + \tau_{ug}\ln w_g + \tau_{uu}\ln w_u + \tau_{uh}\ln w_h + \delta_{ur}\ln q + \emptyset_{uj} \qquad (5.19e)$$

$$S_{hj} = \alpha_h + \tau_{hw}\ln w_w + \tau_{hc}\ln w_c + \tau_{ho}\ln w_o + \tau_{hg}\ln w_g + \tau_{hu}\ln w_u + \tau_{hh}\ln w_h + \delta_{hr}\ln q + \emptyset_{hj} \qquad (5.19f)$$

where $\emptyset_{ij}$ is the random error term which satisfies all ordinary least squares assumptions. The subscript i indexes the energy input factor (wholesale power, coal, gas, oil, nuclear, or hydroelectric power), and j indexes the utility.

Neoclassical production assumptions require three sets of restrictions: symmetry, linearity in input prices, and constant returns to scale (homogeneity of degree one). In chapter 4, production and cost functions were shown to have symmetrical second-order bordered Hessian matrices. As a result, this symmetry also holds for the input demand functions, shown in equation (5.20).

$$\tau_{ij} = \tau_{ji}$$
$$\theta_{kl} = \theta_{lk} \qquad (5.20)$$

Likewise, the cost function is linear homogenous in prices. The summarized restrictions, and associated theoretical assumptions, as imposed on the estimated system, are shown in equation (5.21).

$$\begin{array}{llll} \Sigma\ \alpha_i = 1 & \text{(CRTS)} & & \\ \Sigma\ \tau ij = 0 & \text{(CRTS)} & & \\ \Sigma\ \delta ik = 0 & \text{(Symmetry)} & & (5.21) \end{array}$$

The factor share equations add to one because each is a percentage of total cost; therefore, constant terms must equal one to assure constant returns to scale at zero input levels.

In addition, constant returns to scale implies the sums of estimated parameters for outputs are equal to one; i.e., aggregated output is linear with regard to scale. Since the translog specification is expressed in logarithms, the parameters should sum to zero, as shown below.

$$\begin{array}{ll} \Sigma\ \beta ik = 0 & \\ \Sigma\ \theta kl = 0 & \\ \Sigma\ \delta ik = 0 & (5.22) \end{array}$$

Elasticity of substitution estimates are made from parameter estimates. In chapter 5, the elasticity of substitution was shown to be

$$\sigma(q,w) = (C_i * C_{ij})/(C_i * C_j) \quad (4.23)$$

where

$$C_i = \delta C(q,w)/\delta w_i \quad (5.23a)$$

$$C_{ij} = \delta C(q,w)/\delta w_i \, \delta w_j \quad (5.23b)$$

Berndt and Christensen (1973) developed a relationship between the cost function bordered Hessian, the parameter $\tau_{ij}$, and cost shares $S_{ij}$:

$$\begin{aligned}\sigma_{ii}(q,w) &= (C_i * C_{ij})/(C_i * C_j) \\ &= (\tau_{ii} + S_i^2 - S_i)/S_i^2 \quad (5.24)\end{aligned}$$

where i is not equal to j. The relationship for elasticity of substitution described in chapter 4 (rewritten in translog model notation) is

$$\sigma_{ii}(q,w) = (\tau_{ii} + S_i^2)/S_i^2 \quad (5.25a)$$

for i = j.

$$\sigma_{ij}(q,w) = (\tau_{ij} + S_i * S_j)/S_i * S_j \quad (5.25b)$$

for i = j. Similarly, the price elasticity of demand is given by

$$E_{ij} = \delta \ln x_i / \delta \ln w_j = S_j \sigma_{ij} \qquad \text{for all } i,j. \qquad (5.26)$$

Elasticities will be calculated at the mean values of explanatory variables.

## 5.6 Using Regionally Pooled Data

Utilities in the research data set do not form a homogenous sample set, especially in terms of generation plant mix and fuel types. One conspicuous delineating characteristic is the geographic distribution of primary fuels: geologic formations containing fuels are spatially segregated, as is the regional infrastructure to transport them. The choice made by utility managers to select one energy source to the exclusion of another is influenced by regional disparities, but will be interpreted by the cost model (in the form specified by equation [5.19]) as deviations from optimizing behavior. The desire is to augment equation (5.19) with an explanation for apparent deviations from optimum behavior caused by regional disparities which capture part of the management decision process.

Because ordinary least squares estimation techniques interpret deviations from cost-minimizing solutions as random errors in optimization, the estimation process must account for nonhomogeneity among utilities in different geographic regions. The concern is that unobserved management decisions will be measured by the error term, and those unobserved management actions will correlate with either dependent or independent variables, causing inconsistent or biased parameter estimates, or both. The following technique and rationale for making regional corrections in conditional demand functions follows the approach of Fuss (1977).

One method assumes differences resulting from regional variation imply that the parameters of demand functions specifically identify one region. This system uses regional intercepts. Fuss states that a second approach is to assume that regional effects are stochastic, so that error terms, $\emptyset_{ij}$, are composed of the regional component and an overall component. Two techniques for the second approach are the covariance estimators and the error components estimators methods. Covariance estimation is computationally equivalent to using specific regional intercepts as described in the first approach. Fuss cites Swamy and Arora (1972) who state that when the number of regions is less than 10, covariance estimation is the preferred method.

Using Fuss's rationale, this research also corrects for regional technological disparity by using the covariance estimation technique in its dummy variable form to explain deviation from optimal behavior. In this case, a typical element of the error term vector, $\emptyset_{ij}$, is interpreted as

$$\emptyset_{ij} = \mu_{ijk} + e_{ijk} \tag{5.27}$$

|  |  |  |
|---|---|---|
| where | $\mu$ | is a dummy variable |
|  | i | indexes fuel (w, c, g, o, n, and h) |
|  | j | indexes the observation point (utility) |
|  | k | indexes the region |
|  | $e$ | is the residual error term. |

With regional dummy variables included, the aggregate share equations take the form:

$$\begin{aligned} S_{wj} = {} & (\alpha_w + e_{wjk}) + \tau_{ww} \ln w_w + \tau_{wc} \ln w_c + \tau_{wo} \ln w_o \\ & + \tau_{wg} \ln w_g + \tau_{wu} \ln w_u + \tau_{wh} \ln w_h \\ & + \delta_{wr} \ln q + \mu_{wjk} \end{aligned} \tag{5.28a}$$

$$\begin{aligned} S_{cj} = {} & (\alpha_c + e_{cjk}) + \tau_{cw} \ln w_w + \tau_{cc} \ln w_c + \tau_{co} \ln w_o \\ & + \tau_{cg} \ln w_g + \tau_{cu} \ln w_u + \tau_{ch} \ln w_h \\ & + \delta_{cr} \ln q + \mu_{ijk} \end{aligned} \tag{5.28b}$$

$$S_{oj} = (\alpha_o + e_{ojk}) + \tau_{co}\ln w_w + \tau_{oc}\ln w_c + \tau_{oo}\ln w_o + \tau_{og}\ln w_g + \tau_{ou}\ln w_u + \tau_{oh}\ln w_h + \delta_{or}\ln q + \mu_{ojk} \quad (5.28c)$$

$$S_{gj} = (\alpha_g + e_{gjk}) + \tau_{gw}\ln w_w + \tau_{gc}\ln w_c + \tau_{go}\ln w_o + \tau_{gg}\ln w_g + \tau_{gu}\ln w_u + \tau_{gh}\ln w_h + \delta_{gr}\ln q + \mu_{gjk} \quad (5.28d)$$

$$S_{uj} = (\alpha_u + e_{ujk}) + \tau_{uw}\ln w_w + \tau_{uc}\ln w_c + \tau_{uo}\ln w_o + \tau_{ug}\ln w_g + \tau_{uu}\ln w_u + \tau_{uh}\ln w_h + \delta_{ur}\ln q + \mu_{ujk} \quad (5.28e)$$

$$S_{hj} = (\alpha_h + e_{hjk}) + \tau_{hw}\ln w_w + \tau_{hc}\ln w_c + \tau_{ho}\ln w_o + \tau_{hg}\ln w_g + \tau_{hu}\ln w_u + \tau_{hh}\ln w_h + \delta_{hr}\ln q + \mu_{hjk} \quad (5.28f)$$

Seven regions, defined in chapter 3, are used in this model. To prevent deterministic relationships among independent variables, six regions are represented by regional variables $\mu_1$ through $\mu_6$, and region 7 is represented by the intercept term $\alpha_i$.

As presented in equation (5.28), symmetry is not imposed on the system, nor are the two homogeneity restrictions imposed. When regional variables are included, and symmetry, homogeneity, and constant returns to scale restrictions are omitted, equation (5.28) represents the fully specified model. Restrictions and model specification tests will be run against this fully-specified model.

## 5.7 Estimation Method

Equation (5.28) is estimated simultaneously using an iterative seemingly unrelated least squares (ITSUR) estimation utility of the SAS[1]/Econometric Time Series (SAS/ETS) software package. This section describes the ITSUR technique and associated assumptions. The SAS command file is presented in Appendix A.

Seemingly unrelated least squares uses correlation among error terms across equations to guarantee parametric estimator efficiency by iterating regressions to minimize the general least square function (SAS Institute, 1988). Two basic OLS assumptions applicable to iterated seemingly unrelated regression are that errors are either 1) due to measurement errors in the dependent variable, or 2) errors in the specified relationship between the dependent variable and independent variables. Apart from assumptions about variable measurement and model specification are the four basic OLS assumptions that (1) the expected value of the error term is zero; (2) the error variance is equal to model variance; (3) error terms are serially uncorrelated; and (4)

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[1] SAS is a registered trademark of the SAS Institute Inc., used to identify products or services of SAS Institute.

covariance between the error term in each equation and dependent variables is zero. In addition, the explanatory variables must be uncorrelated; that is, there can be no deterministic relationship between them. Least squares estimators which meet all these criterion are called unbiased, and have minimum variance among the class of all linear unbiased estimators. Minimum-variance parameter estimators are called <u>efficient</u>.

Single-equation systems do not explain interdependencies that may exist between dependent variables themselves or how independent variables relate to each other. For this reason, a six-equation model has been estimated for this research, to explain substitution relationships between the six energy sources. Errors in equations must be uncorrelated to independent variables in other equations, and possess unbiased errors (the expected value of error term is zero), and if these two conditions are not met, simultaneity between equations may occur. The most severe consequence of simultaneity is inconsistent parameter estimators.

Equations within a seemingly unrelated equation system may appear unrelated to one another, but may in fact be related through the error term. This is necessarily true when cost shares are estimated as in equation (5.28). Since the cost share for each commodity is determined by dividing the cost expended on that commodity by total cost, the cost shares for all equations sum to one, and the error terms for all equations must sum to zero. The ITSUR technique measures covariance between equation residuals, and uses this information to make subsequent parameter estimates.

Zellner (1962) suggests efficiency in estimation can be gained when the equation system is estimated as a single equation by generalized least squares using 1) the condition that cross equation error correlations sum to zero for every observation, and 2) information about cross-equation error term covariance. The first step in estimating equation (5.28) is to regress each equation by OLS to obtain the error covariances between equations, and construct a covariance matrix. These first-stage residual variances and covariances are used as consistent estimators of error variances and covariances when the second-stage system regression is performed (Pindyck and Rubinfeld, 1981). Shared cross-equation parameters, which occur when symmetry is imposed, are estimated with respect to the covariance matrix of the residuals across equations (SAS Institute, 1988).

The system in equation (5.28) is estimated simultaneously because cross-equation restrictions are imposed to perform hypothesis tests. Off-diagonal elements of residual covariances are expected to be non-zero, (i.e., residuals are related) and estimates will be consistent if all explanatory variables are exogenous.

### 5.8 Tests On Hypothesis

The SAS Institute (1988) recommends testing maintained model hypotheses by measuring the change in the least-squares criterion function citing Gallant, (1987), and Gallant and Jorgenson (1979), who show that the difference between the full-model and reduced-model criterion function is equivalent to a chi-squared test. The test procedure has two stages. The model is estimated first using ITSUR, as specified in equation (5.28), from which the error covariance matrix is developed. This is the full-model specification. The regression is then performed a second time with restrictions imposed (hereafter referred to as the reduced-form specification), using the same error term covariance matrix developed for the full specification model. The test statistic is the SAS objective function (OBJECTIVE) statistic multiplied by the number of observations. Critical values are obtained from chi-squared tables for degrees of freedom equal to the number of imposed restrictions at the 0.95 confidence level. This method is used throughout the hypothesis-testing procedure described in chapter 7.

## 5.9 Data Description

Most data collected to study wholesale power demand behavior is ultimately derived from the FERC Form 1. All investor-owned utilities exceeding minimum retail power sales, sales-for-resale, interchange volume, and wheeling volume are required to file a Form 1. Some Form 1 data is summarized in the EIA/DOE publication Financial Statistics of Selected Electric Utilities. In 1987, the most recent FSSEU publication available, 279 private utilities representing 9% of the total number of electric utilities in the United States filed a Form 1 with the FERC. In the year data was collected for this study, 1987, these utilities supplied about 80% of all electricity sales to ultimate customers in 1987 (EIA/DOE, 1989a).

One hundred utilities were selected at random from the utilities reporting in FSSEU, and of these, 82 utilities reported all data elements required for regression analysis. Production by utilities in the data set represent about 40% of all electricity generated in the U.S. during 1987. Appendix B contains a listing of all relevant data sets used in this model.

Table 5.1 lists the data sources for variables in the conditional input demand model described in the previous section. Some explanation of specific data series is necessary to understand how the data were collected, and what is being measured by the explanatory variables.

Wholesale Power Purchases: For a specific utility or data point, wholesale power purchases are total wholesale power purchases and net interchanges reported on FERC Form 1. Interchanges are transmission deliveries from other utilities transmitted through the purchasing utility. Net interchange means an algebraic sign is assigned to the difference between transmissions that come into the purchasing utility's system and the transmissions that leave the utility's system. If more interchanges leave the system than enter, the utility is a net seller. Purchased power includes purchases from other utilities, cooperatives, qualifying utilities, and municipals. There were no observations in the data set in which net interchange exceeded purchased power.

Wholesale Power Price: Price is determined by dividing annual purchased power expense, reported in FSSEU, by total annual wholesale purchases and net interchange. The resulting price estimate is therefore an average price over all transactions for the year 1987.

Table 5.1 Conditional Input Demand Model Data Sources

| Data Element Source | Description | |
|---|---|---|
| Wholesale Power Consumption Data | | |
| WHSL: | Sum of Purchased Power and Net Transactions | FERC Form 1 |
| PWHSL: | Wholesale Price | FERC Form 1 |
| Expenditures | | |
| | Purchased Power Expense | FSSEU |
| | Nuclear Fuel Expense | FSSEU |
| | Hydroelectric Power Expense | FSSEU |
| | Fossil Fuel Expense | FSSEU |
| Fuel cost data | | |
| PCOAL: | Coal price paid at plants | FERC Form 1 |
| POIL: | Oil " " | FERC Form 1 |
| PGAS: | Gas " " | FERC Form 1 |
| PU3O8: | Nuclear " " | FERC Form 1 |
| PHYDRO: | Hydro generation costs | FSSEU |
| Fuel Consumption Data | | |
| COAL: | Coal quantity consumed | FERC Form 1 |
| OIL: | Oil " " | FERC Form 1 |
| GAS: | Gas " " | FERC Form 1 |
| U3O8: | Nuclear " " | FERC Form 1 |
| HYDRO: | Khw hydro power generated | FERC Form 1 |
| Total Demand | Retail and Wholesale Demand | FERC Form 1 |

Source: EIA/DOE, 1989, Financial Statistics for Selected Utilities 1987, U.S Government Printing Office, Washington, D.C.

Total Fuel Expense: Total fuel cost is the unit price paid for each fuel times the quantity of each fuel consumed, summed over all fuels. Hydroelectric operating expense is used as a proxy price for fuel expense, since most utilities do not report a cost for water used. Cost shares are determined by dividing the expenditure on each individual fuel by total cost.

Coal, Gas, Oil, and Nuclear Prices: Total units consumed at individual plants are reported on Form 1, as well as the average heat content (in terms of Btus per unit) and the cost per unit delivered. The entire consumption of each commodity by each utility is multiplied by the heat content for that fuel, and this value is divided into the total expenditure for that fuel. This results in an average fuel price per Btu weighted by heat content.

As shown in chapter 2, fuel cost is only a portion of total generation costs. A purchasing utility compares its generation cost to potential wholesale purchases, not the cost of the primary fuel used to generate the wholesale power. Because of thermal inefficiency, only about one third of energy burned for generation is actually converted to electricity, consequently, a Btu of electricity costs at least three times more than a Btu of fuel. To simulate the production frontier actually observed by a utility, and measure all fuel inputs on an equivalent basis, this study must either approximate generation cost or adjust power costs for mechanical inefficiency. The latter approach was taken. Wholesale power is sold in electric energy units (kilowatt hours) but prices in the model are specified in terms of dollars per million Btus, a mechanical energy measure, so all wholesale power sales are multiplied by a factor of 3,412 Btus per kwh. This is the energy required to generate the wholesale power sale for a generator operating at 100% efficiency, and to obtain price, this value is divided into total wholesale power expenditure. The resultant is then multiplied by 0.3345, a typical efficiency factor for baseload generators (equal to 10,200 Btus per kwh). This adjustment results in a normalized price which can be compared to other fuel costs in the model. Hydroelectric power costs have also been adjusted for thermal efficiency.

### 5.10 Specification and Tests: Conclusions

Chapter 4 presented assumptions regarding market and firm behavior pertinent to this research, and this chapter defined those assumptions in a mathematical form which would be convenient to estimate using multiple regression. The translog specification is robust for technologies where strict separability in inputs is not achieved. Industry practice suggests that electric utility input demand is not strictly separable, so the translog function is applicable in this situation. Cost share is interpreted as the equivalent of marginal cost for first-order cost-minimizing criteria. The next chapter records the results of the regression performed on the system defined in equation (5.28), and also presents an evaluation of the estimates obtained and empirical implications.

# Chapter 6

# REGRESSION RESULTS

## 6.1 Introduction

Electric utility behavior, economic theory, and mathematical form suggest a framework for empirical analysis in this research, including assumptions about cost functions, input substitution, and returns to scale. This framework is embodied in the functional form by the choice of explanatory and dependent variables and restrictions on functional form, resulting in the model's maintained hypotheses. Tests are specified to verify that these maintained hypotheses and in addition, OLS assumptions are tested for validity.

Once theoretical and behavioral questions have been addressed, functional form is improved (in terms of conformance to economic behavior) by experimenting with different specifications. The criteria for evaluating any resulting specifications is that they 1) conform to economic theory and 2) explain the underlying technology as it exists in the utility industry.

## 6.2 Tests on Hypotheses and Functional Forms

In chapters 4 and 5, three maintained hypotheses were developed: 1) the adding-up criterion, 2) constant returns to scale (or homogeneity in prices), and 3) symmetry in the bordered Hessian matrix of the system demand equations. These hypotheses are embodied in the analytical model as restrictions, repeated below (equation [5.21]).

$\Sigma \alpha_i = 1$ (Adding-up restriction and CRTS)
$\Sigma \tau_{ij} = 0$ (Homogeneity and CRTS)
$\delta_{ik} = \delta_{ki}$ (Symmetry)

The adding-up restriction is imposed as a result of using cost shares as the demand variable. Cost shares sum to one, and as a consequence, the intercepts for all six equations in equation (5.28) sum to one. Homogeneity is a test of the assumption of constant returns to scale. The translog function is analogous to the Cobb-Douglas representation in which constant returns to scale implies that exponents of the independent variables will sum to one, but the equivalent restriction when regressing logarithms is to have the parameters sum to zero. Symmetry is implied by the assumption that the utility cost functions are concave everywhere, i.e., always increasing, but at a decreasing rate.

These restrictions were arranged in nested forms and tested sequentially. First, all three restrictions were tested together, using an analytical equivalent to the F-test (described in chapter 5), using the test model as the fully-specified model with regional variables included, but no symmetry imposed. Second, pairs of jointly held assumptions were tested, and third, all three assumptions were tested individually. This resulted in seven models being tested, as shown in Table 6.1. The table presents restriction assemblages, number of restrictions (R), degrees of freedom required by each individual restriction and total degrees of freedom for the model, calculated chi-squared ($X^2$) test statistics (calculated as described in chapter 5), critical chi-squared values, and whether or not the null hypothesis, $H_0$, was rejected. In this test, degrees of freedom is the number of imposed restrictions. All tests are performed at the 0.05 significance level. The joint hypotheses of homogeneity and symmetry, combination number 4, is not rejected at the 0.05 significance level.

Besides jointly imposed homogeneity and symmetry, the other maintained hypothesis not rejected is the assumption of symmetry alone, model 7. Because the adding-up and homogeneity criteria are both necessary for acceptance of constant returns to scale, the remaining tests on OLS assumption will be performed using equation (5.28) with the hypothesis of symmetry alone maintained.

Table 6.1 Maintained Hypothesis Test Results (0.05 Level)

| | Restriction | R | D.F. | $X^2$ | C.V. | $H_0$ Rejected? |
|---|---|---|---|---|---|---|
| 1. | Adding-up<br>Homogeneity<br>Symmetry | 1<br>6<br>12 | 19 | 216.0 | 30.1 | yes |
| 2. | Adding up<br>Homogeneity | 1<br>6 | 7 | 754.0 | 14.1 | yes |
| 3. | Adding-up<br>Symmetry | 1<br>12 | 13 | 364.9 | 22.4 | yes |
| 4. | Symmetry<br>Homogeneity | 12<br>6 | 18 | 21.0 | 28.9 | no |
| 5. | Adding-up | 1 | 1 | very large | 3.8 | yes |
| 6. | Homogeneity | 6 | 6 | 353.0 | 12.6 | yes |
| 7. | Symmetry | 12 | 12 | 15.0 | 21.0 | no |

In this study, decreasing returns to scale associates low costs with low expenditure shares and higher costs with higher share, while increasing returns to scale associates low expenditure share with high costs and high expenditure share with low costs. The failure to accept the adding-up restriction and homogeneity implies that homogeneity and constant returns to scale are not evident in short-run electric power production.

### 6.2.1 OLS Assumption Tests

Acceptance of OLS assumptions 2 (explanatory variables are uncorrelated with error terms), 3 (error terms are serially uncorrelated), and 4 (dependent variables are uncorrelated with one another) is crucial for elasticity estimation, and especially to this research, because these three assumptions are most important for the quality of parameter estimates. Without these assumptions and their underlying implications intact, parameters cannot be accepted as valid estimates. Since the objective of this research is to estimate interfuel substitution, and elasticities of substitution are linear functions of parameter estimates, parameter validity is essential.

The failure to meet the second OLS assumption is a condition known as heteroskedasticity, which does not bias parameter estimators but will cause standard error underestimation. Anscombe (1961) and Ramsey (1969) describe a diagnostic test called RESET, which will give a weak indication of heteroskedasticity. The Anscombe/Ramsey tests both involve regressions of predicted values (raised to the first, second, and third powers) on the regression residuals. No heteroskedasticity was detected for coal, oil, and nuclear share equations, and the highest correlation coefficient for the gas, hydroelectric, and wholesale power share equations was 0.32. This low value of heteroskedasticity is not considered damaging to the assumption of constant variance within an equation.

Serial correlation will also cause excessive but understated parameter estimate variance, invalidating Student-t tests for statistical significance. In addition, overall model variance will be underestimated, resulting in deceptively high goodness-of-fit diagnostics. The most common and convenient test for first order serial correlation is the Durbin-Watson D-statistic, a test of the hypothesis that in a regression of

$$u_t = \alpha + p u_{t-1} \qquad (6.1)$$

$p$ is equal to zero, or that there is no first-order pattern to sequential error terms. The lower bound Durbin-Watson D-statistic critical value for a model with 82 observations and 7 explanatory variables extrapolates is approximately 1.30, and an upper bound is 1.65. The hypothesis of autocorrelation is rejected for all but the gas and hydroelectric share equations, which both have D-statistics lying in the indeterminant region where no statement can be made about correlation. Durbin-Watson statistics are shown in the analysis of variance (ANOVA) results shown in Table

6.2. The gas share and hydroelectric share equations are both in the indeterminant region.

Table 6.2 ANOVA Results

| Eq | DF Model | DF Err | SSE | MSE | Root MSE | $R^2$ | Adj-$R^2$ | Durbin Watson |
|---|---|---|---|---|---|---|---|---|
| CS | 11.5 | 70.5 | 4.6463 | 0.06591 | 0.25672 | 0.5095 | 0.4365 | 1.945 |
| GS | 11.5 | 70.5 | 0.7742 | 0.01098 | 0.10479 | 0.6185 | 0.5617 | 2.499 |
| OS | 11.5 | 70.5 | 1.8819 | 0.02669 | 0.16338 | 0.2828 | 0.1760 | 1.980 |
| US | 11.5 | 70.5 | 1.9703 | 0.02795 | 0.16718 | 0.1570 | 0.0314 | 2.128 |
| HS | 11.5 | 70.5 | 2.2837 | 0.03239 | 0.17998 | 0.2059 | 0.0876 | 1.622 |
| WS | 11.5 | 70.5 | 6.0954 | 0.08646 | 0.29404 | 0.3300 | 0.2302 | 1.891 |

Multicollinear data results in parameter estimates with large parameter variance, resulting in low estimate reliability. Multicollinearity may be caused by low variation in independent variables or high correlation between independent variables. A common test to determine multicollinearity is the Belsley, Welsh, and Kuh (1980) multicollinearity diagnostic condition number, defined as the square root of the largest to the smallest eigenvalue of the matrix X'X of explanatory variables (Maddalla, 1988). If the condition number is very large (i.e., many times greater than 30), the likelihood is that correlation exists between two or more explanatory variables. The SAS/ETS

COLLIN diagnostic utility was used to test for multicollinearity. The wholesale price variable in the hydroelectric power equation and three output variables have condition numbers over 30, and all condition numbers for regional dummy variables are extremely high (acceptable for intercept terms).

The conclusions drawn from these tests are that heteroskedasticity, multicollinearity, serial correlation hypotheses are rejected for these data series and equations, consequently estimated parameters, associated standard errors, and t-test statistics are accepted as non-biased and valid. Any remaining inability to reject t-test null hypotheses is attributed to 1) a high level of data aggregation and 2) specification error.

### 6.2.2 Alternative Functional Forms

As noted in the data description section in chapter 5, because of the data collection technique, a utility which does not consume any quantity of a particular fuel exhibits a cost share of zero for that commodity, however, no price has been recorded by the utility. Consequently, if costs are recorded as zero and the share equation is solved with a zero cost for that commodity, zero cost shares will be statistically associated with zero commodity costs, an obvious violation of profit-maximization theory. Ordinarily, if a commodity can be purchased at a zero cost, the consumer would demand the maximum amount of that commodity, i.e., continue to consume until the marginal productivity of the input is zero.

To avoid this statistical aberration, regional prices have been substituted for null commodity cost values to serve as cost approximations for prevailing fuel costs in each region. These proxy costs are the average regional costs presented in chapter 3. For example, the equations for all utilities which did not consume any coal in region 3, the Midwest, were solved using the average coal cost for region 3 in 1987 ($1.58/MBtu) in place of the zero value contained in the data set. This is the proxy cost for coal in region 3 and is identical for all utilities in region 3 which did not consume coal. If the utility did consume coal, the equation is solved using the price observed for that utility. The proxy-cost model differs from equation 5.28 only in that regional average prices are substituted for null energy cost values for coal, gas and oil.

The influence geographic location has upon fuel selection was tested by determining whether inclusion of regional dummy variables in the regression adds to regression quality. Regional variable inclusion was tested by the chi-squared test described in section 5.8 using equation (5.28) as the fully-specified model (with regional variables included), and the reduced-form model was equation (5.28) (without regional variables). This procedure tests for differences in constant term effects across regions. Using the results of the maintained hypothesis tests, the four specifications were tested with jointly imposed homogeneity and symmetry, and symmetry alone. The results are shown in Table 6.3.

Table 6.3 Proxy-Cost Substitution and Functional Forms

| Model | D.F. | $X^2$ | C.V. | $H_0$ Rejected? (0.05) |
|---|---|---|---|---|
| Regional Variables | | | | |
| Homogeneity & Symmetry | 18 | 21.0 | 28.3 | no |
| Symmetry only | 12 | 15.0 | 21.0 | no |
| No Regional Variables | | | | |
| Homogeneity & Symmetry | 18 | 57.0 | 28.9 | yes |
| Symmetry only | 12 | 51.0 | 21.0 | yes |

As shown, the homogeneity/symmetry models were eliminated in the previous section because CRTS was rejected. Therefore, the symmetry alone model with regional variables is retained. As a result, the proxy-cost model with regional dummy variables will be retained in the elasticity analysis.

### 6.2.3 Parameter Estimates

Parameter estimates are shown in Table 6.4. Complete regression results including t-statistics on parameter estimates are presented in Appendix C.

Table 6.4 Parameter Estimates

| | Coal | Gas | Oil | U3O8 | Hydro | Wsale | Sum |
|---|---|---|---|---|---|---|---|
| Coal | 0.024 | 0.030 | -0.010 | 0.067 | 0.011 | -0.122[2] | 0.00001 |
| Gas | 0.030 | -0.069 | -0.003 | 0.032 | 0.011 | 0.000 | 0.00001 |
| Oil | -0.010 | -0.003 | -0.098 | 0.085 | 0.026 | 0.000 | 0.00002 |
| U3O8 | 0.067 | 0.032 | 0.085[1] | -0.150[1] | 0.013 | -0.048[1] | 0.00001 |
| Hydro | 0.011 | 0.011 | 0.026 | 0.013 | -0.036 | -0.025 | -0.00001 |
| Wsale | -0.122 | 0.000 | 0.000 | -0.048 | -0.025 | 0.194[2] | 0.00000 |

Note: [1] Significant at the 0.05 level
[2] Significant at the 0.01 level

The sum of all parameters for each equation is shown under the Sum column, which indicates the direction and magnitude of returns to scale. If parameters of logarithms summed to zero, this would indicate constant returns to scale. The hydroelectric demand equation indicates decreasing returns to scale, while all others indicate increasing returns to scale, except for wholesale power which indicates constant returns to scale.

One disappointing feature of this analysis is that very few parameters are statistically significant at the 0.05 acceptance level. However, there are conspicuous exceptions. Notably, wholesale power cost in the coal equation is significant at the 0.01 acceptance level. The nuclear fuel cost parameter in the oil equation and the oil price in the nuclear fuel equation are both significant, and also the wholesale power cost parameter estimated in the nuclear power share equation.

Because heteroskedasticity, multicollinearity, and autocorrelation hypotheses were rejected, poor significance levels are attributed to data aggregation and specification error. The remaining price elasticity discussion will proceed despite low parameter significance, but all subsequent results and conclusions should be accompanied with a warning regarding regression quality and parameter significance.

## 6.3 Substitution and Price Elasticities

Substitution elasticity is interpreted as the percentage change in the ratio of quantity demanded in one fuel to quantity demanded in another, in response to a change in the price ratio (Binger and Hoffman, 1988). As shown in equations (5.24) and (5.25), these relationships show that substitution elasticity is a function of cost share, shown in Table 6.5. (Average prices and the number of utilities which consumed a portion of production from each commodity are also shown for reference.) The resulting elasticities of substitution shown in Table 6.6 show the percentage change in demand (measured in Btu) of the commodity symbolized by the first letter in response to a price change in the commodity represented by the second letter. Within the coal demand equation, coal cross-price elasticities indicate that coal demand is insensitive to price changes by other commodities, and only the coal cross-price elasticity estimated for natural gas could even be considered economically significant.

Own-price elasticities in Table 6.7 are ranked in order of increasing price elasticity, showing that coal and wholesale power are largely insensitive to changes in their own prices. Cross-price elasticities are shown in Table 6.8.

Own-price elasticities in the proxy-cost model indicate that hydroelectric power and gas are moderately elastic, but oil and nuclear fuel are the most elastic of the six fuels. Oil elasticity is consistent with utility industry behavior

Table 6.5 Average Factor Share Values and Energy Prices (dollars per million Btu)

| Commodity | Average Share | Average Price | Data Points |
|---|---|---|---|
| Coal | 0.3570 | 1.56 | 57 |
| Gas | 0.0739 | 2.27 | 48 |
| Oil | 0.0782 | 3.94 | 62 |
| U3O8 | 0.0594 | 0.80 | 25 |
| Hydro | 0.0562 | 0.29 | 42 |
| Wholesale | 0.3753 | 3.84 | 70 |
| Total | 1.0000 | | |

Table 6.6 Substitution Elasticities

| | Coal (%) | Gas (%) | Oil (%) | U3O8 (%) | Hydro (%) | Wsale (%) |
|---|---|---|---|---|---|---|
| Coal | -1.313 | 2.295 | 1.320 | 0.788 | 1.247 | 0.210 |
| Gas | 2.295 | -24.861 | 0.077 | 7.936 | 3.297 | 0.943 |
| Oil | 1.320 | 0.077 | -28.748 | 16.611 | 6.293 | 1.147 |
| U3O8 | 0.788 | 7.936 | 16.611 | -42.896 | 1.790 | 0.753 |
| Hydro | 1.250 | 3.297 | 6.293 | 1.790 | -30.453 | 1.135 |
| Wsale | 0.210 | 0.943 | 1.147 | 0.753 | 1.135 | -0.914 |

Table 6.7 Ranked Own-Price Elasticities

| Range | E | Estimate |
|---|---|---|
| Inelastic | Eww | -0.34 |
| | Ecc | -0.47 |
| Elastic | Ehh | -1.71 |
| | Egg | -1.84 |
| | Eoo | -2.25 |
| | Enn | -2.55 |

Table 6.8 Cross-Price Elasticities

| E | Estimate | E | Estimate |
|---|---|---|---|
| Ecg | 0.17 | Enc | 0.28 |
| Eco | 0.10 | Eng | 0.59 |
| Ecn | 0.05 | Eno | 1.30 |
| Ech | 0.07 | Enh | 0.10 |
| Ecw | 0.08 | Enw | 0.28 |
| Egc | 0.82 | Ehc | 0.45 |
| Ego | 0.01 | Ehg | 0.24 |
| Egn | 0.47 | Eho | 0.49 |
| Egh | 0.19 | Ehn | 0.11 |
| Egw | 0.35 | Ehw | 0.43 |
| Eoc | 0.47 | Ewc | 0.08 |
| Eog | 0.01 | Ewg | 0.07 |
| Eon | 0.99 | Ewo | 0.09 |
| Eoh | 0.35 | Ewn | 0.04 |
| Eow | 0.43 | Ewh | 0.06 |

since oil price deregulation, nonetheless, hydroelectric and nuclear fuel elasticities are inexplicably high, which seems inconsistent with hydroelectricity's and nuclear fuel's low cost and specialized technologies.

Although cross-elasticities are not generally categorized, for the purpose of this discussion, relative cross-elasticities are ranked in the same manner as own-price elasticities. Cross-price elasticities greater than one are referred to as elastic, elasticities between zero and one are inelastic, and negative elasticity indicates a complimentary relationships.

Ranking cross-price elasticities in order of increasing inelasticity again shows nuclear fuel to be among the most elastic, substituting with coal and wholesale power. The only elastic cross-price relationship is oil substitution for nuclear fuel. Nuclear fuel evidently substitutes for oil, and gas demand is also slightly sensitive to coal price. One of the most notable relationships indicated by the cross-elasticities shown in Table 6.9 is that coal and wholesale demand are relatively insensitive to price changes in each other despite the strong significance of wholesale cost in the coal equation.

The strong, apparently mutual relationship between oil and nuclear fuel demand is possibly influenced by

Northeastern utilities which have restricted access to gas, but have a significant portion of U.S. oil-burning capacity, and also receives a large portion of generation from nuclear facilities. Gas and nuclear fuel substitution may occur in the Midwest, where nuclear generation and natural gas consumption are higher than average.

Table 6.9 Ranked Cross-Price Elasticities

| E | Estimate | E | Estimate | E | Estimate | E | Estimate |
|---|---|---|---|---|---|---|---|
| Eno | 1.30 | | | | | | |
| Eon | 0.99 | Eoh | 0.35 | Eco | 0.10 | Ecn | 0.05 |
| Egc | 0.82 | Egw | 0.35 | Enh | 0.10 | Ewn | 0.04 |
| Eng | 0.59 | Enw | 0.28 | Ewo | 0.09 | Ego | 0.01 |
| Eho | 0.49 | Enc | 0.28 | Ecw | 0.08 | Eog | 0.01 |
| Egn | 0.47 | Ehg | 0.24 | Ewc | 0.08 | | |
| Eoc | 0.47 | Egh | 0.19 | Ech | 0.07 | | |
| Ehc | 0.45 | Ecg | 0.17 | Ewg | 0.07 | | |
| Eow | 0.43 | Ehn | 0.11 | Ewh | 0.06 | | |
| Ehw | 0.43 | | | | | | |

## 6.4 Comparison with Previous Studies

The results obtained from four previous studies are relevant to the present research because they measure interfuel substitution and also use translog input demand models. Other studies have examined fuel substitution with labor, structures, capital, and materials, but such aggregated studies do not provide much information about substitution between individual fuels.

Atkinson and Halvorsen (1976) modeled utility fuel substitution, evidence of scale economies, and separability of input demand by using a cross-sectional, three fuel input system of coal, oil, and natural gas. They measured consumption at individual plants, implying that each observation records consumption of a relatively small number of generating units. The assumption implied by measuring plant-level data is that the decision to substitute fuels occurs at the plant level. In fact, most utilities operate many plants with several units at each plant, meaning that a single management group controls a large number of generation units. Some of Atkinson and Halvorsen's data points were plants which could not burn all three fuel types; in practice, fuel substitution opportunities for these plants were limited to fuels which would burn in the generators installed at the plant. For this reason, Atkinson and Halvorsen broke the three inputs into a system of two-input models: coal-gas, coal-oil, and oil-gas. They concluded that steam electric generation is characterized by substantial fuel substitution, and strong scale economies were absent. The Atkinson-Halvorsen own- and cross-price elasticities are shown in Table 6.10.

Table 6.10 Thesis Results and Comparison to Previous Research

| E | Thesis | AH 76 C-G (%) | AH 76 C-O (%) | AH 76 O-G (%) | F 77 (%) | KL 88 (%) | C 89 xlog (%) | C 89 logit (%) |
|---|---|---|---|---|---|---|---|---|
| Ecc | -0.47 | -0.43[1] | -1.15[1] | - | -1.48 | -0.82 | -1.11 | -1.01 |
| Egg | -1.84 | -1.43[1] | - | 0.21 | -1.30 | - | -0.52 | -0.47 |
| Eoo | -2.25 | - | -1.50[1] | -1.60 | -1.30 | - | -0.44 | -0.33 |
| Enn | -2.55 | - | - | - | - | - | - | - |
| Ehh | -1.71 | - | - | - | - | - | - | - |
| Eww | -0.34 | - | - | - | -0.74 | -0.39 | -0.51 | -0.49 |
| Ecg | 0.17 | 0.09 | - | - | 0.64 | - | -1.34 | -1.01 |
| Eco | 0.10 | - | 0.99[1] | - | 0.23 | 0.52 | 0.95 | 0.63 |
| Ecn | 0.05 | - | - | - | - | - | - | - |
| Ech | 0.07 | - | - | - | - | - | - | - |
| Ecw | 0.08 | - | - | - | 0.02 | 0.31 | 1.51 | 1.38 |
| Egc | 0.82 | 0.45[1] | - | - | 0.76 | - | -0.26 | -0.20 |
| Ego | 0.01 | - | - | 0.58[1] | 0.11 | - | 0.10 | 0.04 |
| Egn | 0.47 | - | - | - | - | - | - | - |
| Egh | 0.19 | - | - | - | - | - | - | - |
| Egw | 0.35 | - | - | - | -0.07 | - | 0.69 | 0.63 |
| Eoc | 0.47 | - | 1.01[1] | - | 0.24 | 0.15 | 0.26 | 0.17 |
| Eog | 0.01 | - | - | 0.76[1] | 0.09 | -0.23 | 0.14 | 0.05 |
| Eon | 0.99 | - | - | - | - | - | - | - |
| Eoh | 0.35 | - | - | - | - | - | - | - |
| Eow | 0.43 | - | - | - | 0.19 | 0.08 | 0.04 | 0.11 |
| Enc | 0.28 | - | - | - | - | - | - | - |
| Eng | 0.59 | - | - | - | - | - | - | - |
| Eno | 1.30 | - | - | - | - | - | - | - |
| Enh | 0.10 | - | - | - | - | - | - | - |
| Enw | 0.28 | - | - | - | - | - | - | - |
| Ehc | 0.45 | - | - | - | - | - | - | - |
| Ehg | 0.24 | - | - | - | - | - | - | - |
| Eho | 0.49 | - | - | - | - | - | - | - |
| Ehn | 0.11 | - | - | - | - | - | - | - |
| Ehw | 0.43 | - | - | - | - | - | - | - |

(Continued)

Table 6.10 (Continued)

| E | Thesis | AH 76 C-G (%) | AH 76 C-O (%) | AH 76 O-G (%) | F 77 (%) | KL 88 (%) | C 89 xlog (%) | C 89 logit (%) |
|---|---|---|---|---|---|---|---|---|
| Ewc | 0.08 | - | - | - | 0.05 | 0.19 | 0.14 | 0.15 |
| Ewg | 0.07 | - | - | - | -0.18 | - | 0.34 | 0.32 |
| Ewo | 0.09 | - | - | - | - | - | - | - |
| Ewn | 0.04 | - | - | - | - | - | - | - |
| Ewh | 0.06 | - | - | - | 0.55 | 0.19 | 0.02 | 0.04 |

[1] Significant at 0.05 level

Notes: A hyphen indicates that the elasticity was not estimated.

Electric power elasticities in previous studies represent electric substitution between fuels in the respective economy or sector.

| | |
|---|---|
| AH 76: | Atkinson and Halvorsen, 1976: Electric utility interfuel substitution (cross-sectional data) |
| F 77: | Fuss, 1977: Canadian manufacturing energy demand submodel (time series) |
| KL 88: | Kim, Labys, 1988: Korean manufacturing interfuel substitution (time series) |
| C 89: | Considine, 1989: U.S. Industrial interfuel substitution (time series of translog (xlog) and logit models) |

Fuss (1977) modeled fossil fuel demand by the Canadian manufacturing sector and estimated price elasticities in four Canadian regions by estimating share equations with quarterly time series price data for six fuels: coal, liquid petroleum gas, fuel oil, natural gas, electricity and motor gasoline. This energy model was then used as an instrumental variable in an aggregated economic model of the Canadian manufacturing sector. Fuss's electricity price-elasticities represent, for the most part, retail electric power substitution with the other five fuels by the Canadian manufacturing sector, and are not directly comparable to results from the current research. Fuss found that substantial interfuel substitution could occur and as a partial consequence, large energy price increases could be absorbed with only a small output price increase in the manufacturing sector.

Kim and Labys (1988) studied energy substitution in a developing country, Korea. They modeled demand for coal, oil, and electricity in nine manufacturing and three non-manufacturing subsectors. The price elasticities presented in Table 6.10 for comparison are for the total Korean economy in 1978. Kim and Labys found that coal exhibited a relatively high own-price elasticity in several sectors, but is relatively inelastic in the aggregate economy. Coal and oil were found to be substitutes, and coal itself substituted for electricity in light manufacturing. Kim and Labys conclude that coal is capable of replacing oil and electricity in the industrial sector, oil and electricity are complements, and the magnitude of the own- and cross-price elasticities indicate that fuels are strongly but not perfectly substitutable in existing industrial energy-using facilities. Policies that are intended to promote coal substitution for oil in order to alleviate Korean foreign exchange deficits would be ineffective and not significantly affect oil imports.

Considine (1989) compares translog demand-share to a logit demand-share specification in demand models for four energy types: petroleum, natural gas, steam coal, and electricity. Considine cites three reasons why previous studies using translog models yield incorrect signs in own-price elasticities. First, including energy material in petroleum and coal categories may aggregate the material and fuel markets in a way which can contribute to incorrect signs. Second, portions of the translog function may violate concavity assumptions. Third, natural gas regulation and partial prohibition of gas-burning facilities were found to influence U.S. industrial fuel demand. With regard to electric power elasticities, as with Fuss, and Kim and Labys, the electricity own-price and cross-price elasticities measure substitution with other primary fuels among industrial end-users.

Compared to the study results summarized above, this research's elasticities indicate that coal demand is less sensitive to changes in its own price in the electric utility market than in domestic and foreign industrial sectors. Coal's own-price elasticity estimated by the thesis research is nearest in scale to the Atkinson and Halvorsen coal own-price elasticity in their coal-gas model. The coal own-price elasticity from the Atkinson and Halvorsen coal-oil model is more elastic.

The estimate from the current research for natural gas elasticity is again nearest in magnitude to the Atkinson and Halvorsen coal-gas estimate. This indicates that the natural gas demand by electric utilities is more sensitive to price than Considine's U.S. industrial demand estimate which indicates that industrial gas demand is relatively price inelastic. The same is true for oil, as both utility models, this thesis and Atkinson and Halvorsen's, indicate that oil demand by utilities is more elastic than Considine's industrial estimate. Nuclear and hydroelectric power elasticities were not estimated in any previous work surveyed for this research. The thesis results indicate that wholesale power is more inelastic within the electric utility market than retail electric power in either the Canadian, Korean, or U.S. industrial markets.

## 6.5 Conclusions from Empirical Results

Results from the foregoing analysis indicate that the symmetry assumption applies to the translog model of conditional demand equations for electric utilities, and also, regional dummy variables are valuable explanatory variables.

For the most part, regression parameter estimates are not statistically significant, but because OLS violations which most influence parameter estimate validity--heteroskedasticity, autocorrelation, and multicollinearity --were absent, poor statistical significance is attributed to either data aggregation or incorrect model specification. Exceptions were wholesale price parameter in the coal and nuclear fuel share equations, nuclear fuel price in the oil share equation, and vice versa.

Despite the poor statistics, some conclusions may be inferred from the resulting own-price and cross-price elasticities.

1. Coal demand is largely insensitive to rising prices in competitive fuels, is own-price inelastic, and

coal substitutes inelastically for natural gas and oil.

2. Gas demand is most sensitive to coal and nuclear fuel prices, and natural gas substitutes for nuclear fuel. Electric utility gas demand is significantly more own-price sensitive in the utility market than in the industrial sector.
3. Oil demand is most sensitive to nuclear fuel price, and oil substitutes elastically with nuclear fuel. Although this phenomena is inconsistent with existing industry technology and practice, statistically, this relationship between oil and nuclear fuel is the strongest relationship in the entire study. This substitution probably occurs most in the Northeast region, where both oil and nuclear fuel intensity-of-use are highest. As with natural gas, oil is more own-price sensitive in the utility market than in the industrial sector.
4. Nuclear fuel demand is sensitive to oil price, and substitutes elastically with oil.
5. Wholesale power demand is insensitive to changes in its own price and primary fuel prices, but substitutes in inelastically for gas, oil, and hydroelectric power.

# Chapter 7

# CONCLUSIONS

The objective of this research has been to estimate interfuel substitution by electric utilities and determine the impact of wholesale power sales on utility demand. Results from this research indicate that baseload fuels substitute for peakload fuels in overall utility markets, resulting in smoother aggregate load curves and lower operating costs by increasing baseload capacity load factors.

## 7.1 Market Dynamics

The relationship between the six electricity energy sources is shown in Figure 7.1. The three combustible fuels (i.e., fuels whose prime movers exhibit some compatibility) are at the top of the diagram, with nuclear, hydroelectric, and wholesale power below. Generating expense increases to the right, leaving those fuels most suitable for baseload (coal and nuclear, and hydroelectric) to the left of gas, oil, and wholesale power.

Lines drawn between fuel symbols represent substitution occurring between those fuels and arrows indicate the direction of substitution. For instance, coal indicated a moderate substitution for oil, shown by the arrow going from

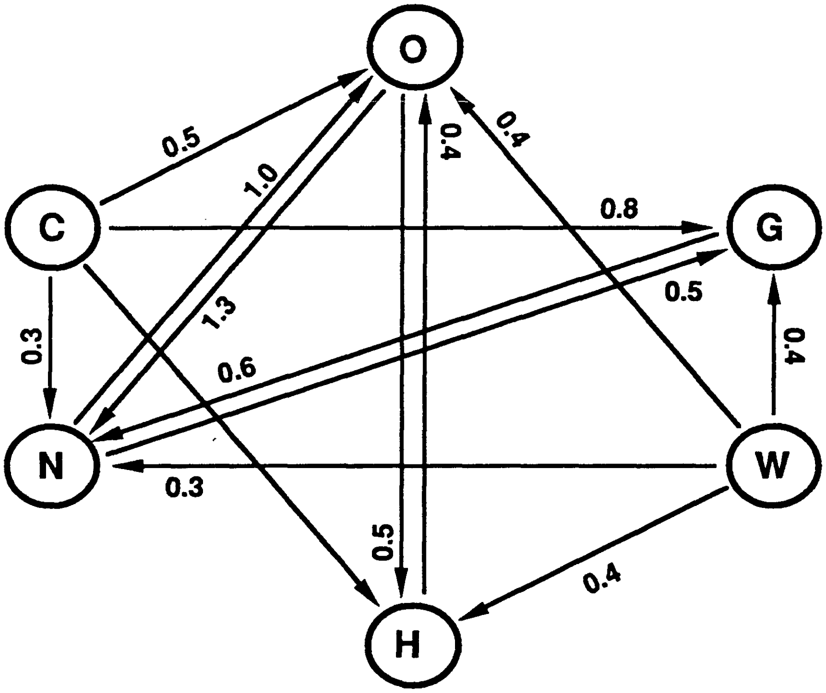

Figure 7.1 Cross-price Elasticities

the coal symbol to the oil symbol. Only elasticities greater than 0.25 are shown to focus on the most important relationships.

There are three intertechnology (from thermal-to-nonthermal or conventional thermal-to-nuclear) substitutions: oil-nuclear, gas-nuclear, and oil-hydro. On a smaller scale, coal substitutes for nuclear generation. Wholesale power also substitutes for the four fuels involved in intertechnology substitution.

Summarizing, coal substitutes somewhat inelastically for all other fuels, wholesale power substitutes inelastically for all primary fuels, nuclear fuel substitutes elastically for oil and inelastically for gas. Intertechnology substitution, such as nuclear fuel substitution for oil or gas, can only be accomplished if wholesale power is available to consumers who do not possess all production technologies. All three intertechnology substitutions (nuclear and oil, nuclear and gas, and hydroelectric power and oil) are bilateral.

Substitution between oil and nuclear fuel is a typical intertechnology association for use as an example. Two circumstances exist in the oil-nuclear fuel substitution problem: 1) the utility observes higher than average oil costs and has both nuclear and oil-burning capacity, or 2) a utility which owns oil-fired capacity observes higher than average oil costs but operates no nuclear capacity. In the first case, the utility increases nuclear capacity to meet demand that would otherwise be supplied with oil-fired units, and in the second case, the utility purchases wholesale power when the wholesale price is lower than the decremental oil costs.

Statistically, a buyer's increased wholesale power shares are associated with higher than average oil prices. Likewise, high nuclear fuel share will be statistically associated with high oil prices if the selling utility encounters the same prevailing oil costs. Over many data samples, using this logic, increased nuclear share will be associated with high oil prices, high oil prices will be associated with increased nuclear and wholesale power share. This result is consistent with what the model suggests has occurred.

## 7.2 Demand Curve Effects

Baseload fuel substitution for peak load fuels implies that baseload capacity displaces peakload capacity, which has the apparent effect of flattening aggregate demand curves. This is beneficial from an efficiency perspective, because flat demand curves are less expensive to satisfy than steeply sloped curves. As shown in chapter 2, flat load curves allow higher generator utilization rates, increasing generator load factors, which in turn influences baserate calculation and capital investment decisions.

Retail demand is not affected by the choice of wholesale power purchases, but such purchases excuse utility buyers from recruiting high-cost capacity to satisfy short-term retail demand. The buyer's peak load capacity is lowered by the amount of wholesale power purchased. Selling utilities increase their baseload by the amount of the sale. Off-peak capacity is elevated because large units neither pick up nor shed output rapidly. The net effect of wholesale power sales on aggregate demand curves, the sum of buyers' and sellers', in the with wholesale purchases, has a lower peak and higher "shoulders" than if all demand were met with self-generation.

### 7.3 Market Impact and Pricing Policy

The discussion in chapter 6 accepted with caution the thesis estimates as reasonable measures of demand elasticity direction and magnitude. These estimates may be used to estimate market response to price increase, and predict the effects of pricing policy by producers of electric utility fuels. Own-price elasticity of demand is interpreted as the percentage change in quantity demand for a given percentage change in price along the ordinary demand curve (Binger and Hoffman, 1988). Using this definition, the effect on electric utility demand caused by a one percent increase in price for the five energy commodities is shown in Table 7.1.

Table 7.1 Own-Price Elasticity Market Impact (millions of units)

| Commodity | 1987 Utility Demand (units) | E | Qty Change (tera-Btu) | Qty Change (units) | Value (87 M$) |
|---|---|---|---|---|---|
| Coal | 718 tons | -0.47 | -69.2 | -3.4 tons | -108 |
| Gas | 2.8 Tcf | -1.84 | -59.7 | -51.4 Mmcf | -144 |
| Oil | 337.8 bbls | -2.25 | -41.5 | -7.6 bbls | -187 |
| U3O8 | 25.3 lbs | -2.55 | -128.6 | -0.6 lbs | -18 |
| Wsale | 337 Mwh | -0.34 | -3.9 | -1.2 Mwh | -15 |

Mmcf = million cubic feet

Source: Data derived from EIA/DOE, 1989, Annual Energy Review 1987 and State Energy Price and Expenditure Report 1987. Washington D. C.: Government Printing Office.

Table 7.1 shows 1987 utility energy demand in respective units of delivery, estimated own-price elasticity, the market volume impact in Btus and delivery units, and the dollar value of the impacted demand. Prices are the average prices observed from the 82 utilities used in the thesis research data set. Oil demand is affected the most dramatically; the value of oil sales to utilities would fall about \$187 million (about 5% of total sales to utilities) if oil prices rose one percent, compared to \$144 million in gas sales, \$108 million in coal sales, \$18 million in uranium sales, and \$5 million in wholesale power sales.

Cross-price market effects are given by cross-price elasticities, interpreted as the percentage change in input quantity demanded in response to a given percentage change in the price of another input. Cross-price market effects, measured in terms of market value and energy, are shown in Tables 7.2 and 7.3. The table convention is that a one percent increase in any commodity identified by a column heading will result in a dollar increase equal to the amount corresponding to the commodities identified in each row. For example, if gas price increased one percent, the entire coal market value would increase \$39 million, oil market value would increase \$0.4 million, and so on.

Pricing policy is implied by marginal revenue analysis, after Binger and Hoffman (1988). Marginal revenue can be expressed in terms of elasticity as shown in equation 7.1.

$$MR(x) = p_x(1 + 1/\sigma_{ii}) \tag{7.1}$$

Table 7.2 Market Value Impact on Electric Utility Commodities (1987 million dollars)

| | Coal | Gas | Oil | U3O8 | Wsale |
|---|---|---|---|---|---|
| Coal | (108.2) | 39.0 | 23.8 | 10.8 | 18.2 |
| Gas | 72.7 | (144.3) | 0.5 | 41.9 | 31.4 |
| Oil | 34.2 | 0.4 | (187.2) | 71.7 | 31.3 |
| U3O8 | 11.4 | 23.7 | 52.4 | (17.5) | 11.4 |
| Wsale | 1.0 | 0.9 | 1.2 | 0.6 | (15.0) |

Table 7.3 Energy Impact on Electric Utility Commodities (in millions of respective delivery units)

| | | Coal | Gas | Oil | U3O8 | Wsale |
|---|---|---|---|---|---|---|
| Coal | tons | (3.4) | 25.0 | 15.2 | 6.9 | 11.7 |
| Gas | Mmcf | 26.6 | (51.4) | 0.2 | 15.3 | 11.5 |
| Oil | bbls | 8.7 | 0.1 | (7.6) | 18.2 | 7.9 |
| U3O8 | lbs | 14.2 | 29.6 | 65.5 | (0.6) | 14.3 |
| Wsale | Mwh | 0.3 | 0.2 | 0.3 | 0.2 | (1.1) |

In the elastic regions of the linear demand curve where marginal revenue increases, total revenue will increase in response to a price drop occurring as the result of an increase in production. Conversely, a price increase will result in a decrease in total revenue. Table 7.4 shows the marginal revenue resulting from a one percent price reduction.

Table 7.4 Marginal Revenue Analysis (Dollars per million Btu)

| Commodity | E | Ave Price | MR (%) |
|---|---|---|---|
| Coal | -0.47 | 1.56 | -1.77 |
| Gas | -1.84 | 2.73 | 1.24 |
| Oil | -2.25 | 3.94 | 2.19 |
| Nuclear | -2.55 | 0.80 | 0.49 |
| Wholesale | -0.34 | 3.84 | -7.35 |

Note: Prices are average prices taken from the Translog Model Data set

The implication for total revenue is that if marginal revenue is positive and prices rise, total revenue increases. Commodities with inelastic demand, such as coal and wholesale power, will lose total revenue as price falls even though supply and deliveries increase, and commodities with elastic demand, (gas, oil, and nuclear power) will increase total revenue although prices fall.

### 7.4 Suggestions for Future Research

This research could be expanded by either of two approaches. To increase the depth of analysis and resolve inconclusive relationships, the data size should be enlarged so that individual regions may be analyzed independently. Perhaps this could be done by pooling time series data with the existing cross-sectional data format. Multiple-output technologies could be modeled to estimate elasticity of supply. Time-of-use, and demand-curve data, if available, would reveal more about the impact of demand characteristics on load curve substitution.

On the other hand, rather than increasing the level of detail, this research could be combined, possibly as an instrumental variable, in a comprehensive, multiple-sector analysis of United States energy demand. However, macroeconomic research would also benefit from a larger data sample.

Other research topics, such as policy analysis, could be studied by verifying fundamental economic assumptions, (i.e., cost-minimization, profit-maximization, etc.) by comparing utility industry historical performance with analytical solutions (such as dynamic programming techniques) to the cost-minimization problem.

Finally, the success of this research may indicate that the transcendental logarithmic function analytical technique, despite its acknowledged shortcomings regarding global nonconcavity, holds promise for analyzing other disaggregated inputs to production, capital and labor, and might be a useful way to analyze disaggregated consumer durables and nondurables in nonenergy market analysis.

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# APPENDIX A

## SAS COMMAND FILE

```
data tc;
infile 'tc.dat';
  input no region tc;

data share;
 infile 'share.dat';
 input cs gs os us hs ws;

data cost;
 infile 'cost.dat';
 input  coal_c gas_c oil_c u3o8_c hydro_c wsale_c;

data output (replace = yes);
 infile 'output.dat';
 input wsale_q rsale_q tot_q;

data xlog;
 merge share cost output tc;

/* logrithms are undefined at 0.0 */

if coal_c <= 0.0 then lcc = 0.000001;
else lcc = log(coal_c);

if gas_c <= 0.0 then lgc = 0.000001;
else lgc = log(gas_c);

if oil_c <= 0.0 then loc = 0.000001;
else loc = log(oil_c);

if u3o8_c <= 0.0 then lnc = 0.000001;
else lnc = log(u3o8_c);

if hydro_c <= 0.0 then lhc = 0.000001;
else lhc = log(hydro_c);

if wsale_c <= 0.0 then lwc = 0.000001;
else lwc = log(wsale_c);

if tot_q <= 0.0 then ltot_q = 0.000001;
else lq = log(tot_q);
```

```
/*   Regional proxy prices are commented out
      */

     if coal_c <= 0.00 & region = 1 then lcc = 0.5365 ;
     if gas_c  <= 0.00 & region = 1 then lgc = 1.6409 ;
     if oil_c  <= 0.00 & region = 1 then loc = 1.7630 ;
     if u3o8_c <= 0.0 then lnc = -0.2231 ;
     if wsale_c <= 0.0 then lwc = 1.3455;

     if coal_c <= 0.00 & region = 2 then lcc = 0.5539;
     if gas_c  <= 0.00 & region = 2 then lgc = 1.4748;
     if oil_c  <= 0.00 & region = 2 then loc = 1.8181;


     if coal_c <= 0.00 & region = 3 then lcc = 0.4574;
     if gas_c  <= 0.00 & region = 3 then lgc = 1.5129;
     if oil_c  <= 0.00 & region = 3 then loc = 1.8610;


     if coal_c < = 0.00 & region = 4 then lcc = 0.3001;
     if gas_c  < = 0.00 & region = 4 then lgc = 1.3737;
     if oil_c  < = 0.00 & region = 4 then loc = 1.8779;


     if coal_c <= 0.00 & region = 5 then lcc = 0.4447;
     if gas_c  <= 0.00 & region = 5 then lgc = 0.8502;
     if oil_c  <= 0.00 & region = 5 then loc = 1.6487;


     if coal_c <= 0.00 & region = 6 then lcc = 0.1044;
     if gas_c  <= 0.00 & region = 6 then lgc = 1.4207;
     if oil_c  <= 0.00 & region = 6 then loc = 1.8594;


     if coal_c <= 0.00 & region = 7 then lcc = 0.4886;
     if gas_c  <= 0.00 & region = 7 then lgc = 1.2754;
     if oil_c  <= 0.00 & region = 7 then loc = 1.7681;


     /*    region dummy variable assignment matrix */

     if region = 1 then d11 = lcc;
     else d11 = 0.0;

     if region = 1 then d12 = lgc;
     else d12 = 0.0;
```

```
if region = 1 then d13 = loc;
else d13 = 0.0;

if region = 1 then d14 = lnc;
else d14 = 0.0;

if region = 1 then d15 = lhc;
else d15 = 0.0;

if region = 1 then d16 = lwc;
else d16 = 0.0;

if region = 1 then d17 = ltot_q;
else d17 = 0.0;


if region = 2 then d21 = lcc;
else d21 = 0.0;

if region = 2 then d22 = lgc;
else d22 = 0.0;

if region = 2 then d23 = loc;
else d23 = 0.0;

if region = 2 then d24 = lnc;
else d24 = 0.0;

if region = 2 then d25 = lhc;
else d25 = 0.0;

if region = 2 then d26 = lwc;
else d26 = 0.0;

if region = 2 then d27 = ltot_q;
else d27 = 0.0;


if region = 3 then d31 = lcc;
else d31 = 0.0;

if region = 3 then d32 = lgc;
else d32 = 0.0;

if region = 3 then d33 = loc;
else d33 = 0.0;
```

```
if region = 3 then d34 = lnc;
else d34 = 0.0;

if region = 3 then d35 = lhc;
else d35 = 0.0;

if region = 3 then d36 = lwc;
else d36 = 0.0;

if region = 3 then d37 = ltot_q;
else d37 = 0.0;


if region = 4 then d41 = lcc;
else d41 = 0.0;

if region = 4 then d42 = lgc;
else d42 = 0.0;

if region = 4 then d43 = loc;
else d43 = 0.0;

if region = 4 then d44 = lnc;
else d44 = 0.0;

if region = 4 then d45 = lhc;
else d45 = 0.0;

if region = 4 then d46 = lwc;
else d46 = 0.0;

if region = 4 then d47 = ltot_q;
else d47 = 0.0;


if region = 5 then d51 = lcc;
else d51 = 0.0;

if region = 5 then d52 = lgc;
else d52 = 0.0;

if region = 5 then d53 = loc;
else d53 = 0.0;

if region = 5 then d54 = lnc;
else d54 = 0.0;
```

```
if region = 5 then d55 = lhc;
else d55 = 0.0;

if region = 5 then d56 = lwc;
else d56 = 0.0;

if region = 5 then d57 = ltot_q;
else d57 = 0.0;


if region = 6 then d61 = lcc;
else d61 = 0.0;

if region = 6 then d62 = lgc;
else d62 = 0.0;

if region = 6 then d63 = loc;
else d63 = 0.0;

if region = 6 then d64 = lnc;
else d64 = 0.0;

if region = 6 then d65 = lhc;
else d65 = 0.0;

if region = 6 then d66 = lwc;
else d66 = 0.0;

if region = 6 then d67 = ltot_q;
else d67 = 0.0;


if region = 7 then d71 = lcc;
else d71 = 0.0;

if region = 7 then d72 = lgc;
else d72 = 0.0;

if region = 7 then d73 = loc;
else d73 = 0.0;

if region = 7 then d74 = lnc;
else d74 = 0.0;

if region = 7 then d75 = lhc;
else d75 = 0.0;
```

```
if region = 7 then d76 = lwc;
else d76 = 0.0;

if region = 7 then d77 = ltot_q;
else d77 = 0.0;

if region = 1 then reg1 = 1;
if region = 2 then reg2 = 1;
if region = 3 then reg3 = 1;
if region = 4 then reg4 = 1;
if region = 5 then reg5 = 1;
if region = 6 then reg6 = 1;
if region = 7 then reg7 = 1;

if region = 1 then reg2 = 0;
if region = 1 then reg3 = 0;
if region = 1 then reg4 = 0;
if region = 1 then reg5 = 0;
if region = 1 then reg6 = 0;
if region = 1 then reg7 = 0;

if region = 2 then reg1 = 0;
if region = 2 then reg3 = 0;
if region = 2 then reg4 = 0;
if region = 2 then reg5 = 0;
if region = 2 then reg6 = 0;
if region = 2 then reg7 = 0;

if region = 3 then reg1 = 0;
if region = 3 then reg2 = 0;
if region = 3 then reg4 = 0;
if region = 3 then reg5 = 0;
if region = 3 then reg6 = 0;
if region = 3 then reg7 = 0;

if region = 4 then reg1 = 0;
if region = 4 then reg2 = 0;
if region = 4 then reg3 = 0;
if region = 4 then reg5 = 0;
if region = 4 then reg6 = 0;
if region = 4 then reg7 = 0;

if region = 5 then reg1 = 0;
if region = 5 then reg2 = 0;
if region = 5 then reg3 = 0;
if region = 5 then reg4 = 0;
if region = 5 then reg6 = 0;
```

```
if region = 5 then reg7 = 0;

if region = 6 then reg1 = 0;
if region = 6 then reg2 = 0;
if region = 6 then reg3 = 0;
if region = 6 then reg4 = 0;
if region = 6 then reg5 = 0;
if region = 6 then reg7 = 0;

if region = 7 then reg1 = 0;
if region = 7 then reg2 = 0;
if region = 7 then reg3 = 0;
if region = 7 then reg4 = 0;
if region = 7 then reg5 = 0;
if region = 7 then reg6 = 0;

/*
proc print;
 var d11 d12 d13 d14 d15 d16 d17;

proc print;
 var d21 d22 d23 d24 d25 d26 d27;

proc print;
 var d31 d32 d33 d34 d35 d36 d37;

proc print;
 var d41 d42 d43 d44 d45 d46 d14;

proc print;
 var d51 d52 d53 d54 d55 d56 d57;

proc print;
 var d61 d62 d63 d64 d65 d66 d67;

proc print;
 var coal_s gas_s oil_s u3o8_s hydro_s wsale_s tot_q;
*/

/* these variables are used in the cost model only */

cc     = 0.5 * lcc * lcc;
cg     = 0.5 * lcc * lgc;
co     = 0.5 * lcc * loc;
cn     = 0.5 * lcc * lnc;
ch     = 0.5 * lcc * lhc;
cw     = 0.5 * lcc * lwc;
```

```
     gg    = 0.5 * lgc * lgc;
     go    = 0.5 * lgc * loc;
     gn    = 0.5 * lgc * lnc;
     gh    = 0.5 * lgc * lhc;
     gw    = 0.5 * lgc * lwc;

     oo    = 0.5 * loc * loc;
     on    = 0.5 * loc * lnc;
     oh    = 0.5 * loc * lhc;
     ow    = 0.5 * loc * lwc;

     nn    = 0.5 * lnc * lnc;
     nh    = 0.5 * lnc * lhc;
     nw    = 0.5 * lnc * lwc;

     hh    = 0.5 * lhc * lhc;
     hw    = 0.5 * lnc * lwc;

     ww    = 0.5 * lwc * lwc;

     qc    = lq * lcc;
     qg    = lq * lgc;
     qo    = lq * loc;
     qn    = lq * lnc;
     qh    = lq * lhc;
     qw    = lq * lwc;

     lqsqr = lq * lq;

/* Cost Model

        cost: model =   lcc lgc loc lnc lhc lwc lq
                        cc cg co cn ch cw
                        gg go gn gh gw
                        oo on oh ow
                        nn nh nw
                        hh hw
                        ww
                        qc qg qo qn qh qw lqsqr/dw; */

     title1 'Unrestricted Additive and Symmetry';
     proc model data = xlog;
        var     cs gs os us hs ws;
        parms   a1 a2 a3 a4 a5 a6

                b11 b12 b13 b14 b15 b16 b17
```

```
        b21 b22 b23 b24 b25 b26 b27
        b31 b32 b33 b34 b35 b36 b37
        b41 b42 b43 b44 b45 b46 b47
        b51 b52 b53 b54 b55 b56 b57
        b61 b62 b63 b64 b65 b66 b67

        r11 r12 r13 r14 r15 r16
        r21 r22 r23 r24 r25 r26
        r31 r32 r33 r34 r35 r36
        r41 r42 r43 r44 r45 r46
        r51 r52 r53 r54 r55 r56
        r61 r62 r63 r64 r65 r66;

cs = a1 + b11*lcc  + b12*lgc  + b13*loc
        + b14*lnc  + b15*lhc  + b16*lwc  + b17*lq
        + r11*reg1 + r12*reg2 + r13*reg3
        + r14*reg4 + r15*reg5 + r16*reg6;

gs = a2 + b21*lcc  + b22*lgc  + b23*loc
        + b24*lnc  + b25*lhc  + b26*lwc  + b27*lq
        + r21*reg1 + r22*reg2 + r23*reg3
        + r24*reg4 + r25*reg5 + r26*reg6;

os = a3 + b31*lcc  + b32*lgc  + b33*loc
        + b34*lnc  + b35*lhc  + b36*lwc  + b37*lq
        + r31*reg1 + r32*reg2 + r33*reg3
        + r34*reg4 + r35*reg5 + r36*reg6;

us = a4 + b41*lcc  + b42*lgc  + b43*loc
        + b44*lnc  + b45*lhc  + b46*lwc  + b47*lq
        + r41*reg1 + r42*reg2 + r43*reg3
        + r44*reg4 + r45*reg5 + r46*reg6;

hs = a5 + b51*lcc  + b52*lgc  + b53*loc
        + b54*lnc  + b55*lhc  + b56*lwc  + b57*lq
        + r51*reg1 + r52*reg2 + r53*reg3
        + r54*reg4 + r55*reg5 + r56*reg6;

ws = a6 + b61*lcc  + b62*lgc  + b63*loc
        + b64*lnc  + b65*lhc  + b66*lwc  + b67*lq
        + r61*reg1 + r62*reg2 + r63*reg3
        + r64*reg4 + r65*reg5 + r66*reg6;

fit cs gs os us hs ws/outsused = unrstcov itsur dw;

run;
```

```
/***************************************************/

      title1 'Additive and symmetry';

     proc model data = xlog;
        var     cs gs os us hs ws;
        parms   a1 a2 a3 a4 a5 a6

                b11 b12 b13 b14 b15 b16 b17
                b11 b12 b13 b14 b15 b16 b17
                b22 b23 b24 b25 b26 b27
                b33 b34 b35 b36 b37
                b44 b45 b46 b47
                b55 b56 b57
                b66 b67

                r11 r12 r13 r14 r15 r16
                r21 r22 r23 r24 r25 r26
                r31 r32 r33 r34 r35 r36
                r41 r42 r43 r44 r45 r46
                r51 r52 r53 r54 r55 r56
                r61 r62 r63 r64 r65 r66;

/* additive restriction */

/*      a1  = 1.0 - a2 - a3 - a4 - a5 - a6;
*/
/* homogeneity restriction */

/*      b11  = 0.0 - b12 - b13 - b14 - b15 - b16 - b17;
        b22  = 0.0 - b12 - b23 - b24 - b25 - b26 - b27;
        b33  = 0.0 - b13 - b23 - b34 - b35 - b36 - b37;
        b44  = 0.0 - b14 - b24 - b34 - b45 - b46 - b47;
        b55  = 0.0 - b15 - b25 - b35 - b45 - b56 - b57;
        b66  = 0.0 - b16 - b26 - b36 - b46 - b56 - b67;
*/
/* symmetry restriction formulated by equation structure */

        cs = a1 + b11*lcc  + b12*lgc  + b13*loc
                + b14*lnc  + b15*lhc  + b16*lwc  + b17*lq
                + r11*reg1 + r12*reg2 + r13*reg3
                + r14*reg4 + r15*reg5 + r16*reg6;

        gs = a2 + b12*lcc  + b22*lgc  + b23*loc
                + b24*lnc  + b25*lhc  + b26*lwc  + b27*lq
                + r21*reg1 + r22*reg2 + r23*reg3
                + r24*reg4 + r25*reg5 + r26*reg6;
```

```
        os = a3 + b13*lcc  + b23*lgc  + b33*loc
                + b34*lnc  + b35*lhc  + b36*lwc  + b37*lq
                + r31*reg1 + r32*reg2 + r33*reg3
                + r34*reg4 + r35*reg5 + r36*reg6;

        us = a4 + b14*lcc  + b24*lgc  + b34*loc
                + b44*lnc  + b45*lhc  + b46*lwc  + b47*lq
                + r41*reg1 + r42*reg2 + r43*reg3
                + r44*reg4 + r45*reg5 + r46*reg6;

        hs = a5 + b15*lcc  + b25*lgc  + b35*loc
                + b45*lnc  + b55*lhc  + b56*lwc  + b57*lq
                + r51*reg1 + r52*reg2 + r53*reg3
                + r54*reg4 + r55*reg5 + r56*reg6;

        ws = a6 + b16*lcc  + b26*lgc  + b36*loc
                + b46*lnc  + b56*lhc  + b66*lwc  + b67*lq
                + r61*reg1 + r62*reg2 + r63*reg3
                + r64*reg4 + r65*reg5 + r66*reg6;

        fit cs gs os us hs ws/sdata = unrstcov itsur dw;

run;
```

# APPENDIX B

## DATA SET

Table B.1 Electric Utilities and Regions of Operation

| Data No. | Name (Legal Business Name) | Region No. |
|---|---|---|
| 1 | AEP Generating Co | 3 |
| 2 | Appalachian Power Co | 2 |
| 3 | Arizona Public Service Co AZ | 6 |
| 4 | Baltimore Gas and Electric Co | 2 |
| 5 | Bangor Hydro Electric Co | 1 |
| 6 | Blackstone Valley Electric Co | 2 |
| 7 | Cambridge Electric Light Co MA | 1 |
| 8 | Canal Electric Co MA | 1 |
| 9 | Central Hudson Gas and Elect Corp | 1 |
| 10 | Central Illinois Light Co | 3 |
| 11 | Central Power and Light Co TX | 5 |
| 12 | Cincinnati Gas and Electric Co OH | 3 |
| 13 | Commonwealth Edison Company IL | 3 |
| 14 | Commonwealth Edison of Indiana IN | 3 |
| 15 | Commonwealth Electric Co | 1 |
| 16 | Connecticut Yankee Atomic Power Co | 1 |
| 17 | Consolidated Edison Co of New York | 1 |
| 18 | Consolidated Water Power Co | 4 |
| 19 | Consumers Power Co MI | 3 |
| 20 | Duke Power Co NC | 2 |
| 21 | Edison Sault Electric Company MI | 3 |
| 22 | El Paso Electric Co | 5 |
| 23 | Florida Power and Light Co FL | 3 |
| 24 | Green Mountain Power Corp VT | 1 |
| 25 | Houston Lighting and Power Co TX | 5 |
| 26 | Idaho Power Co | 6 |
| 27 | Illinois Power Co | 3 |
| 28 | Indianapolis Power and Light Co | 3 |
| 29 | Indiana-Kentucky Electric Corp OH | 3 |
| 30 | Iowa Electric Light and Power Co IO | 4 |
| 31 | James River NH Electric Inc NH | 1 |
| 32 | Jersey Central Power and Light Co | 1 |
| 33 | Kentucky Power Co KY | 3 |

(Continued)

Table B.1 (Continued)

| Data No. | Name (Legal Business Name) | Region No. |
|---|---|---|
| 34 | Long Island Lighting Co | 1 |
| 35 | Louisville Gas And Electric Co | 3 |
| 36 | Madison Gas and Electric Co WI | 4 |
| 37 | Maine Yankee Atomic Power Co MA | 1 |
| 38 | Maui Electric Co HI | 7 |
| 39 | Metropolitan Edison Co PA | 3 |
| 40 | Minnesota Power and Light Co | 4 |
| 41 | Mississippi Power and Light Co MI | 3 |
| 42 | Montana Power Co MT | 6 |
| 43 | Montaup Electric Co MA | 1 |
| 44 | Narragansett Electric Co | 1 |
| 45 | Nevada Power Co NV | 7 |
| 46 | New England Power Co | 1 |
| 47 | New Orleans Public Service Co | 5 |
| 48 | Northern Indiana Pub Serv Co IN | 3 |
| 49 | Northern States Power Co SD | 4 |
| 50 | Northwestern Public Service Co SD | 4 |
| 51 | Northwestern Wisconsin Electric Co | 4 |
| 52 | Ohio Power Co | 3 |
| 53 | Ohio Valley Electric Corp OH | 3 |
| 54 | Oklahoma Gas and Electric Co OK | 5 |
| 55 | Orange and Rockland Utilities | 1 |
| 56 | Otter Tail Power Co | 7 |
| 57 | Pacificorp OR | 7 |
| 58 | Pennsylvania Power Co PA | 3 |
| 59 | Philadelphia Electric Co PA | 3 |
| 60 | Potomac Edison Co MD | 2 |
| 61 | Public Service Co Of NH | 1 |
| 62 | Public Service Co of Oklahoma OK | 5 |
| 63 | Rochester Gas and Electric Co | 1 |
| 64 | Safe Harbor Water Power Corp | 3 |
| 65 | South Beloit Water Gas and Elect Co | 4 |
| 66 | Southeastern Electric Power Co LA | 5 |
| 67 | Southern California Edison Co | 7 |
| 68 | Southwestern Electric Service Co | 5 |
| 69 | St. Joseph Light and Power Co MO | 4 |

(Continued)

Table B.1 (Continued)

| Data No. | Name (Legal Business Name) | Region No. |
|---|---|---|
| 70 | Superior Water, Light and Power Co | 4 |
| 71 | Susquehanna Electric Co PA | 3 |
| 72 | Tapoco, Incorporated | 3 |
| 73 | The Empire District Electric Co MO | 4 |
| 74 | Toledo Edison Co TN | 3 |
| 75 | Tuscon Electric Co | 6 |
| 76 | UGI Corporation PA | 3 |
| 77 | Union Electric Co MO | 4 |
| 78 | Union Light, Heat and Power Co KY | 4 |
| 79 | Utah Power and Light Co UT | 6 |
| 80 | Utilicorp MO | 4 |
| 81 | Warm Springs Power Enterprises | 7 |
| 82 | West Texas Utilities Co TX | 5 |
| 83 | Wisconsin Electric Power Co WI | 4 |
| 84 | Western Massachusetts Elect Power | 1 |

Table B.2 Individual Share Values

| Data No. | COAL (%) | GAS (%) | OIL (%) | U308 (%) | HYDRO (%) | WSALE (%) |
|---|---|---|---|---|---|---|
| 1 | 0.7833 | 0.0000 | 0.0102 | 0.0000 | 0.0000 | 0.2065 |
| 2 | 0.7333 | 0.0000 | 0.0053 | 0.0000 | 0.0026 | 0.2587 |
| 3 | 0.4836 | 0.0153 | 0.0843 | 0.0512 | 0.0008 | 0.3648 |
| 4 | 0.4585 | 0.0376 | 0.1332 | 0.1613 | 0.0000 | 0.2094 |
| 5 | 0.0000 | 0.0000 | 0.1449 | 0.0000 | 0.0214 | 0.8338 |
| 6 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0001 | 0.9999 |
| 7 | 0.0000 | 0.1914 | 0.0689 | 0.0000 | 0.0000 | 0.7397 |
| 8 | 0.0000 | 0.0000 | 0.9545 | 0.0000 | 0.0000 | 0.0455 |
| 9 | 0.1433 | 0.1182 | 0.5287 | 0.0000 | 0.0082 | 0.2016 |
| 10 | 0.9964 | 0.0006 | 0.0031 | 0.0000 | 0.0000 | 0.0000 |
| 11 | 0.2827 | 0.6695 | 0.0013 | 0.0000 | 0.0040 | 0.0425 |
| 12 | 0.9870 | 0.0000 | 0.0081 | 0.0000 | 0.0000 | 0.0049 |
| 13 | 0.5016 | 0.0013 | 0.0677 | 0.2500 | 0.0000 | 0.1795 |
| 14 | 1.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 15 | 0.0000 | 0.0276 | 0.0154 | 0.0000 | 0.0000 | 0.9570 |
| 16 | 0.0000 | 0.0000 | 0.0000 | 1.0000 | 0.0000 | 0.0000 |
| 17 | 0.0000 | 0.2604 | 0.3424 | 0.0158 | 0.0000 | 0.3814 |
| 18 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0274 | 0.9726 |
| 19 | 0.5443 | 0.0011 | 0.0175 | 0.0410 | 0.0041 | 0.3919 |
| 20 | 0.2964 | 0.0004 | 0.0111 | 0.1650 | 0.0060 | 0.5211 |
| 21 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0853 | 0.9147 |
| 22 | 0.0985 | 0.4687 | 0.0002 | 0.2752 | 0.0000 | 0.1575 |
| 23 | 0.0074 | 0.2259 | 0.2262 | 0.0150 | 0.0000 | 0.5256 |
| 24 | 0.0000 | 0.0203 | 0.0323 | 0.0000 | 0.0248 | 0.9226 |
| 25 | 0.3705 | 0.3362 | 0.0179 | 0.0000 | 0.0000 | 0.2755 |
| 26 | 0.6135 | 0.0002 | 0.0053 | 0.0000 | 0.0987 | 0.2824 |
| 27 | 0.7919 | 0.0038 | 0.1273 | 0.0764 | 0.0006 | 0.0000 |
| 28 | 0.9925 | 0.0000 | 0.0075 | 0.0000 | 0.0000 | 0.0000 |
| 29 | 1.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 30 | 0.4018 | 0.0119 | 0.0049 | 0.1291 | 0.0007 | 0.4517 |
| 31 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0369 | 0.9631 |
| 32 | 0.0526 | 0.1283 | 0.0411 | 0.0735 | 0.0005 | 0.7040 |
| 33 | 0.5245 | 0.0000 | 0.0056 | 0.0000 | 0.0000 | 0.4699 |
| 34 | 0.0000 | 0.1421 | 0.7026 | 0.0000 | 0.0000 | 0.1553 |
| 35 | 0.9874 | 0.0006 | 0.0000 | 0.0000 | 0.0111 | 0.0009 |
| 36 | 0.7251 | 0.0736 | 0.0000 | 0.0975 | 0.0000 | 0.1037 |
| 37 | 0.0000 | 0.0000 | 0.0000 | 1.0000 | 0.0000 | 0.0000 |
| 38 | 0.0000 | 0.0000 | 0.8180 | 0.0000 | 0.0000 | 0.1820 |

(Continued)

Table B.2 (Continued)

| Data No. | COAL (%) | GAS (%) | OIL (%) | U308 (%) | HYDRO (%) | WSALE (%) |
|---|---|---|---|---|---|---|
| 39 | 0.5172 | 0.0112 | 0.0159 | 0.0900 | 0.0000 | 0.3658 |
| 40 | 0.5490 | 0.0000 | 0.0000 | 0.0000 | 0.0087 | 0.4424 |
| 41 | 0.1153 | 0.1697 | 0.0095 | 0.0000 | 0.0000 | 0.7056 |
| 42 | 0.3639 | 0.0053 | 0.0000 | 0.0000 | 0.1296 | 0.5011 |
| 43 | 0.0000 | 0.0000 | 0.3791 | 0.0148 | 0.0000 | 0.6061 |
| 44 | 0.0000 | 0.0663 | 0.0685 | 0.0000 | 0.0000 | 0.8652 |
| 45 | 0.5748 | 0.0515 | 0.0086 | 0.0000 | 0.0000 | 0.3650 |
| 46 | 0.3007 | 0.0000 | 0.2505 | 0.0000 | 0.0083 | 0.4406 |
| 47 | 0.0000 | 0.1981 | 0.0000 | 0.0000 | 0.0000 | 0.8018 |
| 48 | 0.7542 | 0.0081 | 0.0028 | 0.0000 | 0.0005 | 0.2344 |
| 49 | 0.6491 | 0.0073 | 0.0042 | 0.1401 | 0.0030 | 0.1964 |
| 50 | 0.6000 | 0.0037 | 0.0103 | 0.0000 | 0.0000 | 0.3860 |
| 51 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0321 | 0.9679 |
| 52 | 0.9932 | 0.0000 | 0.0062 | 0.0000 | 0.0007 | 0.0000 |
| 53 | 0.4297 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.5703 |
| 54 | 0.4158 | 0.5750 | 0.0007 | 0.0000 | 0.0000 | 0.0085 |
| 55 | 0.1105 | 0.3160 | 0.0594 | 0.0000 | 0.0281 | 0.4860 |
| 56 | 0.2634 | 0.0000 | 0.0056 | 0.0000 | 0.0009 | 0.7301 |
| 57 | 0.7883 | 0.0000 | 0.0053 | 0.0000 | 0.0172 | 0.1893 |
| 58 | 0.9189 | 0.0000 | 0.0111 | 0.0000 | 0.0000 | 0.0700 |
| 59 | 0.1823 | 0.0061 | 0.1497 | 0.1579 | 0.0363 | 0.4676 |
| 60 | 0.5368 | 0.0000 | 0.0000 | 0.0000 | 0.0012 | 0.4621 |
| 61 | 0.2851 | 0.0000 | 0.2712 | 0.0073 | 0.0047 | 0.4317 |
| 62 | 0.2823 | 0.6713 | 0.0006 | 0.0000 | 0.0000 | 0.0457 |
| 63 | 0.3183 | 0.0027 | 0.1419 | 0.2339 | 0.0111 | 0.2921 |
| 64 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 | 0.0000 |
| 65 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0118 | 0.9882 |
| 66 | 0.4884 | 0.1048 | 0.3685 | 0.0000 | 0.0000 | 0.0383 |
| 67 | 0.0600 | 0.3799 | 0.0264 | 0.0976 | 0.0055 | 0.4305 |
| 68 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 |
| 69 | 0.5875 | 0.0468 | 0.0466 | 0.0000 | 0.0000 | 0.3191 |
| 70 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 |
| 71 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 | 0.0000 |
| 72 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 | 0.0000 |
| 73 | 0.4118 | 0.0078 | 0.0022 | 0.0000 | 0.0047 | 0.5735 |
| 74 | 0.8042 | 0.0012 | 0.0043 | 0.1903 | 0.0000 | 0.0000 |
| 75 | 0.1905 | 0.0307 | 0.0030 | 0.0000 | 0.0000 | 0.7758 |
| 76 | 0.2558 | 0.0000 | 0.0121 | 0.0000 | 0.0000 | 0.7321 |

(Continued)

Table B.2 (Continued)

| Data No. | COAL (%) | GAS (%) | OIL (%) | U308 (%) | HYDRO (%) | WSALE (%) |
|---|---|---|---|---|---|---|
| 77 | 0.8819 | 0.0045 | 0.0121 | 0.0798 | 0.0083 | 0.0134 |
| 78 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 |
| 79 | 0.9211 | 0.0020 | 0.0047 | 0.0000 | 0.0146 | 0.0576 |
| 80 | 0.5551 | 0.0057 | 0.0003 | 0.0000 | 0.0000 | 0.4389 |
| 81 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0000 | 0.0000 |
| 82 | 0.3169 | 0.5914 | 0.0165 | 0.0000 | 0.0000 | 0.0753 |
| 83 | 0.7859 | 0.0069 | 0.0058 | 0.1639 | 0.0055 | 0.0320 |
| 84 | 0.0000 | 0.1950 | 0.2797 | 0.4664 | 0.0588 | 0.0000 |

Table B.3 Commodity Prices Paid by Electric Utilities

| Data No. | COAL $/Mbtu | GAS $/Mbtu | OIL $/Mbtu | U3O8 $/Mbtu | HYDRO $/Mbtu | W-sale Cost $/Mbtu |
|---|---|---|---|---|---|---|
| 1 | 2.0311 | 0.0000 | 3.8349 | 0.0000 | 0.0000 | 2.2356 |
| 2 | 1.6707 | 0.0000 | 4.2310 | 0.0000 | 0.1670 | 2.4605 |
| 3 | 1.1371 | 3.1349 | 8.5955 | 0.3116 | 0.5569 | 8.5602 |
| 4 | 1.5752 | 2.6368 | 3.0444 | 0.4923 | 0.0000 | 2.8643 |
| 5 | 0.0000 | 0.0000 | 3.2243 | 0.0000 | 0.5085 | 3.8822 |
| 6 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.3214 | 6.1894 |
| 7 | 0.0000 | 2.8957 | 3.1282 | 0.0000 | 0.0000 | 4.2402 |
| 8 | 0.0000 | 0.0000 | 2.7819 | 0.0000 | 0.0000 | 8.0187 |
| 9 | 1.9696 | 2.4841 | 2.9341 | 0.0000 | 0.6605 | 2.1666 |
| 10 | 1.9275 | 4.3515 | 3.8526 | 0.0000 | 0.0000 | 0.0000 |
| 11 | 2.0454 | 2.0768 | 3.5840 | 0.0000 | 2.1457 | 1.4456 |
| 12 | 1.6397 | 0.0000 | 4.1411 | 0.0000 | 0.0000 | 20.3985 |
| 13 | 2.8590 | 4.9913 | 4.1590 | 0.6141 | 0.0038 | 3.3579 |
| 14 | 3.0113 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 15 | 0.0000 | 2.7200 | 2.8584 | 0.0000 | 0.0000 | 4.9562 |
| 16 | 0.0000 | 0.0000 | 0.0000 | 0.9295 | 0.0000 | 0.0000 |
| 17 | 0.0000 | 3.0155 | 3.2474 | 0.2992 | 0.0000 | 2.9805 |
| 18 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.7534 | 3.5073 |
| 19 | 1.8382 | 5.6299 | 2.9539 | 0.6880 | 0.1496 | 2.1958 |
| 20 | 1.8120 | 2.9458 | 4.1412 | 0.4777 | 0.2711 | 6.3335 |
| 21 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.5363 | 2.3728 |
| 22 | 1.0255 | 1.9049 | 7.2533 | 0.9613 | 0.0000 | 1.6073 |
| 23 | 1.6400 | 2.7024 | 2.8343 | 0.6059 | 0.0000 | 4.1446 |
| 24 | 0.0000 | 2.5571 | 3.8000 | 0.0000 | 1.4571 | 3.8622 |
| 25 | 2.1285 | 1.7396 | 14.3081 | 0.0000 | 0.0000 | 3.7472 |
| 26 | 1.2190 | 4.6229 | 4.1508 | 0.0000 | 0.1492 | 3.0312 |
| 27 | 1.4698 | 1.8141 | 4.2510 | 4.4496 | 1.9035 | 0.0000 |
| 28 | 1.1890 | 0.0000 | 3.9736 | 0.0000 | 0.0000 | 0.0000 |
| 29 | 1.0933 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 |
| 30 | 1.3223 | 2.3717 | 4.0184 | 0.7320 | 1.5335 | 4.5334 |
| 31 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.4423 | 24.0372 |
| 32 | 1.2674 | 2.6143 | 3.5762 | 0.7141 | 0.0134 | 3.5617 |
| 33 | 1.4506 | 0.0000 | 4.0228 | 0.0000 | 0.0000 | 4.9761 |
| 34 | 0.0000 | 2.5700 | 3.3728 | 0.0000 | 0.0000 | 2.9633 |
| 35 | 1.3781 | 2.5665 | 0.0000 | 0.0000 | 0.3402 | 0.2092 |
| 36 | 1.5981 | 4.0294 | 3.3848 | 0.4103 | 0.0000 | 1.8999 |
| 37 | 0.0000 | 0.0000 | 0.0000 | 0.5801 | 0.0000 | 0.0000 |

(Continued)

Table B.3 (Continued)

| Data No. | COAL $/Mbtu | GAS $/Mbtu | OIL $/Mbtu | U3O8 $/Mbtu | HYDRO $/Mbtu | W-sale Cost $/Mbtu |
|---|---|---|---|---|---|---|
| 38 | 0.0000 | 0.0000 | 3.3787 | 0.0000 | 0.0000 | 0.0000 |
| 39 | 1.6710 | 2.7149 | 4.1448 | 0.5227 | 0.0000 | 2.3867 |
| 40 | 1.4255 | 0.0000 | 0.0000 | 0.0000 | 0.2334 | 2.0773 |
| 41 | 1.6892 | 1.9229 | 2.7116 | 0.0000 | 0.0000 | 4.0464 |
| 42 | 0.6176 | 0.8904 | 0.0000 | 0.0000 | 0.3957 | 4.0859 |
| 43 | 0.0000 | 0.0000 | 2.7788 | 0.7890 | 0.0000 | 6.4296 |
| 44 | 0.0000 | 2.3104 | 2.5912 | 0.0000 | 0.0000 | 4.4694 |
| 45 | 1.6318 | 1.9833 | 2.8145 | 0.0000 | 0.0000 | 2.2206 |
| 46 | 1.6040 | 0.0000 | 2.5172 | 0.0000 | 0.2123 | 3.9203 |
| 47 | 0.0000 | 1.6341 | 3.4613 | 0.0000 | 0.0000 | 7.4888 |
| 48 | 1.9766 | 2.5903 | 6.3044 | 0.0000 | 0.2316 | 3.4033 |
| 49 | 1.2961 | 2.2441 | 3.4516 | 0.5059 | 1.1030 | 8.4370 |
| 50 | 0.9819 | 2.3936 | 3.5577 | 0.0000 | 0.0000 | 1.4156 |
| 51 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.0916 | 2.7907 |
| 52 | 1.7353 | 0.0000 | 4.5315 | 0.0000 | 0.2181 | 0.0000 |
| 53 | 1.4262 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 1.3523 |
| 54 | 1.5236 | 2.6035 | 3.5323 | 0.0000 | 0.0000 | 6.9077 |
| 55 | 1.8867 | 2.4073 | 2.7749 | 0.0000 | 0.9501 | 2.2815 |
| 56 | 0.9990 | 0.0000 | 4.1551 | 0.0000 | 0.1917 | 1.6590 |
| 57 | 1.0060 | 0.0000 | 3.9052 | 0.0000 | 0.1355 | 0.9681 |
| 58 | 1.3331 | 0.0000 | 5.9165 | 0.0000 | 0.0000 | 0.0797 |
| 59 | 1.5174 | 2.6725 | 3.1617 | 0.7204 | 1.7848 | 2.5466 |
| 60 | 1.4111 | 0.0000 | 0.0000 | 0.0000 | 0.0872 | 3.5360 |
| 61 | 2.0758 | 0.0000 | 2.6437 | 0.8229 | 0.3491 | 5.3454 |
| 62 | 1.6947 | 2.8245 | 3.6954 | 0.0000 | 0.0000 | 3.8251 |
| 63 | 1.7642 | 3.2531 | 3.5190 | 0.5230 | 0.2095 | 1.5233 |
| 64 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.2643 | 0.0000 |
| 65 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.4164 | 2.1318 |
| 66 | 1.9952 | 2.1885 | 4.7588 | 0.0000 | 0.0000 | 1.2805 |
| 67 | 1.0389 | 2.5044 | 5.7969 | 1.1401 | 0.2801 | 4.2106 |
| 68 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 3.6435 |
| 69 | 1.0879 | 2.8061 | 2.7571 | 0.0000 | 0.0000 | 1.4282 |
| 70 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 3.5898 |
| 71 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.8996 | 0.0000 |
| 72 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.1164 | 0.0000 |
| 73 | 1.1603 | 2.9285 | 3.8764 | 0.0000 | 0.4521 | 2.4583 |

(Continued)

Table B.3 (Continued)

| Data No. | COAL $/Mbtu | GAS $/Mbtu | OIL $/Mbtu | U3O8 $/Mbtu | HYDRO $/Mbtu | W-sale Cost $/Mbtu |
|---|---|---|---|---|---|---|
| 74 | 1.8403 | 4.4907 | 3.9383 | 0.8074 | 0.0000 | 0.0000 |
| 75 | 1.2592 | 2.2364 | 4.0814 | 0.0000 | 0.0000 | 5.2951 |
| 76 | 1.3884 | 0.0000 | 3.9306 | 0.0000 | 0.0000 | 4.9801 |
| 77 | 1.6800 | 3.3112 | 2.7753 | 0.5167 | 0.2280 | 0.6368 |
| 78 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 3.9406 |
| 79 | 1.0310 | 2.8993 | 3.8513 | 0.0000 | 0.4571 | 0.5278 |
| 80 | 1.7547 | 1.9562 | 2.5274 | 0.0000 | 0.0000 | 2.3807 |
| 81 | 0.0000 | 0.0000 | 0.0000 | 0.0000 | 0.9569 | 0.0000 |
| 82 | 1.6904 | 1.4919 | 4.3740 | 0.0000 | 0.0000 | 1.8733 |
| 83 | 1.2885 | 3.1140 | 3.7293 | 0.5059 | 0.3622 | 0.7324 |
| 84 | 0.0000 | 2.3778 | 2.9245 | 0.9360 | 0.4827 | 0.0000 |

Table B.4 ~~Commodity Prices Paid~~ Sale by Electric Utilities

| Data No. | W-sale Sales (MW Hours) | Retail Sales (MW Hours) | Total Sales (MW Hours) |
|---|---|---|---|
| 1 | 2,760,294 | 0 | 2,760,294 |
| 2 | 4,718,470 | 20,468,067 | 26,856,275 |
| 3 | 1,372,139 | 13,397,463 | 14,769,602 |
| 4 | 0 | 22,974,965 | 22,974,965 |
| 5 | 12,049 | 1,466,358 | 1,498,546 |
| 6 | 0 | 1,212,031 | 1,212,031 |
| 7 | 0 | 1,140,028 | 1,233,385 |
| 8 | 4,077,966 | 0 | 4,077,966 |
| 9 | 531,431 | 4,354,903 | 4,886,334 |
| 10 | 0 | 4,575,996 | 4,610,116 |
| 11 | 363,430 | 13,045,381 | 14,028,160 |
| 12 | 2,539,920 | 14,790,191 | 17,559,785 |
| 13 | 29,159 | 66,389,046 | 67,489,622 |
| 14 | 1,935,582 | 0 | 1,935,582 |
| 15 | 0 | 3,071,490 | 3,071,490 |
| 16 | 2,536,872 | 0 | 2,536,872 |
| 17 | 2,015,999 | 31,607,920 | 33,623,919 |
| 18 | 243 | 892,086 | 892,329 |
| 19 | 0 | 27,633,834 | 28,489,858 |
| 20 | 1,114,581 | 54,769,631 | 64,671,060 |
| 21 | 13,300 | 409,701 | 548,587 |
| 22 | 376,680 | 3,992,310 | 5,079,754 |
| 23 | 0 | 55,647,258 | 56,591,527 |
| 24 | 179,162 | 1,500,012 | 2,081,288 |
| 25 | 691,168 | 53,439,741 | 55,911,327 |
| 26 | 1,717,389 | 10,175,313 | 11,977,483 |
| 27 | 0 | 10,574,471 | 0 |
| 28 | 0 | 10,574,471 | 10,595,159 |
| 29 | 9,971,697 | 0 | 9,971,697 |
| 30 | 53,607 | 4,105,681 | 4,418,005 |
| 31 | 573 | 330,004 | 330,577 |
| 32 | 0 | 15,260,758 | 15,550,652 |
| 33 | 542,567 | 5,165,589 | 5,741,322 |
| 34 | 238,940 | 15,095,105 | 15,336,187 |
| 35 | 52,313 | 8,674,345 | 8,726,658 |
| 36 | 22,288 | 2,068,231 | 2,090,519 |
| 37 | 3,792,743 | 0 | 4,029,579 |

(Continued)

Table B.4 (Continued)

| Data No. | W-sale Sales (MW Hours) | Retail Sales (MW Hours) | Total Sales (MW Hours) |
|---|---|---|---|
| 38 | 0 | 625,698 | 625,698 |
| 39 | 361 | 8,760,272 | 8,931,379 |
| 40 | 538,016 | 6,802,416 | 8,834,750 |
| 41 | 966,351 | 8,216,929 | 9,183,280 |
| 42 | 1,142,382 | 6,272,752 | 8,674,683 |
| 43 | 4,171,026 | 0 | 4,697,963 |
| 44 | 371 | 4,167,837 | 4,168,208 |
| 45 | 0 | 7,346,668 | 7,390,848 |
| 46 | 19,681,382 | 13,792 | 20,093,255 |
| 47 | 308,942 | 5,055,352 | 5,364,294 |
| 48 | 0 | 11,641,647 | 11,797,562 |
| 49 | 2,411,489 | 23,639,338 | 26,970,889 |
| 50 | 4,945 | 804,234 | 811,179 |
| 51 | 0 | 99,696 | 104,177 |
| 52 | 4,420,323 | 26,517,439 | 31,555,831 |
| 53 | 5,687,323 | 11,841,780 | 17,529,103 |
| 54 | 161,594 | 17,163,768 | 18,471,120 |
| 55 | 1,623,166 | 2,496,875 | 4,120,041 |
| 56 | 451,578 | 2,550,915 | 3,140,117 |
| 57 | 5,119,557 | 20,958,207 | 26,086,331 |
| 58 | 719,022 | 3,345,933 | 4,190,973 |
| 59 | 0 | 29,990,465 | 30,497,628 |
| 60 | 4,468,456 | 9,296,911 | 14,246,625 |
| 61 | 511,513 | 5,342,526 | 6,952,547 |
| 62 | 0 | 11,558,010 | 12,085,469 |
| 63 | 1,047,654 | 5,948,762 | 6,996,416 |
| 64 | 0 | 945,637 | 945,637 |
| 65 | 9,538 | 144,025 | 153,563 |
| 66 | 862,259 | 11,746,024 | 14,910,544 |
| 67 | 1,439,074 | 63,469,291 | 65,514,481 |
| 68 | 101,989 | 791,416 | 893,917 |
| 69 | 0 | 1,180,977 | 1,180,977 |
| 70 | 59,000 | 468,200 | 528,200 |
| 71 | 0 | 0 | 1,577,112 |
| 72 | 0 | 1,595,293 | 1,595,293 |
| 73 | 311,150 | 2,297,880 | 3,427,388 |

(Continued)

Table B.4 (Continued)

| Data No. | W-sale Sales (MW Hours) | Retail Sales (MW Hours) | Total Sales (MW Hours) |
|---|---|---|---|
| 74 | 0 | 7,561,933 | 7,906,076 |
| 75 | 0 | 5,486,249 | 6,377,468 |
| 76 | 0 | 726,461 | 726,463 |
| 77 | 643,059 | 27,521,297 | 29,006,167 |
| 78 | 0 | 2,301,852 | 2,341,701 |
| 79 | 2,606,733 | 18,053,378 | 21,180,013 |
| 80 | 559 | 3,098,116 | 3,255,736 |
| 81 | 0 | 0 | 0 |
| 82 | 418,752 | 3,915,079 | 5,661,534 |
| 83 | 607,726 | 18,112,278 | 20,134,824 |
| 84 | 9,576 | 3,602,115 | 3,625,152 |

Table B.5 Data Set Average Values

| Obs N | Minimum | Maximum | Mean | Std Dev |
|---|---|---|---|---|
| COAL_C | 0 | 3.0113000 | 1.0593812 | 0.8079289 |
| GAS_C | 0 | 5.6299000 | 1.5734047 | 1.5151002 |
| OIL_C | 0 | 14.3081000 | 2.9188541 | 2.2774266 |
| U3O8_C | 0 | 4.4496000 | 0.2443506 | 0.5608166 |
| HYDRO_C | 0 | 2.1457000 | 0.2827788 | 0.4667305 |
| WSALE_C | 0 | 24.0372000 | 3.2071365 | 3.6781337 |
| COAL_S | 0 | 1.0000000 | 0.3533718 | 0.3429762 |
| GAS_S | 0 | 0.6713000 | 0.0744976 | 0.1559566 |
| OIL_S | 0 | 0.9545000 | 0.0777635 | 0.1770794 |
| U3O8_S | 0 | 1.0000000 | 0.0596059 | 0.1669480 |
| HYDRO_S | 0 | 1.0000000 | 0.0555918 | 0.2121959 |
| WSALE_S | 0 | 1.0000000 | 0.3791776 | 0.3361741 |
| WSALE_Q | 0 | 19,681,382 | 1,201,946 | 2,655,647 |
| RSALE_Q | 0 | 66,389,046 | 10,559,280 | 14,599,423 |
| TOT_Q | 0 | 67,489,622 | 12,096,138 | 15,331,490 |

Table B.6 Data Set Average Values

| FUEL | COAL $/Mbtu | GAS $/Mbtu | OIL $/Mbtu | U3O8 $/Mbtu | HYDRO $/Mbtu | W-sale Cost $/Mbtu |
|---|---|---|---|---|---|---|
| PRICE | 1.56 | 2.73 | 3.94 | 0.80 | 0.29 | 3.84 |
| NUMBER | 57 | 48 | 62 | 25 | 84 | 70 |

# APPENDIX C

## DETAILED REGRESSION STATISTICS

Table C.1 Nonlinear ITSUR Summary of Residual Errors

| | DF Model | DF Error | SSE | MSE | Root MSE | $R^2$ | Adj $R^2$ | Durbin Watson |
|---|---|---|---|---|---|---|---|---|
| CS | 11.5 | 70.5 | 4.3876 | 0.06223 | 0.24947 | 0.5368 | 0.4679 | 1.866 |
| GS | 11.5 | 70.5 | 0.7766 | 0.01102 | 0.10496 | 0.6174 | 0.5604 | 2.485 |
| OS | 11.5 | 70.5 | 1.9120 | 0.02712 | 0.16468 | 0.2714 | 0.1628 | 1.987 |
| US | 11.5 | 70.5 | 1.6935 | 0.02402 | 0.15499 | 0.2754 | 0.1675 | 2.341 |
| HS | 11.5 | 70.5 | 2.2577 | 0.03202 | 0.17895 | 0.2150 | 0.0980 | 1.644 |
| WS | 11.5 | 70.5 | 4.4656 | 0.06334 | 0.25168 | 0.5092 | 0.4360 | 1.887 |

Table C.2 Parameter Estimates and T Statistics

| Parameter | Estimate | Approx. Std Err | 'T' Ratio | Approx. Prob>¦T¦ |
|---|---|---|---|---|
| A1 | -1.314562 | 0.39621 | -3.32 | 0.0014 |
| A2 | -0.181650 | 0.17134 | -1.06 | 0.2927 |
| A3 | 0.118211 | 0.26100 | 0.45 | 0.6520 |
| A4 | -0.236104 | 0.24289 | -0.97 | 0.3344 |
| A5 | 0.598967 | 0.26154 | 2.29 | 0.0250 |
| A6 | 2.014929 | 0.36418 | 5.53 | 0.0001 |
| | | | | |
| B11 | 0.023968 | 0.09432 | 0.25 | 0.8002 |
| B12 | 0.029959 | 0.04447 | 0.67 | 0.5027 |
| B13 | -0.010152 | 0.05264 | -0.19 | 0.8476 |
| B14 | 0.067273 | 0.05526 | 1.22 | 0.2275 |
| B15 | 0.010633 | 0.02772 | 0.38 | 0.7024 |
| B16 | -0.121670 | 0.03178 | -3.83 | 0.0003 |
| B17 | 0.107508 | 0.02327 | 4.62 | 0.0001 |

(Continued)

Table C.2 (Continued)

| Parameter | Estimate | Approx. Std Err | 'T' Ratio | Approx. Prob>¦T¦ |
|---|---|---|---|---|
| B22 | -0.069317 | 0.04036 | -1.72 | 0.0903 |
| B23 | -0.00346897 | 0.03144 | -0.11 | 0.9125 |
| B24 | 0.032381 | 0.03282 | 0.99 | 0.3273 |
| B25 | 0.010581 | 0.01233 | 0.86 | 0.3939 |
| B26 | -0.00012274 | 0.01391 | -0.01 | 0.9930 |
| B27 | 0.022187 | 0.0098723 | 2.25 | 0.0278 |
| B33 | -0.097738 | 0.05270 | -1.85 | 0.0679 |
| B34 | 0.085010 | 0.04069 | 2.09 | 0.0403 |
| B35 | 0.026414 | 0.01812 | 1.46 | 0.1494 |
| B36 | -0.00004096 | 0.02129 | -0.00 | 0.9985 |
| B37 | 0.013704 | 0.01508 | 0.91 | 0.3666 |
| B44 | -0.150285 | 0.05698 | -2.64 | 0.0103 |
| B45 | 0.013209 | 0.01770 | 0.75 | 0.4579 |
| B46 | -0.047574 | 0.02030 | -2.34 | 0.0220 |
| B47 | 0.00845341 | 0.01447 | 0.58 | 0.5611 |
| B55 | -0.036275 | 0.02084 | -1.74 | 0.0861 |
| B56 | -0.024569 | 0.01888 | -1.30 | 0.1975 |
| B57 | -0.042083 | 0.01591 | -2.65 | 0.0101 |
| B66 | 0.193979 | 0.03326 | 5.83 | 0.0001 |
| B67 | -0.109762 | 0.02195 | -5.00 | 0.0001 |
| R11 | -0.140734 | 0.13253 | -1.06 | 0.2919 |
| R12 | 0.111283 | 0.16266 | 0.68 | 0.4961 |
| R13 | 0.212500 | 0.12551 | 1.69 | 0.0949 |
| R14 | 0.242442 | 0.13415 | 1.81 | 0.0750 |
| R15 | -0.043384 | 0.14483 | -0.30 | 0.7654 |
| R16 | 0.233282 | 0.16284 | 1.43 | 0.1564 |
| R21 | 0.00605879 | 0.05677 | 0.11 | 0.9153 |
| R22 | -0.072970 | 0.06943 | -1.05 | 0.2969 |
| R23 | -0.054264 | 0.05355 | -1.01 | 0.3144 |
| R24 | -0.045018 | 0.05733 | -0.79 | 0.4350 |
| R25 | 0.267678 | 0.06474 | 4.13 | 0.0001 |
| R26 | -0.085499 | 0.06935 | -1.23 | 0.2218 |

(Continued)

Table C.2 (Continued)

| Parameter | Estimate | Approx. Std Err | 'T' Ratio | Approx. Prob>¦T¦ |
|---|---|---|---|---|
| R31 | 0.055295 | 0.08772 | 0.63 | 0.5305 |
| R32 | -0.096260 | 0.10768 | -0.89 | 0.3744 |
| R33 | -0.125350 | 0.08274 | -1.51 | 0.1343 |
| R34 | -0.135019 | 0.08879 | -1.52 | 0.1329 |
| R35 | -0.130134 | 0.09602 | -1.36 | 0.1797 |
| R36 | -0.116225 | 0.10893 | -1.07 | 0.2897 |
| R41 | 0.113554 | 0.08421 | 1.35 | 0.1818 |
| R42 | -0.00300080 | 0.10366 | -0.03 | 0.9770 |
| R43 | -0.058806 | 0.07975 | -0.74 | 0.4634 |
| R44 | -0.017175 | 0.08577 | -0.20 | 0.8419 |
| R45 | -0.012899 | 0.09159 | -0.14 | 0.8884 |
| R46 | -0.030262 | 0.10197 | -0.30 | 0.7675 |
| R51 | 0.015963 | 0.09152 | 0.17 | 0.8620 |
| R52 | 0.027664 | 0.11524 | 0.24 | 0.8110 |
| R53 | 0.124661 | 0.08845 | 1.41 | 0.1632 |
| R54 | -0.019691 | 0.09486 | -0.21 | 0.8362 |
| R55 | 0.049129 | 0.10166 | 0.48 | 0.6304 |
| R56 | 0.081940 | 0.11455 | 0.72 | 0.4768 |
| R61 | -0.050106 | 0.12884 | -0.39 | 0.6985 |
| R62 | 0.033288 | 0.16217 | 0.21 | 0.8380 |
| R63 | -0.098710 | 0.12432 | -0.79 | 0.4299 |
| R64 | -0.025494 | 0.13313 | -0.19 | 0.8487 |
| R65 | -0.130359 | 0.14175 | -0.92 | 0.3609 |
| R66 | -0.083218 | 0.16130 | -0.52 | 0.6075 |