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REGULATORY FAILURE, REGULATORY REFORM AND
STRUCTURAL CHANGE IN THE
ELECTRIC POWER INDUSTRY

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> ...Utility rate litigation has become sport, a vent for passions. Each contest satiates for the moment, then fuels the appetite for further fight. We shrink from the thought of the season ending.... I am hard pressed to imagine a more inefficient, haphazard approach to utility rate making than our state has witnessed in recent years... Our Public Service Commission presents an innovative and promising... way out and we deliver a stiff left to the jaw.
>
> (Justice Robertson (Dissenting), Mississippi Supreme Court, January 4, 1989)[1]

INTRODUCTION AND OVERVIEW

In the past decade, the U.S. economy has gone through a virtual economic deregulation revolution. Complete or partial deregulation of prices and entry has increased the role of market forces in allocating resources in industries which include airlines, trucking, railroads, telecommunications, natural gas production and transmission, financial services and other sectors. At least on the surface, the electric power industry has been largely unaffected by deregulation. Electric utilities are still subject to extensive price and entry regulation by state and federal regulatory agencies. And the industry has not yet experienced the dramatic structural changes that have followed deregulation in these other industries. Nevertheless, there are several significant changes that have and are taking place in the structure and regulation of the electric power industry. Of most importance is the increasing role of competing wholesale suppliers of power to utilities for resale, the resulting gradual de-integration of the electric power industry, and the regulatory changes that are promoting competition for future supplies of generating capacity acquired by utilities for resale to residential, commercial and industrial customers.

During the 1950s and most of the 1960s, the electric power industry attracted relatively little attention from public policy makers. The industry exhibited a high rate of productivity growth, falling nominal and real prices, few formal rate cases, excellent financial performance, and little regulatory or political controversy.[2] Utilities rarely had to file for rate increases, there were few formal hearings and "voluntary" rate decreases were the norm.[3] The system worked smoothly with relatively little regulatory and political controversy. While numerous academic and government studies identified imperfections in the performance of the industry, the associated public policy reform proposals focused on relatively modest regulatory reforms and the desirability of more cooperation and coordination among utilities many of which were deemed to be too small to exploit available economies of scale. Major structural and regulatory reforms were not high on the political agenda.

Economic conditions changed gradually in the late 1960s and early 1970s. Productivity growth disappeared and key input costs, in particular fuel and interest rates, rose. With prices fixed by regulation, rising costs lead to falling profitability. As a result, in the late 1960s and early 1970s a growing number of utilities filed for rate increased with their state regulatory commissions. These filings lead various interest groups to organize to resist rate these increases in the formal hearing process and to exert pressures for changes in regulatory procedures and rate structures. Requests for much larger rate increases followed quickly after 1973, triggered by large, unanticipated and largely uncontrollable increases in the costs of supplying electricity. These requests for higher rates further intensified regulatory and political resistance to rate increases and created political pressures for regulatory changes that would deal with "the problems" caused by rapidly rising electricity costs. Regulatory resistance to price increases led utility financial performance to decline precipitously. By the late 1970's and early 1980s, the system that appeared to work so smoothly for so long was in a state of virtual collapse, plagued by enormous regulatory and political controversies that had not been associated with the electric utility industry since the late 1920s and early 1930s.[4] The seeds of the changes that are taking place today can be found primarily in a series of regulatory, legislative, and utility responses during the 1970s and 1980s to the interaction of changes in the economic environment affecting the costs of supplying electricity and the regulatory institutions that historically determined how cost changes were supposed to be translated into changes in electricity prices. Probably the most important long term responses to the perceive performance problems that emerged in the 1970s and early 1980s are associated with the growing importance of wholesale power markets, most importantly the development of a competitive independent generating sector made up of power supply entities that sell power to distribution utilities for resale without being subjected to traditional price and entry regulations.

Increased opportunities for wholesale trade between traditionally integrated distribution utilities first emerged naturally in the late 1970s and early 1980s as a consequence of the unanticipated difference between coal, oil and natural gas prices, the primary fuels used to generate electricity, combined with excess generating capacity in most regions of the country. Entry of unintegrated non-utility generators (NUGs) was then encouraged by federal and state regulations issued after 1980 in accordance with the Public Utility Regulatory Policy Act of 1978 (PURPA). The reactions of the traditional utility/regulatory structure to the economic changes that occurred in the past fifteen years, the potential opportunities to rely more on a competitive independent generating sector revealed by the PURPA experience, and the political forces unleashed both by the performance of the traditional system when faced with economic shocks and by PURPA, increased the political demand for alternative regulatory and structural arrangements to govern the acquisition and operation of new generating capacity. As a result, we are now seeing major changes in electric utility generation capacity procurement practices, transmission arrangements, and in federal and state rate regulation to accommodate and encourage them. In the future, these developments are likely substantially to increase the importance of independent competing suppliers of wholesale electricity generation service unencumbered by traditional price regulation making sales to regulated partially integrated distribution utilities.

The purpose of this paper is to discuss the nature, causes and likely consequences of these changes. I begin with a discussion of the "traditional" structure and regulation of the electric power industry as it had evolved by the early 1970s. This is followed by a brief discussion of the rationale for and performance of the "traditional" industrial and regulatory structure. I turn next to an overview of the changes that have begun to take place in the structure of the electric power industry in the last decade with particular emphasis on developments in wholesale power markets generally and on the growth of an unintegrated independent generating sector in particular. This then leads to a discussion of the economic, regulatory and political forces that have led to these changes. The rest of the paper examines and evaluates in much more detail the public policies that have stimulated the rapid development of an independent generating sector, utility purchases from independent suppliers, and the growth and importance of competitive wholesale power markets.

THE STRUCTURE AND REGULATION OF THE ELECTRIC POWER INDUSTRY

a. Industry Organization

Residential, commercial and industrial customers (referred to in what follows collectively as "retail" customers)[5] spent over $150 billion on electricity in 1987.[6] Over 3,000 entities distribute electricity at retail to over 100 million customers. However, between 75 and 80% of the electricity supplied is provided by over 100 independent private investor-owned utilities (IOUs).[7] The rest is generated and/or distributed by nearly 3,000 publicly or cooperatively-owned entities that vary widely in size, structure and ownership form.[8]

Since the focus of this paper is on the IOU sector I limit the discussion here to the structure and regulation of IOUs. While IOUs vary widely in size, they share many common structural and regulatory characteristics (See Figure 1). The typical IOU has traditionally been vertically integrated into the generation, transmission and distribution of electricity (See Figure 1 and the Appendix for definitions of generation, transmission, distribution, retail transactions, wholesale transactions, etc.). As distributors of electricity to residential, commercial and industrial customers utilities typically have either a de jure or de facto exclusive franchise to provide service to the retail customers within their service territories. In return for this exclusive franchise, the retail rates charged by distribution utilities are subject to regulation by state regulatory commissions.[9] Distribution utilities also take on an obligation to provide reliable service at regulated rates to all retail customers located within their service territories. What economists think of as competition has played relatively little role in the determination of retail electricity rates for at least the last fifty years. Multiple franchisees authorized to serve the same geographical areas is an extremely rare phenomenon today in the electric power industry.[10]

Historically, IOUs typically owned and operated all of the generation, transmission and distribution capacity required to serve the needs of their retail customers. As the average size of generating facilities grew in the late 1960s and early 1970s joint ownership of generating facilities operated by one of the owners became common as many utilities found that they were too small to exploit economically state of the art central station generating facilities on their own. Developments in transmission and coordination technology have also led to increased interconnection between independent IOUs, joint planning and operation of facilities owned and operated by several proximate utilities, and, especially in the East, formal power pooling arrangements in order to enhance reliability and economically to exploit generating and transmission capacity owned by independent utilities.[11]

IOUs also make a variety of wholesale transactions. Wholesale transactions are defined as sales by one utility to another for resale to retail customers. Since the passage of the Federal Power Act in 1935, wholesale transactions have been regulated by the Federal Energy Regulatory Commission (FERC, formerly the Federal Power Commission). These transactions fall into two broad categories.

The first category encompasses so-called "coordination" transactions. The term "coordination transaction" emerged to encompass the short term purchases and sales of electricity engaged in by interconnected integrated utilities in order to make economical use of generating plants owned by proximate utilities possible and for reliability purposes.[12] That is, utilities traditionally provided for their capacity needs through ownership of sufficient generating capacity to meet their loads, relying on short term "coordination" transactions to facilitate economical and reliable joint operation of these facilities. This category of wholesale transaction has expanded in recent years to encompass virtually all voluntary bilateral wholesale contracts that do not involve an open ended obligation by the seller to provide for the "requirements" of the purchasing utility. These transactions involve both short term exchanges of energy and capacity for reasons of economy and reliability, including power pooling arrangements, as well as longer term purchase and sale contracts.[13] By and large IOU's traditionally have not built "stand-alone" generation and transmission facilities in anticipation of making "coordination contracts" with of other investor-owned utilities. Rather, wholesale coordination transactions are generally associated with generating capacity that is currently excess to the capacity needed by an integrated distribution utility or public utility holding company to provide service to its requirements customers.

The second broad type of wholesale transaction is referred to as a "requirements" transaction. This refers to sales by integrated IOU's to unintegrated or partially integrated distribution companies which do not provide through ownership generation and transmission capacity sufficient to supply the power demanded by their retail customers and which generally operate within the control area of a vertically integrated utility. Most of these unintegrated (full requirements customers) or partially integrated (partial requirements customers) purchasers are municipal or cooperative distribution utilities. Under a requirements contract a selling utility must stand ready to supply all of the "net" requirements of the buyer for the anticipated duration of the contract.[14] Requirements transactions are heavily regulated by FERC using fairly rigid cost-of-service principles similar to those used by state regulatory commissions in regulating retail rates. Wholesale requirements transactions account for roughly 10% of IOU generation and roughly 5% of IOU revenues.[15] The distinction between coordination service and requirements service has become increasingly fuzzy over time as medium and long term non-requirements wholesale contracts for specific services have been relied upon both by integrated distribution utilities and unintegrated distribution utilities.

In some cases, an economical wholesale transaction can only be consummated with the help of one or more third parties that control transmission facilities required to move power from buyer to seller. In these cases the buyer must arrange for <u>transmission</u> or <u>wheeling</u> service. Transmission service is a wholesale power transaction and is subject to the exclusive jurisdiction of FERC. However, FERC's jurisdiction is limited. It can regulate the rates charged for transmission service, but except in extraordinary circumstances, it cannot order a utility to provide such service. Thus, most transmission arrangements are voluntary, reflecting regulatory and financial incentives, the availability of transmission capacity to serve non-requirements loads, the historical cooperation between proximate integrated utilities and the threat of antitrust sanction.

In addition to production by utilities, electricity has also always been produced by industrial and commercial establishments almost exclusively for their own use (until recently). During the early history of the electric power industry, self-generation was an economically attractive alternative to utility supplied electricity for many industrial and large commercial customers. As recently as 1925, over 25 percent of the electricity supplied in the U.S. came from "non-utility," primarily industrial, power plants. However, as the cost of large-scale utility generation and transmission fell, most industrial customers were induced to abandon self-generation in favor of individually negotiated long-term power supply contracts with the local utility. By 1978, electricity provided through self-generation had fallen both absolutely and relative to total domestic electricity production to about 3 percent of the total electricity produced in the U.S.. Most of the "non-utility generating" (NUG) capacity had been built almost exclusively to provide for all or part of the electricity needs of the establishment where the electricity was produced; they generally were not designed to provide additional electricity to help to meet the generation capacity needs of proximate utilities serving other customers. Truly unintegrated independent wholesale power companies owning and operating power plants built to provide generation service under contract to meet some of the needs of unaffiliated distribution utilities were virtually non-existent and neither state nor federal regulatory policies have traditionally contemplated, let alone encouraged, their development until recently.[16]

b. State and Federal Regulatory Processes

Public utility companies are organized pursuant to state law and are authorized to do business by the individual states in which they have facilities and make sales. Retail rates are regulated by state public utility commissions. The terms and conditions of retail franchises are also determined by state law. Because the typical distribution utility receives the vast bulk of its revenues from retail sales, is generally vertically integrated into generation, transmission and distribution and because generation, transmission and distribution assets are typically owned by the same corporate entity, rather than through common ownership of separate corporate distribution and bulk power (G&T) subsidiaries, the bulk of a utility's costs are subject to state rather than federal regulatory authority.[17] A majority of the states also require utilities to obtain certificates of convenience and necessity before building major new generating or transmission capacity and many states review utility construction planning procedures.[18]

There is no federal regulation of entry, supply planning, or facility construction in the electric utility industry.[19] FERC has no authority to authorize an electric utility to enter the business. And unlike the case of interstate gas pipelines, FERC has no authority to issue certificates of convenience and necessity to electric power facilities.[20] This is true even if the public utility in question only engages in wholesale transactions. FERC's authority is limited to the regulation of rates and related terms and conditions for interstate wholesale transactions, data filing requirements, the establishment of a uniform system of accounts, approvals of mergers between electric utilities, etc.

b.1 State Regulation of Retail Rates

A utility must submit to its state commission, in advance of their effective date, any proposed changes in the level or structure of its existing rates as specified in its filed tariffs. The Commission then may either allow such changes to go into effect or disallow them in whole or in part subsequent to regulatory review.[21] A commission on its own initiative can also order the utility to change the level and structure of its rates if they are not consistent with state law. The administrative proceeding in which proposals for changes in the price and non-price conditions of service are made are called rate cases. Tariffs approved in rates cases specify the prices that a utility must charge until new tariffs are approved by the commission. To a first approximation, prices are fixed between rate cases and until new tariffs are approved by the commission. But some tariffs also have automatic adjustment provisions, generally for fuel and certain purchased power expenses, so that prices move up and down as these input prices change.

Most state commissions operate under fairly vague statutory mandates which provide that the commission is to set rates that are "just, reasonable, and non-discriminatory." State statutes may elaborate more specific criteria as well. For example, state law may provide that facilities must be "used and useful"[22] in order for their associated costs to be incorporated in rates, or specify that only costs which have been "prudently incurred" may be included in rates. They may restrict the use of fuel adjustment clauses, restrict the inclusion of construction work in progress in rates, define criteria for rate base determination, etc. By and large, however, the details of regulatory procedures have been defined through the development of regulatory case law, court reviews of regulatory decisions, and rulemakings. In the last few years, however, there appears to have been increased activity by state legislatures to revise state statutes to provide more "guidance" to state commissions, however.

The basic principle that currently guides state commission regulation of electricity rates is that prices should reflect the "cost of service".[23] For the utility as a whole, prices are, in theory, set so that total revenues equal total costs or, alternatively, so that the average revenue per unit of electricity sold equals the average cost of supplying it. For specific services provided by the utility (such as residential, commercial, and industrial service in different seasons and at different times of day) prices generally, in theory, reflect the costs of providing the individual services based on a variety of different cost allocation schemes.

Commissions theoretically set rates so that both operating costs (fuel, labor, and materials) and capital costs are covered. Fuel, labor, materials and the costs of power purchased from third parties (wholesale purchases)[24], can be obtained directly from the utility's accounting system if rates are set on the basis of actual costs in a past "test year," or they can be estimated fairly easily if a future "test year" is employed. Capital cost is equal to depreciation plus a "fair return" on the utility's capital investment stock or "rate base". While there was considerable debate earlier in this century as to the proper method for computing the "fair return" to which utilities are entitled,[25] most commissions now obtain this quantity by multiplying an estimate of the utility's nominal cost of capital by the depreciated original cost of its assets.[26] This latter quantity is called the utility's "rate base". Straight-line depreciation is employed, with asset lifetimes that are to some extent arbitrary--and thus the subject of debate from time to time.

This approach to determining capital cost would, if applied exactly and continuously, give the utility a stream of earnings for each asset that has as its present value (using the cost of capital as the discount rate) exactly the original cost of the asset.[27] Or alternatively, the expected rate of return on a utility investment is equal to its cost of capital. Thus, in theory, this approach provides incentives for utilities to invest (present value of expected cash flows greater than or equal to initial investment cost) and protects consumers from being charged monopoly profits. It is also the case that if rates are continuously adjusted according to these ratemaking formulas so that the utility earns its cost of capital exactly, then the market value of a utility's common equity will exactly equal the book accounting cost value of equity.

There are of course many possible capital cost accounting formulas that could be used for ratemaking purposes which have the property that the expected return on investment is exactly equal to the utility's cost of capital. The particular virtues of depreciated original cost ratemaking of the type that has been used traditionally are primarily (a) accounting simplicity and (b) ease of verification of actual investment costs and deterrence of asset transfers designed artificially to inflate the rate base (daisy chaining). The primary disadvantage (aside from incentive effects) is that the capital cost or retail rate charged at any one point in time does not generally equal the true, economic cost or rental rate associated with the firm's capital at that point in time; accounting capital costs and economic carrying charges are equal only by chance at any point in time.[28]

In practice, regulation does not follow these simple ratemaking principles either exactly or continuously. Two important practical features of electric utility ratemaking are worth noting. First, commissions do not continuously adjust prices through time as costs change. Rates are changed only on the motion of the company or the commission and after the commission has held often lengthy hearings. Prices (or, more precisely, the provisions of filed tariffs) may remain unchanged for years as the did during the 1950s and 1960s for some utilities. The tendency of regulated rates to adjust slowly to changes in costs is frequently referred to as "regulatory lag." Due to regulatory lag, the actual rates of return earned by electric utilities may be above or below the commission-determined fair rate of return at any instant. Moreover, when prices are fixed, utilities can increase profits by cutting costs, while there would be no such incentive if prices were continuously adjusted so that all costs incurred by a utility would be recovered at every instant.

Second, commissions are not bound to set rates that cover all costs incurred by regulated firms. Regulators have the authority to "disallow" both capital and operating costs incurred by a utility if they find that the associated expenditures were "imprudent" or are not "used and useful." In principle, a commission can disallow certain costs if it believes that the utility was inefficient because it could have obtained the corresponding services more cheaply or did not require those services at all. While a state has considerable flexible to define the regulatory rules that it will apply, the effect of the application of these rules must be consistent with Constitutional guarantees against the taking of private property without just compensation.[29]

In addition to setting rate levels (average price for all units sold) and rate structures (prices for specific classes of customers and different services), commissions also establish other terms and conditions of service, such as line extension requirements, billing procedures, and service quality attributes; issue certificates of convenience and necessity to allow the addition of new plant and equipment; supervise franchising and refranchising; approve mergers and acquisitions; and, sometimes, get deeply involved in supply side planning and operating issues. These non-price attributes of regulation vary much more from state to state that does the basic structure of price regulation.[30]

b.2 Federal (FERC) Regulation Of Wholesale Rates

Until very recently the basic regulatory principle governing FERC regulation of wholesale transactions has been "accounting cost of service". However, for wholesale coordination transactions between unaffiliated utilities, this has increasingly become a regulatory fiction. Wholesale coordination transactions associated with transfers of energy and capacity between integrated utilities are market driven not accounting cost of service driven as sellers compete with one another to make sales to proximate utilities; the buyer is under no obligation to buy and the seller is under no obligation to sell. Although sellers have generally been required to cost-justify negotiate contracts, this has frequently been accomplished through a variety of ex post cost allocation mechanisms.[31] Over the past decade, the FERC staff has been increasingly willing to accept mutually satisfactory negotiated coordination contracts between integrated utilities that are de facto unencumbered by the rigid cost accounting principles that are used to set retail rates. This flexible regulatory approach has been critical for encouraging the development of an active wholesale market for energy and capacity associated with facilities built to serve the expected requirements loads of the seller but which are temporarily excess to these needs. Cost of service regulation based on rigid cost accounting rules and lengthy regulatory reviews would have made the evolution of such a market almost impossible.

FERC sets rates for wholesale requirements service and approves cost allocations between affiliates of interstate holding companies using embedded cost of service ratemaking principles that are very similar to those used by the states in setting rates for retail customers. An allocation of accounting costs between FERC and retail jurisdictions is made based upon the characteristics of their respective loads on the system, including peak load, voltage at which power is taken, and load factor. A depreciated original cost rate base, nominal cost of capital, and straight line depreciation are used to determine capital costs. Fuel and non-fuel O&M costs, taxes, etc. are added in much the same way as they are at the retail level.

This entire state and federal regulatory structure (including the Public Utility Holding Company Act of 1935) has evolved in the context of vertically integrated IOUs that are primarily in the business of providing service to retail and "captive" wholesale requirements customers. Aside from the relatively recent developments affecting the prices cogenerators and small power producers can charge under PURPA and the implicit regulatory flexibility that has evolved for coordination transactions (see below), FERC never developed, and until recently didn't even contemplate, explicit regulatory rules to accommodate unintegrated ("stand-alone") wholesale power producers which would compete with one another to contract to build generating plants and produce power for sale under contract to unaffiliated distribution utilities in competitive wholesale power markets. Despite a lot of rhetoric about competition in wholesale markets FERC regulatory policies historically neither encouraged nor accommodated entrepreneurial investments in generating facilities to provide service in a competitive wholesale generation market.

THE RATIONALE FOR AND THE PERFORMANCE OF THE "TRADITIONAL" SYSTEM

The appropriate structure and regulatory environment for promoting the efficient production and pricing of electricity has been the subject of academic discussion and debate for many years.[32] The combination of economies of scale, economies of multiproduct production, and economies of vertical integration provide the primary "public interest" rationale for the emergence of vertically integrated electricity supply firms with de facto legal monopoly franchises to provide retail service to a specific geographical area, subject to price regulation. That is, the distribution of electricity in any geographical area is a natural monopoly; transmission functions, broadly defined, are natural monopolies over even larger geographical areas; and economies of vertical integration between generation and transmission effectively make the generation required to serve a distribution utility's load efficiencly a natural monopoly as well. Thus, the "optimal" organizational form for an electric utility is incompatible with competition at the distribution or transmission level or with a completely separate generation sector made up of competing firms. Regulated integrated monopoly distribution utilities are then viewed as the efficient institutional response to the desire to obtain the perceived cost savings of single firm production without incurring the costs of monopoly pricing.

What do we know about the natural monopoly characteristics of electricity supply and the performance of regulated integrated electricity monopolies?[33] Is the "public interest" rationale for the traditional system consistent with the empirical evidence? It is generally acknowledged that the distribution and transmission (encompassing transportation, coordination, and reliability functions) of electricity have natural monopoly characteristics.[34] There are clearly at least some economies of scale at the generating unit and plants levels as well.[35] There also appear to be multiplant economies associated with economical coordination of dispersed generating facilities to meet fluctuating loads and to maintain reliability for a product whose demand varies widely from hour to hour, in not storable, and where an economical technology to signal retail customers with spot prices is not available to balance supply and demand in real time.

The extent of economies of scale in generation per se at the firm level, however, is more controversial. While it is common to talk about generation, transmission and distribution as if they were completely separate processes, and while cost and investment data are often broken into these three segments, there are important technical and economical interdependencies between these three components of electricity supply. Furthermore, the characteristics of generation and transmission investments, the multiproduct nature of the products supplied by a utility (time of delivery, voltage level, reliability, load factor, etc.), and uncertainties on both the supply and demand sides, suggest that there may be significant costs associated with linking efficiently investments in and operations of decentralized generation and transmission systems through bilateral contracts. As a result, the conventional wisdom has been that there are likely to be important economies associated with common ownership of generation and transmission (vertical integration).[36] In addition, because economies of coordination and reliability associated with an AC transmission network extend over large geographical areas, economies associated with horizontal integration, or extensive cooperation between proximate owners of generating and transmission capacity, are likely to be significant as well. In this regard it is especially important to recognize that there are significant potential externalities and free rider behavior associated with decentralized operation of individual pieces of an interconnected electric power network; changes in generation, interconnections, or demand at any point in the system have real time effects throughout an interconnected AC system. These effects are a consequence of physical laws and are not coincident with ownership boundaries or contractual transmission paths.[37]

I believe that the available empirical evidence suggests that at the very least the distribution of electricity has important natural monopoly characteristics. This implies that electricity should continue to be distributed to final customers (retail service) by franchised monopoly distribution companies subject to price regulation. While there continues to be discussion of possibilities for competition in the distribution of electricity, especially for large industrial customers, there has been little serious contemporary public policy interest in encouraging competing suppliers of electric <u>distribution</u> service to serve the same geographical areas or in broad deregulation of retail electricity prices. As a result, in this paper I assume that the distribution of electricity continues to be provided by franchised monopolies subject to some form of price regulation and focus on changes associated with the growth of competitive wholesale power markets generally and an independent generation supply sector in particular.

As I discuss in more detail below, we are seeing structural and regulatory changes that would increase opportunities and incentives for investor-owned utilities (IOUs) that have historically been vertically integrated into the distribution, transmission and generation of electricity to rely more on competing third party suppliers to provide them with long term supplies of generating capacity to satisfy the requirements of their retail customers when these sources are more economical than utility-owned capacity. Assuming that retail rates continue to be regulated so that the monopoly distributor's prices will reflect the total economic cost, including generating costs, of providing electricity service efficiently to final consumers, the benefits and/or costs of these changes affect retail customers indirectly through their effects on the distribution utility's costs.

These changes challenge the conventional view that vertical integration between generation and transmission/distribution and horizontal integration between interconnected generating plants represents the most efficient organizational arrangement for supplying electricity given the imperfections of the institution of regulated integrated monopoly.[38] Probably the most fundamental issues associated with the current trend toward de-integration of generation and the development of competitive wholesale generation markets are associated with questions about the properties of alternative organizational arrangements.[39] What really is the most economical organization form through which these three segments of the electricity supply system should be integrated with one another? What is the nature of the tradeoffs between the potential efficiencies associated with integrated monopoly distribution companies and the potential inefficiencies associated with the institution of regulated monopoly? What are the properties of "second best" organizational arrangements (power pools or other cooperative arrangements, bilateral contracting, etc.) that might sacrifice some of the theoretical efficiencies of vertical and horizontal integration in order to reduce some of the inefficiencies of regulation by relying more on competition to allocate generation resources?[40]

I believe that from a purely technical or engineering economics perspective there are in fact important economies of scale and economies of vertical integration associated with the supply of electricity. Indeed, from this perspective there are far too many utilities involved in generation and (especially) transmission/coordination in the United States. However, how these technical characteristics influences ones views about the optimal industry and regulatory struture for the electric power industry depends on how it performs in practice. Do vertically integrated monopoly firms subject to regulation minimize costs statically and dynamically? Do regulators set rates in a way that passes the efficiency benefits of single firm production on to consumers and provide consumers? Given that electric utilities are insulated from competition and subject to cost of service regulation it is only natural to hypothesize that they face diminished incentives to minimize costs and that the regulated rates they are allowed to charge may depart from the most efficient (first or second-best) prices. As a result, a great deal of the scholarly analysis of the electric power industry has focused on the effects of regulation on costs and prices and has examined regulatory and structural changes to reduce inefficiencies caused by prevailing regulatory processes. Most of this literature is discussed elsewhere[41] and I will provide only a brief selective summary here.

By and large studies that have examined the effects of regulation as it interacts with the current structure of the industry find that electric utilities do not minimize costs in the neoclassical sense that cost minimization implies equality between the marginal rate of transformation of one input for another and the ratio of the associated input prices. Some studies find evidence that electricity production is biased toward the use of capital inputs. Other studies find that it is biased toward the use of fuel or labor inputs. At least one study looks for and finds evidence of "X-inefficiency" as well[42].

The nature and magnitude of these static inefficiencies varies widely from study to study, however. Furthermore, the accuracy of the results is very uncertain. These studies necessarily must rely on ex post cost data to estimate long run cost functions, a questionable undertaking for an industry with long-lived capital facilities and uncertain and changing input prices and demand. There is also much less real variation in state regulatory procedures than is reflected in some of the indicia that are typically used to pick up variations in regulation. Empirical work is based on data for firms that have very similar structures and operate in ery similar regulatory environments. Data do not exist to compare performance under fundamentally different structural and regulatory arrangements. While I believe that the literature does support a presumption that there are some inefficiencies associated with the supply of electricity, the magnitude and causes of the inefficiencies and reliability of the results are very uncertain. Furthermore, we do not know if these inefficiencies are of greater magnitude than would be found by applying the same techniques to unregulated industries.

Studies that examine the effectiveness of state rate regulation in keeping rates close to the cost of service also yield fairly consistent conclusions. During the late 1950s and the 1960s regulatory lag worked to allow utilities to earn returns on investment greater than their cost of capital. Since real costs and prices declined throughout this period of time and because regulatory lag can encourage static and dynamic cost minimization, it is conceivable that customers were actually better off than they would have been had regulators tried to match revenues and costs exactly and continuous.[43] However, I am not aware of any empirical studies that try to show that this regulatory lag was "optimal". The pattern of real and nominal costs changed dramatically in the 1970s. As the real and nominal costs of supplying electricity increased in the 1970s and early 1980s (see below) regulatory lag worked to keep prices below the accounting cost of service and earned returns below the cost of capital.[44] Some of the work focusing on the latter period suggests, I believe correctly, that the regulatory process had become so punitive that utility incentives to invest in new generating capacity under prevailing regulatory arrangements had been sharply diminished.[45]

To the extent that there is any general consensus that can be drawn from the scholarly literature on the performance of the electric power industry it points largely toward regulatory reforms aimed at improving the way electricity prices are structured, to the desirability of developing better regulatory incentive mechanisms to guard against inefficient production decisions, and to increased cooperation, coordination and horizontal mergers, rather than to simple prescriptions for deregulation of entry and prices. With a few exceptions, the literature does not consider in any detailed way or even anticipate the changes in wholesale power markets that are now taking place.[46] Nor is it particularly helpful for dealing with the difficult issues that arise in efficiently integrating decentralized power producers into a synchronized interconnected AC power system.

THE CHANGING STRUCTURE AND REGULATION OF ELECTRIC UTILITIES: OVERVIEW

The structure and regulation of IOUs is changing in several important dimensions. In this section I provide an overview of the nature of those changes. The next section examines the economic, regulatory and political forces that are leading to these changes. The sections that follow discuss the changes taking place in utility generation procurement processes and the development of competitive wholesale generation markets in much more detail.

Figure 2 contains a schematic diagram of what I refer to as "The Evolving IOU." By comparing Figure 2 with Figure 1 we can see several obvious changes. First, the IOU is much more heavily engaged in wholesale transactions involving medium and long term contracts for energy and capacity with other integrated utilities than it was fifteen years ago. As Figure 2 is drawn the IOU is a buyer, but obviously at the other side of the transaction is another IOU that is making the sale. In addition to contract sales between domestic IOUs, these wholesale transactions also have expanded due to increasing trade with Canadian utilities in both the East and West. Thus, rather than relying on wholesale transactions with proximate utilities primarily for short term economy and reliability purposes, utilities with excess generating capacity are increasingly signing medium and long term contracts to allow other utilities to defer capacity additions or to displace uneconomical generating capacity. I want to emphasize, however, that most of this trade to date involves capacity that was built to meet the needs of an integrated utility's requirements customers. The increases in inter-utility wholesale trade that we see reflects (so far) primarily an effort to exploit differences in relative fuel prices and excess generating capacity to minimize the cost of supplying electricity from existing generating capacity. The capacity associated with this trade was not generally built explicitly to serve unaffiliated buyers in the wholesale market.

The second change reflected by the differences between Figure 2 and Figure 1 is the introduction of two new categories of suppliers of generation service referred to as "QF" and "IPP" suppliers. The term QF refers to independent cogeneration and small power production facilities that qualify for special regulatory treatment under PURPA (see below). These independent generating entities are not subject to cost of service regulation. As I will discuss in more detail presently, the prices they are paid are supposed to reflect the purchaser's opportunity cost of the type of generation service offered rather than the supplier's cost of service. Supplies of power made available to utilities from QFs (plus QF power used internally by the seller to reduce demands on the utility) has increased significantly in the last few years. More importantly, QFs are expected to contribute a large fraction of future generation requirements over the text ten or twelve years.

The "IPP" category refers to "stand alone" producers of generating service built explicitly to supply power to unaffiliated distribution utilities to meet some of their long-term capacity needs. These producers would not be subject to traditional cost of service or profit regulation, but rather would negotiate contracts with unaffiliated utility buyers in competitive generation markets. IPPs differ from QFs in at least two ways. First, there would be no requirement that they meet PURPA's technology, fuel, or size limitations. They would simply be stand alone power plants of the developer's choosing. Second, there would be no special statutory requirement that utilities purchase from IPPs. Whether or not they do so will depend on the state and federal regulatory environment governing utility procurement practices and the economic advantages that IPP suppliers can offer compared to traditional integrated ownership and operation of generation or purchasing from QFs.

At the present time IPPs are primarily a gleam in the eye of potential developers, some potential purchasers and some regulators. Technically, few such facilities currently exist. Furthermore, the current regulatory environment is not particularly conducive to their further evolution. There are developments on the fringes of the IPP market, however. An increasing number of large QFs are really simply standard power plants which have found minimal contrived steam loads to qualify as QFs. Spending unnecessary money or wasting energy to heat a greenhouse in order to obtain QF status is obviously inefficient and the developers of these projects would like the opportunity to enter to supply generation at wholesale without having to make unnecessary expenditures to become "barely" cogenerators and qualify for QF status. There is clearly a growing interest in making the regulatory changes necessary to make it possible for independent power suppliers that are not QFs under PURPA to compete to provide generation service to distribution utilities unencumbered by cost of service rate regulation. These developments will be discussed in more detail presently.

The increase in wholesale trade that we are observing has also been associated with increases in transmission or wheeling arrangements which make it possible to move power from supplier to purchaser when they are not directly interconnected with one another.

Table 1 summarizes the changes in total electricity consumption and wholesale transactions of various types that took place between 1973 and 1985 and between 1985 and 1986. I have chosen these time periods to cover the period of rising oil and gas prices and to see the competitive wholesale market response to the dramatic decline in oil and gas prices between 1985 and 1986. Total electricity consumption increased by roughly 32% between 1973 and 1985 . Wholesale trade of all kinds increased much more than did total consumption during this time period leading to a larger relative role of wholesale transactions in contributing to the resource mix used to supply electricity to retail customers. After 1985, short term interchanges between domestic utilities and Canada, and associated wheeling service, declined as lower oil and gas costs made short term interchanges transactions less economical. Longer term contracts and purchases from NUGs continued to increase, however reflecting longer term trends in the market. Overall, utilities have come to rely more on wholesale trade to meet the needs of their retail customers since 1973.

In addition to these structural changes, there have also been important regulatory changes in the industry. In both Figure 1 and Figure 2 the arrow linking the distribution utility to the retail customers naturally goes through an intervening regulatory process. That regulatory process has changed dramatically over the past fifteen years. Prior to the early 1970s the regulatory process governing electric utilities was a relatively passive process which presided over a period of rapidly increasing productivity, declining prices, rapidly expanding loads, good financial performance, strong incentives for utilities to invest in new capacity to meet expanding loads and little political controversy. It has been transformed into a very activist regulatory process with heavy regulatory involvement in the review costs and operating performance, frequent cost disallowances, regulatory involvement in utility planning, the introduction of incentive mechanisms[47] designed to increase efficiency, new power supply procurement processes, increasing prices, declining productivity, poor utility financial performance, strong disincentives for utilities to invest in new generating capacity themselves, and substantial political controversy. Whether "the regulatory compact has been broken" or not, it has certainly changed dramatically, and not always for the better (see below).

A final change that is worth noting is the increasing importance of competition of a sort at the retail level. There has been little if any movement toward changing the status of distribution utilities as de facto exclusive suppliers of retail service.[48] However, even an exclusive supplier can't charge a customer any price that he chooses do. Even monopolists serve customers whose consumption is sensitive to price. Electricity demand is particularly price elastic in end uses where fuel switching is likely to be economical, in industries where cogeneration is economically attractive, and in industries where the location of production can be shifted economically in response to changes in electricity prices. Economic and regulatory changes have increased the threat of self-generation and this has tended to moderate rates for certain classes of large industrial customers. It may have lead to higher rates for other customer classes, however.

ECONOMIC AND POLITICAL PRESSURES FOR STRUCTURAL AND REGULATORY CHANGES

The motivation for regulatory and structural change in the electric power industry cannot be found in a general intellectual consensus about performance problems or the specific solutions to them that evolved along with the industry after WW II. None existed. While there has been substantial academic analysis of the performance of the electric utility industry in the U.S., it has not led to the kinds of strong conclusions regarding the effects of regulation and the desirability of "deregulation" or specific regulatory reforms as has been the case in industries such as airlines,trucking, railroads, and, (perhaps) telecommunications. Nor are these changes part of a coherent comprehensive public policy response to a clear set of generally agreed upon performance problems. Only in the classrooms at the Kennedy School do rational comprehensive public policy responses to real economic problems emerge. Rather, the structural and regulatory changes taking place are a consequence of a series of individual uncoordinated regulatory and political "fire fighting" responses to the economic, regulatory and political turmoil caused primarily by several economic shocks experienced by the electric power industry during the last fifteen years.

Changes in regulatory procedures began to take place in the late 1960s as rising costs led to more and more requests for rate increases and formal hearings.[49] However, these changes were fairly modest responses to inflation and growing concerns about the effects of electricity generation on the environment. It is the economic shocks of the 1970s, in particular the post-1973 period, that led to economic and political turmoil and resulting pressures for change. These shocks include (a) large increases in fossil fuel prices in 1974/75 and again in 1979/80 (see Figure 3); (b) new environmental constraints on air and water emissions from power plants beginning in the 1970s increasing the costs of building and operating fossil-fired plants;[50] (c) unexpectedly costly nuclear power plants (see Table 2) and opposition to nuclear power based on economic, environmental and safety concerns; (d) an increase in the general rate of inflation and high interest rates in the late 1970s and early 1980s; and (e) unanticipated reductions in the rate of growth of demand,[51] resulting in substantial excess generating capacity (see Figure 4).[52] These economic shocks fell heavily on the <u>generation</u> component of electricity supply which accounted for roughly 75% of operation and maintenance costs and 65% of capital costs in 1986. As a result, the pressures for regulatory and structural changes have focused on generation.

Prior to roughly 1968 rising input costs generally were more than compensated for by real cost savings due to scale economies, increased coordination between systems, or opportunities to increase the thermal efficiency of generating units using conventional steam-turbine technology, and other technological changes.[53] However by 1970 as input price increases began to accelerate, productivity growth due to fuller exploitation of economies of scale and coordination and technological innovation stagnated.[54] Rather than falling real and nominal average costs per Kwh we began to see large increases in the nominal and real cost of supplying a kwh of electricity. These large cost increases naturally led utilities to file for large rate increases with state and federal regulatory agencies.

I argued many years ago,[55] that the regulatory process works in such a way that prices are sticky downward and upward in response to changes in nominal costs. It is especially resistant to price increases requiring administrative approval. To reflect rising costs in rates, utilities had no choice but repeatedly to seek regulatory approvals for large rate increases. These applications were set for formal hearings. The formal hearings in turn provided a forum for those adversely affected by the price increases to oppose them. Not surprisingly, large rate increases were aggressively resisted by groups representing residential, commercial and industrial customers, their political agents in the legislative and executive branches, and ultimately by regulators appointed by governors (or in a few states elected directly) and responsible to legislatures. In the end, utilities found that they had a very difficult time recovering the costs that they had expected would be afforded traditional cost of service treatment through the ratemaking process.

We can get a feeling for the nature and magnitude of the economic shocks that hit the electric power industry in the 1970s and 1980s and the regulatory responses to them, by examining patterns of electricity prices, rate increases approved by state regulators, and industry financial performance before, during and after the economic shocks that I just discussed. Let's start with electricity prices.

The average nominal price per Kwh of electricity for the U.S. as a whole for the period 1960 to 1987, averaged over all consumer groups, and for the residential and industrial classes separately, can be found in Figure 5. A time series for the real prices of electricity (in $1982 using the GNP deflator) is displayed in Figure 6. The nominal and real average price per kWh of electricity fell almost continuously between 1960 and 1970. Nominal prices began to rise in 1970, took a big jump after 1973, and another big jump after 1979. Real electricity prices show a similar pattern. By 1985 nominal and real prices stabilized and then began to decline, as fossil fuel prices, interest rates, and the general rate of inflation declined and capacity utilization began to increase.

Another way to look at this is by examining the pattern of base rate increases (or decreases) approved by state regulatory authorities over time. Figure 7 displays the annualized value of net base rate increases from 1963 to 1987.[56] Until roughly 1969 there were no net base rate increases; indeed there were rate decreases. Applications and approvals of rate increases then began to increase, with big jumps after 1973 and again after 1979. Rate increase requests fell off sharply after 1985 as interest rates declined, inflation abated, capacity utilization increased, and utility generating capacity construction programs came to an end.

The modern electric power industry had never experienced a sustained period of nominal and real cost increases and repeated formal rate hearings to pass on rate increase requests since state commission regulation was widely introduced between 1907 and 1920.[57] In the past there had been relatively few formal rate cases, little public intervention in rate cases to consider rate increase requests, and extensive reliance on informal moral suasion by regulators to bring about rate reductions. The regulatory process that had evolved over that period of time was not designed to deal with large and continuing cost increases that occurred after

1973 and the controversies over the associated administrative proceedings initiated in response to utility requests to pass these costs along in higher prices.

The "regulatory resistance" view that I subscribe to suggests that large increases in nominal costs should have been accompanied by reduced profitability for utilities after 1968 and in particular after 1973 as price increases lagged behind cost increases. We should also see a recovery beginning in roughly 1984 as the cost pressures abated or reversed. There are a variety of indicators that we can examine to infer how utilities performed financially before, during, and after these cost shocks. These include the earned rate of return on equity investments (calculated symmetrically with the way allowed rates of return are calculated) relative to the cost of capital, interest coverage levels, the ratio of a utility's common stock price to the per share book value of equity invested,[58] and the proportion of book earnings that are cash earnings.[59] Table 3 provides information for several of these indicators of the financial performance for the 24 utilities in Moody's electric utility average over the 1960-1987 period.

The period from roughly 1960 to 1968 was a era of excellent financial performance. Earned rates of return on equity were far above the average cost of new utility debt, virtually all of the earnings reported were cash earnings, price/book ratios were significantly greater than one, interest coverage ratios were high, etc. By 1968, the financial performance of the industry was already starting to deteriorate as measured by these indicators, although the system appeared to be stabilizing before 1974 with earned rates of return approximately equal to the cost of capital. After 1973, the financial performance of the industry deteriorated dramatically, however. Common stock price/book ratios fell below one, the earned rate of return on equity did not keep up with changes in interest rates, utilities generally failed to earn their allowed rates of return on equity (see Figure 9), and a growing fraction of earnings were non-cash accounting credits the basis for which was the assumption that generating plants under construction would eventually be given rate base treatment and a return on the associated investment equal to the cost of capital earned. Financial performance only began to improve after 1984 as economic conditions became more favorable again and utility generating capacity construction programs came to an end.[60]

Public utility regulation is often characterized as a cost-plus system. While capital and operating costs are the primary determinants of electricity rates in the long run, the financial experience of the electric utility industry over the last twenty years makes it clear that it is not a pure cost plus system, however.

How exactly did the regulatory process "resist" price increases? At first, the regulatory process simply relied on natural inertia built into conventional regulatory procedures. It takes at least a year to put a rate filing together and to get a state commission to render a decision. Many state commissions still rely on an historical "test year",[61] so that new rates might go into effect based on costs that are at least two years old.[62] The effects of regulatory lag per se can be seen by examining the relationship between the average rate of return on equity allowed by regulatory agencies in rate hearing in a particular year and the rate of return on equity actually earned by utilities in that year. The allowed rate of return is supposed to reflect the utility's current cost of equity capital, so earned and allowed rates of return should be approximately equal.

Figure 9 provides information on the relationship between allowed rates of return and earned rates of return between 1974 and 1987. It is clear that earned rates of return are substantially below allowed rates of return (and thus the cost of equity capital) during most of this period of time. The gap disappears only after 1985 as fuel prices decline, inflation and interest rates decline, and utility generation construction programs come to an end. Comparable data for the pre-1974 period are not available. However, my earlier work[63] suggests that the earned rate of return was greater than or equal to the cost of capital prior to the mid-1970s. The relationship between allowed and earned rates of return is also completely consistent with the behavior of utility common stock price/book ratios (See Figure 8).

Regulatory lag of course simply delays rate increases. Regulators also initially tried to respond to the pressures that they were subjected to with a variety of modest and often quite sensible "regulatory innovations" that did not depart significantly from established regulatory principles. For example, regulators came to understand that the use of a depreciated original cost rate base plus a nominal cost-of-capital based rate of return tends to "front-load" revenue requirements. This leads to "rate shocks" when there is rapid inflation, high nominal interest rates, and big "lumps" of capital additions.[64] A variety of "phase in" mechanisms were applied as a reasoned regulatory response designed to smooth the revenue requirements stream to avoid "rate shock."[65] State regulators also become much more sensitive to the potential efficiency disincentives resulting from cost plus regulation. This led some state regulators to begin to experiment with the use of formal incentive mechanisms, applied primarily to generating unit performance.[66]

However, none of these regulatory innovations fully responded to the political pressures to insulate consumers from cost increases. And in the late 1970s and early 1980s cost increases and associated rate increase requests escalated as utilities continued to build nuclear and coal burning generating plants in anticipation of future capacity needs or to displace uneconomical oil and gas-fired generating facilities.[67] These plants turned out to be much more costly than had been anticipated, had per Kw costs far greater than the average embedded cost of plant in rate base, and when completed would have led to significant increases in the size of the rate base on which capital charges are based if traditional cost of service principles had been applied. Some of the most costly plants began to enter service after 1979 in the face of a growing surplus of generating capacity, rapidly rising fuel prices, rising interest rates, and an increase in the general rate of inflation affecting other inputs (See Figures 3 and 4 and Table 2). Giving these new plants conventional rate base/cost-of-service treatment often implied large increases in rates on top of prices that were also increasing rapidly in response to inflation in fuel and other operating costs. As a result, regulatory commissions came under considerable pressure to resist including the costs of these plants in rates.

Many regulatory commissions responded by subjected new power plants to ex post "prudence" reviews.[68] Between 1945 and 1975 there were fewer than a dozen prudence cases.[69] However, prudence reviews have now become a routine component of the regulatory process. Virtually all nuclear plants completed since 1980 have been subject to "prudence" reviews. In the majority of cases some fraction of the total cost of these plants was disallowed.[70] Where regulatory commissions could not show that investments were "imprudent" they sometimes have simply changed the rules of the game, taking the position that cost of service compensation would only be provided if the economic value of the plant was greater than its accounting cost---the so-called used and useful concept. This made it possible selectively to disallow costs based on "excess capacity" and unanticipated changes in economic conditions (To the best of my knowledge no regulatory agency has yet rewarded a utility for building and operating plants with accounting costs less than the economic value of the plant.) All together, utility stockholders probably ate on the order of 20% of their investments in nuclear power plants, amounting to tens of billions of dollars (Kahn and Perl (1985)).

Prudence determinations and associated cost disallowances were largely a political response to a political problem rather than the application of clear well established regulatory principles.[71] However, the requirement that regulators repeatedly deal with requests for large rate increases during the past decade and a half has led to rather profound changes in the regulatory process. Many of these changes, while motivated by the economic turmoil of the 1970s and early 1980s, have become permanent fixtures of the regulatory process. In particular cost disallowances for generating facilities have become routine while changes in the ratemaking process to account for the increased risk of disallowances have not been forthcoming.

Utility behavior has naturally responded to the incentives created by the experience of the post-1973 period. Utilities learned that if they built a large new generating plant there was a very good chance that they would not fully recover their investment in it. That is, there was a significant risk that the ratemaking process would resist large rate increases even if those increases are fully justified by cost increases. The result appears to be a sort of generating investment minimization effect. The expected return on major new generating plant investments is perceived to be below the cost of capital. Few utilities appear to be willing to build large new base load generating facilities, even in areas of the country where additional capacity is needed, in light of the experience of the recent past.[72] Instead, they are looking to third parties, smaller less capital intensive generating technologies, and investments in customer conservation, to reduce the financial risks associated with traditional utility investments. Several commentators have suggested that utilities are underestimating demand and underinvesting in new capacity in response to the financial penalties recently experienced when they built conventional central station generating capacity.[73] Absent changes in the regulatory environment that make investments in generating capacity economically viable, the long term implications of this behavioral response are clearly quite unattractive. Higher electricity costs and reduced reliability would be the consequences.

The economic "problems" stimulating regulatory, behavioral and structural changes were not largely a consequence of inherent performance failures associated with the structure of the industry or the theoretical regulatory principles that it was subject to. Input price increases, declining economic growth, costly environmental regulations, excess generating capacity, etc. would have occurred in the late 1970s and early 1980s whatever the structure of the industry or the way that it was regulated. Exactly the same problems affected integrated government and cooperatively owned utilities in the U.S. and utilities in other countries. However, the structure of the industry and the way that it is regulated did affect the distribution of the burdens of higher costs and provided a political mechanism for affecting that distribution. As a result, the "failure" of the system was largely, though not necessarily entirely, a political and administrative failure rather than a fundemental failure associated with electric utility firms or the theoretical principles governing the way that they thought that they would be regulated.

Nevertheless the experience of the 1970s and early 1980s has made it clear that existing industrial and administrative institutional arrangements are politically incompatable with rapidly rising costs of supplying electricity.[74] The inability of the system to deal satisfactorily with these economic shocks created a latent demand for a better set of institutional arrangements to govern the regulation of the electric power industry in the future, in particular the regulation of investments in and operation of generating facilities. The excess capacity situation gave regulators, utilities, and other interest groups an opportunity to "hold up" utility investors while some breathing space to come up with alternatives before the disincentives to invest in new capacity was revealed as a supply shortage. The excess capacity cushion is rapidly disappearing in some parts of the country, however, so that the need to fix a system that was broken has become more urgent.[75] While no intellectual consensus existed to provide a natural framework for regulatory and structural reforms, experience with Title II of PURPA, passed in late 1978, but not really implemented until the early 1980s, has turned out to have provided both a positive and normative framework for some potential solutions.

THE PUBLIC UTILITY REGULATORY POLICY ACT OF 1978 AND COMPETITIVE ENTRY INTO GENERATION

In November 1978, Congress enacted the Public Utility Regulatory Policy Act (PURPA).[76] PURPA was one of several pieces of energy legislation promoted by the Carter Administration to deal with "the energy crises". Two portions of PURPA were of particular importance to electric utilities. The first (Title I) deals with the regulation of retail electricity rates and load management services.[77] It directs the states to consider a variety of alternatives to traditional ratemaking methods, including time-of-day rates, interruptible rates, life-line rates, the application of marginal cost pricing principles and to determine whether or not each individual state will adopt them. However, the states were under no federal obligation to do more than consider and evaluate the alternatives, although many states have gradually implemented retail ratemaking reforms along these lines.[78] I think that it is fair the say, however, that PURPA's requirement that the states "consider and determine" whether the introduction of innovative ratemaking principles would be desirable had little effect on state regulatory decisions to adopt new rate structure principles and this section of PURPA is of no current policy importance.

The second primary section of PURPA of relevance to electric utilities (Title II) deals with utility obligations to purchase power from and provide backup services to companies that install cogeneration equipment to produce electricity jointly with heat for use in commercial or industrial processes (cogeneration)[79] and to purchase power from certain small power production facilities[80] that make use of renewable energy sources and a variety of waste fuels, including garbage. PURPA requires utilities to purchase power from qualifying cogeneration and small power production facilities (referred to generally as "QFs") and to provide them with supplemental and backup service at "non-discriminatory" rates.

PURPA directed FERC to issue rules defining the specific criteria an independent supplier had to meet to be a QF and specifying the methods that were to be used to determine that rates at which utilities would be obligated to purchase power from them and provide backup and supplemental services to them. The only specific guidance in the statute, aside from the boilerplate provisions for just, reasonable and non-discriminatory rates, is that utilities could not be required to purchase at rates that "exceeds the incremental cost to the utility of alternative electric energy."[81]

In 1980 FERC issued rules specifying how the relevant prices were to be determined.[82] The approach FERC took was to establish general ratemaking principles in its rules, but to delegate the implementation of these rules to the individual state regulatory commissions. The general principle incorporated in the 1980 rules is that the price a utility is obligated to pay a QF should reflect the <u>costs that the utility avoids</u> (the "avoided cost principle") by purchasing from an independent supplier compared to the best alternative available to the utility to meet its load.[83] Thus, utilities are obligated to purchase from QFs at rates equal to some estimate of their "avoided costs." Thus, QF suppliers are not themselves subject to price, profit or cost of service regulation. They can seek to obtain a price that reflects the market value for the electricity as specified in bilateral contracts with utilities. Given price and non-price provisions specified in the contracts, the QF's financial performance depends entirely on its ability to control costs and deliver electricity. FERC largely left it to the states to specify exactly how they would implement this principle.

As with any statute, the intent of Congress embodied in PURPA is difficult to determine. The statute and the legislative history refer to energy conservation, efficient use of electric facilities, reduced reliance on imported fuels, equitable rates for consumers, etc.[84] It is fairly clear, however, that the statute does not reflect a broad vision to promote competition in wholesale generation markets, to encourage vertical de-integration of the electric utility industry, or anything nearly so exciting. However, it is clear that PURPA provided the first significant opportunity for "entrpreneurial" independent suppliers of generation unencumbered by cost of service regulation to enter the market and provide an alternative to utility-owned generation.

SUPPLY SIDE RESPONSES TO PURPA

We now have roughly five years of experience with PURPA.[85] It is therefore useful to examine the effects that PURPA has had on supplies of generation provided by "non-utility generators" (NUGs). Table 4 shows the amount of capacity and Kwh of generation associated with operating NUGs from 1966 to 1986, the latest year for which data are currently available.[86] These figures include all kinds of non-utility generation, including cogenerators and small power producers[87] that fall under PURPA as well as older cogenerators and conventional privately-owned generating plants that were in operation before PURPA was passed.[88] The aggregate U.S. numbers show that NUG capacity declined slightly until about 1983 and then began to increase rapidly. The fraction of U.S. generating capacity available from NUGs declined significantly until 1983 and has increased slightly since then. By 1986, NUGs still provided a much smaller proportion of total U.S. generating capacity than they did in 1966, however. The pattern is similar for generation.

These aggregate figures mask three conflicting trends. During this time period a significant amount of pre-PURPA conventional industrial generating capacity which provided some or all of the electrical needs of certain types of large industrial users was retired. This appears to have been especially true with regard to private power plants in the primary metals (iron and steel), mining and transportation industries.[89] We get a better feeling for the quantity responses to PURPA by disaggregating the figures into pre and post-PURPA capacity. Table 5 breaks down NUG capacity for 1979 (pre-PURPA) and 1986 (post-PURPA) by type of supply source--cogeneration, smaller power producers, and other types of industrial generating plants-- along with retirements and additions in each category. About 40% of the NUG capacity operating in 1979 had been retired by 1986. Most of this capacity was associated with conventional industrial generators (included in "other"). Approximately 15,000 MW of NUG capacity was added between 1979 and 1986, almost all of which falls into the cogeneration or small power production categories that would qualify under PURPA. Finally, although NUG capacity represents a very small fraction of current utility generation, it represents a much larger fraction of expected <u>additions</u> to domestic generating capacity. Projections are of course uncertain, but if we ignore the nuclear plants that are still in the construction and licensing pipeline, projected capacity from cogeneration and small power production accounts for a third to a half of anticipated electricity capacity requirements over the next ten years.[90]

It is also useful to examine the relationship between NUGs and their local utilities. Prior to PURPA a great deal of the NUG capacity was used exclusively to meet all or part of the electricity requirements of the industrial user owning that capacity. As I have already discussed, by and large NUGs supplied power for their own use, reducing demand on the utility, but did not produce additional power for sale to utilities. PURPA gave NUGs the opportunity to sell all of their production to the utility at the utility's marginal supply cost. Despite the fact that rising retail rates have probably increased incentives for cogenerators to use internal production to "back-out" utility purchases---rather than to sell their output to the utility--there has been a dramatic increase in the proportion of NUG generation that is sold to utilities rather than consumed internally since PURPA was passed. Table 4 displays NUG generation broken down between total NUG production and sales to the utility. In 1978 only 5% of NUG generation went to utilities. By 1986 the figure was 36%.

PROBLEMS WITH IMPLEMENTING THE AVOIDED COST PRINCIPLE

The experience of the last several years makes it clear that significant supplies will be forthcoming from independent suppliers at _some_ price. But how do we know that the states are in fact setting the right price when they implement the "avoided cost" principle? The process that regulators choose for specifying the price and non-price terms and conditions of contracts between utilities and third party suppliers largely determines whether the system works in a way that promotes an economical and reliable supply of electricity. Prices that are too high encourage unnecessary costly QF capacity to be built and operated. This wastes resources and leads to higher electricity rates. Prices that are too low discourages less costly NUG supplies and leads to higher retail electricity rates. Is this regulatory environment leading to the "right" prices and quantities?

It is useful to start by asking why we need special regulations to govern utility decisions vis a vis purchased power at all. Why not treat utility procurement of purchased power like utility procurement of any other input? There are three primary sets of potential problems that may have required regulatory intervention to promote economical purchases by integrated distribution utilities from third party suppliers, whether QFs or independent suppliers more generally:

(1) Regulated distribution utilities may have had private incentives to own generating facilities rather than purchasing power from third parties even when

buying was more economical. Because purchased power expenses are more or less passed through automatically in retail rates, the regulatory process historically provided little profit incentive rely on purchases from third parties to meet capacity needs;[91] purchased power transactions are more or less a wash. This may have lead utilities to avoid purchasing power from third party suppliers and to discourage self-generation.[92]

(2) Since a commercial or industrial firm that wants to cogenerate is connected to only one utility it has only one buyer to deal with. The local utility may therefore have classical monopsony power, pay prices below competitive market levels, and artificially restrict third party purchases in favor of internal production.[93]

(3) Prior to the early 1980s retail rates were generally below estimates of the long run costs of supplying central station electricity. Retail rates thus provided the wrong signals to industrial customers considering whether to buy from the utility or to self-generate.

The requirement that utilities purchase from QFs at a price reflecting the buyer's "avoided cost" appears to have been a response to these perceived problems. Assuming that appropriate purchase contracts can be fashioned from avoided cost in estimates in practice, the avoided cost principle is a pricing standard that will encourage QF supplies to be offered by developers and selected by utilities if and only if these supplies are less costly than the other alternative generation options available to the utility. The avoided cost approach has both strengths and weaknesses, however. It's primary strength is conceptual. In order to minimize the costs of supplying electricity, utilities should be willing to purchase from third parties when these third parties can supply generation with equivalent non-price attributes[94] at a lower cost than the utility can supply from generating facilities it owns or would otherwise build. Furthermore, the optimal supply of third party production will be forthcoming if the price on the margin is equal to the utility's avoided cost evaluated at the point where supply and demand is in balance.

The primary weakness of the avoided cost principle is the difficulty of implementing it properly in practice. Early discussions of the avoided cost principle often gave the impression that "the avoided cost" is a single objective number that can be easily calculated and utilized by regulators to establish the terms and conditions of purchased power contracts. In reality it is very difficult to calculate accurately the "true avoided cost" associated with a particular contractual relationship except in those circumstances where the utility simply agrees to compensate the supplier based on the short run operating and shortage costs avoided at the time of supply---a spot pricing system reflecting supply and demand conditions in real time. However, in addition to "avoided energy cost at time of delivery rates," FERC and state regulatory rules often require that utilities offer to provide diverse QF suppliers with the opportunity to enter into long term contracts which provide that the supplier will be paid for capacity and energy delivered based on a pre-determined set of prices and price adjustment formulas. Such long term contracts must be signed with suppliers that vary widely in terms of initial delivery dates, duration of supply commitments, fuels, technologies, reliability characteristics, dispatchability, price determination formulas, allocations of risk between buyer and seller, etc.

Unfortunately, there simply is no single objective measure of a utility's "true avoided cost" that can be calculated and then applied to determine the "proper" prices that a utility should agree in advance to pay cogenerators pursuant to a diverse set of long term supply relationship. When we are estimating avoided costs in advance of delivery the best we can do even theoretically is to calculate some measure a utility's expected avoided cost at the time a contract is executed given a host of assumptions about future supply and demand conditions. Even a utility's expected avoided cost will vary with numerous non-price terms and conditions of specific contracts and with alternative assumptions about future electricity supply (utility and non-utility) and with demand conditions over the term of the contract. We can estimate it using mechanical formulas only imperfectly; in many cases very imperfectly. It is quite clear that neither FERC nor most state regulatory agencies initially understood the difficulties of implementing the avoided cost principle through administrative determination of the terms and conditions of contracts between buyers and sellers.[95]

A very simple example will help to illustrate some of the basic conceptual and implementation problems that FERC's "simple" avoided cost principle has run into. Let's assume that utilities can either build and operate their own generating capacity or purchase power from a heterogeneous group of third party suppliers to meet expected loads in a particular period in the future. Let's take as the reference case, the situation where the utility meets all future needs with its own generating resources. We can then calculated one measure of a utility's long run avoided cost by determining how much its average annual gross supply costs would be reduced with increasing quantities of capacity purchased from third party suppliers in order to replace generation that the utility would otherwise own and operate itself. Such a calculation is reflected in the downward sloping function AVC_1 in Figure 10. This is a cost-minimizing utility's derived demand for third party supplies. The AVC_1 function has purposely been drawn to have a slope that varies with the amount of capacity acquired. Power purchased from third parties initially simply displaces capacity that the utility would otherwise build to meet expected electricity demand. As more QF capacity is purchased, additional utility capacity is no longer needed and the utility eventually experiences a growing surplus of generating capacity. The additional capacity purchased initially has some value related to improved reliability and deferral of subsequent capacity additions.

At some point, additional capacity has no capacity value at all and serves only to displace the operation of existing utility generating capacity.

The first thing to note is that even if we knew AVC_1 with certainty, it will generally be a function of the amount of third party supply acquired, not a single value. The second thing to note is that since we must make the calculation for a period that typically extends far into the future, there is great uncertainty about where AVC_1 actually lies. If, for example, fuel prices are higher than expected, the actual avoided costs could end up looking more like AVC_2. If demand growth is slower and fuel costs lower than expected the actual avoided cost function could end up looking like AVC_3. The best that we can do is come up with some expected value for the avoided cost function, recognizing that it is uncertain.

Third, it should be obvious that even if we knew with certainty that AVC_1 is the "true" avoided cost function, determining administratively the right price that utilities are required to offer to pay requires knowing what the supply of third party generation will be at various prices, since avoided cost is not a single valued function.[96] A hypothetical QF supply schedule is depicted as S_1 in Figure 10. Of course this supply schedule is known only with considerable uncertainty as well. It could be higher (S_2) or lower (S_3). If we knew with certainty that the relevant avoided cost and QF supply functions were AVC_1 and S_1, then the optimal price would be P_1. If a utility offered to buy at this price, then a competitive QF supply response would be Q_1. However, if there are two other possible states of nature (AVC_2/S_2 and AVC_3/S_3), then the optimal prices could be either P_2 and P_3. As I have drawn Figure 10, the optimal quantity is always Q_1, however.

Assume that the regulator guesses wrong. He sets P_2 as the offer price assuming that AVC_2 is the relevant avoided cost function and S_2 is the relevant QF supply function. It turns out, however that S_1 or S_3 are the actual supply functions and AVC_1 or AVC_3 the actual avoided cost functions. By setting P_2, a competitive QF supply response is Q_2 or Q_3, much more than the optimal quantity that should be supplied (Q_1). Alternatively, assume that the regulator sets P_3, assuming that AVC_3/S_3 are the true avoided cost and QF supply functions, but it turns out that the actual state of nature is AVC_2/S_2. The competitive supply response is now zero output rather than Q_1. Setting prices and allowing the competitive QF supply sector to respond to them can lead to very costly mistakes when there is uncertainty over avoided costs and QF supply responses.

To complicate matters further, long term supply contracts with QFs are generally negotiated at least five years before first delivery of power and specify a delivery and payment schedule for periods of ten to twenty years thereafter. At any particular time, the set of contracts negotiated generally includes suppliers who promise to begin delivery in several different years.[97] Contracts for capacity that is needed beyond roughly five years into the future may be negotiated at a variety of different points in time.[98] While contracts could specify a single fixed price, there are good reasons to believe that this would be inefficient (Joskow (1988a, 1988b). Optimal long term supply contracts will generally have fairly complex price and non-price provisions to properly align incentives to perform, to properly reflect differences in the value of contracts with different supply attributes, and properly to reflect the allocation of risks between the buyers and the sellers (a discussion of actual QF contracts follows below). Thus, the regulators' task involves simulating what a diverse set of optimal third party supply contracts would look like if there were a competitive market for third party supplies. This is a formidable undertaking. Indeed, to do so accurately, regulators would have to go beyond the frontier of current knowledge regarding the economics of long term contractual relationships. There was initially very little sensitivity to the problems associated with regulatory "simulation" of the right equilibrium price and non-price contractual terms and conditions. Several states used fairly mechanical estimation approaches to come up with "standard offer contracts" with fixed terms and conditions available to all QF suppliers.[99] Costly mistakes have been made by those states that have taken this approach.[100] Probably the worst example of the dangers of relying on administrative procedures to simulate the terms and conditions of generally available long term fixed-price "standard offer contracts" for QFs is the experience in California. These contracts specified payments that were too high, these payments were not adjusted quickly to reflect changing fuel prices and the unanticipated large supply response that resulted, and the excessive payment attracted too much supply. The costs of these contracts, or the payments utilities have been making to buy them out or defer them, will lead to higher electricity prices for other customers.[101] Other states (e.g. Texas, Maine, New York, Connecticut) faced similar problems, although they generally found a way to allocate the excess supplies offered to reduce the adverse impacts on electricity consumers. The experience with the "price regulation" approach through standard offer contracts has shown us how to integrate third party suppliers into the system inefficiently. It has or will unnecessarily increase electricity costs and prices. If all we had to go on was the early experience with PURPA and standard offer contracts, the effort to develop an independent power sector would not at first blush have much to recommend it.

COMPETITIVE BIDDING AND NEGOTIATION SYSTEMS AS AN ALTERNATIVE

Happily, proceeding as they did in California, to set administratively the prices (and more generally the terms and conditions of standard long term contracts) at which utilities will be obligated to take supplies from third parties and requiring utilities to sign contracts with all of those who offer to supply based on this standard offer (the price regulation approach) is not the only way to structure an efficient QF generation procurement system. One alternative is to set target quantities, for example Q_1 in Figure 10, and require utilities to solicit competing bids to supply these quantities, choosing the most economical mix of bids submitted (the quantity regulation/competitive bidding approach).[102] The regulatory sets the quantities and the market sets the prices.

Another approach would be to go to the heart of the matter by removing the primary regulatory distortions that may lead utilities to fail to make economical contracts with third party suppliers. Once these distortions are removed, utilities would simply be expected to negotiate with competing QF suppliers, along with other wholesale suppliers, just as they do with suppliers of other inputs such as coal to provide for their future generation needs.[103] Since at least some internal production could be more efficient than power supplied by third parties, utilities could also be permitted to own new generating capacity themselves, but only if they can convince regulators that more economical third party supplies are not available. Information derived from contracts signed with third parties by utilities in a given region provide a natural yardstick against which to evaluate utility construction projects. I will refer to this approach as the competitive negotiation/yardstick approach.

There are good reasons to believe that a competitive bidding or competitive negotiation/yardstick approach (quantity regulation) will have much better performance attributes than a standard offer contract offer approach (price regulation). It is often much easier for regulators to make a fairly precise estimate of how much capacity a utility is likely to need over a reasonable time horizon than it is for them to specify the price and non-price terms and conditions of standard offer contracts that will yield an efficient supply response from suppliers willing to supply at this posted price. Figure 10 has been drawn to make this point quite starkly. The optimal price could be P_1, P_2 or P_3, depending on which of three uncertain states of nature is realized. The optimal quantity Q_1 is invariant to the state of nature, however. Setting the wrong price can lead to quantities that are far from being optimal. Since we know approximately what the right quantity is, it makes much more sense to target quantities and use a bidding or negotiation system to determine the proper price and non-price terms and conditions of contracts. By specifying quantities, the risks of buying too much or too little capacity and paying too much for whatever capacity is acquired are minimized. These two approaches also fit in naturally with utility planning procedures.

The difference between the competitive bidding and the competitive negotiation/yardstick approach turns primarily on how much flexibility is given to the utility to select specific projects and the terms and conditions of contracts through bilateral negotiation and how much must be specified through mechanical "self-scoring" contract evaluation mechanisms subject to detailed regulatory scrutiny.[104] If regulatory incentives toward or against owning generating capacity can be ameliorated or a utility agrees to buy all future generating capacity in the market, a flexible competitive negotional approach clearly is the preferable approach. The potential suppliers have diverse characteristics of economic consequence. It therefore makes sense to rely on a system that allows the utility, rather than the regulator, to specify weights for evaluating price and non-price terms and conditions, subject to regulatory review to guard against self-dealing, as well as its planning assumptions regarding fuel prices, general inflation and interest rates. The suppliers are then free to structure the price and non-price terms and conditions of their bids to reflect the weights announced by the utility, the economic and technical attributes of a particular supply technology and the supplier's own risk preferences. The utility in turn is free to meet its capacity needs with the best mix of supply offers made. Competition between third party suppliers helps to ensure that the utility does not pay too much third party supplies. If the utility does not get enough bids to meet its capacity needs or determines that it is more economical to build capacity itself to satisfy some or all of its needs as well, the offers made to it through a competitive solicitation process provide a natural benchmark or yardstick against which this decision can be evaluated and, in theory, upon which compensation arrangements for utility-owned generation can be made. In either case, the regulatory objective is to stimulate a competitive market for third party supplies of generation and to introduce regulatory rules and incentives that lead the utility to choose the best mix of supply options.

Only further experience with alternative generation procurement approaches can give us firm empirical evidence regarding the strengths and weaknesses of various combinations of structured bidding programs and more flexible negotiation programs. However, I believe that it is already becoming clear that rigid self-scoring competitive bidding systems for supplies from "to be built" generating facilities that leave little room for bilateral negotiation work quite poorly compared to more flexible competitive negotiation systems.

BIDDING AND NEGOTIATION SYSTEMS IN PRACTICE

A growing number of states have wisely either permitted or required utilities to use a competitive bidding or competitive negotiation system to determine the terms and conditions governing purchases from PURPA qualifying facilities rather than relying of price regulation based on standard offer contracts.[105] In several cases competitive bidding or negotiation systems have been extended to encompass all supply sources, not just QFs.[106] A selected list of utilities that have introduced competitive bidding or competitive negotiation systems of one type or another are listed in Table 6. In general, these programs involve utilities issuing requests for proposals (RFPs) for specified quantities of QF capacity (and increasingly capacity from non-QF wholesale suppliers (IPPs) as well. These proposals contain the evaluation criteria that the utilities propose to use, in various levels of detail. In some cases the RFP specifies evaluation criteria in sufficient detail that responses can be used directly to rank and select winners ("self-scoring" RFPs), subject only to the limited negotiation of the detailed terms and conditions of a final contract. In other cases, the initial RFP is used as a screening device to select a small set of target suppliers that the utilities then negotiate with further to arrive at final selections and specific contracts.

So far all utilities that have introduced competitive bidding and negotiation systems have found abundant supplies offered to meet the supply needs put up for bids (see Table 6) and have generally been able to fill some or all of their capacity needs with QF and non-QF (IPP) generation contracts that appear to have very attractive price and non-price terms and conditions. The winning bidders are not generally "mom and pop" operations, but major companies with substantial experience designing, building and operating generating plants.[107]

It has also become clear that QF suppliers are generally willing to build facilities to supply power to utilities if and only if these purchases are supported by long term purchase contracts that obligate the utility to purchase power over a long period of time at prices specified in advance in the contract. I don't find the reliance on long term contracts as an (perhaps imperfected) alternative to vertical integration to be very surprising. Investments in generating facilities have important "relationship specific attributes" of the type discussed in the literature on the theory of the firm and contracts.[108] Independent generating facilities have generally been built to provide power to be sold to a single utility or, in a few cases, to two or three proximate utilities. In the latter cases, the independent supplier most rely on the utility which serves the area in which the plant is located to provide a contractual transmission path to the other buyers. Once these investments are sunk, the suppliers are not likely to be in a particularly attractive bargaining position with their customers and investors must be concerned about the hazards of opportunistic behavior ex post. Even in areas like New England, where wheeling service has generally been made available to independent power suppliers if they want it to get to their preferred customers, long term contracts are the norm.[109] While regulation can in principle mitigate these contractual hazards, suppliers generally recognize that regulatory protections are necessarily limited.

The reliance on long term contracts leads to several interesting but difficult contracting issues. The first set of issues involves price determination in such long term contracts. Some mechanism must be found for setting the level and structure of prices for each contract that encourages efficient suppliers to make efficient investments, that encourages efficient production decisions once facilities have been built, and that protects consumers from paying more than is necessary to obtain efficient supplies.[110] This is not an easy task. Independent power supplies come from a variety of different technologies with different capital, fuel, reliability, and dispatchability characteristics, rely on different financing arrangements. The price structure chosen affects the incentives sellers have to perform when uncertain contingencies arise, the allocation of risks between the buyer and the seller, and the ability economically to integrate individual generating facilities into the larger integrated electric power system. The competitive market value (or avoided cost) of different supply arrangements will vary. It is difficult to quantify these variations in value in a precise and unambiguous way.

As I have already discussed, these contracting complexities suggest that regulators should try to rely as much as possible on allowing the parties to negotiate freely when their is reasonable confidence that regulatory rules and incentives will not create a bias against third party suppliers, will encourage the buyer to put together an efficient supply mix, and competitive conditions are such that monopsony power is not a serious source of distortion.[111] Efforts to create a regulatory environment that provides incentives for utilities to evaluate all supply options on an equal footing without regard to ownership per se makes it possible to maximize the flexibility utilities have to negotiate bilateral contracts with diverse suppliers and to minimize direct regulatory intervention into the structure of the contracts negotiated between utilities and third party suppliers, an area where regulation is likely to be especially imperfect.

The recent experience in Massachusetts is, I believe, quite instructive. Despite a very tight supply situation, aside from some peaking capacity and repowering of old generating facilities, utilities in Massachusetts, and New England generally, have no plans to build any major power plants at the present time under traditional cost of service regulation.[112] In the absence of a credible redefinition of the regulatory compact, I believe that the perception is that building major new generating projects under cost of service regulation leads to a significant risk of losing money with little prospect of any symmetrical gain. Utilities are therefore committed to looking first to the wholesale market (including Canada) for additional generating capacity to meet future needs.

In 1987, utilities in Massachusetts began implementing new regulations regarding purchases from QFs under PURPA.[113] They now operate under two parallel systems. All of the utilities in the state, except for the largest, were required to introduce competitive bidding systems for QF capacity using a regulator approved "self-scoring" competitive bidding approach that left little room for post-bid negotiation. The regulations require utilities to seek bids for a specified amount of new capacity at least once each year. Utilities are required to file an RFP and standard contract with the Department of Public Utilities (DPU) that specifies the buyer's projected avoided costs for each of twenty years into the future, underlying fuel price, inflation, and interest rate assumptions, and the weighting criteria that the utilities propose to use to evaluate competing bids.

Utilities were given considerable freedom to define weighting factors for a large number of supplier and contractual attributes, subject to ultimate approval by the DPU. Once the RFP is approved, utilities seek bids, rank the bids, select an award group and then negotiated final contracts with the suppliers in the award group. Opportunities to negotiate on price-related terms and conditions of the final contracts are severely limited by the bidding process, however. Utilities were permitted to continue to negotiate contracts with QFs outside of the bidding process, but capacity purchased in this way did not count against the amount of capacity they were required to put up for bids.

The largest utility in the state (MECO) sought an experimental exemption from the bidding rules. MECO proposed that it be given an experimental exemption from the bidding rules which would allow it to continue to purchase power from QFs using a negotiation system of their own choosing rather than under the highly structured "self-scoring" bidding system proposed by the commission. The company supported is requests based on its good prior experience with negotiation with QFs, its commitment to purchasing from third parties when the offered the most attractive supply sources, its willingness to "wheel out" QF supplies to other utility purchasers in New England so that sellers located in its territory had competing buyers to sell to, and its view that self-scording bidding systems affording limited opportunities for negotiation would not work well. In return for this exemption MECO agreed to collect and evaluate data on contracts consummated through both bidding and negotiation for all utilities in the state and to survey QF developers regarding their views about the strengths and weaknesses of the different systems.

The results for the first year of the Massachusetts experiment are now in. Table 7 lists the expected real levelized prices and the capacity offered for the 23 contracts consummated by Massachusetts utilities through either bidding or negotiation in 1987. Two sets of prices are listed. In each case the price indicated is the levelized real expected price over the life of the contract given the escalation provisions in the contract. The first price series calculates these values using Boston Edison's (BECO) assumptions about future fuel prices and interest rates. The second price series makes these calculations using MECO's assumptions. Table 8 lists other attributes of the contracts and the associated projects.

There are several things that are interesting to note from the information reported in Tables 7 and 8. First, the expected prices fall within a fairly narrow band. The mean prices for the 23 contracts are 5.2 cents/kWh and 5.6 cents/kWh respectively (median 5.01 and 5.73 respectively) with standard deviations of 0.61 and 0.64.[114] Second, projects of a wide variety of sizes and fuels were chosen. However, the 5 projects with capacities of 100 Mw or more account for about 70% of the capacity that will be supplied from the projects involved in the 23 contracts.[115] This is consistent with national data. Of 2,449 NUG projects operating in 1987, the 58 projects with capacity greater than 100 Mw accounted for 40% of the total NUG capacity.[116] Finally, it is clear that it is not possible to rank projects independently of the underlying assumptions that one makes about future fuel prices, interest rates, etc. For example the project that had the lowest expected price under BECO's assumptions had the highest expected price under MECO's assumptions. Similarly, the project that had the third lowest price under MECO's assumptions had the ninth lowest price under BECO's assumptions.

Table 8 provides information about the nature of the price adjustment provisions contained in the 23 contracts. Most of the contracts have base price plus escalation (BPE) adjustment provisions; the contract specifies an initial price and a formula for adjusting that price over time. The specific adjustment provisions vary significantly from contract to contract. Some contracts index prices to changes in the CPI or the GNP deflator. Others include various fuel price indices (oil, gas and coal) in the adjustment formulas. The specific price adjustment provisions chosen by some of the sellers reflect provisions in their own fuel supply contracts.[117] Only one of the contracts has anything like a market price adjustment provision. These pricing provisions are consistent with buyer concerns that the contracts not have pricing provisions that create a significant probability that it will be in the interest of the seller to stop performing on the agreement as economic conditions change over time.[118]

As hypothesized by Joskow and Schmalensee,[119] long term contracts appear to be of importance in securing investments by new independent suppliers of generation service. However, the nature of these contracts is far different from the implicit contract associated with textbook cost of service regulation. These contracts are not pure cost plus contracts. The sellers generally take on most of the risks associated with the construction costs of the project and the performance (i.e. availability) of the facilities over time. While it is possible that larger more capital intensive projects will allocate more of the construction and operating risk to buyers, it is clear that the allocation of risks for the projects that are now being built is much different from that implicit in "ideal" textbook cost of service regulation.

This experience also helps to shed some light on the relative costs and benefits of highly structured bidding systems vs. more flexible competitive negotiation systems. Utilities in Massachusetts have clearly moved aggressively to meet pressing capacity needs with third party supplies <u>almost exclusively</u>. There is certainly no evidence that utilities are trying to avoid buying from third parties so that they can build themselves. If there is a bias here it probably goes the other way. Buyers also appear to have had little difficulty so far in arranging for wheeling service to move contract power from one utility to another. More than half of the contracts signed by Massachusetts utilities in 1987 were accompanied by wheeling arrangements. This means that suppliers which are tied to a specific site, can still seek to sell their capacity to competing buyers and not just to the local utility. This certainly diminishes any monopsony power that the local utility might otherwise have. This in turn is consistent with the fact that the estimated prices for the contracts reported in Table 7 do not appear to be affected by whether they were consummated through bidding rather than negotiation. A statistical analysis of expected real prices in "bid" vs. "negotiated" contracts showed no significant difference between them after controlling for other contract characteristics.[120] Thus, we can find no evidence here that a negotiation system allows utilities to exercise monopsony power, pay less and buy less from QFs. Furthermore, an independent survey of QF developers found that they generally preferred the flexibility of the negotiation approach to the highly structured bidding system, although they had numerous suggestions for improvement in both approaches.[121]

At the very least, for a utility with attributes such as MECO's there appears to be little reason <u>not</u> to rely on a flexible competitive negotiation/yardstick approach. On the other hand there are clear practical problems with rigid self-scoring competitive bidding systems. These problems may already be coming home to roost in Massachusetts. Boston Edison, the company farthest along with a highly structured bidding system with little room for bilateral negotiation, has run into problems with several of the projects that were selected through bidding.[122]

THE IMPACT OF THE PURPA EXPERIENCE

PURPA's likely long term effects on the electric power industry cannot be measured solely by looking at how much QF capacity has been forthcoming or how much money utilities have saved (or lost) by increasing their reliance independent suppliers. Whatever its original intent, and despite numerous implentation problems, PURPA has been a sort of experiment with partial deregulation of entry into generation supply stimulated by pricing arrangements that are not tied directly to the seller's accounting costs and that allocate substantial construction cost and operating performance risks to the seller. PURPA has shown that under the right conditions independent suppliers will come forward to provide economical supplies of electricity; utilities are not the only ones who can build and operate generating plants successfully. (It has also shown that under the wrong regulatory and economic conditions uneconomical supplies will be forthcoming.) While Title II of PURPA was originally passed primarily as an energy conservation initiative, it has turned out to be the "can opener" that has opened the way for competitive entry into generation and bulk power market competition. Why should we restrict the opportunities for unregulated suppliers of wholesale generating service to contract with distribution utilities to certain classes of technology or certain size categories specified by PURPA? Why not expand the opportunities buyers and sellers have to negotiate mutually satisfactory wholesale power supply contracts, unincumbered by entry restrictions or cost of service regulation, to any supplier of generating service that is willing to compete to supply electricity at wholesale to distribution utilities?

PURPA has created a new constituency of incumbent independent power suppliers who have an interest in breaking down the barriers to the expansion of the independent power sector. They have been active in promoting state and federal policies that expand opportunities for independent power producers (IPPs) that do not meet PURPA's efficiency, fuel and size restrictions, to compete to supply generation to utilities at prices that reflect the competitive market value of the electricity rather than the supplier's accounting cost of service.

There are many utilities that are receptive to increased reliance on third party supplies given the regulatory problems they have had with building their own generating capacity subject to cost of service regulation. As a consequence of the financial pain resulting from economic conditions and regulatory decisions of the

1970s, many utilities are quite reluctant to commit themselves to building major new generating facilities.[123] They would like to shift more of the financial risk in some way to third parties. As a result there is clearly a growing interest among a large number of utilities in encouraging competitive entry into the generation supply business in order to help them balance supply and demand in the 1990s through increased reliance on power purchased from third parties. Still other utilities see this as a way for them to compete to supply generation to other distribution utilities outside of their traditional service territories and without traditional cost of service constraints.

Thus, we are seeing growing interest from both potential buyers and sellers in non-PURPA generating facilities dedicated to the wholesale market and making sales under contract to traditionally integrated utilities for resale. This interest goes beyond QFs under PURPA to encompass non-QF independent power suppliers and wholesale trade more generally. The planned 470 Mw Ocean State Power combined cycle plant located in Rhode Island, which received FERC approval for a novel sales contract, is an excellent example.[124] Other facilities designed to burn gas or coal are on the drawing boards and looking for buyers who are willing to make contractual commitments to purchase power.[125] Increasingly we are seeing large cogeneration projects entering the market that are really simply small stand-alone generating plants that have inefficiently obtained contrived process steam loads to obtain QF status under PURPA.[126] But for the PURPA's technology, size fuel and thermal efficiency restrictions on qualification for competitive entry and waiver of cost of service regulation these facilities would not be cogenerators, but simply small power plants.[127] The developers would like the opportunity to enter the market in competition with other supply sources without having to pay a "PURPA tax." In return, they are willing to give up utility obligations to purchase arising directly from PURPA.

EVALUATION OF CURRENT TRENDS TOWARD COMPETITIVE PROCUREMENT OF GENERATION AND DE-INTEGRATION OF GENERATION?

The recent experience with the development of an independent generating sector has yielded some promising and some discouraging results to date. It is clear that if the price and regulatory conditions are right third party suppliers are willing to enter the market to supply electricity to utilities pursuant to long term contracts that allocate construction cost and operating risks to the sellers. Many of these suppliers have been able to supply at a price less than the utility buyer's estimate of its own supply costs. Once operating, cogenerators in particular appear to have excellent availability records[128]. We have also learned that the costs and benefits of third encouraging more reliance on independent suppliers depends critically on the regulatory rules and procedures under which the terms and conditions of contracts are determined. The standard offer contract (price regulation) approach has been a failure. The highly structured competitive bidding approach is better, but I think will prove to be unworkable for larger projects. The utilities that have been allowed to use more flexible competitive negotiation approaches appear to be achieving the greatest success and I believe as further evidence is accumulated it will turn out to reinforce this early experience. It is also clear that negotiating a contract is only one step toward a project generating electricity. Many contracts have already been terminated and not led to power plants. This suggests that careful evaluation of the realism of proposed projects as well as ongoing cooperating between the buyer and the seller to make the project a reality is very important.

I am reasonably optimistic that current developments can help to improve the allocation of resources associated with providing electricity by creating a competitive market for wholesale power supplies and providing incentives to utilities to provide from their generating needs through purchase rather than ownership when purchases from third parties are more economical. While I am optimistic about the potential benefits of these changes, I believe that there are some significant uncertainties about their long term consequences that must be recogized and factored into the evolution of public policies affecting the procurement of new generation and the regulation of the terms and conditions of wholesale power contracts. There are also several regulatory barriers that continue to exist that could lead to serious problems if they are not removed.

a. System Reliability

Perhaps the primary issue that critics of the expansion of the NUG sector argue has not been addressed adequately is whether increased reliance on third party generation will, in the long run, create coordination and reliability problems that are handled more efficiently when generation, transmission and distribution are under common ownership and where cooperation rather than competition has been the norm.[129] To date this has not been a serious problem. On the other hand the quantity of independent generating capacity that is operating is still quite small, has been able to take advantage of a large existing integrated "backbone" generation and transmission system, and most projects have operated for only a short period of time. The efficiency of the existing electric power system relies extensively on economic dispatch of multiple generating units under common ownership, real time coordination of interconnected facilities under separate ownership through power pooling arrangements and bilateral agreements, and extensive cooperation among interconnected utilities to maintain reliability. How well will these arrangements function with many more independent competing players in the system? What changes will have to be made to make an interconnected electricity system with a large number of competing wholesale power suppliers work efficiently? What kinds of contractual rigidities and imperfections will emerge as economic conditions change ?

This is not a silly set of questions and they should be taken seriously. There are good economic reasons to believe that uncertainty, relationship investment, asymmetric information, the complexities of coordinating an integrated electric power system reliably and economically (including externality and free rider problems), and incomplete contracting may favor vertical integration, assuming that the integrated firms minimize costs. Are there significant benefits to vertical integration of generation, transmission and distribution that are likely to be foregone by relying on many independent owners and operators of generating plants linked to partially integrated utilities with long term contracts?[130]

We presently have no way of answering this question empirically with any degree of precision. Extensive vertical and horizontal integration in electricity supply is the norm everywhere on earth. Vertical integration typically includes at least the generation, transmission functions. If distributors are not integrated they tend to rely on long term requirements contracts for the bulk of their needs. Aside from the recent experience with PURPA, the world has just not run a natural experiment that would make a definitive conventional empirical test feasible. And while contractual and reliability problems have not yet emerged as a serious problem with QFs in the U.S., the relatively small amount of QF capacity, its recent vintage, and the lack of economic shocks that may lead to contractual failures provide too little experience to say anything definitive. In short, the world has simply not run the natural experiment that would make a definitive empirical test possible.

The fact that we can't prove empirically which industry organizational mode (vertical integration, partial integration, complete de-integration, etc.) dominates does not imply that change should be discouraged until the requisite "proof" and "ideal" public policy changes can be obtained. The traditional system has proven to be less than perfect and the limited experience with independent suppliers, when a suitable regulatory environment is established, has yielded promising results. And, fortunately, it appears to be feasible to proceed with changes that increase opportunities for third party suppliers to enter the market without making a definitive decision one way or the other about the relative economies of vertical and horizontal integration vs. contractual integration _if_ the right regulatory environment is created. None of the players in the public policy debate about QFs, IPPs, bidding, negotiation, retail rate regulatory reforms, etc. appears to be suggesting that we should require integrated utilities to divest their existing generation and distribution assets,[131] as is being required for the monopoly generation/transmission entity (the CEGB) in the UK,[132] or to preclude distribution utilities from owning new generating capacity. Most proponents of these changes are talking about creating opportunities for gradual change in the extent of vertical and horizontal integration by creating incentives for independent suppliers to enter and distribution utilities to buy when it is efficient to do so. Even if we make some mistakes on the margin, they need not be fatal and are potentially reversible.

b. How Competitive Are Wholesale Market?

Another issue raised by critics of the changes we are seeing is associated with the extent to which extensive price regulation of wholesale transactions is necessary. Interventionists argue that wholesale markets are not sufficiently competitive to leave price determination to competitive bidding or negotiation systems. Non-interventionists like myself argue that price regulation leads to costly distortions in wholesale trade and that reliance on even an imperfectly competitive wholesale market will lead to more efficient outcomes.

I am quite optimistic that the wholesale markets that are emerging are and will be quite competitive. The PURPA experience indicates that there is a fairly elastic supply of capacity that independent power producers are willing to offer at attractive prices. In addition to the supply offers obtained in response to utility offers to buy pursuant to PURPA, active markets for short and medium term power that are excess to the current needs of integrated utilities have emerged in most areas of the country. Over the past fifteen years, coordination and wheeling transactions have increased substantially to the mutual benefit of buyers and sellers (see Table 1). As I discussed earlier, these markets are for all intents and purposes subject to only very lose FERC regulation. As a result of extensive interconnections, coordination agreements and power pooling arrangements, voluntary wheeling, etc., the anecdotal evidence suggests that these markets are often quite competitive.

Additional evidence regarding the competitiveness of unregulated bulk power markets can be found in a recent experiment approved by FERC. In 1983 FERC encouraged a group of utilities in the West to participate in an "experiment" (more like a demonstration program) which provided considerable price flexibility for certain types of short term transactions. The relaxation of formal regulatory constraints had little obvious effect---either positive or negative--on prices or quantities.[133] This is consistent with my own perception that FERC regulation of the prices for coordination transactions has not been a binding constraint in short and medium term coordination markets.

c. Transmission Access and Pricing

The extent of competition in wholesale markets is necessarily related to the number and size distribution of actual and potential competing suppliers of generation service that a distribution utility can choose from. Since potential suppliers may be remote from the areas where a distribution utility owns transmission facilities, the competitive characteristics of the market will be affected by access to and the pricing of transmission service. As things stand now FERC can regulate the rates charged for transmission service, but utilities have only a very limited legal obligation, under the FPA, to provide it. Nevertheless, utilities voluntarily negotiate transmission arrangements with other utilities all of the time. As I indicated earlier, extensive "wheeling" service has been provided in New England to provide contract paths for QF power. The preliminary results of a second FERC approved experiment allowing for the flexible pricing of transmission service in the West[134] suggests that FERC regulation of transmission service inhibits rather than promotes wholesale trade since relaxed regulation appears to lead to increased trade rather than reduced trade.[135]

Transmission access and pricing raises difficult technical, regulatory, organizational, jurisdictional, and economic problems.[136] It is perhaps the most difficult and certainly the most controversial aspect of the changes leading to increased reliance on competitive wholesale power markets. A comprehensive discussion of transmission issues is well beyond the scope of this paper, but let me make a few observations here.

Most of the historical controversy over transmission access and pricing has been associated with wholesale requirements customers or the distribution of economic rents when transmission capacity is scarce relative to the demand for bulk power transactions. The disputes with wholesale requirements customers reflect more the problems associated with the terms and conditions of FERC regulated wholesale requirements <u>power</u> contracts and the asymmetric obligations associated with wholesale requirements service than with the pricing or access to transmission service per se. Creative solutions to problems associated with wholesale requirements customers have recently been approved by FERC and could serve as a model for future relationships between utilities and "captive" wholesale requirements customers.[137] I suspect that once problems associated with the relationship between integrated utilities and wholesale requirements customers are resolved, issues associated with wholesale wheeling of contract power can be solved relatively easily <u>if</u> FERC would allow for appropriate pricing and contracting for transmission service. Reforms in FERC's transmission pricing regulations are clearly needed as are new state and federal policies to resolve transmission line siting and certification roadblocks.

While I believe that more coherent public policies governing wholesale transmission pricing, service obligations, and siting will have to evolve in the future, solving these problems in the abstract before continuing with the evolution of competitive pricing of wholesale power is unnecessary. The evidence from the growth and changes in the coordination market and the results from competitive bidding programs suggest that there is lots of competition to supply utilities and that wheeling service is often provided through negotiation without any special regulatory obligation. In light of the controversies over transmission access obligations, trying to "jump start" competitive wholesale markets by starting with transmission policies is a prescription for making no progress at all. I view the most important target for regulatory reform as removing regulatory impediments affecting entry, pricing and procurement of <u>generation</u>. Once these impediments are removed we can turn to any remaining transmission access and pricing problems. This is the approach and FERC and Congress are taking so far.

OTHER REGULATORY BARRIERS TO THE DEVELOPMENT OF COMPETITIVE WHOLESALE MARKETS AND EFFICIENT GENERATION PROCUREMENT DECISIONS

a. Alternatives To Traditional Cost of Service Regulation

The incentives a utility has to negotiate good contracts with third parties or to seek to build itself are largely a functions of how it believes these decisions will be treated in the regulatory process. Simply <u>requiring</u> utilities to provide for their generating capacity needs only by buying from third parties does not solve the problem. Currently the costs of purchased power contracts are pure dollar for dollar pass-throughs to rates. There are few direct incentives to pick the best mix of contracts, aside from the threat of regulatory review and the potential for ex post cost disallowances. Furthermore, it is not likely to be efficient from either a cost or reliability perspective to mandate that currently integrated utilities must purchase all of their future generating needs from third parties. The utility may itself be the least cost supplier so it would be desirable for the regulatory system to preserve that option. Similarly, simply requiring utilities carefully to compare third party supply opportunities with building themselves <u>and</u> subjecting utility construction to the kind of cost of service regulation that has been imposed in the past decade places a significant burden on imperfectly informed regulators to guard against biases toward or against distribution utility ownership of generation.

If the kind of flexible competitive negotiation procedures for selecting new generating capacity that I favor are to work well over the long run it seems to me that some changes in retail rate regulation are going to be required. In particular, regulatory changes are required that provide utilities with better incentives to make minimum cost supply choice independent of ownership arrangements per se. Two different alternatives to traditional cost of service treatment of new utility-owned generating facilities have recently been suggested which point to the kinds of changes that are likely to be desirable. The Massachusetts Commission has announced that it has abandoned traditional rate base cost of service regulation for new utility-owned generating facilities.[138] The Commission indicated that it wants to continue to give utilities the option of meeting some or all of their future needs with utility-owned generating capacity if that is the most economical choice. However, the Commission also indicated that it wants to avoid what it perceives as the efficiency distortions of traditional cost of service regulation. What the Commission has proposed is effectively to replace traditional cost of service regulation for new generating plants by negotiating a project specific pre-approved "regulatory contract" with a utility specifying the compensation arrangements that will be associated with a particular new plant. The regulatory contract will define ex ante exactly how utility compensation for power produced by the facility will be determined. The utility must convince the Commission that the generating project it proposes to build is likely to be more economical than other alternatives and agree to an incentive contract that has similar risk allocation attributes to those being signed with third party suppliers in the region. In particular, utilities would be expected to bear construction cost and reliability risks in return for a compensation formula that yields a suitable expected rate of return on investment. This contract would thus partially decouple the revenues a utility receives from the costs that it actually incurs.[139]

A task force appointed by the Governor of New Jersey has suggested an alternative approach.[140] Compensation for the costs of new power supplies, whether owned by the utility or purchased from third parties, allowed for retail ratemaking purposes, would be based on some index of comparable wholesale power costs in the region. Rather than getting into the details of supply procurement or writing new "regulatory contracts" for each new utility-owned power plant, this approach would decouple compensation for new generating supplies generally from the actual costs a utility incurs for these supplies by tying compensation to a representative index of the cost of wholesale power opportunities in the region.

The details of neither approach have been worked out and numerous practical issues must be addressed to put either approach into practice with any confidence. Both require that there exist an active wholesale market in the region that can be used to provide appropriate benchmarks either for writing "regulatory contracts" or for developing an appropriate index of regional wholesale power costs. While the Massachusetts scheme, as proposed, can work without a fully developed competitive wholesale market, I don't think that the New Jersey approach can.[141] On the other hand, the difficulties associated with trying to write an "ideal" regulatory contract to simulate what such contracts might look like in a hypothetical competitive market is a formidable task. Both approaches recognize, however, that the potential benefits of competitive wholesale power markets are most likely to be fully realized if changes are made in the process that governs the recovery of the costs of purchased power or new utility generating projects at the retail ratemaking level so that utility financial performance is at least partially decoupled from the actual accounting costs incurred by individual utilities over time.[142] A lot more effort must go into finding practical alternatives to traditional cost of service regulation to ensure that the incentives provided by rate regulation are symmetrical with the objective of encouraging utilities to make efficient supply decisions.

b. Regulatory Barriers To The Development of Competitive Wholesale Markets And Efficient Generation Procurement Mechanisms.

There currently exist several other regulatory barriers to encouraging further development of competitive wholesale generation markets. The first set of barriers is associated with state implementation of PURPA. Several states that continue to rely on administrative determination of avoided costs and standard offer contracts estimate the relevant avoided costs incorrectly, and specify the terms and conditions of utility obligations to purchase from QFs that yield prices that are either too high or too low. Second, despite the fact that several states and utilities have successfully implemented competitive bidding and negotiation programs to comply with PURPA's requirements, there still remains some uncertainty regarding whether these systems are legal under PURPA.

FERC is in the process of trying to clarify its avoided cost rules and the criteria bidding systems must meet to be legal under PURPA. In March 1988, FERC issued two Notices of Proposed Rulemaking (NOPR) to achieve this objective.[143] Unfortunately, these NOPRs, in conjunction with a related NOPR issued at the same time which proposes changes in the regulation of non-QF independent power producers (IPPs) under the FPA,[144] have generated an enormous amount of controversy among state regulators, legislators and utilities and as this is written it is unclear what will happen to the proposed rules.[145] Fixing inefficient PURPA-related price regulation and allowing for competitive bidding and negotiation as an alternative to price regulation is essential if this experiment with unintegrated third party supplies is to yield efficient outcomes in the long run.

For those of us interested in expanding opportunities and incentives utilities have to choose among the widest array of alternative generation supply options (including utility construction of generation--vertical integration) the regulatory reforms proposed in a third FERC NOPR dealing with IPPs seem to be especially important. Ideally, we would like a utility to be able to turn to the most economical supply sources whether they are QF generating plants, independent non-QF plants, excess capacity and energy available from proximate utilities, or internal utility production. Substantial QF capacity has been forthcoming for two primary reasons. Utilities have an obligation to buy at (in theory) a competitive price <u>and</u> QF suppliers were freed from cost of service regulation. QF suppliers have been able to take on construction cost and reliability risks because the compensation they receive is not tied to their accounting cost of service or to prudence reviews. A wholesale supplier which is not a QF under PURPA, however, is subject to rate regulation under the Federal Power Act (FPA) rather than PURPA. The rates charged for long term wholesale power supply contracts from "single facility" wholesale suppliers subject to FPA jurisdiction have traditionally been regulated by FERC using traditional embedded cost of service accounting principles. While the FPA does not appear to mandate cost of service regulation, it is the principle that has guided regulation of long term wholesale power contracts for the last fifty years.

Absent changes in the way rates and related contractual terms and condition for non-QF independent wholesale suppliers are regulated, a viable, efficient, and competitive wholesale power market which includes non-utility generators simply will not emerge because cost of service regulation does not provide adequate incentives for an independent supplier to incur the risks associated with competition. Given uncertainty about production costs, plant performance, and changing market conditions, a system that allows an independent suppliers to recover nothing more than its accounting cost of service at any point in time, as the accounting cost of service has traditionally been defined by regulators, means that an entrant can only expect to recover its costs by entering into a life-of-plant accounting cost of service contract with a distribution utility before he enters. To see this, assume that the typical independent supplier expects that it will be able to supply electricity for 5 cents/kWh, but because of uncertainty the cost could turn out to be 4 cents or 6 cents. The potential supplier considers entering the market and selling his output under a series of short term contracts with a maximum price equal to the accounting cost of service at each point in time. While the independent supplier is free to sell for a price up to whatever its actual accounting cost of service is at any point in time, the distribution utility buyers are not under any obligation to buy at that price in the absence of an ex ante commitment to do so. When the seller realizes a 4 cent cost of service there will be many interested buyers to buy at that price. When the seller realizes a 6 cent accounting cost of service, potential buyers are likely to turn to less costly alternatives, and the seller will have to charge less than its accounting cost of service. By setting an accounting cost of service ceiling on prices, the potential entrant faces the unappealing prospect of being compensated for his realized accounting costs or the current market value of his capacity whichever is less. The potential entrant might be quite satisfied with a contract which simply agreed to pay him 5.5 cents/Kwh.

This would give him an expected profit of 0.5 cents/Kwh. However, such a contract would violate the accounting cost of service ceiling whenever the supplier's accounting costs are below 5.5 cents.

If we want to encourage competitive entry of non-QF suppliers into generation and meaningful competition to supply unintegrated or partially integrated utilities pursuant to contracts with a wide range of risk/reward characteristics, reforms in federal regulation under the FPA of the contracts negotiated with these entities are necessary. In particular, these suppliers will have to be treated in much the same way as are QFs under PURPA. They must be exempted from cost of service regulation, in much the same way as "non-dominant" long distance telephone companies have been exempted from cost of service regulation by the FCC.

FERC's IPP NOPR goes a long way toward removing FPA restrictions on entry and contracting between utilities and independent power suppliers. FERC proposes creating a new class of suppliers---independent power producers (IPPs)--that will not be subject to cost of service regulation. Since the FPA may not actually give FERC the authority to formally deregulate the terms and conditions of contracts negotiated by IPPs, the regulatory changes have been referred to as providing "relaxed regulatory treatment." Basically, the proposed "relaxed regulatory treatment," provides that contracts negotiated by IPPs that do not have significant market power would be presumed to be just and reasonable by FERC and would not be subject to cost of service regulation. To guard against monopoly pricing and self-dealing the NOPR proposes a variety of criteria that an IPP must meet to obtain such treatment. Among other things, the rates in the contracts (properly discounted) must have an expected value that is less than or equal to the buying utility's avoided costs (properly discounted), the seller cannot have dominant control over the buyer's access to competing suppliers, and the transaction must be between unaffiliated entities (to avoid self-dealing between a regulated distribution company and a wholesale affiliate).

While I do not agree with all of the details of the IPP proposal, its basic thrust makes a lot of sense. It does not force utilities to buy from IPPs, but it creates a regulatory environment that makes it feasible for them to do so. In particular, it provides symmetry between QFs and non-QF independent suppliers and makes it possible for utilities to integrate QF and non-QF sources in a common competitive procurement process. Although the prospects for the IPP NOPR are quite uncertain at the present time,[146] [147] FERC can accomplish the same results through case by case consideration of applications of the kind of regulatory treatment proposed in the IPP NOPR.

CONCLUSIONS

It is clear to me that the firm and industry structure and regulatory arrangements which governed the electric power industry during the 25 years following World War II were poorly adapted to dealing with the economic turmoil that emerged after 1973. While it may very well be that no regulatory system would have worked very smoothly when confronted with similar types of shocks, these shocks mobilized the affected interest groups to seek alternative institutional arrangements to respond to it. The regulatory process, and legislative oversight of it, became forums through which these interest groups could extract economic rents. The primary long run effects of this turmoil has been to raise serious questions about the performance and viability of the traditional institution of regulated integrated monopoly suppliers of electricity. This in turn has led to efforts to reform the regulatory process so it provides improved incentives for efficient performance. Some of these reforms can help to improve the incentive properties of regulation. Others (e.g. pernicious "prudence" disallowances) merely reflect _ex post_ changes in the rules of the game---"hold-ups"---made possible by poorly defined legal principles and opportunities to reallocate rents associated with changing economic conditions. The latter unfortunately have adverse consequences for utility investment and operating behavior in the future.

This economic and regulatory turmoil has also led to growing interest in providing incentives to distribution utilities to secure the most economical supplies of generating capacity, whether purchased or owned, and to expand opportunities for competing independent generation suppliers to enter the market to seek to meet distribution utility requirements for generating capacity. The PURPA experience, though not without its problems, has served to provide evidence that independent suppliers can often provide at least a fraction of a utility's generation needs economically and without reducing system reliability. It has clearly been a major factor in stimulated interest in promoting the development of an independent generation market.

This recent experience with QFs does not of course prove definitively that the institution of regulated integrated monopoly electricity supply is dominated by an industry made up of numerous competing generating companies and regulated distribution/transmission companies. Even if the electric power industry had not been vertically integrated, just as the natural gas industry is not vertically integrated, the economic turmoil of the 1970s and 1980s would have almost certainly created enormous stresses on an industry whose primary pieces were linked together by long term contracts. Vertical separation has not saved the natural gas industry from chaos associated with unanticipated changes in economic conditions after 1984. Furthermore, our experience with independent suppliers is still quite limited and, when bad regulatory procedures have been applied, has been quite poor.

The independent generator cat is now out of the bag, however, and I see little reason to try to stuff it back in. Where the states have allowed utilities to adopt sensible competitive bidding and negotiation systems for NUGs, the results so far have been quite promising. Now that independent suppliers have become a significant presence in the electric power industry it is inevitable that they will bring continuing pressures to open up more opportunities for independent power producers and to create a regulatory environment for distribution utilities that can accommodate effectively this new class of suppliers. There are, however, many legitimate questions about how well the electric power system will perform from both a reliability and cost perspective if it comes to rely exclusively on competing independent suppliers. Perhaps the feared problems will not emerge, or perhaps they will be no more costly than the imperfections of traditional institutional arrangements. The primary task for state and federal regulatory agencies is to develop a regulatory environment that is sensitive to both the opportunities and potential problems that the movement to a de-integrated system based on competing independent suppliers of generation capacity raise. Several state commissions, FERC, and a number of utilities have made significant progress along these lines. There is still a lot to do to create a more effective regulatory environment to accommodate efficient change and plenty of room to learn quickly from the inevitable mistakes.

APPENDIX

DEFINITIONS OF MAJOR TECHNICAL TERMS

The generation of electricity refers to the physical process of producing electricity. Electricity is produced primarily by transforming mechanical energy into electric energy by turning a shaft to create an electrical current in a generator. This is most frequently accomplished by using fossil or nuclear fuel to produce high pressure steam. The high pressure steam in turn is exhausted through a turbine to turn the shaft in the generator. Falling water (hydro), wind or an internal combustion engine may also be used to turn the shaft in a generator.[148]

The transmission of electricity refers to the use of high voltage conductors to transport electricity from generating plants to load centers, interconnect generating plants and individual utilities with one another to maintain voltage, frequency and system reliability generally throughout a synchronized AC system, and which facilitate the economical coordination of dispersed generating facilities. The transmission system thus serves several related functions; it is not just a transportation network.

The distribution of electricity refers to the lower voltage facilities used to move electricity from points of interconnection with transmission lines to the locations where residential, commercial, and industrial customers, referred to collectively as retail customers, can purchase electricity from the network.

A distribution utility is a utility that is authorized to supply electricity at retail to residential, commercial, and industrial customers. A distribution utility may own all of the generating and transmission capacity required to serve its retail customers (a fully or close to fully integrated distribution utility) or rely on purchases from other suppliers of generation service for some or all of its power supply needs (an unintegrated or partially integrated distribution utility). When a distribution utility purchases power from a third party to supply the power necessary to serve retail customers this purchased power transaction is a referred to as a wholesale transaction.[149] A wholesale transaction is defined as the sale of electricity by one utility to another utility or a "sale-for-resale."[150]

Suppliers of wholesale electricity may be other integrated distribution utilities with excess capacity or energy to sell in the wholesale market or separate wholesale power companies that own and operate generating and perhaps transmission capacity specifically to consummate wholesale transactions, but which make no direct sales to the public. There are several different forms that wholesale power companies can take. They may be subsidiaries of distribution utilities or they may be subsidiaries of public utility holding companies that also own distribution utility subsidiaries (wholesale subsidiaries). They may, in principle, be "stand-alone" generating companies which are jointly owned by the distribution utilities that they provide electricity to (jointly-owned wholesale power companies). Finally, they may be organized as independent power suppliers that provide power exclusively to unaffiliated distribution utilities.[151]

Electricity is also produced in the U.S. at industrial plant sites (manufacturing, mining, transportation companies, etc.). Historically, such production occurred primarily for the internal use of an industrial firm at its plant site. The industrial or commercial establishment supplies some or all of its electricity requirements rather than purchasing from a distribution utility. This is referred to as self-generation. It can be accomplished in a variety of different ways. Industrial establishments may simply build small versions of standard steam turbine, internal combustion, or hydroelectric power plants (industrial power plants) or exploit economical opportunities to produce electricity and heat jointly for use in an industrial process (cogeneration). An industrial firm with its own generating capacity may also make some sales to a distribution utility. These sales constitute wholesale transaction and, using my definitions, the industrial supplier would be defined as an independent power producer when it sells to a utility. Industrial firms with their own generating capacity are generally precluded by the states from making sales directly to other retail customers.[152]

FOOTNOTES

[1]State of Mississippi et. al. v. Mississippi Public Service Commission and Mississippi Power Company, Supreme Court of Mississipi, No. 57,740, January 4, 1989, Justice Robertson, dissenting, p. 1.

[2]Joskow, P.L., "Inflation and Environmental Concern: Structural Change in the Process of Public Utility Price Regulation," Journal of Law and Economics, Vol. 17, No. 2, October 1974, pp. 291-327.

[3]Joskow, P.L., "Pricing Decisions of Regulated Firms: A Behavioral Approach," Bell Journal of Economics and Management Science, Spring 1973, pp. .

[4]Controversies over the structure and regulation of electric utilities, especially electric utility holding companies, during this period of time led to two very important pieces of legislation. The first, the Federal Power Act of 1935 (FPA), substantially increased the federal role in the regulation of transactions between utilities (wholesale transactions), electric utility mergers, the development of a uniform system of accounts, the replacement of "fair value" rate bases with "original cost" rate bases, and data collection and reporting requirements for all electric utilities. The second, the Public Utility Holding Company Act of 1935 (PUHCA), led to a complete reorganization of the complex public utility holding companies that had emerged during the 1920s and 1930s. Most of the reorganizations required under this act were completed by the mid-1950s. Public utility holding companies continue to be subject to regulation by the SEC under PUHCA.

[5]Retail customers are generally grouped into residential (40 % of retail revenues), commercial (30 % of retail revenues), industrial (27 % of retail revenues) and other (3% of retail revenues) categories. The "other" category includes street lighting, public authorities, railroads, etc.

[6]Edison Electric Institute, 1988a, Statistical Yearbook of the Electric Utility Industry/1987, Washington, D.C. (page proofs), Table 56.

[7]There are technically over 200 investor-owned utilities. Electric World, Directory of Electric Utilities, McGraw-Hill, New York, 1988. However, after consolidating utilities that are wholly-owned subsidiaries of holding companies and jointly-owned wholesale power facilities, and ignoring very small unintegrated distribution companies, the number of independent IOU entities is reduced substantially.

[8]These entities include the Federal Power Marketing Agencies (e.g. TVA and Bonneville), municipal utilities, cooperative distribution, and cooperative generation and transmission entities established as a consequence of federal legislation passed in the 1930s to facilitate (and subsidize) the electrification of rural areas, and a variety of public utility districts and authorities established by the states. Many of the public and cooperative distribution systems rely on the Federal Power Marketing Agencies, IOU's, state or cooperative generation and transmission organizations for all or part of their generation requirements, reselling power purchased from third parties to retail customers.

[9]The Federal Power Act limits federal rate regulation to wholesale transactions between unaffiliated utilities (as defined by the Federal Power Act) and between corporate subsidiaries of interstate holding companies.

[10] Primeaux, W.J., "The Decline In Electric Utility Competition," Land Economics, Vol. 51, May 1975, pp. 144-48. Primeaux, W. J., 1986, Direct Electric Utility Competion: The Natural Monopoly Myth. While in many states electric utility franchises are technically non-exclusive, economic and regulatory barriers to the creation of directly competing distribution systems give most incumbents a de facto exclusive franchise to serve specific geographical areas. Franchise exclusivity means that a retail customer at a given location must either purchase electricity from the local utility or generate electricity himself. In a few areas, utilities do compete

with one another on the fringes of their established service areas or to extend service to industrial facilities at remote sites, but this competition is quite limited. State regulatory restrictions on price discrimination limit the price impacts of any such competition even further.

[11] Federal Energy Regulatory Commission, Power Pooling in the United States, FERC-0049, December, 1981.

[12] Federal Energy Regulatory Commission, 1987, "Regulating Independent Power Producers: A Policy Analysis," Office of Economic Policy, October 13, 1987, pp. 4-5; Early, W.C., "FERC Regulation of Bulk Power Coordination Transactions," FERC Staff Working Paper, July 1984; Federal Energy Regulatory Commission, 1985, Notice of Inquiry Re Regulation of Electricity Sales-For-Resale and Transmission Service, 31 FERC 61,376. "Coordination transaction" is the term that FERC uses. It made some sense when most transactions between integrated utilities were short term economy or reliability transactions. It now makes much less sense. Calling these transactions something like "voluntary contract transactions" probably makes more sense.

[13]It is difficult to measure the value of wholesale coordination transactions. For the industry as a whole purchases and sales balance out so that the net revenue attributable to coordination transactions is zero. Roughly 20% of the Kwh generated by IOU's are sold to other utilities (primarily other IOU's) in the coordination market.

[14]Such contracts often have notice provisions for termination or firm termination dates. However, FERC has often required utilities to continue to provide service regardless of contractual termination provisions.

[15]The status of wholesale requirements customers is somewhat ambiguous. On the one hand they are treated very much like large retail customers from the perspective of rate regulation and a utility supplier's obligation to serve. Once a utility takes on a wholesale requirements customer it is difficult to stop serving

that customer even at the conclusion of the contract term. On the other hand, a utility does not have an exclusive franchise to serve wholesale requirements customers and these customers can, in principle, shop around among competing suppliers, subject only to the generally short notice provisions contained in FERC approved tariffs. The terms and conditions under which such shopping can take place has been the subject of ongoing regulatory and antitrust controversy between IOU's and publicly- and cooperatively-owned distribution entities. Bouknight, J.A. and Raskin, D.B., "Planning For Wholesale Customer Loads In A Competitive Environment: The Obligation to Provide Wholesale Service Under the Federal Power Act," Energy Law Journal, Vol. 8, 1987, pp. .

[16]There are 19 companies in Electrical World's Directory of Electric Utilities (1988) that are characterized as wholesale generating companies. Nine of these are wholly-owned subsidiaries of utilities or utility holding companies and primarily make transactions with affiliated distribution utilities. Six are plants owned by separate corporations which are in turn jointly-owned by distribution utilities which have entitlements to the power produced from the associated plants. The responsibility for operating these plants is generally placed on one of the joint owners. So, in fifteen of the nineteen cases the wholesale power companies are de facto vertically integrated into transmission and distribution since they are owned by distribution utilities. One of the remaining companies is a joint venture between a group of utilities which own a plant that was built to provide the requirements of a single customer---a uranium enrichment plant owned by the Department of energy. Of the three remaining wholesale generating companies two are tiny companies operating hydroelectric facilities (combined capacity 21 MW) and one is a company created in 1985 through the spinoff of excess generating capacity owned by Tucson Electric Power Company. In the early history of the electric power industry independent wholesale power companies, typically created to develop hydroelectric sites, were more common. They generally merged with the distribution utilities that they sold power to.

[17]If a utility is organized with distribution and generation/transmission assets owned by separate corporate subsidiaries within a holding company framework, then transfers of generation and transmission service between the subsidiaries would be wholesale power transactions subject to FERC rather than state regulation. The transfer prices would appear as purchased power costs to the distribution utility and the state commission would be obligated to pass them along in retail rates. At least superficially, vertical integration with generation, transmission, and distribution assets owned by the same corporation, maximizes state regulatory authority.

[18]National Association of Regulatory Utility Commissioners, 1986 Annual Report On Utility and Carriers Regulation, Washington, D.C., 1988, pp 537-549. .

[19]Except for FERC's authority to issue licenses for hydroelectric sites on navigable waterways under the Federal Water Power Act of 1920 as amended.

[20]National Association of Regulatory Utility Commissioners, 1986 Annual Report, p. 538.

[21]Technically, the company files new rates which are then suspended by the commission for some period of time.

[22]The "used and useful" principle has been subject to cruel and unusual punishment in recent years people have tried to use it as a rationale for excluding "excess capacity" from rates. McConnell, M. W., "Public Utilities' Private Rights," Regulation, No. 2, 1988, pp. .

[23]The discussion that follows in this section is drawn from Joskow and Schmalensee, "Incentive Regulation For Electric Utilities," Yale Journal On Regulation, Vol. 4, No. 1, December 1986, pp. 5-8.

[24]Two recent Supreme Court decisions make it fairly clear that a state regulatory commission must allow a utility to pass along in retail rates the costs associated with wholesale power purchased pursuant to a FERC approved wholesale tariff or

contract. Mississippi Power & Light Co. v. Mississippi Ex. Rel. Moore, Attorney General of Mississippi, et. al., U.S. Supreme Court, No. 86-1970, June 24, 1988; Nanatahala Power & Light Co. v. Thornburg, 476 U.S. 953 (1986). See also Narragansett Electric Co. vs. Burke, (1977) Rhode Island Supreme Court, 381 A2d 1359, cert. denied. 435 U.S. 972 (1979). That is, the state commission must assume that the prices charged by the seller are "just and reasonable." A state commission may, however, be able to disallow all or part of the purchased power costs if it determines that it was imprudent for the purchaser to enter into the contract in the first place. Pike County Light & Power Co. vs. Pennsylvania Public Utility Commission, Pennsylvania Commonwealth Court, 1983, 465 A2d 735. The circumstances under which a state can do so are uncertain.

[25]Smyth v. Ames, 169 U.S. 747, 790 (1968), Federal Power Commission v. Hope Natural Gas Company, 320 U.S. 591 (1944), Duquesne Light Co. et. al. v. Barasch et. al. ____ U.S. _____(January 11, 1989).

[26]National Association of Regulatory Utility Commissioners, 1986 Annual Report, p. 429 and p. 461.

[27]Schmalensee, R. "A Note On Depreciation and Profitability Under Rate of Return Regulation," mimeo, September, 1987, and the references he cites.

[28] Myers, S.C. et.al., 1985, "Inflation and Rate-of-Return Regulation," **Research In Transportation Economics**, Vol. 2., pp. and the references they cite.

[29]Duquesne Light Co. et. al. v. Barasch et. al. ____U.S. ____ January 11, 1989

[30]See generally National Association of Regulatory Utility Commissioners, 1986 Annual Report.

[31]The typical approach is to structure the transaction in such a way as to get the accounting costs to yield a price that is sufficiently attractive to the buyer to get him to sign a contract in competition with other third party suppliers or internal

production by the buyer. This can be accomplished by structuring the contract so that it associates the output with a mix of generating plants whose accounting costs yield the prices that the buyer is willing to pay.

[32]Joskow, P.L. and Schmalensee, R., 1983, Markets For Power: An Analysis of Electric Utility Deregulation, MIT Press survey the literature and analyze several "deregulation" scenarios.

[33]Ibid., pp. 25-78, for a more extensive discussion of the natural monopoly issue.

[34]Ibid, pp. 59-77.

[35]Joskow, P.L. and Rose, N.L., 1985, "The Effects of Technological Change, Experience and Environmental Regulation on the Construction Cost of Coal-Burning Generating Units," Rand Journal of Economics, Vol. 16, No. 1., pp. 1-27; Joskow and Schmalensee, Markets For Power, pp. 45-58.

[36]Joskow and Schmalensee, Markets For Power, pp. 59-77.

[37]Ibid., pp. 62-77.

[38]That is, large vertically integrated monopoly suppliers may theoretically be the most efficient organization form for the production of electricity if they achieve their full potential, but the combination of monopoly insulated from the natural selection properties of competition and imperfect regulation lead actual performance to depart from this theoretical ideal.

[39]Partial de-integration of generation is not inconsistent with increased concentration at the transmission and distribution levels, for example through mergers. Indeed, expanding the boundaries of horizontal control over transmission systems, combined with suitable provisions for wholesale transmission access and pricing, may facilitate economical and reliable de-integration of ownership og generation from transmission and distribution.

[40]In this regard I should point out that the _current_ structure of the electric power industry is inconsistent with this natural monopoly story. If it were, we would have a much smaller number of large vertically integrated utilities. A variety of cooperative arrangements involving multiple utilities have been introduced to achieve the economies of scale and coordination available from electricity supply technology. There is little doubt in my mind that there are opportunities to reduce costs through mergers of IOUs. These mergers have not occurred because state and federal regulation place direct and indirect restrictions on them.

[41]Joskow, P.L. and R. Noll, 1981, "Regulation in Theory and Practice: An Overview," in G. Fromm, ed. _Studies in Public Regulation_, MIT Press;
Joskow P.L., and Rose, N.L. (forthcoming), "The Effects of Economic Regulation," in R. Schmalensee and R. Willig, eds., _Handbook of Industrial Organization_, Volume 2, North Holland Press; Joskow and Schmalensee, _Markets For Power_.

[42]Gollop F. H. and Karlson, S.H., "The Impact of Fuel Adjustment Mechanisms On Economic Efficiency," _Review of Economics and Statistics_, Vo. 60, November 1978, pp. 574-584.

[43]Klevorick, A.K., "The Behavior of Firms Subject To Stochastic Regulatory Review," _Bell Journal of Economics_, Spring, 1973, pp. .

[44]Greene, W.H., and Smiley, R.H., 1984, "The Effectiveness of Utility Regulation in a Period of Changing Economic Conditions," in M. Marchand, _et.al._ eds, _The Performance of Public Enterprises: Concepts and Measurement_, Elsevier Science Publishers, Amsterdam; Smiley, R.H. and Greene, W.H., "Determinants of Effectiveness of Electric Utility Regulation," _Resources and Energy_, Vol. 5, 1983, pp. 65-81.

[45]Federal Energy Regulatory Commission, "Regulating Independent Power Producers," pp. 14-23 and the references cited there; U.S. Department of Energy, 1987, Energy Security: A Report To The President of the United States, DOE/S-0057, March., pp. 130-160.

[46]We can find some work being done as early as the 1960s (discussed in Joskow and Schmalensee, Markets For Power, pp. 179-198) that explored the possibilities for reorganizing the electric utility industry so that unintegrated distribution utilities could rely on competing unregulated suppliers of generation service instead of owning generating capacity themselves subject to cost of service regulation. These studies envisioned breaking up the electric power industry into separate generation, transmission and distribution sectors with a "common carrier" transmission system facilitating competitive interactions between monopoly distributors and competing generating companies. This model lies behind the current reorganization of the electric power industry in the United Kingdom. For more recent work regarding compretition in wholesale power markets see Schmalensee, R. and G. Golub, "Estimating Effective Concentration in Deregulated Wholesale Electricity Markets," Rand Journal of Economics, Vol. 15, Spring 1984, pp. 12-26.

[47]Joskow P.L. and Schmalensee, R., "Incentive Regulation For Electric Utilities," Yale Journal On Regulation, Volume 4, No. 1, December, 1986, pp. 1-49.

[48]There has also been pressure exerted by industrial customers for retail wheeling. They have met with little success and I will not discuss this issue further here. citations.

[49]Joskow, "Inflation and Environmental Concern."

[50]Gollop and Roberts, "Environment Regulations,", Joskow and Rose, "The Effects of Technological Change."

[51]Between 1960 and 1973 the annual compound rate of growth in electricity consumption was 7.3% per year. Between 1973 and 1985, the annual compound rate of growth of electricity consumption was 2.5% per year.

[52]A utility's reserve margin is equal to the difference between the utility's nominal generating capacity and the peak load on the system divided by the peak load on the system. Generating capacity must be built to meet expected peak demands. As a consequence of uncertain demands, scheduled and unscheduled equipment outages, uncertainty in construction schedules, etc. maintaining a high level of reliability requires that a utility maintain a significant reserve margin. A very rough rule of thumb for a modern utility that is interconnected with and able to coordinate with its neighbors is 20%. Since generating capacity investments are lumpy, have long construction periods, and demand is uncertain, actual reserve margins will generally be higher or lower than this target.

[53]Joskow, P.L., "Productivity Growth and Technical Change in the Generation of Electricity," The Energy Journal, Vol. 8, No. 1, January 1983, pp. 17-38; Joskow, P.L. and Schmalensee, R, 1987, "The Performance of Coal-Burning Electric Generating Units In The United States: 1960-1980," Journal of Applied Econometrics, Vol. 2, No. 1, April 1987, pp. 85-109.

[54]Joskow (1987)

[55]Joskow, "Inflation and Environmental Concern."

[56]This excludes automatic price increases associated with fuel adjustment clauses.

[57]Nominal electricity prices declined continuously from at least 1925 until 1970. See Edison Electric Institute, Historical Statistics of the Electric Utility Industry, Washington, D.C., 1974.

[58]In theory if a regulatory agency relies on a depreciated original cost rate base and allows a utility to earn exactly its nominal cost of capital, the price/book ratio should be equal to one. Due to mandatory normalization of certain income tax benefits for ratemaking purposes, if regulation is working "perfectly," the price/book ratio should be about 1.1 for a typical utility. A price/book ratio less than one implies that the utility is expected to earn a return on its investment that is less than its cost of equity capital. A price/book ratio significantly greater than one means that the market expects a utility to earn significantly more than its cost of equity capital.

[59]Regulated utilities operate under special accounting rules issued by the Financial Accounting Standards Board (FASB) as adopted by the SEC, FERC and state commissions. Of particular importance is the treatment of plant under construction. In most jurisdictions utilities are not permitted to include construction work in progress in the rate base or are only allowed to include some of it. However, utilities are allowed to book non-cash credits called allowances for funds used during construction (AFUDC) against interest expenses and equity earnings. These credits reduce net book interest costs and increase book equity returns. AFUDC credits are capitalized and included as part of the cost of the plant when (and if) it is completed and placed in rate base.

[60]The improvements in the financial health observed for the electric utility industry as a whole after roughly 1984 is consistent with the regulatory resistance story. As major generation construction programs ended, fuel prices declined, interest rates declined, capacity utilization increased, and general inflation abated, utilities benefitted once again from regulatory lag. It does appear, however, that contemporary regulatory agencies have been quicker to require rate adjustments to reflect lower costs. Improved financial health is not universal, however. Utilities that still have incomplete nuclear projects, or have not yet resolved the ratemaking treatment of recently completed nuclear plants, exhibit poor financial performance

as do utilities with a significant amount of excess capacity and/or industrial customers with good self-generation opportunities. Gulf States Utilities and Northern Indiana Public Service Company are good examples.

[61]National Association of Regulatory Utility Commissioners, 1986 Annual Report, p. 417.

[62]Automatic fuel adjustment clauses of course cushioned the effects of this regulatory lag of course.

[63]Joskow, "Pricing Decisions of Regulated Firms," and Joskow, "Inflation and Environmental Concern," pp. 305-311.

[64]Myers et. al. "Inflation and Rate of Return Regulation."

[65]An alternative would have been to allow some or all of construction work in progress in the rate base.

[66]Joskow and Schmalensee, "Incentive Regulation For Electric Utilities."

[67]It should be noted that utilities did not just keep pumping out generating plants under the assumption that they could recover anything that they spent in higher rates. Many power plants that were in the planning/construction pipeline were eventually cancelled, some after substantial construction expenditures had been incurred. Roughly 100 nuclear plants announced by utilities by 1975 were eventually abandoned, some after substantial construction expenditures were made. Most of the abandonments involving substantial sunk costs appear to have taken place after 1979 in response to the Three Mile Island Accident, high interest rates, declining demand, and financial difficulties. Roughly 80 coal units that were in the planning or construction cycle were either delayed or abandoned as well. It is also misleading to look only at nominal reserve margins. In many cases continued construction of coal and nuclear generating plants was economically justified to back out expensive oil and gas fired generation, rather than to meet short run

capacity needs. The collapse of oil and natural gas prices after 1985 changed this economic calculus significantly.

[68]The Prudent Investment Test in the 1980s, National Regulatory Research Institute, Columbus, Ohio, April 1985.

[69] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking Re Regulations Governing Independent Power Producers, Docket No. RM88-4-000, March 16, 1988, p. 13.

[70]Federal Energy Regulatory Commission, "Regulating Independent Power Producers," pp. 13-21, U.S. Department of Energy, Energy Security, pp. 154-157, A. Kahn and L. Perl, "The Historical Regulatory Bargain and the Treatment of Nuclear Plants," 1985 (mimeo), Hearth, D. et.al. "Regulatory Issues in Nuclear Power Plant Cancellations," Public Utilities Fortnightly, September 1, 1988.

[71]McConnell, "Public Utilities' Private Rights."

[72]An examination of generating capacity that is being constructed or planned by utilities makes this quite clear. Aside from unlicensed or incomplete nuclear plants, utilities that are building anything are generally building much smaller generating units than they did in the past. National Electric Reliability Council, 1988 Electric Supply and Demand For 1988-1997, Princeton, N.J., October, 1988.

[73]U.S. Department of Energy, Energy Security, pp. 154-157, Federal Energy Regulatory Commission, "Regulating Independent Power Producers," pp. 13-23 and the references they cite.

[74]Federal Energy Regulatory Commission, "Regulating Independent Power Producers," pp. 9-23 and the references cited there; U.S. Department of Energy, Energy Security, pp. 154-160.

[75]"Unprecedentedly Low Electric Reserve Margins Ahead, Warns U.S. CEA," The Energy Daily, September 7, 1988, p. 4; "Nationwide Peak Up 6.2% From 1987, Tripling What Industry Predicted," Electric Utility Week, October 17, 1988, p. 1; "NEPOOL Capacity Margin Worsening Despite More Small Power Development," Cogeneration Report, April 22, 1988, p. 18.

[76](PURPA) Public Law 95-617 (H.R. 4018), November 9, 1978.

[77] Joskow, P.L., "The Public Utility Regulatory Policy Act of 1978," Natural Resources Journal, Vol. 19, Autumn 1979, pp. 787-809.

[78]Parmesano, Hethie, "The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey," National Economic Research Associates, November, 1987; Electric Power Research Institute (1988) Electric Power Research Institute, Innovative Rate Design Survey: 1986, EPRI EM-5705, March 1988.

[79]Joskow, P.L. and Jones, D., "The Simple Economics of Industrial Cogeneration," The Energy Journal, Vol. 4, No. 1, January 1983, pp. 1-22.

[80]Not to exceed 80 Mw in the case of garbage burners and 30 Mw in the case of other qualifying fuels. There is no restriction on the size of qualifying cogenerators and several such facilities exceed 300 Mw.

[81]Public Utility Regulatory Policy Act of 1978, Section 210(d); U.S. Department of Energy, "Emerging Issues in PURPA Implementation," DOE/PE-70404-H1, March, 1986, Chapter 5.

[82]18 CFR 292

[83]18 CFR 292.101(a)(6). There has been ongoing controversy about whether the statute and the rule establish avoided cost as a ceiling, a floor, or the exact amount utilities must pay. FERC's initial rules were challenged because they appeared to require that utilities pay prices equal to their avoided costs. In American Paper Institute V. AEP 461 U.S. 402 (1983) the Supreme Court held that FERC had the authority to require payments up to the buying utility's avoided cost. However, the original rules clearly anticipate that large QFs and utilities would negotiate individual contracts with the avoided cost rule available as leverage to appeal to the state regulatory agency if a mutually satisfactory contract could not be negotiated. FERC recently ruled that utilities cannot be required to pay more than avoided cost by the states (Orange and Rockland Utilities ____FERC____ (1988)).

[84]Conference Report on H.R. 4018, Public Utility Regulatory Policy Act of 1978, H. Rep. No. 1750, 95th Congress, 2nd Session, 1978.

[85]While PURPA was passed in late 1978, FERC did not issue regulations until 1980. Uncertainty over the key pricing provisions contained in these regulations was not resolved until 1983 in American Paper Institute v. AEP, op. cit.

[86]I would estimate 1989 NUG capacity at roughly 32,000 MW.

[87]Primarily small hydro plants, wind turbines, and steam plants fueled by wood and municipal waste.

[88]The federal government cleverly stopped collecting systematic data on NUGs after 1978, just as PURPA was passed. Since then we have had to rely on surveys and estimates. The data for 1985 and 1986 are based on comprehensive Edison Electric Institute (EEI) surveys and are consistent with other surveys and estimates.

[89]For example, in 1981 the electricity generated by the primary metals industries was half of what it was in 1971. It continued to decline between 1981 and 1986. Total electricity used in P,imary Metals in 1986 was only 20% of what it was in 1971. U.S. Department of Commerce, Census of Manufacturers and Annual Survey of Manufacturers various years.

[90]North American Electric Reliability Council, 1988 Supply and Demand, RCG/Hagler, Bailly Cogeneration and Small Power Data Base, as reported in Cogeneration Report, April 22, 1988, p. 13.. The aggregate figures also mask wide interregional differences in NUG capacity and generation.

[91]To the extent that there is an Averch-Johnson effect it is almost certainly revealed in the own/buy decision rather than through input utilization distortions assuming an integrated firm. However, since vertical integration is ubiquitous around the world and preceded modern state rate regulation in the U.S., there is more to it than the A-J effect.

[92]As I have just discussed, regulatory developments in the past decade have changed these incentives. Better to buy from a third party than to lose money building a generating plant yourself. This effect shoul;d not be confused with classical monopsony power.

[93]I find it hard to get terribly excited about inefficiencies arising from utility monopsony power per se. The primary efficiency concern associated with classical monopsony power, a subject that has received little theoretical, empirical or public policy attention, is that purchases of the inputs over which the buyer has market power will be artificially restricted. This increases the social costs of producing output, while reducing the buyer's private costs of production. The extent of the restriction depends on the input (purchased power) supply elasticity, the elasticity of the derived demand for purchased power, the ability of the buyer to price discriminate, and various regulatory rules and

procedures, including the use of competitive bidding procedures. I believe that restrictions on purchases of economical supplies of purchased power resulting from buyer market power per se are likely to be small. Monopsony power concerns are of even less important for independent power producers which are not cogenerators and are not tied to specific sites within a single utility's service area or where independent suppliers can obtain wheeling service to gain access to multiple purchasers. The primary barriers to the development of an independent generating sector prior to 1978 were unattractive economics and regulatory disincentives and barriers.

[94]Capacity, equipment availability, transmission costs, fuel price related risks, timing of capacity additions, etc.

[95]Actually, except for contracts with very small QFs, there is nothing in the statute or FERC's initial rules that requires state regulators to force utilities to specify a general "standard offer" contract based on which they must purchase from any and all willing suppliers. The original rules seem to anticipate that bilateral negotiation is to be preferred to administrative specification of generic contract terms and conditions that a utility must stand ready to buy under.

[96]While this observation may seem obvious, it has eluded many regulators.

[97]One supplier signing a contract today may offer to begin deliver in 1992, another in 1995, etc.

[98] Lets say I need 100 MW of long term capacity in 1993 and 100 MW more in 1995. I can sign a contract today for 100 MW for deliver in 1993 and another contract for 100 MW of capacity to begin delivery in 1995 or I can sign a contract for the first 100 MW today and wait a couple of years to sign a second contract to begin delivery in 1995. There is an option value associated with waiting. This value must be traded off against the prices offered today.

[99]See generally, U.S. Department of Energy, "PURPA Implentation".

[100] U.S. Department of Energy, "PURPA Implementation", pp. 5.24-5.25 and Table 11, Federal Energy Regulatory Commission, 1988a, Notice of Proposed Rulemaking Re Administrative Determination of Full Avoided Costs, Docket No. RM88-6-000, March 16., p. 11, note 24. The problem was not just that regulators made mistakes estimating avoided costs. The enthusiasm of some state regulators and legislators to promote cogeneration and small power production led them to set rates that were far above reasonable estimates of avoided costs. U.S. Department of Energy, "PURPA Implementation", Chapter 6. On the other hand, many state commission recognized that there was already plenty of generating capacity around, mandated initially only that utilities pay avoided energy costs at time of delivery, leaving longer term capacity contracts to negotiation (Federal Energy Regulatory Commission, "Avoided Cost Rulemaking," page 12, note 26. This was the initial approach taken by Massachusetts, for example.

[101]U.S. Department of Energy "PURPA Implementation", pp. 635-642, Federal Energy Regulatory Commission "Avoided Cost Rulemaking", p. 11, note 24.

[102]The analogy to the price vs. quantities literature should be obvious. Weitzman, M.L., "Prices Vs. Quantities," Review of Economic Studies, Vol. 41, October, 1974, pp. 477-491.

[103]This appears to be precisely how FERC originally anticipated contracts between utilities and larger QFs would be consummated. The 1980 rules do not entitle large QFs to standard offer contracts. Regulations Implementing Section 210 of PURPA, FERC Stats & Regs 30,128 and 30,868.

[104]It probably makes sense to think of there being a continuum between a very highly structured "self-scoring" bidding system and a competitive negotiation system in which the utility retains considerable flexibility to evaluate individual contracts

and various combinations of contracts and internal production.

[105]Houston Lighting and Power was the first utility to propose using a competitive bidding system to deal with excess supplies resulting from standard offers. The Texas Commission did not approve the bidding system, in part because it was uncertain whether of not it was legal under PURPA, but allowed them to set quantities and then negotiate the best deals they could with competing suppliers. Central Maine Power, faced with a similar problem, was permitted to implement the first competitive bidding system in the country. U.S. Department of Energy "PURPA Implentation," pp. 5.44-5.54.

[106]There is also a growing trend to allow conservation options to bid against new supply sources. This trend is unfortunate and reflects a profound confusion between supply, demand, consumer and producer behavior. Joskow, Paul L. Testimony Before the Subcommittee on Energy and Power, Committee on Energy and Commerce, U.S. House of Representatives, March 31, 1988, and Stalon, Charles, "The Role of Conservation Programs in The Bidding NOPR," March 4, 1988. Memorandum from Commissioner Charles Stalon to other FERC Commissioners.

[107]"At Least 3 Utility Independent Power Units Win in Va. Power Solicitation," Electric Utility Week, November 28, 1988, p. 12; "Utility Units Tripled Investments in Independent Power in Past Year," Electric Utility Week, December 5, 1988, p. 17.

[108]Klein, B., Crawford, R. and Alchian, A., 1978, "Vertical Integration, Appropriable Rents and the Competitive Contracting Process," Journal of Law and Economics, October; Joskow, P.L., "Vertical Integration and Long-Term Contracts: The Case of Coal Burning Electric Generating Plants," Journal of Law, Economics and Organization, Vol. 1, No. 1, Spring, 1985, pp. 33-80; Joskow, P.L., "Contract Duration and Relationship Specific Investments," American Economic Review, Vol. 77, No. 1, March, 1987, pp. 168-85; Williamson, O. E., "Credible

Commitments: Using Hostages to Support Exchange," American Economic Review, Vol 73, September, 1983, pp. 519-540.

[109]See Table 9 which I will discuss presently.

[110]Joskow, "Vertical Integration and Long Term Contracts," and Joskow, "Price Adjustment in Long Term Contracts."

[111]As I indicated earlier, I think that it is unlikely that monopsony power per se is a significant efficiency problem in reality if utilities are obligated to purchase from third parties when third party supplies are more economical than internal production.

[112]National Electric Reliability Council, 1988 Supply and Demand, Appendix D.

[113]Massachusetts Department of Public Utilities, D.P.U. 84-276-B (October, 1986).

[114]There is significantly less variance in the contract prices than I found for prices in comparable long term coal contracts in previous work; Joskow, "Price Adjustment In Long-Term Coal Contracts".

[115]Note that in several cases the contract capacity is less than the project capacity. This is the case where projects anticipate selling to two or more utilities. The other contracts are not reported because they were not executed in 1987.

[116]Edison Electric Institute, Capacity and Generation of Non-Utility Sources of Energy, 1988, Washington, D.C., July, p. 32.

[117]For example, one of the projects has a long term coal contract that has a base price plus escalation pricing provision that escalates the base price with the CPI. This escalation provision in the coal supply contract is mirrored by the escalation provision in the power supply contract. The gas fired facilities

with CPI adjustment mechanisms are generally supported with long term gas supply contracts with CPI adjustment provisions.

[118]Joskow, P.L., "Price Adjustment in Long Term Contracts," Journal of Law and Economics, Vol. 21, April 1988, pp. ; Joskow, P.L., "Price Adjustment in Long Term Contracts: Further Evidence From Coal Markets," mimeo, 1988.

[119]Joskow and Schmalensee, Markets For Power, pp. 109-127.

[120]Massachusetts Electric Company, "Alternative Energy Negotiation-Bidding Experiment 1988 Report," Westborough, MA, March, 1988.

[121]Temple, Barker and Sloane, "Qualifying Facilities Survey: Results of Findings," December 1987.

[122]"Edison Small Power Plans Dim," The Boston Globe, December 11, 1988, p. 73.

[123]Federal Energy Regulatory Commission, "Regulating Independent Power Producers", pp. 18-21, U.S. Department of Energy, Energy Security, pp 154-160 and the references they cite.

[124]"FERC OKAYS Ocean State Plant in R.I. Where Investors Will Bear Full Risk," Electric Utility Week, January 19, 1987, page 1; Ocean State Power 38 FERC 61,140 (1987) and 44 FERC 61,261 (1988).

[125]"PG&E, Bechtel Form Joint Venture For Independent Projects," Cogeneration Report, January 1, 1988, page 12.

[126]Federal Energy Regulatory Commission, "Regulations Governing Independent Power Producers," p. 6.

[127] PURPA has also had more indirect effects on the retail ratemaking process. Although distribution utilities provide retail service pursuant to de facto exclusive geographical franchises, they cannot keep customers from supplying electricity for themselves---self-generation. The "stand-alone" cost of self-generation is a natural upper bound on what a utility can charge regardless of what its accounting costs happen to be. PURPA has helped to reduce the costs of self-generation by requiring utilities to provide non-discriminatory backup and supplemental service for cogeneration and to purchase excess production from the supplier at a rate reflecting the market value of the supplies. In industries where cogeneration is technically and economically feasible (pulp and paper, chemicals, food processing, oil refining, etc.) the threat of self-generation has increasingly forced utilities to offer special rates below the traditional accounting cost of service. These are sometime called incentive rates or cogeneration deferral rates. Cogeneration deferral rates have now become quite routine. While the discount rate is below the average accounting cost of service is above the utilities marginal or avoided cost associated with serving the affected customers. For example see, "New Rates Designed to Encourage Economic Development and Load Retention," NRRI Quarterly Bulletin, Vol. 8, No. 2, April 1987, pp. 227-239; "Florida Okays Second Cogeneration Deferral Agreement For Gulf Power," Electric Utility Week, November 18, 1988; "PG&E, Socal Ed File Cogeneration Deferral Contracts With California PUC," Electric Utility Week, November 18, 1988.

[128]"Texas Cogeneration Projects Said to Have 95.7% Availability Factor," Electric Utility Week, December 12, 1988, p. 12.

[129] White, W.S. and G.S. Vassell, "U.S. Electricity Supply At A Crossroads--The Technical and Historical Background," Public Utilities Fortnightly, Vo. 123, No. 1, January 5, 1989, pp. 9-14 and "U.S. Electricity Supply At The Crtossroads--The Federal Energy Regulatory Commission Proposals," Public Utilities Fortnightly,

Vol. 123, No. 2, January 13, 1989, pp. 9-13.

[130]Where only generation and transmission are integrated, distribution systems have tended to rely on long term requirements contracts with a single bulk power supplier.

[131]Forced vertical disintegration of existing electric utilities, a la the reorganization of AT&T is, in principle, a possibility. However, I do not think that it is a realistic possibility and will not discuss it further. Among other constraints, state regulators oppose vertical restructuring because they feel that they would lose regulatory jurisdiction over generation costs which would be wholesale transactions subject to FERC jurisdiction rather than internal corporate transfers subject to state jurisdiction. While this constraint reflects primarily a bureaucratic turf battle between state and federal regulators, rather than any real differences in the quality of state vs. federal regulation, it is a very real constraint indeed. There was also only one AT&T; there are over 100 IOUs. Any general reorganization would require federal legislation and would have to deal with many complex financial, ratemaking, and regulatory complexities. It could not be done through an antitrust settlement involving one firm. Structural change in this industry is most likely to take place on the margin.

[132]Privatising Electricity, Presented to Parliament by the Secretary of State For Energy, London, HMSO, February 1988.

[133] Acton, J.P. and Besen, S.M., Regulation, Efficiency and Competition in the Exchange of Electricity: First Year Results From the FERC Bulk Power Market Experiment, Rand Corporation, Report R-3301-DOE, Santa Monica, CA, 1985.

[134]Federal Energy Regulatory Commission, Order Accepting Experimental Rates For Filing, Docket No. ER87-97-000, March 12, 1987.

[135]"Participants Claiming Satisfaction with WSPP Bulk-Power Experiment," Electric Utility Week, October 24, 1988, p. 14.

[136]Pace, J., "Wheeling and the Obligation to Serve," Energy Law Journal, Vol. 8, No. 2, 1987, pp. 265-302; Frame, R. and Pace, J, "Approaching the Transmission Access Debate Rationally," TRG Working Paper No. 1, NERA, Washington, D.C., 1987.

[137]Pacific Gas and Electric Company, 44 FERC 61,010 (1988) (Modesto Irrigation District); Turlock Irrigation District, 43 FERC 61,403 (1988)

[138]Massachusetts Department of Public Utilities, D.P.U. 86-36-C, May 12, 1988. The California Commission recently entered into a non-traditional "regulatory Contract" with Pacific Gas & Electric governing the pricing of power produced by the completed Diablo Canyon nuclear plant. National Association of Regulatory Utility Commissioners, Bulletin, January 9, 1989, pp. 3-6.

[139]Subsequent to this order, the Massachusetts Commission proposed a new "all source competitive solicitation" regulatory framework; Mass DPU Order 86-36-F, November 30, 1988. This proposal would require utilities to develop a highly structured self-scoring competitive bidding system that would be used to solicit bids to provide additional supplies from all types of supply and conservation "resources." This bidding system would be integrated with a complex "least cost planning process." All of this would be subject to extensive and time consuming regulatory review. The proposed rules seem to me to be extremely ill-advised. They are an unfortunate example of the aggegation of a couple of good ideas with some bad administrative procedures, with the latter dominating.

[140]Report To The Governor: Findings and Recommendation of the Task Force on Market Based Pricing of Electricity, November, 1987.

[141]The New Jersey Task Force proposal does not appear to be going anywhere. The New Jersey Commission did recently enter into a settlement agreement that requires utilities to introduce a competitive bidding system for new generating capacity. Unfortunately the state chose to rely on a highly structured self-scoring bidding system.

[142]; Laffont, J. J. and J. Tirole, "Using Cost Observations To Regulate Firms," Journal of Political Economy, Vol. 94, 1986, p. 614; Joskow and Schmalensee, "Incentive Regulation."

[143] Federal Energy Regulatory Commission, Notice of Proposed Rulemaking Re Regulations Governing Bidding Programs, Docket No. RM88-5-000, March 16,1988; Federal Energy Regulatory Commission, Rules Governing Administrative Determination of Avoided Costs.

[144]Federal Energy Regulatory Commission, Regulations Governing Independent Power Producers.

[145]"1988: The Year the FERC Shook Electricity," Public Utilities Fortnightly, September 1, 1988, pp. 29-32; "NARUC Electricity Panel Seeks Congressional Hearings on NOPRs" and "Future of FERC Electricity Strategy Uncertain," Electric Utility Week, September 26, 1988, p. 15; "NARUC Representative Provides Views on FERC Electricity Policy Initiative To Congress," NARUC Bulletin, September 19, 1988, pp. 15-18; "Senators Urge FERC Not to 'Rush to Judgement' On Electricity NOPRs," Electric Utility Week, September 26, 1988.

[146]"NARUC Electricity Panel Seeks Congressional Hearings on NOPRs" and "Future of FERC Electricity Strategy Uncertain," Electric Utility Week, September 26, 1988, p. 15; "NARUC Representative Provides Views on FERC Electricity Policy Initiative To Congress," NARUC Bulletin, September 19, 1988, pp. 15-18; "Senators Urge FERC Not to 'Rush to Judgement' On Electricity NOPRs," Electric Utility

Week, September 26, 1988.

[147]The Public Utility Holding Company Act of 1935 (PUHCA) creates another federal regulatory barrier to the development of a competitive non-QF independent generation market along the lines envisioned by FERC. The provisions of PUHCA are complex and a discussion of the problems that it creates are beyond the scope of this paper. See Statement of Catherine C. Cook (with attachments), Federal Energy Regulatory Commission, and Statement of Marianne Smythe (with attachments), Securities and Exchange Commission, Before the House Subcommittee on Energy and Power of the Committee on Energy and Commerce, September 14, 1988.

[148]Electricity can be produced in other ways, also.

[149]See "Interutility Bulk Power Transactions," Energy Information Administration, DOE/EIA-0418, October 1983.

[150]The Federal power act defines an "electric utility" as any person or state agency which sells electrical energy.

[151]This does not exhaust the list of possible ownership and organization forms that have been utilized.

[152]Except perhaps to an adjacent establishment if the sale can be accomplished without running wires across municipal rights of way.

TABLE 1

GROWTH IN WHOLESALE POWER TRANSACTIONS

TYPE OF TRANSACTION	% GROWTH 1973-85	1985-86
Short term interchange	60%	-21%
Longer term Contracts	56%	+ 2%
Canada	270%	-12%
wheeling	290%	-32%
Purchases From NUGs	318%	+44%

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Total sales to ultimate customers	32%	+2.0%

TABLE 2

AVERAGE NOMINAL CONSTRUCTION COST OF NUCLEAR UNITS
1968-1987

Period Units Entered Service	Nominal Cost $ Per Kw
1968-71	161
1972-73	217
1974-75	404
1976-78	623
1979-84	1,373
1985	2,466
1986	2,765
1987 (est)	3,776

Source: Nuclear Power Plant Construction Activity, U.S. Department of Energy, Energy Information Administration, 1987.

TABLE 3

ELECTRIC UTILITY FINANCIAL PERFORMANCE*
1960-1987

YEAR	ROE	YIELD ON NEW UTIL DEBT	DIFFERENCE	PRICE/BOOK RATIO	% EARNINGS AFUDC	INTEREST COVERAGE (EX AFUDC)
1960	10.20%	4.72%	5.48%	1.73	6.55%	5.11
1961	10.30	4.72	5.58	2.15	5.77	5.13
1962	10.70	4.40	6.30	2.06	5.07	5.22
1963	10.80	4.40	6.40	2.22	3.61	5.23
1964	11.10	4.55	6.55	2.22	4.07	5.20
1965	11.70	4.61	7.09	2.31	4.56	5.18
1966	12.10	5.53	6.57	1.97	5.40	4.97
1967	12.20	6.07	6.13	1.98	7.80	4.49
1968	11.50	6.80	4.70	2.02	10.19	4.06
1969	11.40	7.98	3.42	1.70	13.87	3.50
1970	10.80	8.79	2.01	1.59	21.48	2.69
1971	10.80	7.72	3.08	1.48	26.33	2.53
1972	11.00	7.50	3.50	1.34	30.27	2.58
1973	10.50	7.91	2.59	1.10	31.92	2.41
1974	10.40	9.59	0.81	1.15	35.91	2.16
1975	10.30	9.97	0.33	1.06	34.23	2.20
1976	10.60	8.92	1.68	0.93	31.53	2.41
1977	11.00	8.43	2.57	0.61	29.40	2.54
1978	10.70	9.30	1.40	0.64	37.37	2.53
1979	11.00	10.85	0.15	0.74	46.82	2.09
1980	10.70	13.46	-2.76	0.65	56.01	1.89
1981	12.40	16.31	-3.91	0.68	52.85	1.95
1982	13.20	14.93	-1.73	0.77	56.06	1.92
1983	14.30	12.70	1.60	0.89	51.35	2.57
1984	14.90	14.25	0.65	0.84	46.99	2.67
1985	14.40	11.83	2.57	0.99	42.70	2.79
1986	14.50	9.61	4.89	1.23	32.33	3.32
1987	12.70	9.75	2.95	1.18	30.39	3.08

*Moody's 24 Utility Average
Moody's <u>Public Utility Manual</u> (Blue Sheets)

TABLE 4

NON-UTILITY GENERATION (NUG)
1966-1986

YEAR	NUG GENERATING CAPACITY (MW)	NUG AS % TOTAL U.S. CAPACITY	NUG GENERATION (MWH)	NUG SALES TO UTILITIES (MWH)
1966	18,973	7.11%	105,094	2,837
1967	18,933	6.57	102,935	5,079
1968	19,123	6.17	106,586	3,560
1969	19,257	5.79	110,575	5,372
1970	19,237	5.34	108,162	5,722
1971	19,297	4.97	103,239	5,744
1972	18,768	4.50	104,508	6,267
1973	19,377	4.22	102,529	6,768
1974	19,351	3.91	101,572	6,617
1975	19,177	3.63	85,362	6,022
1976	19,113	3.47	87,084	4,678
1977	19,245	3.32	87,575	4,032
1978	19,391	3.24	78,967	6,670
1979	17,436	2.83	71,375	6,034
1980	17,323	2.75	67,945	7,576
1981	17,142	2.63	64,446	8,401
1982	16,938	2.54	61,076	12,004
1983	16,765	2.48	57,678	15,649
1984	17,371	2.52	71,520	19,395
1985	22,920	3.22	94,925	28,300
1986	25,321	3.45	112,008	40,719

Source: Edison Electric Institute (1988a, 1988b)

TABLE 5

NUG CAPACITY: ADDITIONS AND RETIREMENTS 1979-1986 (MW)

1. 1979 NUG Capacity:	17,878		
Cogeneration:		10,538	
Small Power Production:		730	
Other Industrial Plants:		6,610	
2. Apparent Retirements (1979-1986):	7,255		(note #1)
Cogeneration:		2,184	
Small Power Production:		46	
Other Industrial Plants:		5,025	
3. Net Pre-PURPA Capacity 1986:	10,624		(note #1)
Cogeneration:		8,354	
Small Power Production:		684	
Other Industrial Plants:		1,585	
4. Post-PURPA Additions (1979-86):	14,697		(note #1)
Cogeneration:		10,093	
Small Power Production:		3,156	
Other Industrial Plants		334	
5. Total NUG Capacity 1986	25,321		
Cogeneration:		18,448	
Small Power Production:		4,953	
Other Industrial Plants:		1,920	

note #1: assumes non-identified capacity is post-PURPA capacity

Source: Edison Electric Institute (1988b)

TABLE 6

SELECTED UTILITY COMPETITIVE BIDDING/NEGOTIATION PROGRAMS

Utility		Mw of Capacity Requested (MW)	Bids Received (MW)
Central Maine Power (1987 solicitation)		200	1,444
Sierra Pacific (Nevada)		125	2,800
New England Power		200	4,729
Virginia Power		1,750	14,000
Eastern Edison (Mass.)		30	180
Boston Edison	(first)	200	2,053
	(second)	400	(in progress)
Green Mountain Power (Vermont)		114	806
Jersey Central P&L		180	(in progress)
Delmarva P&L (Delaware)		200	(in progress)
Orange & Rockland Utilities		100	(in progress)
Long Island Lighting		300	(in progress)

Source: Trade Press Reports

TABLE 7

QF CONTRACTS SIGNED BY MASSACHUSETTS UTILITIES
1987

CONTRACT #	Real Expected Levelized Price (cents/kWh-MECO Assump)	Real Expected Levelized Price (cents/kWh-BECO Assump)	CAPACITY (MW)
1	4.40	6.92	38.0
2	4.48	4.43	2.5
3	4.52	5.75	40.0
4	4.58	6.44	47.0
5	4.68	5.93	25.0
6	4.69	4.75	12.0
7	4.71	5.84	46.0
8	4.71	4.57	68.0
9	4.82	5.06	2.4
10	4.93	5.66	100.0
11	5.01	5.21	24.5
12	5.01	5.21	10.0
13	5.01	5.21	3.3
14	5.01	5.21	3.3
15	5.12	5.17	11.3
16	5.12	5.17	11.3
17	5.25	5.17	7.4
18	5.83	5.88	24.0
19	5.92	5.97	81.0
20	5.93	5.73	200.0
21	5.94	5.94	25.0
22	6.07	6.14	40.0
23	6.75	6.87	34.0

Source: Massachusetts Electric Company (1988)

TABLE 8

1987 MASSACHUSETTS QF CONTRACT CHARACTERISTICS

Contract #	Contract Capacity (MW)	Project Capacity MW	Duration (Years)	Wheeling	Fuel	Price Escalators
1	38.0	38.0	25	yes	gas	GNP, oil
2	2.5	2.5	20	no	waste	3%/year
3	40.0	80.0	15	yes	gas	CPI, gas, pipeline
4	47.0	47.0	20	yes	gas	fixed esc., fuel cost
5	25.0	156.0	20	yes	gas	CPI, gas, coal, oil, pipeline
6	12.0	12.0	20	no	landfill gas	CPI
7	46.0	46.0	20	no	gas	CPI, gas, coal, oil, pipeline
8	68.0	300.0	20	yes	gas	fixed esc.('92); 7.5%/year
9	2.4	2.4	20	no	landfill gas	CPI, oil
10	100.0	156.0	20	yes	gas	CPI, gas, coal, oil, pipeline
11	24.5	24.5	20	yes	gas	CPI
12	10.0	10.0	20	yes	gas	CPI
13	3.3	3.3	20	yes	gas	CPI
14	3.3	3.3	20	yes	gas	CPI
15	11.3	11.3	25	no	refuse	CPI
16	11.3	11.3	25	no	refuse	CPI
17	7.4	7.4	20	yes	refuse	fixed esc., CPI
18	24.0	48.0	(abandoned)	no	coal	CPI, GNP
19	81.0	180.0	30	yes	coal	CPI, GNP
20	200.0	200.0	n/a	no	coal	CPI, coal, rail
21	25.0	25.0	20	no	waste wood	fixed esc., avoided cost
22	40.0	40.0	25	no	refuse	CPI
23	34.0	34.0	n/a	no	coal	GNP

Source: Massachusetts Electric Company (1988)

FIGURE 1

CLASSICAL IOU

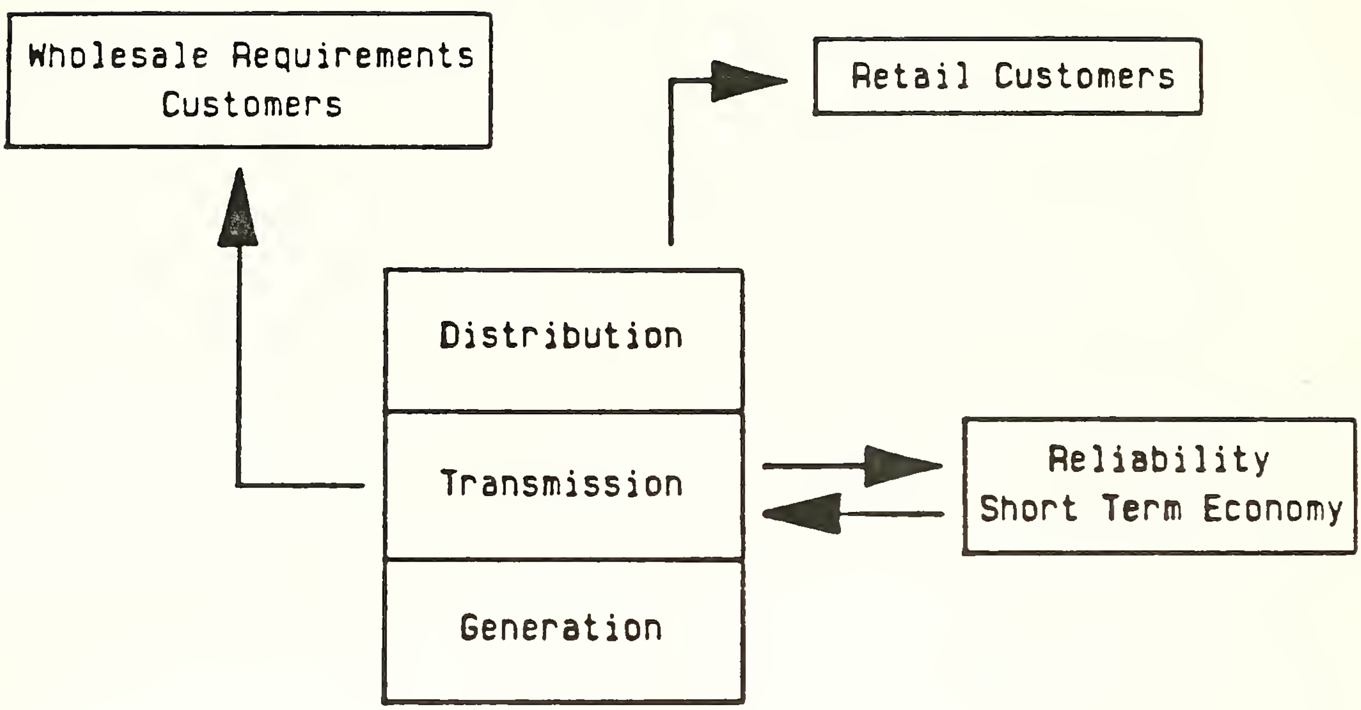
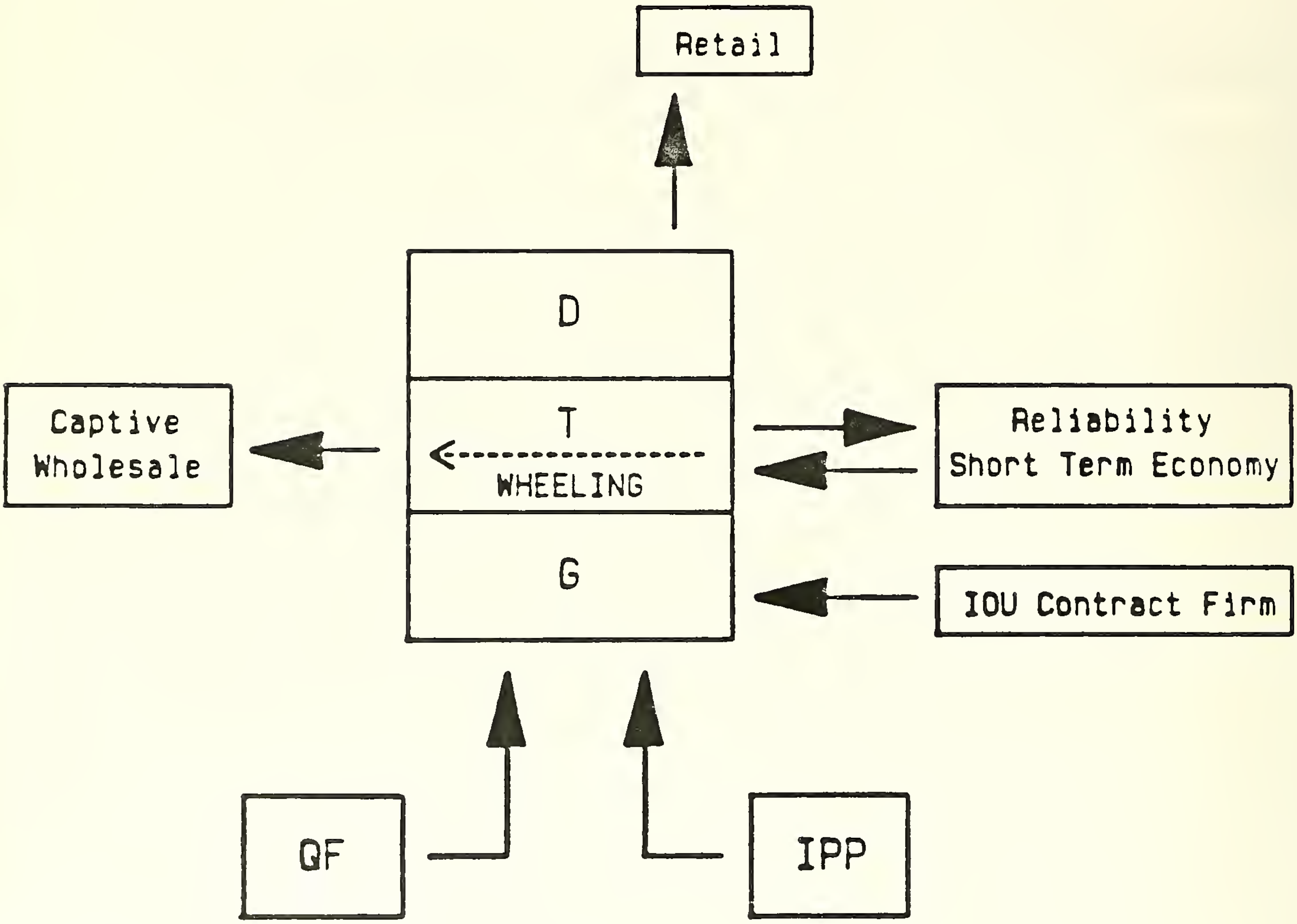


FIGURE 2

EVOLVING IOU



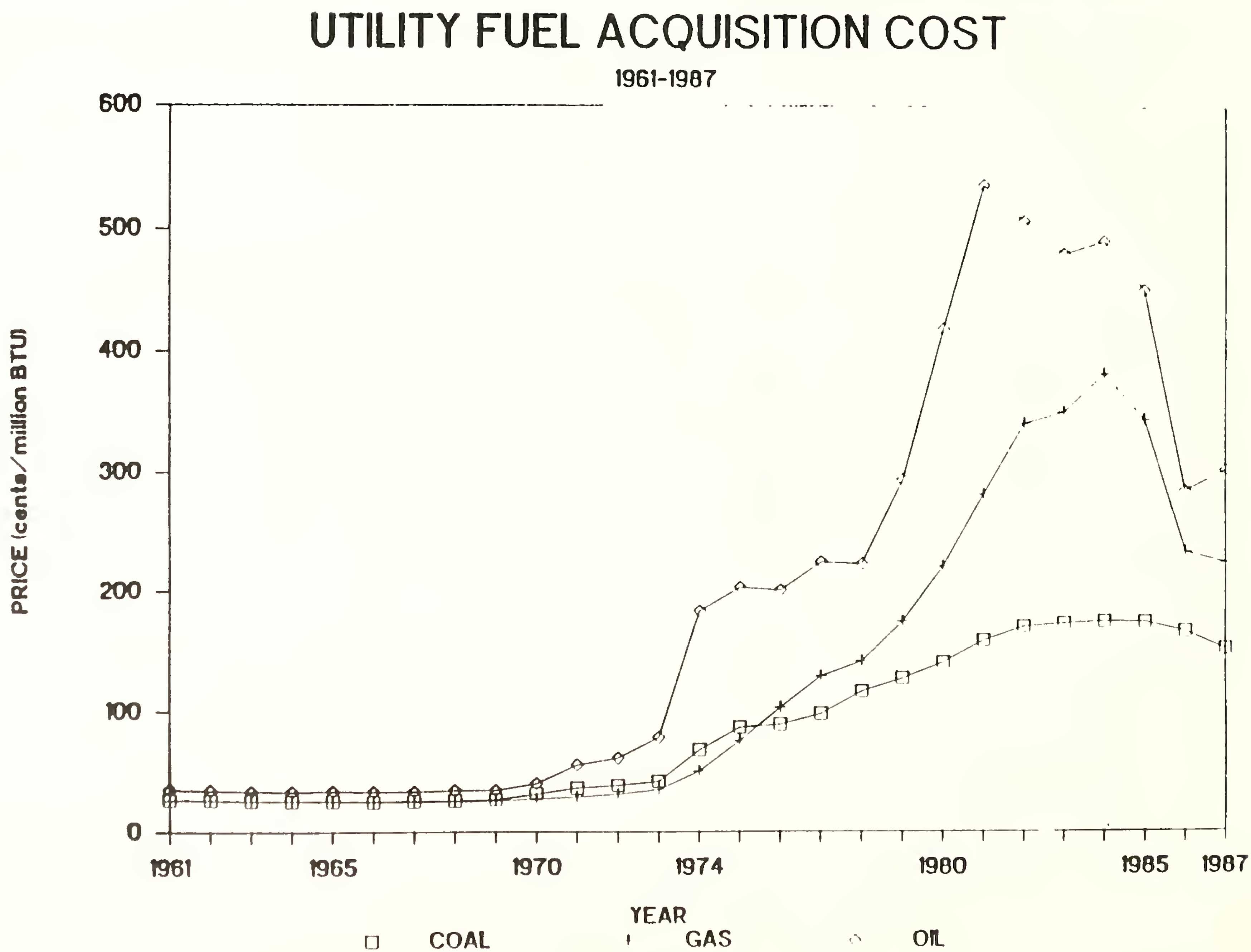
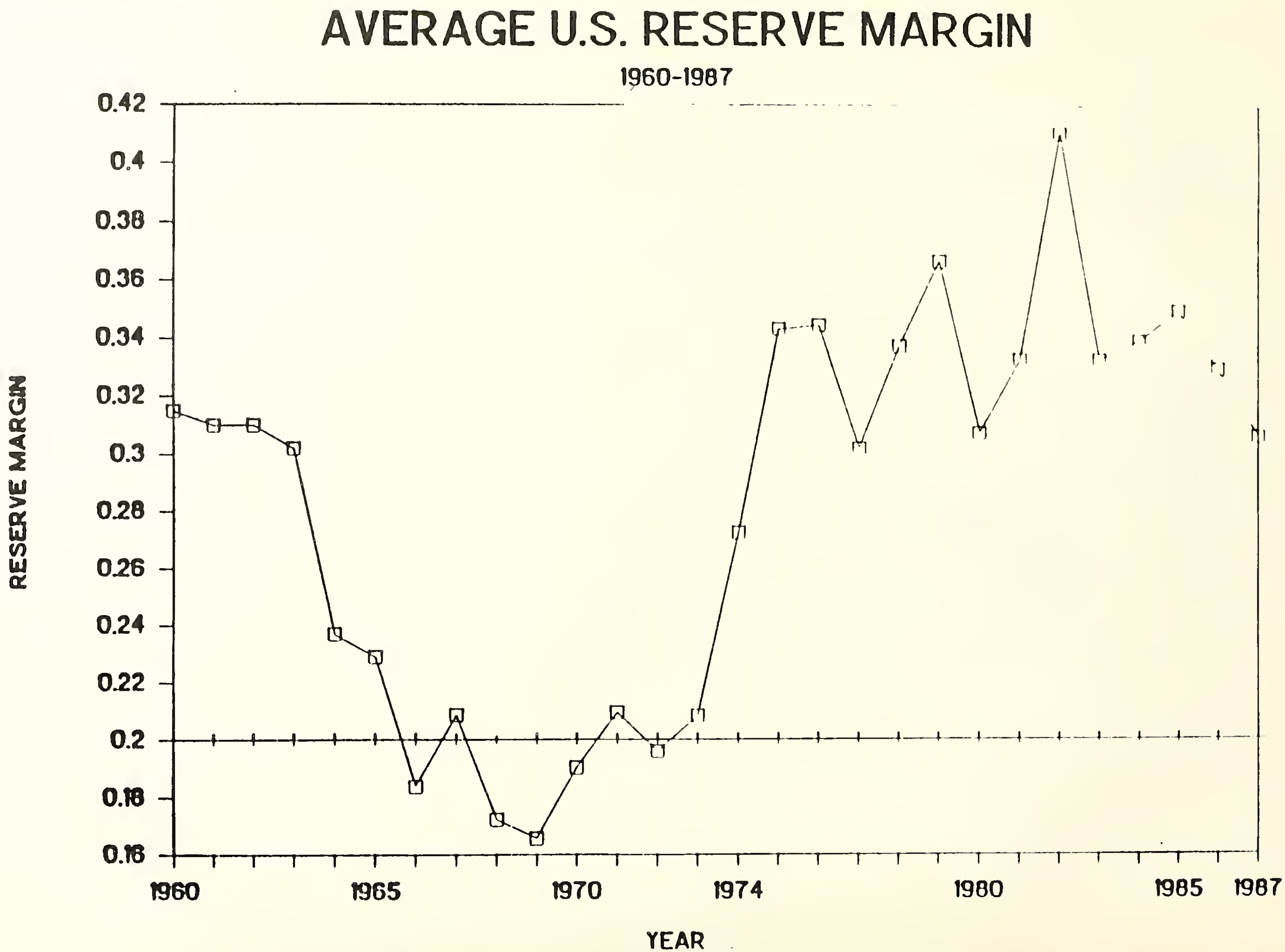
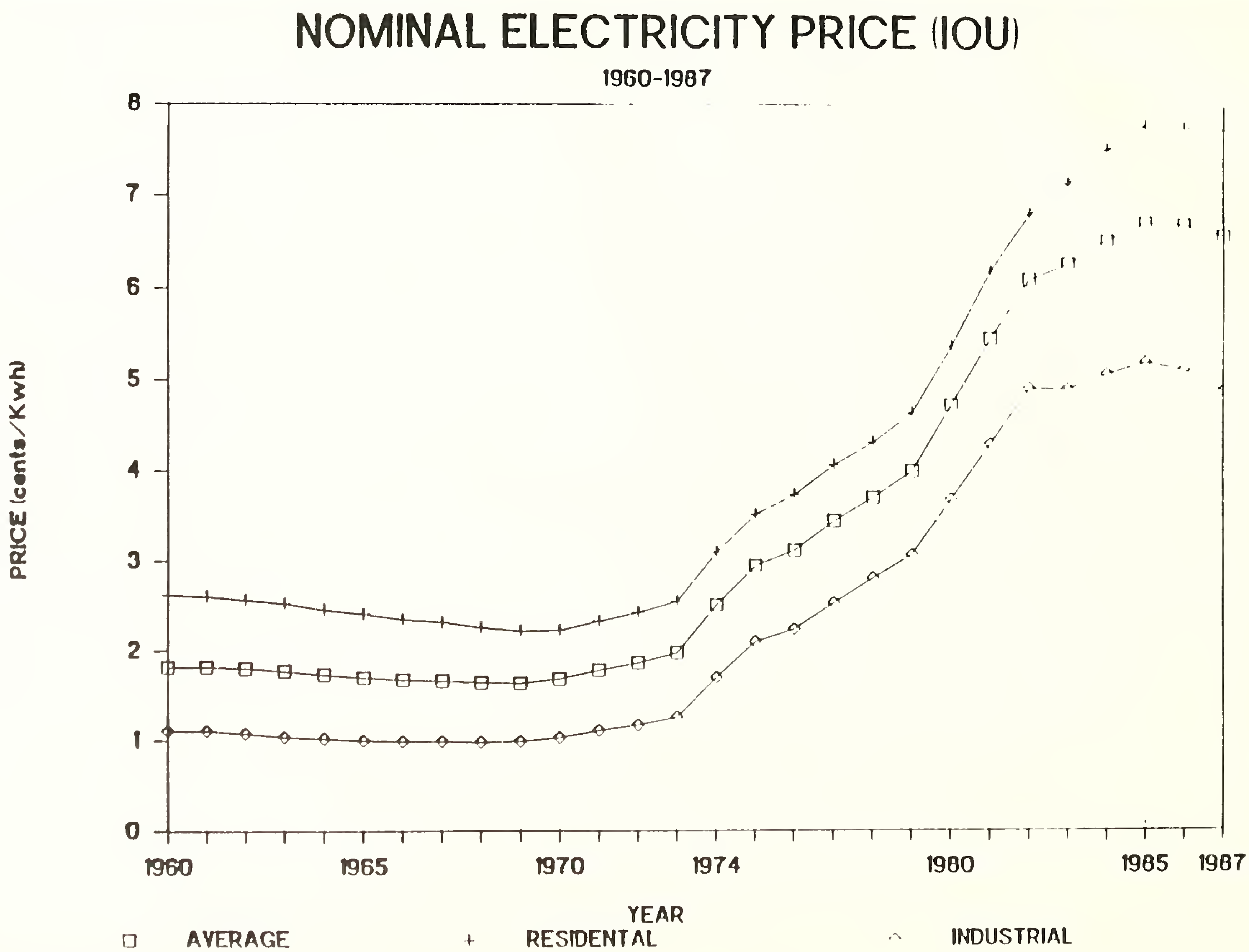

UTILITY FUEL ACQUISITION COST
1961-1987
PRICE (cents/million BTU)
600
500
400
300
200
100
0
1961
1965
1970
1974
1980
1985
1987
YEAR
COAL
GAS
OIL

FIGURE 3



SOURCE: Edison Electric Institute (1988)

FIGURE 4

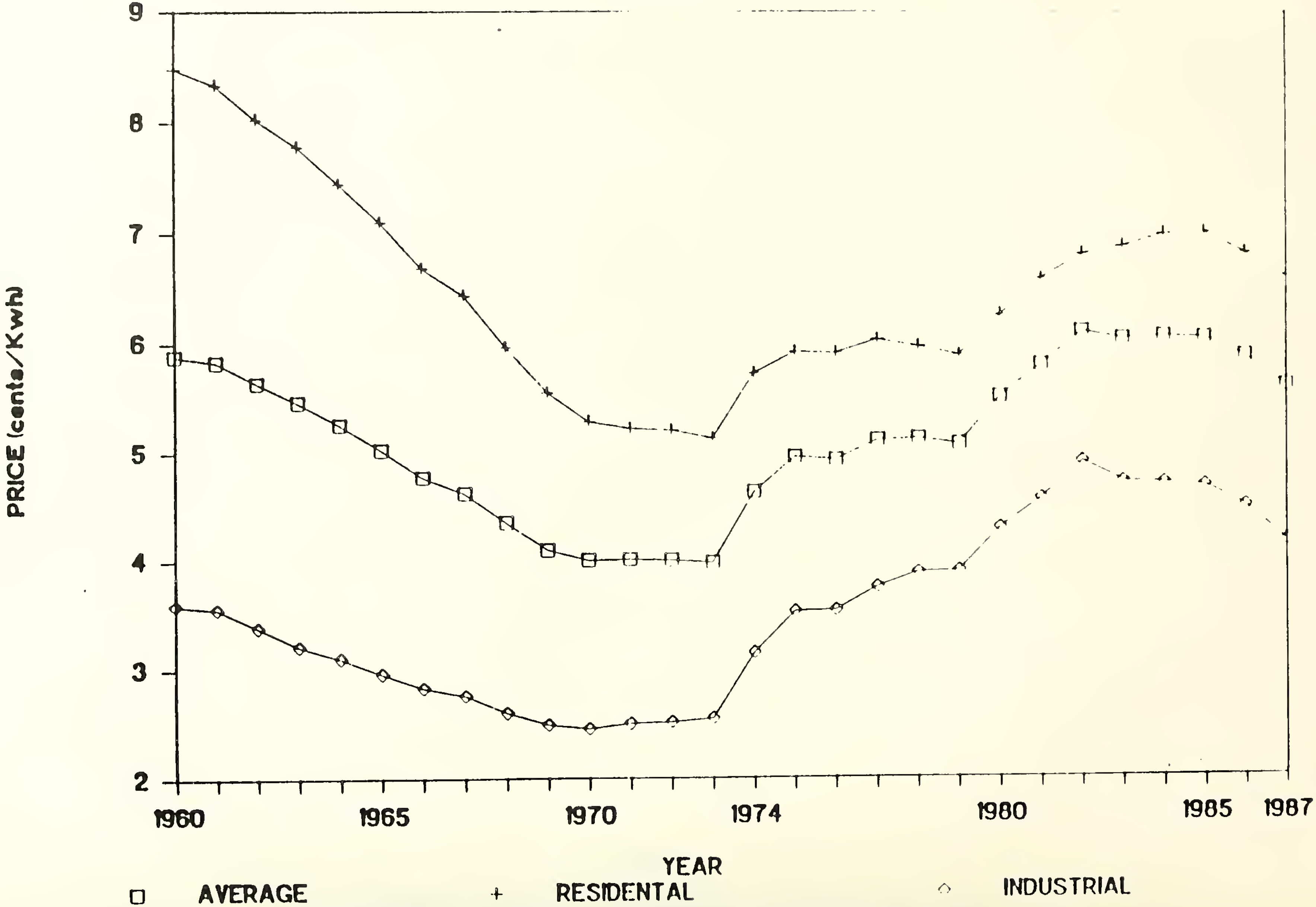


SOURCE: Edison Electric Institute (1988)

FIGURE 5

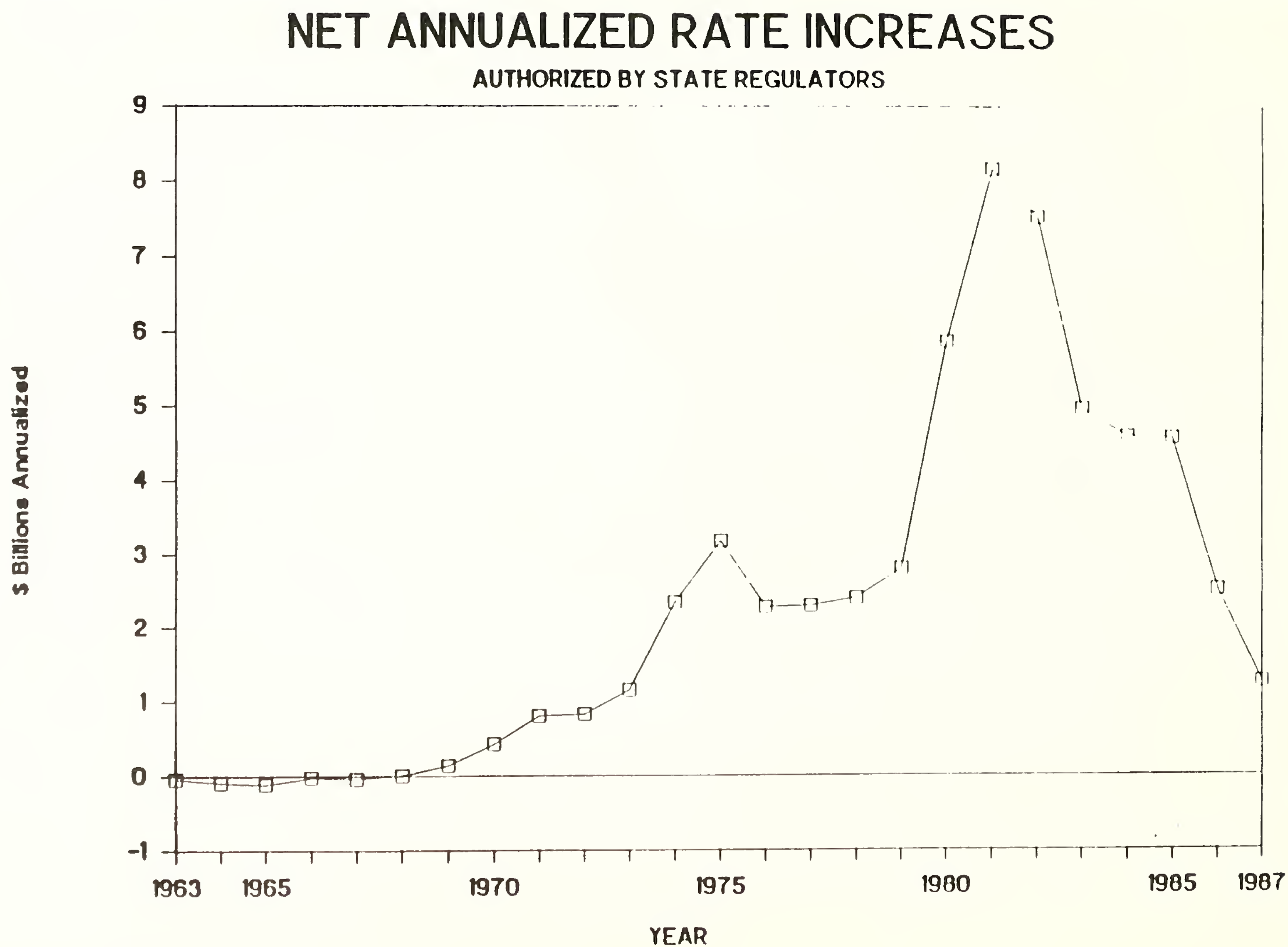
REAL ELECTRICITY PRICE ($1982)

1960-1987



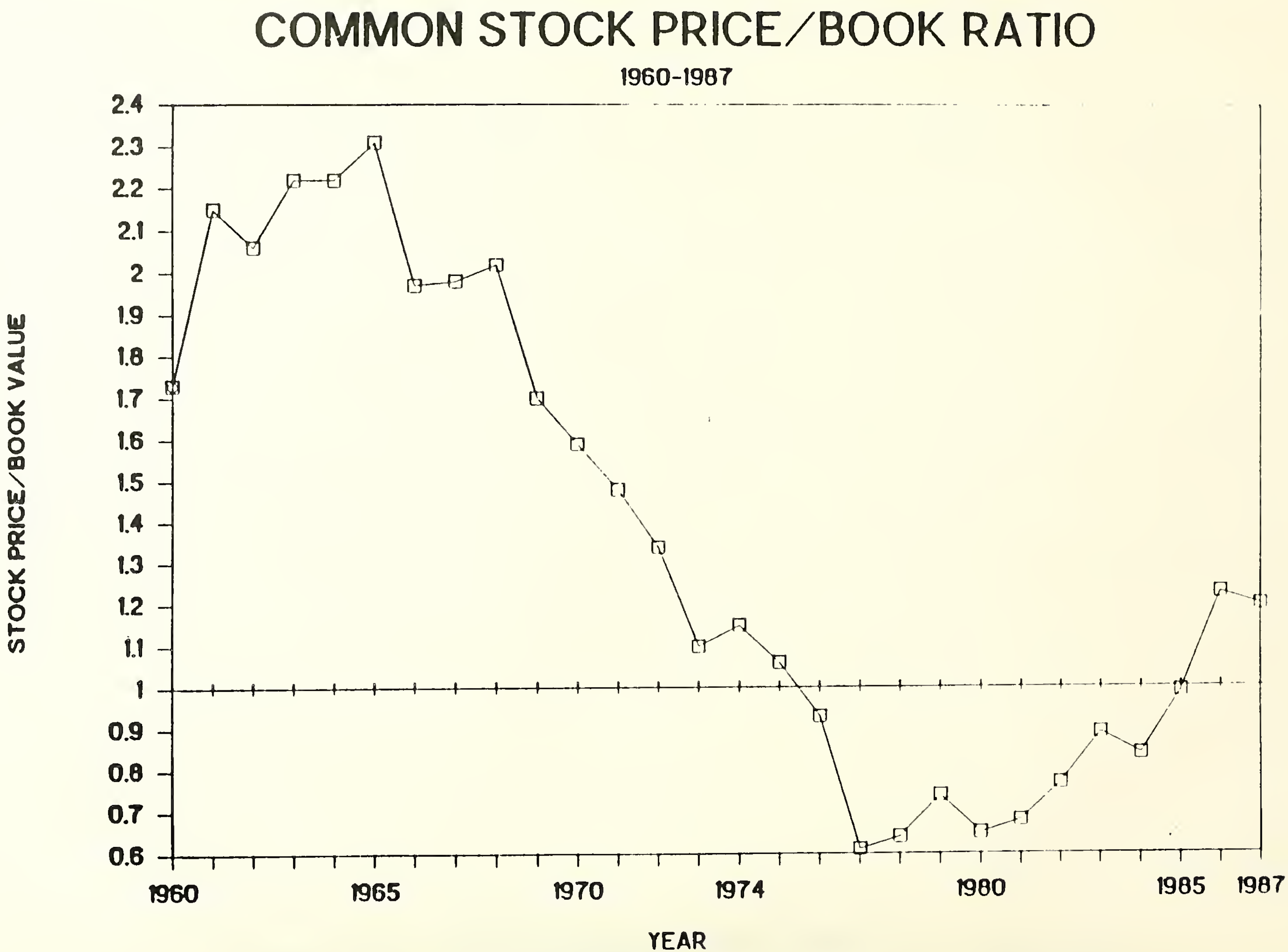
SOURCE: Edison Electric Institute (1988)

FIGURE 6



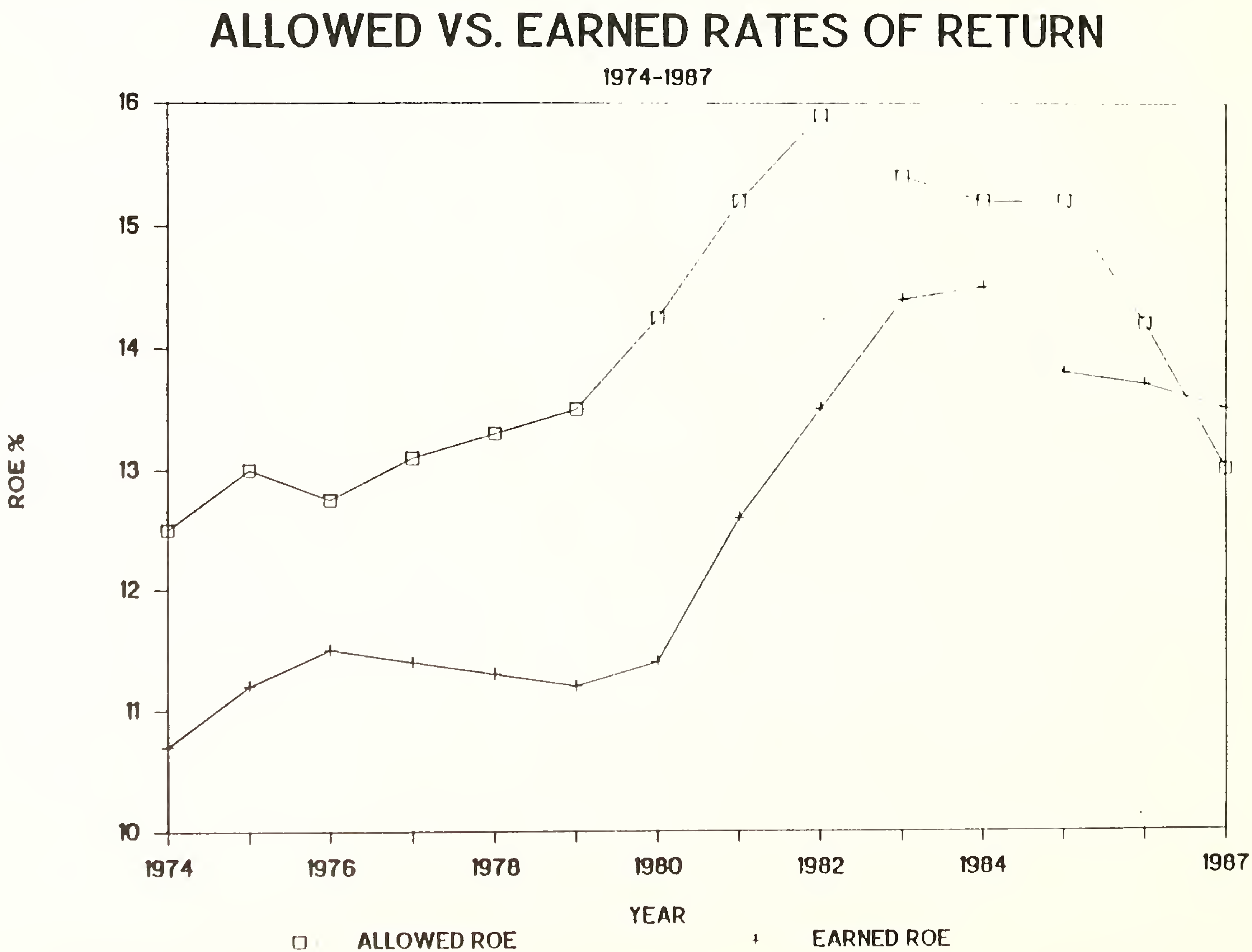
SOURCE: S&P Industry Studies

FIGURE 7



SOURCE: Moody's 24 Utility Average

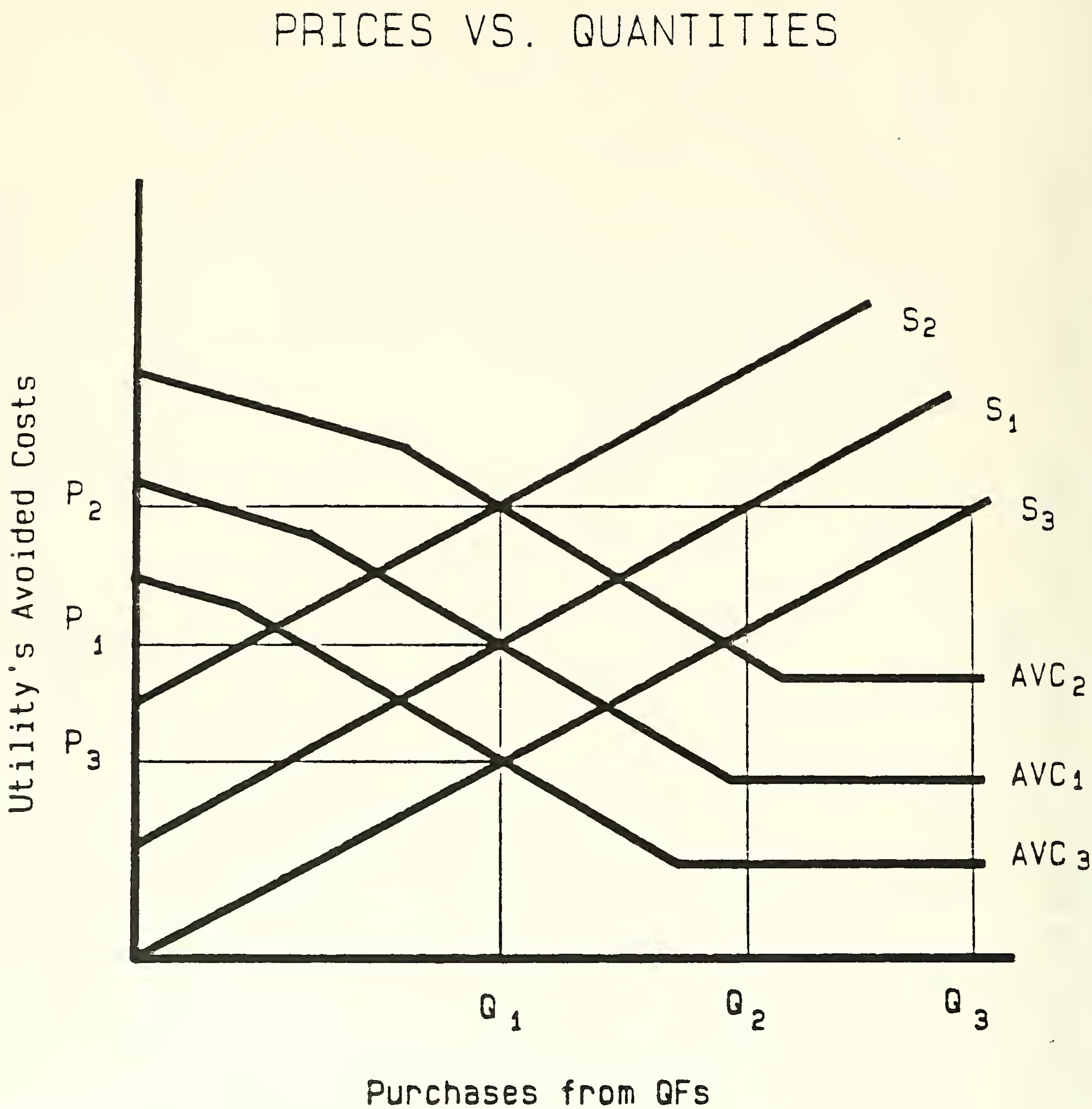
FIGURE 8



SOURCE: S&P Industry Studies

FIGURE 9

FIGURE 10



PRICES VS. QUANTITIES
Utility's Avoided Costs
P 2
P 1
P 3
S2
S1
S3
AVC2
AVC1
AVC3
Q1
Q2
Q3
Purchases from QFs

Figure 3

1961-1970, Edison Electric Institute, Historical Statistics of the Electric Utility Industry To 1970, Washington, D.C. 1974; 1971-1986, Edison Electric Institute, Statistical Yearbook Of the Electric Utility Industry 1986, Washington, D.C. 1987; 1987 (gas and coal), Statistical Yearbook Of the Electric Utility Industry 1987, Washington, D.C. 1988; 1987 (oil) estimated.

Figure 4

The average U.S. reserve margin is computed as the difference between the generating capability at the time of summer peak load and the non-coincident summer peak load divided by the non-coincident summer peak load. Edison Electric Institute, 1987 Statistical Yearbook, p.14 (1967-1987) and Historical Statistics of the Electric Utiluty Industry to 1970, p.20.

Figure 5

Edison Electric Institute, 1987 Statistical Yearbook, p.74, Table 64.

Figure 6

Data in Figure 5 Adjusted by the GNP Deflator (1982 = 100).

Figure 7

Standard and Poor's Industry Studies (Electric Utilities), various years.

Figure 8

Table 3

Figure 9

Standard and Poor's Industry Studies (Electric Utilities), various years

Sources For Tables and Figures

Table 1

Computed from U.S. Department of Energy, Financial Statistics of Selected Electric Utilities 1986, DOE/EIA-0437, Washington, D.C., various years.

Table 2

Nuclear Power Plant Construction Activity, U.S. Department of Energy, Energy Information Administration, 1987, page 10.

Table 3

Computed From Moody's Public Utility Manual (1988) (Blue Sheets) for Moddy's 24 Utility Average. Book values exclude deferred taxes.

Table 4

Source: Edison Electric Institute, Statistical Yearbook of the Electric Utility Industry 1987, Washington, D.C. December 1988, p.7 and p. 16.

Table 5

Source: Edison Electric Institute, 1985 Capacity and Generation of Non-Utility Sources, Washington, D.C., July 1988, pp. 13-14

Table 6

Trade Press Reports

Table 7

Massachusetts Electric Company, Alternative Energy Negotiation-Bidding Experiment: 1988 Report, Westborough, MA, March 1988, pages 41 and 43.

Table 8

Massachusetts Electric Company, Alternative Energy Negotiation-Bidding Experiment: 1988 Report, Westboroigh, MA, March 1988, pages 10 and 41-69.