MAINE PUBLIC UTILITIES COMMISSION

ELECTRIC UTILITY INDUSTRY RESTRUCTURING
Docket No. 95-462

REPORT
AND
RECOMMENDED PLAN

December 31, 1996

Chairman Thomas L. Welch
Commissioner William M. Nugent
Commissioner Heather F. Hunt

Executive Summary

On July 3, 1995, Legislative Resolve 1995, ch. 48 "Resolve, to Require a Study of Retail Competition in the Electric Industry" became Maine law. The underpinning of the Resolve is that broader market competition and customer choice in the electric market will benefit the public more than continued regulation. A central question of the Resolve is how to facilitate development of a competitive market in the retail purchase and sale of electric energy consistent with the public interest.

The Resolve directed the Commission to construct a plan for the Legislature's consideration to achieve retail market competition for the purchase and sale of electric energy in Maine. Today, we advance a recommendation to restructure the market which fundamentally challenges the historical method of delivering, purchasing and regulating the provision of electric services. We embrace competition and advocate cautious implementation.

The following fundamental principles guided the Commission's recommended path to achieve retail competition by the year 2000:

- Where viable markets exist, market mechanisms should be preferred over regulation and the risk of business decisions should fall on investors rather than consumers.
- Consumers' needs and preferences should be met with the lowest costs.
- All consumers should have a reasonable opportunity to benefit from a restructured electric industry.
- Electric industry restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize energy security.
- All consumers should have access to reliable, safe and reasonably priced electric service.
- Electric industry restructuring should not diminish low income assistance or other consumer protections.
- The electric industry structure should be lawful, understandable to the public, and fair and perceived to be fair.
- Electric industry restructuring should improve Maine's business climate.

We believe our recommendation comports with these fundamental principles and approaches industry restructuring in a manner that is practical, efficient and in the public interest.

Our recommendation reflects our preference for competition and market mechanisms. We believe the principal long-term benefit of our recommendation is to shift the risk of business decisions about investment in generation away from ratepayers and onto shareholders. Another benefit is to bring competitive pressure to rates, which may move Maine's electric prices closer to the national average. Our recommendation reveals our desire to make the transition from theory to implementation in a way that allows Maine to benefit from the experience of other states and to preserve important state objectives.

In broad outline, we recommend the following:

<u>Retail Competition and Deregulation</u>

- Beginning on January 1, 2000, all customers would have the option to purchase power in the competitive market.
- All customers would have the option to purchase power directly from power suppliers or from intermediaries such as load aggregators, power marketers or energy service companies.
- All customers could aggregate in any manner.
- Once customers can purchase power in the competitive market, the Commission would not regulate, as public utilities, companies that produce or sell power.
- The Commission would continue to regulate as public utilities the companies that transmit and distribute electricity. These transmission and distribution (T&D) utilities would have exclusive service territories and an obligation to connect customers to the power grid.
- Before 2000, the Commission would consider progress in other jurisdictions and at the regional level in making the decisions necessary to implement retail competition.
- The Commission would not require that other states or Canadian provinces allow retail competition in their jurisdictions as a condition to permitting suppliers from those states or provinces to enter Maine's market.

Corporate Structure and Divestiture

- By January 2000, investor-owned utilities would transfer all generation related assets to corporations distinct from their transmission and distribution businesses.

- By January 2006, Central Maine Power Company and Bangor Hydro-Electric Company would be required to divest all generation assets. They could divest earlier.

- By January 2000, investor-owned utilities would be required to transfer the rights to power from all qualifying facilities (QF) contracts.

- Consumer-owned utilities would not have to structurally separate or divest their generation assets.

- Contracts between investor owned utilities and qualifying facilities would remain with the transmission and distribution utilities.

- Maine Yankee decommissioning liability would be collected in the rates of transmission and distribution utilities.

- Investor-owned transmission and distribution utilities would not market power. After 2006 Central Maine Power Company and Bangor Hydro-Electric Company could not have affiliates that market power. Maine Public Service Company may have such an affiliate, but it could market power only in its service territory.

- After 2005, consumer-owned utilities could market power only within their service territories.

Standard Offer

- Standard offer service would be provided to customers who do not choose a competitive power provider and to those who cannot obtain power in the market on reasonable terms.

- The transmission and distribution utility would administer a competitive bid process to select the standard offer service provider. Prior to a request for bids, the Commission would decide the terms and conditions of the standard offer service.

- Standard offer service price would be capped so that the price for power combined with the regulated rates of T&D utility service will not, on average, exceed the total rate for electricity prior to retail competition.

- If the standard offer service price plus the regulated rates of transmission and distribution service is not, on average, at or below the total rate for electricity prior to retail competition, the Commission would investigate whether beginning retail competition at that time remains in the public interest.

- The Commission would regulate the credit, collection, and disconnection practices relating to standard offer service.

Customer Protection

- The Commission would regulate power suppliers' interactions with customers, but not the prices or services offered.

- The Commission would regulate the transmission and distribution utilities, including their rates and credit, collection, and disconnection practices.

- The Commission would resolve customer complaints against transmission and distribution utilities.

- Transmission and distribution utilities could not disconnect customers from their systems for non-payment of charges by, or other disputes with, power suppliers.

- If a power supplier terminates service to a customer, that customer would default to the standard offer service.

- Upon passage of an electric restructuring plan by the Legislature, the Commission would immediately begin customer education and outreach programs.

Low Income Assistance

- The Commission strongly recommends that the Legislature fund low income assistance programs through either the general fund or a tax or surcharge on all energy services.

- If low income assistance is not funded through taxes, low income programs would continue to be funded by ratepayers through the rates of the T&D companies.

Energy Policy and the Environment

Renewable sources

- All companies selling power to retail customers in Maine should include a minimum amount of renewable energy in their generation portfolio.

- Power suppliers could meet minimum renewable requirements with credits they could buy and sell.

- The Commission would consider the market's ability to develop and sell power from renewable resources in establishing the renewable portfolio standard.

Conservation and Load Management

- Ratepayers would continue to fund cost effective energy efficiency programs through revenue collected in the rates of transmission and distribution utilities.

- The transmission and distribution utility, with Commission oversight, would select the energy efficiency service providers through periodic competitive bidding.

Siting and certification

- The Commission would not review or approve construction of generating facilities.

Environmental risk

- The Commission supports the application of air emissions standards that minimize differentiation between old and new source generating plants. The Commission will work with other states and appropriate agencies to accomplish this goal.

Stranded Costs

- Utilities would have a reasonable opportunity to recover legitimate, verifiable, and unmitigatable costs stranded as a result of retail competition. Utilities should have only the opportunity for cost recovery comparable to that under current regulation.

- The Commission would require utilities to take all reasonable steps to mitigate those costs.

- The Commission would establish initial estimates of stranded costs prior to 2000, using market information wherever possible. The Commission would not reconcile stranded costs after the fact, but would review them periodically and adjust them if warranted. The stranded costs associated with QF contracts would be subject to adjustment until the contracts end.

- Stranded costs would be collected from customers through the regulated rates of the transmission and distribution utilities.

- To the extent generation-related costs incurred after March 1995 become uneconomic due to retail competition, the Commission would not include any recovery for those costs in the stranded cost recovery charge.

Regional issues

- The Commission endorses and will continue to work for reforms to the governance of the New England Power Pool (NEPOOL) to allow fair and meaningful representation for all market participants.

- The reformed NEPOOL should ensure that providers meet the North American Electric Reliability Council reliability standards.

- The Commission endorses the establishment of an Independent System Operator (ISO)to be responsible for the day-to-day operations of the transmission system; the ISO must be effectively independent and have no financial interest in any market participant.

- The Commission endorses the establishment of a voluntary power exchange.

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I. INTRODUCTION

This document advances the Commission's recommendation for electric utility industry restructuring in Maine. An outline of the recommendation is attached in the Executive Summary.

Legislative Resolve 1995, ch. 48 "Resolve, to Require a Study of Retail Competition in the Electric Industry" became law on July 3, 1995. Through the Resolve, the Legislature directed the Commission to begin to study restructuring Maine's electric utility industry no later than January 1, 1996 and to submit a report to the Legislature by January 1, 1997. The Commission initiated the study through a Notice of Inquiry on December 12, 1995. To obtain the proposals and views of various stakeholders, the Commission solicited and received written comments. Twenty-two parties filed initial comments, and 11 filed responsive comments. Thirty-five parties filed comments on the Draft Plan issued July 19, 1996. Eleven filed reply comments.

The Commission used a variety of means to gather public opinion. Specifically, the Commission held a series of roundtable discussions with various interest groups; created a "homepage" on the World Wide Web to share information and receive comment; held a total of nine public hearings around the state, in May and September; issued four restructuring bulletins; met with groups of small business owners; produced, in cooperation with Time Warner Cable Company, a television program called "Electricity: Can We Cut Your Bill?," which was shown on cable public access channels throughout Maine; conducted formal surveys of both residential and small business customers to learn more about their attitudes, expectations and information regarding retail competition; and participated in regional and national conferences on electric utility restructuring.

The recommendation follows careful consideration of the positions and arguments articulated throughout this process, a study of activities in other states and the vast literature on industry restructuring.

The following fundamental principles guided the Commission's recommendation to achieve retail competition by the year 2000:

- Where viable markets exist, market mechanisms should be preferred over regulation and the risk of business decisions should fall on investors rather than consumers.
- Consumers' needs and preferences should be met with the lowest costs.
- All consumers should have a reasonable opportunity to benefit from a restructured electric industry.
- Electric industry restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize energy security.
- All consumers should have access to reliable, safe and reasonably priced electric service.
- Electric industry restructuring should not diminish low income assistance or other consumer protections.
- The electric industry structure should be lawful, understandable to the public, and fair and perceived to be fair.
- Electric industry restructuring should improve Maine's business climate.

The Commission believes the recommendation comports with these fundamental principles and approaches industry restructuring in a manner that is practical, efficient and in the public interest.

II. RETAIL COMPETITION AND DEREGULATION

A. Recommendation

On January 1, 2000, electricity customers in Maine would have the option to choose their power supplier, that is, the entity that sells electric power as distinct from the entity that delivers the power over wires and other facilities. All customers, regardless of size, type, or location, would have the opportunity to elect a power supplier effective on the same date. Customers could contract with power suppliers, purchase from power exchanges and spot markets, and aggregate in any manner they elect. Customers would not need special meters to choose their power provider.

After retail competition begins, Maine would no longer regulate, as public utilities, companies that generate or sell electric power. Regulated public utilities would provide electric transmission and distribution (T&D) services. The T&D utilities would have to allow generation service providers[1] to reach any customer within their exclusive service territories. The Commission would retain regulatory authority over the T&D utilities' rates and other activities.

[1]Throughout this Report, we have used the terms "generation service" and "power" as synonyms. In this document, these terms refer to the provision of electric power as distinct from transmission and distribution services (i.e., the wires and other facilities needed to transport the power, and access to those facilities). "Generation providers" refer to generators, marketers, brokers, aggregators, or any other entity producing or selling electric power.

The Commission would not require that other states or Canadian provinces allow retail competition in their jurisdictions as a condition to permitting providers from those states or provinces to enter Maine's retail market. Maine customers should have the opportunity to purchase diverse products and services from providers in any location.

The Commission would watch closely other states' and regional initiatives concerning retail competition. The Commission would implement, or recommend to the Legislature as appropriate, changes to the restructuring plan proposed here to the extent warranted by experience and developments elsewhere.

B. Discussion

1. Existing Industry Structure

a. Regulatory system

Currently, the Commission regulates the electric industry comprehensively. There is limited competition. This industry structure developed because providing electricity had natural monopoly characteristics, such as economies of scale, which suggested a single entity could provide service at the lowest cost. As a result, electric utilities have provided generation, transmission and distribution services packaged or "bundled" together to all customers within geographic service territories. As a substitute for competition, the government regulated electric utilities to ensure they provided all customers with safe and reliable service at just and reasonable rates.

Government imposed a system of regulation called "rate of return" or "cost-of-service." It allowed utilities to collect sufficient revenue to meet the legitimate costs of providing service, including a fair return on necessary capital investment. Rate of return regulation produced reasonable results for many years. In the 1970s, however, high inflation, "oil shocks," and cost overruns for new generating plants, primarily nuclear, increased rates. Because rate of return regulation was based on actual utility costs, ratepayers, not shareholders, carried the business risks of those events. As a result, in the 1980s, regulators focused on "before-the-fact" reviews of utilities' activities; utility commissions began to review utility proposals to construct or purchase generating capacity and established rules for utility resource planning. Nevertheless, the ratepayers continued to carry the primary risks and benefits of power supply decisions.

In the late 1980s and early 1990s, Maine's electric rates increased significantly for two principal reasons. First, utilities were bound by contract to purchase power from qualifying facilities (QFs) at rates which were based on estimates of future costs which turned out to be too high. Second, an economic recession reduced electricity consumption, which consequently decreased the revenue available to cover the utilities' fixed operational costs. The rate increases suggested that utilities were not operating as efficiently as possible and that traditional regulatory tools, as applied in Maine, were ineffective at keeping prices low. Moreover, utilities with high rates were vulnerable to competition from different energy sources, such as self-generation and other heating fuels. In Maine and elsewhere in New England, increases in the price of electricity outpaced the increases in other regions of the country.

Maine responded by adopting price cap regulation for the electric industry.[2] The price cap approach focuses on price, not the utility's underlying cost, and relies on indices, such as the rate of inflation, to determine rate changes. Price cap regulation provides utilities with pricing flexibility to meet competition and transfers more of the business risks away from ratepayers and onto shareholders. Price cap regulation has delivered predictable and stable prices to ratepayers. For utilities, it has created incentives to minimize cost and allowed some flexibility to compete for current and new customers.

b. Development of competition

Competition in the generation market began when Congress enacted the Public Utility Regulatory Policies Act of 1978 (PURPA). That legislation was Congress's response to a series of oil embargoes by the OPEC nations and to forecasts that the world was rapidly depleting known oil reserves. PURPA encouraged cogenerators and small power producers to produce energy

[2]The Maine Commission was the first to adopt comprehensive price cap regulation for electric utilities. The approach is common in the telephone utility industry.

efficiently and using renewable fuels.[3] The PURPA requirements advanced a non-utility independent power industry that proved entities other than utilities could provide electricity reliably. New technologies suggested that electric generation did not have significant economies of scale and could be delivered in a competitive market.

A competitive wholesale market developed in which independent power producers and utilities in New England and Canada competed to provide power to retail utilities. For example, the Maine PUC required utilities to buy the power needed to serve their customers through a competitive bid process. However, because utilities that owned transmission were not generally required to allow competitors to use their systems, competition in the wholesale markets was not robust. Further, the pricing of transmission distorted the wholesale market. To encourage more effective competition in wholesale generation markets, Congress enacted the Energy Policy Act of 1992 (EPAct). EPAct broadened the class of independent power producers and required utilities that owned transmission to allow competitors to use their systems for wholesale transactions.

Pursuant to EPAct, the Federal Energy Regulatory Commission (FERC) adopted rules to promote competition in wholesale markets.

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[3]Cogeneration refers to the use of excess thermal energy, generally produced as a result of manufacturing processes, to generate electricity. Small power production relies on renewable resources such as hydro and biomass as the primary source of fuel.

FERC Order No. 888 (April 24, 1996). FERC required transmission utilities to provide competitors the use of their system, for wholesale transactions, on terms comparable to what utilities provide themselves. FERC also required all utilities to file "open access" transmission rates.[4] In addition, New England utilities and others are developing a transmission pricing system to create uniform prices and terms for transmission throughout the region.[5] The goal of these Federal and regional efforts is effective competition in the wholesale market.

Currently, electricity prices in the wholesale market are low, due in part to excess generating capacity in New England. The excess capacity is the result of utilities preparing for an increased need for power that never occurred due to the recession in the early 1990s. New England's low wholesale prices, contrasted with high retail prices, have increased pressure to deregulate the retail market.[6]

2. Retail Competition

a. Description

A cornerstone of restructuring is to allow customers to choose their power provider. Once customers can purchase power in the

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[4]These filings are currently under review by FERC.

[5]Regional matters are discussed in section VIII, below.

[6]NEPOOL currently projects that the regional surplus of generating capacity will end in approximately 2000. As surpluses in generating capacity diminish, the price for electric power at the wholesale level is likely to increase.

competitive market, the Commission would not regulate, as public utilities, entities that sell power. The Commission would regulate entities that own transmission and distribution facilities ("T&D utilities"). However, the T&D utilities would no longer buy power for their customers. Customers would have the option to buy power directly from power suppliers or from intermediaries such as a load aggregators, power marketers or energy service companies.

The Commission would regulate as public utilities the companies providing T&D services because they would continue to have natural monopoly characteristics.[7] The T&D utilities' rights and obligations would mirror many of those of traditional utilities. For example, T&D utilities would have exclusive service territories and an obligation to connect customers, with wires and other facilities, to the regional electric grid.[8] T&D utilities would have to provide reliable and safe service at regulated rates. Supplying power reliably depends on distribution line maintenance and regional grid operation. Because a regulated T&D utility would maintain the distribution system, restructuring should not adversely

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[7]There may be components of distribution service (e.g., metering) that could be unbundled and provided by competitive markets. Our plan neither proposes nor precludes any such unbundling of distribution services in the future.

[8]As a matter of physics, electricity generated by or for a retail provider is not actually consumed by its retail customer. Instead, all generators in the region place electric power on the grid that is simultaneously consumed by all end use customers on the system. As a result, retail competition only allows for financial transactions involving the obligation of providers to place specified amounts of electric power on the regional system to meet the demands of their retail customers.

affect its reliability. Restructuring may, however, affect the reliability of the regional grid.[9]

The T&D utilities would provide their services separately from the companies providing power; customers would no longer buy T&D services and power packaged or "bundled" from one company. Customers would pay T&D utilities regulated rates and pay power providers rates set by the market.[10] Each would charge customers separately; however, T&D utilities and power suppliers could contract to include both charges in one bill. This practice is common in the telephone industry, where local exchange companies' bills often include the charges of unaffiliated long distance carriers.

The Commission would establish the T&D utilities' retail rates and rate design.[11] T&D utility regulation is likely to occur through performance based regulation, such as price caps, not rate of return-based regulation.

Although some commenters expressed varying degrees of caution regarding the restructuring process, there is general support for customer choice at the retail level.

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[9]This matter is discussed in section VIII, below.

[10]Customers that do not choose a competitive generation provider would take service under the standard offer. This service is discussed in section IV, below.

[11]To the extent a separate or unbundled retail transmission rate is established, FERC has indicated that it has jurisdiction to determine the rate. FERC Order No. 888 (April 24, 1996).

b. Benefits, risks and uncertainties

Allowing customers to choose their power supplier should create significant benefits to Maine and its consumers. Wholesale competition holds the promise of lowering the cost of producing power. Retail competition, however, will dramatically increase the number of buyers in the power market. This increase alone should spur even greater efficiencies (and lower prices) in power production. Economists generally agree that competition works best when there are many buyers and many sellers. Creating a direct market relationship between many sellers of power and many buyers should also lead to creative service offerings: better reliability for a premium price, for example, or less reliable service at a discount. Customers will also have the opportunity, either alone or through associations or brokers, to negotiate credit and risk management instruments better tailored to their needs than the products that are generally available under regulation.[12]

Just ás important, for Maine in particular, retail competition and the deregulation of power production would transfer business risks associated with power generation away from ratepayers and onto investors. Shareholders, not ratepayers, would suffer financial loss if the plants they build, or

[12]As the industry is restructured, some amount of additional price volatility can be expected as a natural consequence of moving away from a regulated environment. Customers should, however, have tools available to them to limit that volatility, much as purchasers of home heating oil do today.

the contracts they execute, lose value due to changes in the marketplace. Companies that make wise business decisions will thrive, while those that make poor decisions may fail.[13] No matter what companies win and what companies lose, Maine is likely to benefit by shifting investment risk from ratepayers to shareholders. The cost of power in Maine would be determined by the price in the regional and perhaps national competitive market and not by whether Maine's utilities or regulators predict the future accurately.

These benefits will occur provided there are effective markets and vigorous competition. Most benefits from retail competition would occur gradually over several years, from innovation and efficiencies as providers construct new plants and tailor their services to meet customer needs. Other benefits, such as lower costs from increased incentives to operate plants more efficiently, will come sooner. The size of the ultimate customer benefit is impossible to predict with confidence. At least initially, however, most of the savings will be from lower power production costs, costs that represent less than one third of today's typical customer's electric bill. While there may be savings in other areas, such as increases in transmission and distribution efficiency and

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[13]The introduction of retail competition will create winners and losers among generation providers. There are likely to be mergers and consolidations as companies seek the best ways to be competitive. As a result, the current mix of "local" and "regional" producers serving the Maine market is likely to change. This is a natural consequence of allowing competition in retail generation markets.

reductions in the amount needed to pay stranded costs,[14] these other savings are not directly related to retail competition.

No change as basic and extensive as the deregulation of power production and retail competition is free from risk or uncertainty. There is no qualitative or quantitative analysis that can prove retail competition will, in fact, reduce the total cost of producing and delivering power or whether all customer groups will benefit from cost reductions. For example, the cost of capital to finance new power production facilities is likely to rise because investors could no longer place the risk on ratepayers. Similarly, no tool exists to determine with certainty whether competition among generation providers will decrease the reliability of the electric grid. Nor can we predict with complete confidence whether sufficiently robust markets will develop to avoid anti-competitive behavior, or whether prices will become too volatile. It is possible, but not certain, that funding for research and development of generation technologies will decrease.[15] There is also a risk that retail competition could initially create customer confusion about pricing and new options, limiting the extent to which many customers could

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[14]Stranded costs are discussed in section VII, below.

[15]Traditionally, research and development (R&D) of generation technologies occurred, to a large extent, through the Electric Power Research Institute (EPRI), an organization funded by utilities and their ratepayers. With the deregulation of generation, EPRI is likely to reduce or eliminate generation R&D. The extent to which unregulated entities will devote resources to generation R&D is unknown.

benefit. On balance, however, it is reasonable to conclude that retail competition will be more beneficial to consumers than regulation.

c. State and local economies

Expanding the power market and allowing customers to select their power supplier could improve Maine's economy. Retail competition could improve Maine's business climate by reducing electricity rates below where they would be under the current form of regulation. As importantly, retail competition and the deregulation of power suppliers should reduce the disparity between Maine's rates and those in other states. Maine's rates, like those throughout New England, are significantly higher than those in other regions.[16] Expanding the market from which retail customers can buy power and reducing the price impact from specific regulatory decisions should move Maine's rates closer to the national average. Allowing Maine companies the opportunity to purchase power at prices comparable to those elsewhere, and thus compete more effectively, would improve Maine's ability to attract and retain businesses.

Deregulating power production could affect local economies as well. Clearly, municipalities would benefit from moving their own

[16]Areas such as the South and Northwest have relatively lower rates due in part to federally subsidized hydro-electric projects (e.g., Tennessee Valley Authority, Bonneville Power Administration) and the close proximity of relatively inexpensive coal, oil and natural gas.

power costs closer to the national average. Their economies would also improve if local businesses and residents achieved similar savings.

Deregulation would, however, have tax implications for municipalities with power production facilities in their tax base. Deregulation would change the way in which municipalities assess the value of those facilities, and thus the associated property tax assessments. Specifically, municipalities often base property tax assessments of power production facilities on book or accounting value as a proxy for market value. When power production facilities are no longer owned by a regulated utility, they will likely have a readily identifiable market value. The market values, and consequently tax assessments, could be higher or lower than those based on book value. Also, power production facility owners would have a greater incentive to pursue lower tax assessments than did regulated utilities, which passed tax increases on to ratepayers.[17] Municipalities should anticipate these property tax implications. If the competitive market creates an immediate, disproportionate and negative tax effect on some communities, the Legislature could act to mitigate the level and pace of tax consequences.[18]

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[17]In Maine, this change in incentives should not be dramatic, because under the regulatory methods and commitments already in place for Central Maine Power Company, Maine Public Service Company, and Bangor Hydro-Electric Company, changes in tax assessments <u>already</u> flow almost entirely to shareowners rather than ratepayers.

[18]For example, the Massachusetts Legislature considered a bill to compensate municipalities for any loss in property tax revenue that may result from a devaluation of electric generation facilities due to the restructuring of the electric

Deregulating the production and sale of power could affect Maine's paper and biomass industries. Because paper companies consume vast amounts of power, lower rates and diverse services and products would, over the long term, decrease their production costs and improve their financial health. Maine's paper companies' ability to compete successfully within their industry influences their ability to preserve and create Maine jobs. Besides consuming power, paper companies generate power from cogeneration and hydro facilities and sell it into the wholesale market. Maine also has a substantial biomass industry that produces renewable power and provides a market for the waste from Maine's wood products sector. Many paper companies and biomass generators have contracts to sell to utilities that power at prices well above the market rate. Nothing inherent to restructuring justifies abrogation or involuntary modification of contracts. However, when the contracts expire, the paper companies and biomass generators would lose the guaranteed buyer for their power. This is not a result of competition; under current regulation, the contracts have little, if any, chance to be renewed at current rates. While these companies would likely have an opportunity to sell power into the regional market, market prices would probably fall below current contract rates. Some customers may, however, be willing to pay a higher price for renewable or environmentally benign power. Ultimately, the long term

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industry. The Massachusetts Legislature has not taken any final action on the bill.

benefits of competition for all companies should outweigh the loss of benefits in the near term for those companies with large contracts.

d. Rural electricity consumers

Retail competition should offer rural and urban customers comparable benefit. Some commenters questioned whether competition would harm residents in rural Maine. The restructuring principles that guided our decisions reflect our concern about rural residents. Specifically, we believe all consumers should have a reasonable opportunity to benefit from retail competition.

Price disparities between rural and urban customers are unlikely for two reasons. First, a substantial portion of each customer's bill would be for T&D services that are price regulated and location blind. Second, a customer's location is largely irrelevant to power suppliers absent significant transmission constraints; these do not disproportionately affect rural areas.

3. Timeframe for Retail Competition

All customers should have the opportunity to choose a power supplier on January 1, 2000.[19] Most commenters, and the Paradigm,[20] concurred with that date.

Beginning retail competition in January 2000 has several advantages. Maine would have an opportunity to observe successes and failures in other states. Several New England states currently intend to implement retail competition, for some or all customers, in 1998.[21] Waiting until 2000 should provide the opportunity to assess whether viable markets develop and whether the mechanics for retail competition will be successfully designed and implemented.

A 2000 start date would also allow critical regional initiatives to be completed and tested. Such initiatives include creating an independent system operator of the transmission grid, agreeing on rules for transmission access and

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[19]The Commission would have the authority to delay or accelerate the beginning of retail competition by up to 90 days if necessary for administrative or technological reasons. A change in the start date by more than 90 days would require legislative action.

[20]In this document, the "Paradigm" refers to the "Paradigm for Restructuring Investor-Owned Electric Utilities: A New Industry Structure," a restructuring plan that was supported by eight members of the Work Group on Electric Industry Restructuring. The eight members of the Work Group that presented the Paradigm are: American Association of Retired Persons, Senator John Cleveland, Conservation Law Foundation, Independent Energy Consumers Group, Independent Energy Producers, Representative Carol Kontos, Office of the Public Advocate, and Pine Tree Legal.

[21]These states are Rhode Island, New Hampshire, Massachusetts and Vermont.

pricing, and reforming the New England Power Pool (NEPOOL) to include new power suppliers.[22] Without the successful execution of these regional changes, fair and effective competition is unlikely to develop in Maine. The Commission would carefully monitor regional developments and ask the Legislature to delay beginning retail competition if necessary regional mechanisms are not working successfully.

The timeframe for beginning retail access also provides significant benefits for addressing stranded costs. Within a few years, the amount of stranded costs in Maine will diminish significantly. This should lessen the controversy over stranded cost recovery, and, more importantly, reduce the risk of projecting and calculating such costs erroneously. The greatest calculation risk of stranded costs is estimating the market value of utility generation assets and power contracts. Valuing assets and contracts later will provide an opportunity to observe transactions in the emerging markets, such as the sale of generation assets. Moreover, because litigation over stranded costs is possible, a later start date may allow Maine to watch costly litigation in other jurisdictions before committing to a specific stranded cost treatment.[23] That experience could reduce the potential for delay and uncertainty inherent in litigation in Maine.

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[22]These matters are discussed in more detail in section VIII, below.

[23]Such litigation appears likely in New Hampshire.

Another advantage to beginning retail competition in 2000 is to allow customers time to become educated about their role in a restructured industry. The success or failure of retail competition will not turn on whether a few will navigate well through a proliferation of choices, options and services, but on whether the public as a whole does the same. In short, ratepayers must become effective consumers for choice to be meaningful. That will take time and considerable effort.[24]

Finally, restructuring in 2000 corresponds with the conclusion of Central Maine Power Company's (CMP) Alternative Rate Plan (ARP). Coordinating the end of the ARP with the beginning of retail choice would obviate the need for complex regulatory proceedings that would arise if retail competition began later. Similarly, the year 2000 generally coincides with the end of Maine Public Service Company's (MPS) current rate plan and Bangor Hydro-Electric Company's (BHE) pricing flexibility plan.

Enron Capital and Trade Resource, National Independent Energy Producers, Alliance to Benefit Consumers, and Conservation Law Foundation argued that retail competition should begin earlier. They suggested that by waiting until 2000, Maine customers will not benefit from competition for several years. We agree that deferring retail competition until 2000 creates the possibility that Maine customers will receive the benefits of retail choice, either real or perceived,

[24]Customer education efforts are discussed in section V, below.

later than in other jurisdictions. As noted, some New England states currently intend to allow retail competition for at least some customers in 1998. However, because the cost of power is only a portion of current electric rates, and the efficiency gains of competition will occur over time, it is unlikely that retail competition will substantially and immediately reduce total rates, absent some form of cost-shifting.[25] In any event, if there are significant immediate benefits from retail competition achieved by another means elsewhere, Maine should, and could, accelerate retail choice.

MPS, Eastern Maine Electric Cooperative (EMEC), and Madison Paper Industries recommended that Maine set certain conditions before introducing retail competition, such as the existence of mechanisms to ensure regional reliability and proof of a viable competitive market. We agree in principle, but disagree with their proposed remedy.

Specifically, we concur that solutions to regional issues are necessary for a robust retail market. But we believe that waiting until 2000 will afford Maine the opportunity to observe the regional solutions at work and decide then whether they suffice to protect consumers. Similarly, we concur that market power would frustrate the ability of competitive pressure to lower rates. But to

[25]The efficiencies and innovations that should result from retail competition will develop over time. The shifting of costs from ratepayers to shareholders or among ratepayer groups is in no sense an "efficiency gain" from competition. It is simply a transfer of dollars.

identify conditions now, without the benefit of retail competition experience in any other state, would require the Commission to predict, rather than accurately evaluate, the market's development. Accordingly, the Commission would complete a market power study in December 1998. If the findings reveal a level of market power that would frustrate competition, the Commission would recommend the Legislature modify Maine's approach.

MPS proposed that retail competition begin later in 2000 because stranded costs associated with its Wheelabrator-Sherman contract will be significantly lower by then. We disagree. There is no need to link retail competition to its contract. The stranded cost treatment we propose would give MPS a reasonable opportunity to recover its purchased power costs stranded by retail competition. Customers in MPS territory would pay the costs through a stranded cost charge. MPS's proposal would have the same customers pay the same costs in their bundled electricity rates. This "distinction without a difference" does not justify delaying MPS's customers' opportunity to choose a power supplier.

4. Customer Access and Options

a. Simultaneous access

Beginning January 1, 2000, all customers, regardless of size, type or location, would have the opportunity to choose a power supplier. Allowing all customers to choose a power supplier at the same time is fair and should bring the full benefits of competition to Maine sooner than a phase-in approach. Most commenters, and the Paradigm, agreed that all Maine customers should have choice simultaneously. The approach follows the restructuring principle that all customers should have a reasonable opportunity to benefit from a restructured industry.

Several utilities suggested that allowing choice to all customers at once could present logistic problems, such as difficulties in developing and running new billing programs. The utilities did not present specific information to support that assertion. The start date of January 1, 2000, however, should provide sufficient time to resolve the logistic problems associated with simultaneous retail access for all customers. In the event experience in other jurisdictions reveals practical problems of allowing all customers choice at once, the Commission could stagger the start dates.

MPS and EMEC proposed to phase-in retail competition and require small commercial and residential customers to take service from the standard offer as a means to reduce customer confusion. Specifically, MPS proposed that these customers take standard offer service until 2006. We reject the proposal and disagree with the rationale. We do not share the assumption that all residential and small commercial customers will be "confused" by the opportunity to choose suppliers. Consumers who may be confused by the market should not prevent consumers who are not from choosing a supplier. Moreover, a phase-in approach could increase customer confusion and complicate public education efforts. In any event, standard offer service, as an option, would be available to counter any customer confusion.

b. Available options

The Commission would not proscribe or limit market options. For example, customers and power suppliers could enter bilateral contracts of any duration and on any terms. Customers could also purchase on a shorter term "spot market," using a power exchange.

Customers could aggregate at will. "Aggregation" is the organization of customers into groups to purchase power at more attractive prices and terms than an individual customer could get alone. Aggregation will likely be an important means for small customers to obtain more attractive prices in the near term; larger demand generally increases buying power, and provides opportunities to create attractive load characteristics. Therefore, aggregation may give residential customers and small businesses who might not fall in the marketing mainstream prices comparable to those offered to large users.

Customer aggregation may occur in many ways. For example, municipalities could aggregate residents' load.[26] Trade organizations could aggregate their members' load. Customers could organize into buyer

[26]Customers in a town could choose alternate suppliers even if a municipality decides to aggregate load on behalf of its residents. A municipality would have to seek legislative authorization to restrict consumer choice.

cooperatives. Finally, electricity marketers could combine individual loads and offer lower cost power.

As part of the public education before retail competition, the Commission would inform customers, customer groups and municipalities about aggregation. Customers who understand their options are a critical component of effective competition.

c. Special meters

Special meters should not be a precondition for allowing retail competition. Some commenters suggested special meters, which measure customer demand and usage in small time increments, may be necessary for bilateral arrangements and other benefits of retail competition. However, there is no evidence that this is a necessary precondition to successful retail competition. The use of average load curves or other estimated usage data should be a workable alternative to special meters. Such an approach should allow generation providers to market services that do not require special meters. Other states' experience should reveal any issues about special meters that are not apparent at this time.

Some power suppliers may require that their customers have particular meters or may provide them as part of their service.[27]

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[27]The cost of special meters has been dropping in recent years and is likely to continue to do so. Applied Resources Group stated in their comments that reasonably priced load profile meters are likely to be available by 1998. BHE suggested that necessary meters entail a substantial cost, while the Maine Municipal Utilities Group (MMUG) stated that the necessary technology does not

Alternatively, some customers may find that certain meters minimize power costs by, for example, targeting purchases to low cost hours. Ultimately, the market would decide if customers need special meters.

5. Reciprocity

The Commission would not require that other states or Canadian provinces allow retail competition in their jurisdictions as a condition to permitting suppliers from those states or provinces to enter Maine's market. Maine customers should have the opportunity to purchase diverse products and services from any supplier in any location. The number of suppliers in the market directly affects the level of competitive pressure on rates.

Utilities have proposed a reciprocity requirement to prevent power suppliers from states that have not authorized retail competition from competing in Maine. They rest their proposals on the need to mitigate revenue losses, and possibly reduce stranded costs. We disagree that reciprocity should be required. Retail competition should begin in Maine when there is a viable, functioning electricity market. The utilities (or, more precisely, the companies who acquire the generation now owned by Maine's utilities) will continue to be able to sell into the wholesale market and the retail market at prevailing prices. That we reject a reciprocity requirement does not diminish those opportunities.

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exist unless load is aggregated on a geographic basis.

The independent power producers (IPPs) suggested a reciprocity requirement to prohibit out of state power suppliers from selling subsidized power in Maine. An example of such power is that available from the quasi-governmental utility structure in Canadian provinces or from states that do not allow retail competition. The IPPs claimed such a requirement is necessary to ensure fair competition among power suppliers. We disagree. To the extent other states or the Canadian provinces allow their ratepayers to subsidize power sold in Maine, consumers here will pay less, at least in the near term. The use of such subsidies in a way that develops market power and forecloses competition is not likely to be sustainable. Moreover, the Commission could not identify with any confidence which power suppliers selling in Maine are subsidized in other jurisdictions. Finally, to the extent any generation provider believes a subsidy exists that is anti-competitive, it may seek a remedy in the courts.[28]

Moreover, reciprocity requirements have legal implications for interstate and international transactions between Maine's customers and providers in other states or the Canadian provinces. Attempts to condition entry into the Maine market upon reciprocal treatment by other states would likely be subject to court challenge on constitutional commerce clause or other bases. A reciprocity requirement could be considered economic protectionism of in-state power

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[28]Once generation services are no longer subject to price regulation, any currently-existing immunity from the anti-trust laws would effectively disappear.

producers. Such a requirement would burden interstate commerce and discriminate against competitors located in states that have not adopted an electric industry model acceptable to Maine. In cases where states have attempted to limit or burden interstate commerce for the purpose of "simple economic protectionism," the Supreme Court has established "a virtually *per se* rule of invalidity." *Philadelphia v. New Jersey*, 437 U.S. 617, 624 (1978). Even if it were determined that the purpose of the reciprocity requirement were not simply the protection of private in-state economic interests, such a requirement would still need to pass muster under the balancing test enunciated in *Pike v. Bruce Church*, Inc., 397 U.S. 137 (1970). This test requires that a legitimate local purpose outweigh the burden on interstate commerce. *Id.* at 142. The Court, however, views state reciprocity requirements for trade in other commodities unfavorably. *See Sporhase v. Nebraska ex rel. Douglas*, 458 U.S. 941 (1982); *Great Atlantic and Pacific Tea Co., v. Catrel*, 424 U.S. 366 (1970).[29]

C. Further Proceedings

The Commission would implement retail competition and deregulate power suppliers with caution and flexibility. The Commission would watch closely

[29]Some have raised questions regarding the impact of the North American Free Trade Agreement (NAFTA) on reciprocity issues and access by Maine providers to Canadian markets. Basically, NAFTA provides for equal treatment of United States and Canadian producers. For example, if it were lawful for Maine to have a retail access reciprocity requirement, the requirement could be applied to Canadian providers.

restructuring in other states and participate in processes on the regional and Federal levels to inform its implementation proceedings. If it appears that retail competition should be delayed or accelerated, or that other modifications are warranted, the Commission would, on its own motion or at the request of an interested party, initiate an investigation. All interested parties would have an opportunity to be heard. If the Commission finds that any provision of the restructuring legislation is not in public interest, the Commission would report to the Joint Standing Committee on Utilities and Energy explaining the basis for the conclusion so that the Legislature could consider modifying Maine's approach.

The Commission would establish the revenue requirements that the T&D utilities would be allowed to recover from ratepayers for their services. The Commission would also determine the appropriate design of rates for each T&D utility. While the Commission has traditionally set rates for vertically integrated utilities, these proceedings would also require that the T&D costs and rates be separated from the generation-related costs of the utility. Once the T&D utility's revenue requirement and rate design are determined, a price-cap plan or some other form of incentive regulation could be adopted to provide the T&D utilities with efficiency incentives and to provide ratepayers with stable and predictable rates.

Significant issues to be determined in these proceedings are likely to include cost of capital, the value of any assets transferred to the generation subsidiary or other entity, rate design and marginal cost of service, and the proper form of regulation for T&D utilities.

III. CORPORATE STRUCTURE AND DIVESTITURE

A. Recommendation

By January 1, 2000, Maine's investor-owned utilities (IOUs)[30] would transfer all generation-related assets and activities, including all electric energy sales activities, to corporations distinct from their transmission and distribution (T&D) businesses. After this date, investor-owned T&D utilities could engage in generation-related businesses only through a separate corporation. Maine's consumer-owned utilities (COUs)[31] would not separate generation from T&D. Contractual obligations between qualifying facilities (QFs) and electric utilities would remain with the T&D utilities; however, by January 1, 2000, Central Maine Power Company (CMP) and Bangor Hydro-Electric Company (BHE) would sell the rights to the capacity and energy associated with their QF contracts. Maine Public Service Company (MPS) would transfer these rights to its generation affiliate.

By January 2006, CMP and BHE[32] would divest their generation assets and related functions. The remaining T&D utilities would not be affiliated with any company that owns generating facilities or sells power. T&D utilities would maintain their contracts with QFs and could own small, distributed generation facilities installed to minimize distribution costs. MPS could maintain an

[30]Maine's IOUs are CMP, BHE and MPS.

[31]COUs are municipal or quasi-municipal electric utilities and electric cooperatives.

[32]When referring to the period after December 1999, the terms "CMP" and "BHE" refer to those two companies' continuing T&D utility entities.

affiliated generation company after 2005, but only to provide retail service in its territory. MPS's affiliate would not be permitted to construct or acquire ownership interest in generating facilities, and would be permitted to make only wholesale sales incidental to reducing costs of its retail service.

Maine's utilities would not be required to divest their ownership in Maine Yankee unless the plant's operating life extends significantly past 2008. To the extent they retain ownership after 2005, CMP and BHE would be required to sell the rights to power associated with that ownership. MPS's Maine Yankee entitlement would remain with its generation affiliate. T&D utilities would retain the liability for nuclear plant decommissioning costs.

After December 1999, T&D utilities could modify QF contracts but could not extend the term of any contract or increase purchases pursuant to any contract. Consistent with the prohibitions of T&D utility power production and sales, T&D utilities could not enter new contracts with QFs after December 1999.

CMP and BHE would transfer the rights to power they now hold under contracts with QFs through competitive bidding. CMP and BHE would complete the bidding in time to transfer all such power effective January 2000. To protect against the risk of changing market prices, CMP and BHE would periodically resell these rights.

COUs would not be required to divest, or structurally separate, generation from T&D and could continue to construct and own generation facilities,

and purchase and sell electric power. After 2005, COUs could market electric power only within their franchise territories, and could make only wholesale sales incidental to reducing costs of their retail service. The Commission would limit the investments in and purchases of power to those necessary to serve the COUs' own customers.

B. Discussion

1. Need for Divestiture

a. Power production and sales

BHE and CMP would be required to divest their generation assets, except Maine Yankee, by 2006. After divestiture, companies that own generation facilities would have no affiliation with BHE and CMP. BHE and CMP would also be prohibited from selling power. These requirements would ensure effective competition in the retail market by reducing the T&D utilities' opportunities to exercise market power.

Market power exists when one company can gain an advantage over competitors through its affiliation with the provider of a related service. If a T&D utility is affiliated with a power provider, the T&D utility would have the incentive and the ability to use its monopoly position in the T&D market to favor its affiliate. Favoritism could take the form of "self-dealing" (i.e., favoring the affiliate when purchasing services), steering customers toward the affiliate, or giving the affiliate preferential access to information or T&D services.

Common ownership of power production facilities and T&D is an impediment to effective competition. Removing the impediment through divestiture, however, has costs. First, divestiture would impose transaction costs including fees for investment bankers, attorneys, accountants and other expenses. Next, divestiture creates the risk that T&D utilities, and their ratepayers, will not realize the full value of the assets because many generation assets could be on the market simultaneously, or because the divestiture occurs when market values for power production facilities are low. Accordingly, utilities would have flexibility to plan and carry out divestiture over several years, and the responsibility to minimize divestiture-related costs and risks.

Despite the costs and risks, the benefits of CMP's and BHE's divestiture of their generating assets predominate. Effective competition among generation providers is critical for consumers to benefit from a right to choose suppliers. Effective competition depends, in large part, upon the T&D utility being a neutral link between power providers and customers. Ordering divestiture and prohibiting the T&D utility from selling power into the retail market are necessary to ensure the T&D utility serves as that neutral link.

Non-utility commenters, including the Office of the Public Advocate (OPA), Conservation Law Foundation (CLF), independent power producers (IPPs), and marketers agreed divestiture is needed to ensure the market works effectively and efficiently. The Paradigm recommended divestiture for Maine's IOUs. In addition, CMP has stated its intent to divest before 2000.

BHE, MPS and Eastern Maine Electric Cooperative (EMEC), however, believe divestiture is unnecessary. They argued that functionally separating generation from T&D, and creating separate subsidiaries or affiliates under a holding company structure would suffice. They suggested that regulatory oversight of affiliate transactions would prevent market abuse.

For several reasons, we believe structural separation alone is inadequate. First, structural separation would require continued regulatory oversight, which would depart from the restructuring principle that, where viable markets exist, market mechanisms should be preferred over regulation. Ensuring arms-length transactions in a competitive market would protect customers more effectively than regulating affiliate conduct. Reviewing, in the regulatory process, the details of multiple and complex affiliate transactions would be cumbersome, litigious, and expensive. Ultimately, it would protect consumers less effectively than the direct price discipline of a competitive market. Divestiture would allow competitive forces to replace regulation as the guarantor of arms-length dealing.

Second, affiliated companies' incentives to take advantage of joint ownership of power-producing and T&D facilities are identical to the incentives in a vertically integrated utility. In fact, the incentive for abuse in the affiliate model may be greater than the incentive in the vertically integrated utility model under traditional regulation because there would be no limit on the profit from power sales. At the same time, regulators' ability to detect and remedy such conduct would diminish. Specifically, under a subsidiary structure, there are schemes that favor the unregulated generation company at the expense of the T&D utilities' customers. These include using capital structures to subsidize higher risk, non-regulated enterprises; "creative" accounting for shared costs; preferential access to T&D customer information and records; insufficient reimbursement to the regulated T&D utility for personnel transferred to the unregulated subsidiary; expansion, or refusal to expand, the transmission and distribution systems to the benefit of affiliated generation companies over other competitors; and preferential bundling of ancillary services. Such activities are difficult and expensive to detect and correct through regulation or anti-trust litigation.

The utilities argued that even if T&D utilities are prohibited from owning generation, they should be allowed to sell power to retail customers. We disagree. Permitting T&D utilities to sell power would create the same problems as allowing them to own assets or companies that produce power. A T&D utility would have the same incentive and ability to favor its sales affiliate or partner.

To support its argument that T&D utilities should be allowed to sell power to retail customers, BHE described the benefits it could give customers by virtue of its knowledge of customers' needs. BHE's comments, however, merely emphasize the risk of allowing the T&D utility to sell retail power. BHE's knowledge of, and relationship with, customers results from its public utility status; using those to advantage its own power sales is precisely the kind of unfair advantage in the market that no seller should have. Whatever useful customer information the utility developed by virtue of its public utility status should be available to all competitors in the market.

T&D utilities should continue to develop services, information and customer expertise to deliver energy most efficiently to customers of all energy providers. But transmission, distribution, voltage regulation maintenance, and other core services[33] must be available without undue discrimination to all customers and to all energy providers to create and maintain an effective competitive energy market.

BHE and others suggested that regulation could resolve issues arising from T&D utility involvement in selling energy to retail customers. Again, we disagree. Regulation would not work any better over a T&D utility retail power sales operation than it would over a T&D utility power generation operation. Also, creating the need for more regulatory oversight contradicts the principle that, where viable markets exist, market mechanisms should be preferred over regulation.

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[33]T&D utilities may develop services which are largely unrelated to their core regulated activities. In such cases the T&D utility would have no obligation to offer such non-core and non-regulated services to all customers or energy providers.

The Commission would retain authority to allow T&D utilities to acquire or continue to own small, distributed generation facilities when that ownership would minimize distribution system costs. The Commission would consider approving acquisitions case by case. The T&D utilities would not be allowed to sell power at retail from a distributed facility, and all revenue from sales at wholesale would flow to the T&D utility.

b. Other services

There would be no blanket proscriptions of T&D utility involvement in unregulated businesses. Except for power-related operations, the issue of unregulated activities is separate from retail competition. Questions about the range of services T&D utilities should be allowed to provide and the types of subsidiaries and affiliates they should be permitted to form cannot generally be answered in the abstract. The Commission would, for the most part, consider those issues as they arise in the same manner as it does today.

2. Authority to Order Divestiture

Historically, the generation, transmission and distribution of electricity were considered natural monopolies requiring comprehensive regulation to protect customers. Public utility regulation thus covered the range of utility actions, including the purchase or construction of major generation or transmission projects; the creation or dissolution of subsidiaries and affiliated interests; oversight of affiliated and insider transactions; bond issues, share offerings and other financial transactions; and rates. In addition, the State determined utilities' service territories.

Restructuring rests on the premise that electric generation is not a natural monopoly and should not be provided and regulated as such. However, T&D remains a natural monopoly service and would be regulated accordingly. Under current law, the Commission must approve utility proposals to build, purchase or invest in new generating sources, or to enter into significant contracts for power. In *Public Utilities Commission, Re: Investigation of Seabrook Involvement's by Maine Utilities*, 67 PUR 4th 161 (MPUC, 1985), the Commission found it had the authority to order Maine utilities to divest their interests in a nuclear power plant. The Commission has also denied utility proposals to purchase or construct power plants. Whether or not the Commission has current statutory authority to order complete divestiture, however, it is clear that the State, through the Legislature, may order divestiture or delegate that authority to the Commission.[34]

Some commenters suggested that mandatory divestiture may violate the takings clause of the United States Constitution. On the contrary, the United States Supreme Court found mandatory divestiture of utility assets under the Public Utility Holding Company Act (PUHCA) § 11(b)(1) does not violate that

[34]For an analysis of the State's authority to order divestiture, *see* Responsive Comments of OPA, filed on September 13, 1996 in Docket No. 95-462.

clause. *See North America Company v. SEC*, 327 U.S. 686 (1946). State-ordered divestiture raises no constitutional issues different from those addressed by the Court in *North America*. Moreover, although the takings clause could be implicated if forced divestiture resulted in a substantial reduction in the value of investors' holdings in the utility, the Commission would allow investors the same opportunity as they have now to recoup the value of their holdings though the stranded cost charge and the fair determination of the value of divested assets.

3. Process for Divestiture

CMP and BHE should have the flexibility to complete divesture over several years. Therefore, the Commission would permit a two-step process. First, by January 2000, CMP and BHE would transfer their generation assets, entitlements, and related activities to companies structurally separate from their transmission and distribution businesses. The Commission would determine, prior to retail competition, the degree of separation necessary to protect T&D ratepayers and the competitive market. Second, by January 2006, CMP and BHE would divest these assets, entitlements and activities. CMP and BHE could propose to divest some or all generation earlier. This flexible, two-step process would reduce the risk of the T&D utilities, and ratepayers, receiving too little value for these assets, and thus help reduce stranded costs.

The OPA, the IPPs, and the Industrial Energy Consumers Group (IECG) argued for divestiture to occur sooner, on the grounds that T&D utilities could behave, before 2006, in a way that would hinder the development of a healthy competitive market. The IPPs and IECG proposed no phase-in period; the OPA proposed divestiture by 2004. We are persuaded that the likely benefits, in the form of lower stranded costs, of a longer period with flexibility outweigh the likely harm to competition during the transition. The concerns raised by these commenters, however, underscore the need for Commission oversight of utility affiliate transactions during the pre-divestiture period.

4. Separation of Qualifying Facilities and Maine Yankee Power

a. Qualifying facility contracts

Contracts between IOUs and QFs would remain with the T&D utilities. BHE and CMP would periodically sell their output to the QF power to the highest bidders. This periodic bidding would help reduce errors in estimating stranded costs. MPS would transfer the output of its QF contract to its generation affiliate.

The nature of the contracts between QFs and utilities distinguishes them from other generating assets. The parties entered the contracts pursuant to Federal and state policies. That the payment obligations rest with utilities is a material term of the contracts. Nothing inherent to restructuring requires abrogating that term. QF investors would continue to have the opportunity to obtain their revenues from a regulated utility.

Placing the QF contracts with the T&D utility, coupled with periodic bidding for the power, also reduces the risk that stranded costs relating to these contracts would be estimated incorrectly. If the T&D utility divested the QF contracts, they would be held by entities not linked to the T&D utility by common shareholders. This means that if market conditions increase the value of power it would be difficult to recover additional value from the unregulated company holding the contract. If the estimate of value is made at the time of divestiture, therefore, and market conditions change, the T&D utility would be unlikely to be able to adjust its rates to reflect those changes.[35] By keeping QF contracts with the T&D utility, the Commission could periodically adjust the stranded cost rates to reflect changing market conditions. Likewise, continuing opportunities for renegotiation and mitigation would remain available to benefit ratepayers; these could be lost if QF contracts move to another entity.

The IECG, the IPPs, and the OPA supported this treatment of QF contracts. CMP opposed it and argued that QF contracts ought to reside with the unregulated generation company. According to CMP, QF contracts should be subject to the same risks as other generation assets. The flaw in CMP's argument is that QF contracts are <u>not</u> like other generation assets. CMP's shareowners now own the full economic value of its power plants, together with the right to any associated stranded cost recovery. Divestiture will not change that

[35]For further discussion of this issue, *see* Section VII(B)(3)(a), below.

shareowner value. If the plant is sold, shareowners will obtain the full economic value (as proceeds of the sale) plus the right to associated stranded cost recovery (if any) as shareowners of the T&D utility. If divestiture is accomplished through a stock spin-off or similar transaction, the sum of the value held by the deregulated owner of the plant and the value of the stranded cost recovery allowed the T&D utility should be no less than the value they hold today.

For QF contracts, however, there is another set of shareowners, namely those now owning the right to the revenues. If CMP's proposal is intended to reduce the certainty of those shareowners' recovery, by exposing them to additional market risk, the proposal is inconsistent with our conclusion that restructuring is not sufficient reason to change the contracts. Under CMP's proposal, the stranded cost revenues needed to pay the QFs and recovered by the T&D utility would flow to the generation company. If those revenues are sent directly to the QF owners, CMP's proposal is in all substantial respects identical to the Commission's. If they are not, the increase in risk to the QFs cannot be squared with law or equity.

b. Maine Yankee

The T&D utilities would retain nuclear plant decommissioning obligations. The utilities would not be required to divest their ownership interests in Maine Yankee, but would be required to transfer the rights to the output to an affiliated generation company. After 2005, BHE and CMP would be required to sell the rights to the output to the highest bidder.

Maine Yankee entitlements present unique issues when evaluating the value and practicality of divestiture. Maine Yankee's operating license is currently scheduled to expire in 2008, two years after the date by which CMP and BHE would be required to divest other generation assets. CMP believes that divestiture's transaction costs and other risks would not be justified given Maine Yankee's remaining license life. CMP's arguments are persuasive. If Maine Yankee's operating license is extended significantly beyond 2008, the Commission would reassess whether divestiture should be required.

Some commenters expressed concern that leaving decommissioning obligations with the T&D utility places the risk of decommissioning cost overruns on ratepayers rather than investors. They argued that if past amounts collected for decommissioning prove inadequate, ratepayers will be responsible for shortfalls. Under Federal law, however, divestiture cannot alter ratepayer exposure to this risk. FERC establishes decommissioning rates. Under the "filed rate" doctrine, state commissions cannot adjust them. The State has limited authority to place the risk of decommissioning cost overruns on investors or to protect against such overruns by increasing current or future decommissioning funds in rates.

5. Maine Public Service Company

MPS should not be required to divest its generation or be prohibited from purchasing and selling power as needed to serve customers in its service territory. MPS would, however, be required to do these activities through a separate subsidiary. After 2005, sales by MPS's affiliate outside its franchise territory would be permitted only to the extent necessary to minimize the cost of serving MPS's native load customers.

Because it is small, the transaction costs for MPS to divest could outweigh the benefits to MPS's customers. First, even though customers' purchasing option may be fewer than elsewhere in Maine, even a small number of competitors should reduce the risk that MPS could use market power to its customers' disadvantage. Second, MPS's relative isolation (MPS is not part of the New England Power Pool (NEPOOL)), raises a concern about sufficient power supply. The Commission would periodically review whether divestiture should nevertheless be required.

MPS agreed, arguing that forced divestiture might leave northern Maine without a reliable and economic generation supply. MPS also asserted that a forced sale would risk the loss of substantial value associated with its Canadian subsidiary. According to MPS, the assets of this subsidiary, principally a hydro-electric plant located in New Brunswick (Tinker Station), could be expropriated by the Province with reimbursement to MPS well below the assets' value. OPA, EMEC and others supported exempting MPS from divestiture.

The IECG disagreed with granting MPS a blanket exemption from divestiture, but would support exempting Tinker Station. IECG noted that much of MPS's generation is located outside Aroostook County, and within NEPOOL; this generation, at least, ought to be treated similarly to that of CMP and BHE. The IECG also argued that it could be beneficial to Aroostook County if restructuring made MPS less isolated from the rest of New England. On balance, it appears that divestiture's transaction costs would likely outweigh these benefits. Moreover, it is unlikely that, absent divestiture, MPS's ownership interests in Maine Yankee and Wyman 4 would be large enough for MPS to have noticeable market influence. Finally, nothing would prevent other retail power sellers from competing in MPS territory; this will allow the market to determine the extent to which MPS becomes more integrated into the New England market.

6. Consumer-Owned Utilities

COUs would not be required to divest generation assets and would be permitted to continue to purchase and sell generation to serve retail customers in their territories. COUs would have to limit power purchases to the amount necessary to serve their customers. Like MPS, after 2005, a COU would be permitted to sell outside its territory only the incidental excess power acquired to serve its native load. This limit would not modify or limit any current legal right COUs have to expand their service territories or serve new customers.

COUs are smaller and serve fewer customers than most investor-owned utilities and also have a fundamental difference of purpose and governance that warrant different treatment. Specifically, an IOU is a business managed to profit investors. COUs seek to provide the best value to their members or customers, not to earn profit for investors. COUs, including municipals and cooperatives, are directly answerable to their members or customers through political or other channels not available to customers of investor-owned utilities. The absence of the incentive to maximize investor profit, combined with direct avenues of redress for customer dissatisfaction, virtually eliminates the risk that the COUs will use their power sales activity to the detriment of their customers. Finally, although COUs may have tax or other advantages over IOUs, these advantages benefit COU customers and are unlikely to harm other customer groups.

The COUs agreed that they should be permitted to sell power. The OPA and the IPPs also agreed but would prohibit COUs from buying new generation. The Paradigm exempted COUs from separation and divestiture requirements. CMP, BHE, and MPS, on the other hand, disagreed. BHE and CMP asked whether allowing COUs to retain control of and continue to purchase generation would give them a competitive advantage. CMP claimed that today's small COUs could grow. The limits on COU generation purchases and their lack of profit incentive should, however, largely resolve concerns raised by these commenters. Absent extraordinary and unforeseen growth, the impact of allowing COUs to own and sell power either within their service territories or elsewhere is slight.

C. Further Proceedings

The Commission would conduct a proceeding, beginning in mid-1998, to establish the requirements for structural separation between the T&D utilities and their generation-related activities. The Commission would precisely define the parameters of structural separation necessary to curb market power and cross-subsidization. Issues likely to arise concerning structural separation include what codes of conduct need to be established to ensure that the separation is effective, restrictions on employee activities, accounting standards, and information and service comparability requirements. Once separation standards are established, each utility may be required to make a compliance filing.

CMP and BHE would file their plans for full divestiture prior to 2006. The Commission would review the plans and ensure their consistency with the objectives of restructuring. A primary issue in these proceedings would likely be whether the plan is reasonably designed to capture the highest possible value.

IV. STANDARD OFFER

A. Recommendation

Standard offer service would be available to all customers who do not choose a competitive power provider or who cannot obtain power in the market at reasonable terms. From the customers' perspective, the service would be comparable to that currently available from utilities. The terms of the service would be simple and understandable. The Commission would cap the standard offer rate so the cost of power and transmission and distribution (T&D) services together does not exceed the cost of electricity before retail competition. As the market matures, the Commission would reevaluate the need for the standard offer, and its structure.

The T&D utility would administer a competitive bid process to select the standard offer provider for its territory. The T&D utilities would solicit and evaluate bids and recommend a provider to the Commission. The Commission would review the process, supporting documents and finally select the provider.

Prior to the bidding, the Commission would establish terms and conditions for standard offer service, including eligibility criteria, requirements for entering and exiting the service, and credit, collection, and disconnection provisions.

B. Discussion

1. Need for Standard Offer Service

Customers would receive standard offer service if they do not elect or cannot obtain service from a competitive power supplier. Standard offer service is power supply that when packaged with T&D service would resemble service currently provided by utilities. For instance, the Commission would approve the price and service terms and the customer would receive one bill. Standard offer service departs from reliance on the market, but provides a safeguard for the public during the transition to competition. Most commenters supported some type of standard offer service.

As experience in the evolving telecommunications industry suggests, many customers may not have the immediate ability or interest to elect alternative providers of services historically provided by a monopoly. Customers opting not to choose may predominate, at least initially, in the electricity market. Other customers, for financial or other reasons, may not be able to obtain service from a competitive provider on reasonable terms. The standard offer service should guarantee that all customers have access to electricity service at a reasonable price.

Bangor Hydro-Electric Company (BHE) and the National Independent Energy Producers (NIEP) argued that standard offer service is unnecessary because the retail market should meet the needs of all customers. We are less confident that a fully competitive power market will develop immediately. Even if the market developed quickly, customers may be confused, at least initially, and make unfortunate, or even no, choices about suppliers. The service would give customers time to adapt to changes without the risk of immediate price increases.

At some point, it may be appropriate to reduce or end government intervention in the competitive market. For example, if a robust power market develops and sufficient market intermediaries emerge, a more narrow standard offer may suffice, comparable to an "assigned risk pool" in the insurance industry. As the market matures, the Commission would reevaluate the need and structure of standard offer service.

2. Provider of Standard Offer Service

a. Competitive bid

The T&D utilities would administer a competitive bidding process to select the standard offer provider in each of their territories. Selecting the standard offer provider through bidding should allow standard offer customers to benefit somewhat from competitive pressure on rates. The Paradigm advanced a similar periodic bidding approach; the Maine Equal Justice Project (MEJP), Alliance to Benefit Consumers (ABC), Coalition for Sensible Energy (CSE), Enron Capital and Trade Resources (Enron), and Maine's independent power producers (IPPs) concurred.

The utilities urged that T&D utilities provide the standard offer service and obtain power either through a bid process or other mechanisms. They believe that method is simple, would reduce customer confusion and would help them remain viable. More specifically, Central Maine Power Company (CMP) proposed that the T&D utility would provide the service on a "regulated basis" and get regulatory preapproval of significant purchasing decisions so that it would be insulated from major risks.

The IPPs proposed that T&D utilities provide the standard offer service by getting bids for portions or "blocks" of the standard offer load. The IPPs' proposal for standard offer "blocks" is similar to the decremental avoided cost process used previously in qualifying facilities (QF) bidding.[36] The IPPs claimed that approach is essential to allow small power producers an opportunity to compete for part of the standard offer load.

The issue is whether the market should decide who provides standard offer service or whether the Commission should create a scheme that follows present practice by granting the T&D utilities the right to offer the service with regulatory oversight. One principle that guided our decision making was that where viable markets exist, market mechanisms should be preferred over

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[36]In prior years, the Commission determined electric utility avoided costs in blocks of capacity referred to as "decrements." The utilities then went out to bid for blocks of power from independent producers, primarily QFs, for each decrement capped at the avoided cost.

regulation. We believe for several reasons that the market would do a better job than regulators selecting the provider.

First, the bid process would declare as the standard offer provider the entity that can best combine supply resources and offer the lowest price. There is no reason to assume that T&D utilities would necessarily outperform the market. Second, the bid process, relying on market forces, would minimize regulatory oversight of supply acquisition. If the T&D utilities were automatically declared the standard offer service provider, the Commission would have to decide whether the T&D utility secured the best possible resource portfolio. One goal of deregulation is to shift risk away from ratepayers and onto shareholders; CMP's suggestion would preserve PUC protection of investments and continue ratepayer risk. Third, industry restructuring should not, by design, guarantee local utilities competitive advantages. Designating T&D utilities as standard offer provider would almost ensure they initially retain most customers. Finally, the standard offer service would supply customers at a fixed price, without the customers' involvement in selecting the provider. Customer confusion is of real consequence when that confusion leaves them vulnerable to abusive or deceptive business practices. By design, the standard offer shields customers from that risk.

b. <u>Bidding process</u>

Each T&D utility would solicit, evaluate and rank bids, and submit their recommendation, with supporting documents, to the Commission.

The Commission would review the materials and select the standard offer provider. The winner would contract with the T&D utilities to provide the service pursuant to Commission standards. Also by contract, the T&D utilities would include, but list separately, charges for the standard offer in their bills.

Power providers affiliated with a T&D utility could bid to provide standard offer service in the utility's territory. Similarly, consumer-owned utilities (COUs) could bid to provide the standard offer in their territories. The IPPs argued that affiliated generation companies should not be able to bid because there is too great of a risk of self-dealing, cross-subsidization and anti-competitive tactics. We agree there are some risks. The principal risk, in our view, is not cross-subsidization, as the rates of the T&D utility and the standard offer would be capped. Instead, the risk that the generation affiliate would have an unfair advantage centers on its potential access to T&D utility information. The short term remedy, until divestiture, is for the Commission to ensure that the T&D's generation affiliate has only the same information as every other potential bidder.

The Commission would decide many details of the standard offer service in proceedings prior to 2000. For example, one issue is the appropriate length of time between rebidding the standard offer service. The Paradigm proposed bids occur every five years. Enron urged the Commission to bid the standard offer every year. We decline to choose a specific interval now. To define the length of service commitment, the Commission would consider factors such as price stability, market risk, and flexibility. The standard offer proceeding would also address issues such as rate design, and customer class and voltage level differentiation. Suppliers would offer other service terms in their bids.

Finally, some commenters expressed concern over situations in which the standard offer provider fails to fulfill its service obligations or if no entity submits a satisfactory bid. In the standard offer proceeding, the Commission would consider means to protect against a provider's failure to give service. For example, the Commission could require the standard offer provider to post a performance bond. Or, the Commission could direct the T&D utility to provide service through the spot market pending selection of another provider.

As discussed below, if bids are above the cap, the Commission would investigate whether retail competition is appropriate for Maine at that juncture, and could recommend that the Legislature delay competition. The Commission could also reconsider allowing the T&D utility to provide the standard offer, particularly if only a few service territories have unsatisfactory bids.

c. Standard offer service territories

Each T&D service territory would have a standard offer service that may be supplied by different providers under terms unique to each. This approach should encourage bidders to craft creative proposals tailored to a territory's specific characteristics. That would serve customers better than a one-size-fits-all package. It would also allow the Commission to evaluate the merits of various service packages and refine subsequent bidding processes.

The Office of the Public Advocate (OPA) suggested that separate standard offer bids in each T&D service territory could result in marked differences in prices due to variations in loads and customer composition. Therefore, the OPA proposed, as an alternative, that Maine be subdivided into four or six regions with about the same mix of industrial, urban and semirural, and island/remote customer loads to prevent inequitable distribution of benefits across the State.

The OPA's suggestion would at least complicate and perhaps increase the cost of standard offer service without providing offsetting benefits. Geographic cost differences are primarily a function of transmission and distribution costs. Retail competition will not alter that fact. Customer location should remain largely irrelevant to power suppliers. The OPA did not couple its proposal with any persuasive rationale for the view that standard offer bids coterminous with utility service territories will cause substantial price variations. The OPA's proposal would likely create administrative and practical obstacles disproportionate to any benefit.

d. Availability of information

Before soliciting bids, T&D utilities would give potential bidders customer information necessary to formulate an informed bid. The

Commission would decide what specific information the T&D utilities should disclose from the general categories of customer load and usage data, such as monthly demands and energy consumption, the number of customers in each customer class and possibly general credit data, including uncollectible revenue and the number of customer disconnections. If the T&D utilities incur additional costs to develop and produce the data they could recover those through rates.

To uphold individual customer confidentiality, the T&D utilities would provide information in aggregate in a standard form. T&D utilities would release customer-specific data only with permission by the customer and there could be confidentiality protections. The T&D utilities' possession of confidential customer-specific information and perhaps other data may unfairly advantage their generation affiliates. The same effect would result if a COU bid in its territory. The Commission would restrict the type of information the T&D utilities may disclose to employees of their affiliated companies or COUs that bid to provide the standard offer.

CMP argued that it should not have to release information it developed in its market research efforts. It claimed to have gathered that category of information at considerable expense and therefore argued it alone should use it for marketing purposes or sell it for profit. We believe information utilities hold by virtue of their status as providers of T&D services must be given to standard offer bidders.[37] Other kinds of information, such as that which private entities could obtain in other pursuits, would not be subject to mandatory disclosure.

3. Price Cap on Standard Offer Service

The Commission would cap the standard offer so that its price plus the regulated rates of the T&D service, including any stranded cost charge, would not, on average, be higher than total electricity rates just before the beginning of retail competition. The Commission would consider whether the cap should escalate at an inflation-based index or by another mechanism.

A cap on the standard offer service would test whether retail competition will generally benefit all customer groups. If the initial standard offer bids exceed the cap, it may be evidence that the promised benefits of industry restructuring are illusory. In that case, the Commission would investigate, with an opportunity for all to participate, whether Maine should delay retail competition until it can be certain that the new framework would not increase rates for what may be most customers. Issues such as whether all or only some territories had bids above the cap would be likely to affect the Commission's findings; if bids in all territories exceeded the cap, that would certainly argue for delay. The Commission

[37] To the extent such information has value and is transferred to a utility affiliate or sold for a profit, the value should accrue to ratepayers.

would, of course, report the resulting recommendation to the Legislature for its consideration.

The American Association of Retired Persons (AARP), MEJP, and CSE supported a cap. AARP suggested the cap reflect 1995 rates. The Paradigm proposed a cap based on the total cost of existing service. The utilities, however, argued that setting a cap and using bid prices as a litmus test for retail competition is improper and unworkable. Specifically, BHE asserted that the Commission may be designing deregulation process to fail by requiring that standard offer service be no more expensive than 1999 retail electric rates. BHE and CMP suggested that by 2000, without restructuring, rates might increase if, for example, fuel prices rise. Therefore, CMP suggested it is more appropriate to compare the standard offer bids to rates that would have been in effect under regulation.

The utilities' argument has merit. The purpose of the standard offer cap is to ensure restructuring does not harm Maine's customers. Accordingly, rates that would have existed absent competition are a fair comparison. However, that comparison would require a counter-factual analysis that would be impractical or, perhaps, impossible.[38] Therefore, the rates when

[38]A counter-factual analysis attempts to isolate the economic effects of a policy change during a time period and compare them to the economic effects that an alternative policy would have had during the same time period. For example, it is often impossible to separate the impact of one policy change from contemporaneous changes in other factors. Moreover, it is difficult to estimate what the status quo

retail competition begins are the best proxy for what electric rates would be absent restructuring.

For several reasons, a standard offer cap based on the rates in effect just before retail competition is workable and does not portend failure. First, absent retail competition, generation costs should decrease as purchased power contracts expire, generation assets depreciate, and regulatory assets are reduced. Those decreases in costs over the years make it reasonable to believe bidders could offer a rate below the cap. Second, the Commission would consider escalating the cap according to an index. Third, if all bidders exceed the cap, the Commission would not automatically delay retail competition, but would investigate whether it is in Maine's interest to wait. If there is persuasive evidence that rates would have significantly increased absent restructuring, it would be one factor to consider in deciding whether to recommend delaying competition.

4. Terms and Conditions on the Standard Offer

The conditions and restrictions on the standard offer must balance its purpose with the need to keep the price as low as possible. The Commission would adopt standards governing the standard offer in the general categories of eligibility requirements, entry and exit restrictions and credit, collection and disconnection practices. As the market matures and as customers

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would have been absent the policy change. These difficulties would be especially apparent in electric restructuring due to the many policy changes embodied in the effort.

become experienced energy buyers, the Commission would amend the initial requirements accordingly.

For the standard offer to be effective serving those who cannot obtain service on reasonable terms from competitive providers and to allow customers time to adjust to competitive options, customers should have flexibility to enter and exit the standard offer unimpeded by restrictive policies, at least during a transition period. However, allowing every user of electricity unfettered freedom to enter and exit the standard offer may increase its cost. On balance, we are inclined to allow few, if any, restrictions on entry or exit during the early years of retail competition to encourage customers to experiment with the market. Later, it may be appropriate to limit the number of times a customer may enter and exit, specify times of the year when a customer may change service, or charge a fee to reenter.

Further, we are inclined to exclude large customers, for example those with loads over a specified amount, such as 1 MW. Large customers tend to be sophisticated energy users and would probably have competitive choices immediately. Therefore, the purpose of the standard offer option does not apply. Also, if large customers could take standard offer service, and if there were limited restrictions on entry and exit, the cost of the service would likely increase for all customers.[39]

Finally, we would adopt credit, collection, and disconnection rules to govern the standard offer. The availability of standard offer service would not relieve customers of the obligation to pay for service. The standard offer provider would have authority to disconnect a customer for nonpayment, but only pursuant to Commission rules. Disconnecting customers who do not pay for service can avoid the accumulation of uncollected debt that would increase the standard offer service cost for other customers.

C. Further Proceedings

The Commission would, in proceedings beginning in late 1997, establish terms and conditions (including the rate design) for standard offer service, and would later (during 1999) review and approve the selection of bidders to provide standard offer services in each of the T&D utility service territories. There would be two groups of proceedings related to standard offer services.

First, the Commission would conduct a proceeding to establish terms and conditions for standard offer service, including eligibility criteria, requirements for entering and exiting the service, and credit, collection, and disconnection provisions.

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[39]This could occur if customers continually take service from the market when conditions are favorable and then switched to the standard offer when market conditions change.

Once the design of the terms and conditions of standard offer service has been established, the T&D utilities would request bids from power suppliers and would present the results of the bidding, together with a recommendation, to the Commission. The Commission would review the utilities' filings and would determine the winning bidders. These activities would be completed by mid-1999 so that the standard offer providers would have sufficient time to secure the necessary resources to provide the service, and to establish customer service programs. Issues in these proceedings would likely include whether the bidding process was fair, and whether the bidders met reasonable standards for reliability and financial security.

The Commission would review the winning bids for standard offer service to ensure that the price of power, when added to the price for other services (e.g., T&D) and the stranded cost charge would not, on average, be higher than the electricity rates paid during 1999. In the event that bids were too high to achieve this objective, the Commission would consider whether it should recommend modifications to the process of electric restructuring to ensure that regulation in Maine remains consistent with the public interest.

V. CUSTOMER PROTECTION AND LOW INCOME ASSISTANCE

A. Recommendation

The Commission would adopt standards to govern the relationship between customers and power suppliers. The subject matter would include the power suppliers' registration to offer service, the obligation to notify customers of price and term changes, and to file information with the Commission. The Commission would have jurisdiction to resolve some types of disputes between customers and power providers. The Commission would have authority to investigate and remedy business conduct that is abusive or anti-competitive.

The transmission and distribution (T&D) utilities and the standard offer provider would have credit, collection, and disconnection obligations comparable to those that currently govern utilities, with some variation to reflect the changed marketplace. For instance, T&D utilities would not disconnect customers for failing to pay their power supplier. T&D utilities could, however, disconnect customers for failing to pay for T&D or standard offer service.

The Commission strongly recommends the Legislature fund electricity-related low income assistance through tax revenues. If it elects not to, the Commission would continue to include low income assistance in T&D rates.

The Commission would begin immediately to educate the public about the opportunities and obligations of retail competition. In addition to diverse

education efforts, the Commission would require utilities to separate charges for power from the remainder of the utility bill beginning in January 1999.

B. Discussion

1. Oversight of Generation Providers

The Commission would regulate power suppliers' interactions with customers, but not the prices or services they offer. Customers' ability to select another supplier would replace regulation as the price control system. Even where customer choice controls cost, there must be some rules to govern the rights and obligations of both buyers and sellers. Specifically, in the near term, customers would have to learn to be effective consumers of a product they have never before bought in the open market. Their inexperience may cause confusion or, worse, make them vulnerable to suppliers who capitalize on that inexperience with devious business practices. Indeed, the public reaction to competitive opportunities in telecommunications suggests that the public wants, and expects, some Commission oversight of new providers of competitive services.

Accordingly, as detailed below, the Commission would oversee power suppliers, including registration, business practices, filing requirements, and billing formats. Similarly, the Commission would adopt rules to govern credit, collection and disconnection issues. Finally, because information is customers' best means to protect themselves, a central role for the Commission will be to distribute accurate and timely information to the public. Giving customers rights, information and a forum for dispute resolution comports with the principles that all customers should have a reasonable opportunity to benefit from a restructured industry and that the industry structure should be understandable and fair to the public.

Commenters generally supported Commission oversight of power suppliers, but disagreed as to the appropriate level for a competitive industry. Customer groups advocated extensive oversight. Utilities and independent power producers believe unnecessary or restrictive regulation would limit their ability to craft diverse service offerings.

We are mindful that in a fully matured competitive market where customers are experienced buyers, the need for regulations to protect the public is minimal. For a market in its infancy, however, the public interest calls for a heightened, even if temporary, level of protection. When the market and customers become more seasoned, the level may decrease. We agree with the utilities that customer protection standards governing suppliers' conduct in Maine must respect their need to create diverse offerings. Further, we believe that the standards in Maine ought not be significantly more burdensome than those in other states. The Commission would balance the needs of competitive suppliers with consumer protection.

a. Registration and reporting

Power suppliers would have to register to sell to customers in Maine, and file periodic reports after that. Registration and reporting would serve several purposes. First, it would provide the Commission with information on how many suppliers are selling into the Maine market. Second, it would help the Commission monitor the market's development. Third, it would allow the Commission to be a source of information for customers.

Registration requirements would allow the Commission to confirm for customers that power suppliers have the financial and technical resources to carry out their business obligations and customer commitments. Reviewing suppliers' information before they provide service may enhance reliability and increase customers' confidence to participate in the market.

The registration process would include an application with information specified by the Commission, verified and filed by a corporate officer. The Commission would likely streamline registration for suppliers registered in other states.

As part of registration, the Commission would consider requiring a bond. Bonding could deter providers who do not have the financial ability or the intent to stand behind customer commitments. Also, bonding could be evidence of financial ability to withstand market disturbances or fluctuations or other events that may temporarily increase the cost of providing service.

Customers should have some confidence in their supplier's financial ability to withstand such market fluctuations.

Central Maine Power Company suggested, and we agree, that bonding might also cover the costs to ensure uninterrupted service if a provider suddenly ceases operations or otherwise abruptly stops service. In that event, the bond could pay costs incurred by the standard offer provider and the T&D utility to continue service. Ultimately, bonding could lower the cost of those services.

b. Business practices

The Commission would adopt minimum standards for suppliers' conduct. The standards would include the following: minimum notice provisions for changes in rates or other service terms, conditions for service terminations, requirements governing a change in service providers, minimum requirements for information and marketing materials. The standards would make clear the responsibilities of suppliers that want to sell to Maine customers. They would also give customers confidence that the Commission would hold every supplier to uniform obligations. To be effective, the Commission should have the authority to impose fines, issue injunctions and provide other appropriate remedies for violations of consumer protection standards.

In a competitive market, the Commission would turn from comprehensive economic control to more narrowly tailored consumer protection enforcement. Thus, the Commission would have the authority to investigate and prosecute possible violations of Maine's Unfair Trade Practices Act, 5 M.R.S.A. § 205-A-214, involving the retail practices of power suppliers. The Attorney General should retain authority to sue under those statutes in court, and could assist the Commission to investigate violations of the Act. The Attorney General should have responsibility to enforce the Act for power suppliers in the wholesale market.

c. Filing requirements

The Commission would require power suppliers with a service generally available to the public, or a significant segment of the public, to file their rates, terms and conditions. The Commission would review the filings only to ensure that all terms and conditions comport with business practice standards established by the Commission. The filings would be part of the information resources available to the Commission to help customers or to investigate and solve customers' disputes with power suppliers. The Commission would not require suppliers to file service contracts with individual customers.

d. Standard billing

Whether competition benefits customers depends in large part upon their ability to make informed choices. That, in turn, depends upon the availability of accurate, clear and timely information. Therefore, the Commission would consider adopting a standard bill format for power service. A standard bill format could perform the same function for consumers as do nutrition content labels on food products: it would help the consumer understand options, allow easier comparison of different offers, and reduce the likelihood of deceptive marketing.

In developing a standard bill format, the Commission would consider similar requirements in other New England states and may encourage a consistent regional bill format. That approach could reduce the administrative costs of compliance for suppliers throughout the region, including Maine.

e. Dispute resolution

The Commission would resolve certain customer complaints against, or disputes with, power suppliers. The Commission's authority would be similar to that it currently exercises for public utilities, modified to reflect the competitive market. Customers should have one forum to help them resolve disputes with T&D utilities and power providers.

2. Credit, Collection, and Disconnection

Retail competition will not relieve the consumer of the obligation to pay for services. Nor will retail competition create the possibility that customers will be disconnected except as provided by Commission rule. The Commission would continue to govern the credit, collection, and disconnection practices for the

T&D utilities much as it does currently for public utilities.[40] As discussed above, the Commission would also create credit, collection and disconnection standards for standard offer service providers.

The Commission would not authorize the T&D utilities to disconnect customers for nonpayment of charges by, or other disputes with, power suppliers. T&D utilities and power suppliers would be separate services provided by different companies. If a customer fails to pay a power supplier, the T&D utility would not be allowed to disconnect the customer from its system. Power suppliers should face the same risk and employ the same methods of debt collection as other competitive businesses. Power suppliers would not be obligated to continue to provide power to nonpaying customers. If the customer cannot find another supplier, the customer would default to the standard offer service.

T&D utilities would have the authority, pursuant to Commission rules, to disconnect customers who do not pay for T&D or standard offer services. Disconnection avoids the accumulation of uncollected debt that ultimately increases the costs of T&D and standard offer service.

3. Low Income Assistance Program

The needs of Maine's low income citizens are independent of the structure of regulation; for that reason, retail competition should not itself

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[40]The Commission's Rules for credit, collection and disconnection are currently contained in Chapters 81 and 86. The Commission anticipates re-examining these Chapters and may modify their provisions.

reduce the availability of low income assistance. Currently, Central Maine Power Company, Bangor Hydro-Electric Company and Maine Public Service Company administer low income assistance programs paid for by customers through rates. The percent of total rates that fund low income assistance is small, about half of 1 percent of total revenues, or less than $7 million per year.

The Commission strongly recommends that the Legislature fund low income assistance programs through general taxes or a tax or surcharge on all energy services. Most commenters supported funding low income assistance through the tax system.

The Legislature should fund low income programs through the tax system for several reasons. First, the tax system is a more equitable means of collecting funds than electricity use because general taxes are based on ability to pay rather than electricity consumption. Second, government agencies created to provide social services may administer low income assistance programs more effectively than T&D utilities, resulting in greater benefits from the same amount of dollars. Third, funding low income assistance through electric rates raises electric rates relative to other energy alternatives, causing an uneven competitive environment among different energy sources. A tax or all-energy-source funded program would correct that imbalance.

A system funded by general revenues would also more effectively balance income disparities among service territories. The division by service territories of low income programs may disproportionately burden customers in economically depressed areas because low income assistance is needed most in areas where residents are least able to support it. Because of the disparity between need and revenues, it could be simpler and less controversial to deliver statewide assistance under a general revenue system. The Commission, together with the State Planning Office, would develop a recommendation and proposed legislation for funding assistance to low income consumers of electricity through the general fund or through a tax on all energy sources in the State. This proposal would be provided to the Legislature by January 1, 1998.

The Industrial Energy Consumer Group (IECG) indicated concern about funding low income assistance through the general fund. It argued that it would subject vulnerable citizens to the risk that the Legislature would not continue to support low income assistance. The IECG believes funding low income assistance through rates is not as regressive as other mechanisms, such as property taxes, because electricity consumption tends to vary with income. The IECG also doubted that the small amount of low income support in rates would distort the market.

We concur that low income citizens ought not be harmed by restructuring. That view is reflected in the principle that restructuring should not diminish low income assistance or other customer protections. During the transition to a competitive market, however, it is appropriate to reexamine subsidies and evaluate whether they are recovered by the most equitable and efficient means.

In the event the Legislature elects not to fund low income assistance through the general fund or through a tax designated for this purpose, it could preserve the Commission's authority to fund low income programs through electric rates. Then, the Commission would fund programs in an amount comparable to that in rates in 1999. The Commission would also investigate whether COUs should provide low income programs and whether there are better means to distributing funds.

4. Customer Education and Information

Ratepayers must become effective consumers for choice to be meaningful. To that end, commenters supported public education programs to ensure Maine citizens understand retail competition, how choice would affect them, and what they need to know to participate in the market.

The Commission would immediately begin public education, including, but not limited to, holding public forums, publishing and distributing information bulletins, and developing an information data base accessible to users of the Internet. The data consumers might find useful are information from suppliers' registration applications, terms and conditions of service filings, and power portfolio disclosure statements. Beginning retail competition in 2000 would enable the Commission to observe public education efforts in other New England states and mirror those that appear most effective.

The Office of the Public Advocate proposed that separating or "unbundling" power charges from the rest of customers' utility bills before 2000 would educate customers about retail competition. According to the OPA, giving customers an opportunity to see their electricity bills divided by services before retail competition would allow them to understand the separation of costs between power and transmission and distribution services. We agree. Accordingly, beginning in January 1999, all utilities would separately identify charges for generation.

C. Further Proceedings

In mid-1998, the Commission would begin one or more proceedings to determine what requirements should be imposed on companies selling electric power to retail customers in Maine. The issues to be addressed in these proceedings, which would be concluded by mid-1999, would likely include what registration requirements are appropriate; what jurisdiction the Commission should have over disputes between power sellers and their customers; what penalties should the Commission impose for violations of Commission rules; and what disclosures should power sellers make to their customers concerning the characteristics (e.g., fuel mix) of their production facilities. Other issues may be examined, including performance bonding; notice requirements for rate changes, other terms, and termination; and standard billing.

The Commission would also determine what credit, collection and disconnection practices would be appropriate for T&D utilities. During 1997, the Commission would begin to review Chapters 81 and 86 of its rules, dealing with its disconnection and deposit regulations for residential and nonresidential customers respectively, and would complete new rules appropriate for a restructured electricity market by the end of 1998. Issues in this proceeding would include the implications of a T&D utility providing billing service for power providers, and whether existing rules concerning credit and collection continue to be appropriate.

During 1997, the Commission, together with the State Planning Office, would prepare a recommendation, including proposed legislation, for funding assistance to low income consumers of electricity through the general fund or through a tax on all energy sources ("all fuels") in Maine.

If the Legislature does not fund low income assistance through tax revenues, the Commission would investigate whether ratepayer-funded low income programs should exist in all service territories, and whether the means by which utilities distribute funds should be amended.

The Commission would establish a comprehensive customer education and outreach program beginning in 1997. The Commission would intensify its customer education efforts in 1999, as the January 2000 implementation date approaches, drawing on the experience in other states with electric restructuring.

During January 1998, each electric utility would file a bill unbundling proposal for Commission review. The primary issue likely to be resolved is the "price" of power (i.e., energy and capacity) as distinct from other services. The Commission would complete its review by July 1998, so that utilities would have approximately six months to complete any needed computer system and procedure modifications. Utilities' bills would be unbundled beginning January 1999.

VI. ENERGY POLICY AND THE ENVIRONMENT

A. Recommendation

All companies selling electric power to retail customers in Maine should include a specified minimum amount of renewable energy in their generation portfolio. Retail providers could fulfill this requirement with credits that they could buy and sell. The Commission would consider the market's ability to develop and sell power from renewable resources, and would establish the renewable portfolio standard.

The Commission would require every retail power seller to report the mix of fuels used in its generation. The Commission would publish this information quarterly.

Ratepayers would continue to fund cost effective energy efficiency programs through revenue collected through the rates of transmission and distribution (T&D) utilities. The Commission would establish funding levels, comparable to the levels in 1999 before the beginning of retail competition, and regularly reevaluate the need and level. The T&D utility, with Commission oversight, would select the energy efficiency service providers through periodic competitive bidding.

When retail competition begins, the Commission would cease to review and certify the construction of generating facilities in Maine and would no

longer oversee plans and planning processes intended to meet the State's future electric needs.

The Commission supports and will continue to work with other states and appropriate agencies for air emission standards that minimize differences between old and new source plants.

Finally, the Legislature should consider directing one or more state agencies to review the environmental impacts from electric restructuring and its implication for Maine's energy policy.

B. Discussion

1. Energy Policy and Electricity

The Maine Energy Policy Act (MEPA), the Small Power Production Act (SPPA), and the Electric Rate Reform Act (ERRA) embody Maine's electricity-related energy policy. These statutes promote the use of indigenous and renewable resources, encourage energy efficiency and conservation, and balance short- and long-term costs and benefits in meeting Maine's electricity needs. The Commission has carried out these policies through regulatory orders. For example, the Commission has pre-approved the utilities' power plant construction and certain types of power purchases, and has made decisions about power supply and demand-side resource planning and acquisition.

The Commission's ability to carry out energy policy has largely depended on the fact that it regulated comprehensively the provision of electricity.

Restructuring would substantially limit this ability. Beginning in January 2000, customers would choose among power suppliers; the Commission would not regulate these companies as public utilities.[41] Thus, the Commission's oversight of electricity-related decisions would change in both form and degree. Supplier and consumer choice would replace Commission decisions over what resources will meet electricity needs, and whether, when and where suppliers build new plants.

The effect of restructuring on energy policy is significant: decisions about the production and use of electricity directly impact the environment and the economy. A fundamental restructuring principle is that it should not diminish the quality of the environment, compromise energy efficiency, or jeopardize energy security. Relying abruptly and only on the market to make electricity supply choices could conflict with that principle. Competitive markets may place more value on short-term rather than long-term cost savings. And it is uncertain how the market would value other state policy objectives. This could lead, absent some intervention, to a power supply that is, in the long run, less efficient and more costly.

Energy resource decisions, thus, should not initially be completely relinquished to the market. Although a competitive power market could benefit customers by lowering prices and increasing options, its effect on the

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[41]The Commission would continue to regulate standard offer service providers to some extent.

environment is uncertain. The Commission would therefore (1) ensure the use and development of generation using renewable resources; (2) require ratepayers to fund cost-effective energy efficiency; and (3) ensure the availability of accurate and timely information so customers can choose power providers based on fuel mix.

Commenters generally supported Maine's energy policy. The Office of the Public Advocate (OPA), the Industrial Energy Consumer Group (IECG), Conservation Law Foundation (CLF), American Association of Retired Persons (AARP), Coalition for Sensible Energy (CSE), Maine's independent power producers (IPPs) and others supported preserving energy efficiency and renewable resources. The Paradigm concurred. Residential and small business consumers in Maine appeared to agree. In a recent Commission survey, residents and small businesses expressed concerns about the environment. In New Hampshire's retail competition pilot, companies have used the fact that their power is environmentally benign to promote sales.

The utilities, by contrast, suggested the market alone should decide energy resource development and use. In their view, government involvement in the market to further energy policy goal is unnecessary and undesirable.

We disagree. The market may bring price and choice benefits to customers, but its ability to yield a resource mix that balances other state objectives is unclear. Maine should ensure the use of renewables and conservation through modest market-based and market-compatible portfolio and demand-side management (DSM) requirements. When and if the market delivers a resource mix consistent with energy policy and environmental goals, the Commission would cease to place requirements on market participants.

The utilities also argued that placing requirements on electricity and not on other fuel sources disadvantages electricity providers. They recommended that any requirement on electricity providers should apply to all energy sources. The Commission agrees that public policy should, to the extent possible, avoid burdening one sector of the market with requirements not imposed on competing sectors. The Commission does not agree, however, that the solution to any current imbalance is to abandon all attempts to integrate energy policy with the regulation of electricity markets.

The utilities argued that Maine cease to regulate electricity supply and demand choices when retail competition begins. We disagree, at least in the early years. Restructuring provides a vehicle to reexamine electricity-related energy policies; however, it does not itself require or justify their immediate elimination.

2. Renewable Resources in Electric Power Generation

a. Perspective

Nature replenishes renewable energy resources. Several renewable resources can generate electricity, including biomass or wood, water, sunlight, and wind. Renewable-fueled generating plants often have high capital costs, low or zero fuel costs, intermittent output and low environmental impacts.

Maine's generation mix has a substantial renewable component. In 1995, hydro-, wood-, and municipal solid waste (MSW)-generated power provided about 47% of the State's electricity need. In the same year, hydro, wood, and MSW provided about 10% of New England Power Pool's (NEPOOL) need.[42] Nationally, renewable plants comprise about 12% of electric generating capacity.

Federal and state government has encouraged, in a variety of ways, generation of electricity with renewable resources. One method used in Maine and elsewhere has been to require utilities to incorporate renewable resources in their long-term supply planning. Once the Commission no longer regulates generation, however, this tool will not be available. The market may, at least initially, disfavor generation using renewable resources, in part because such facilities tend to have high start-up costs. To encourage the continued development of renewable resource generation during at least the initial period of retail competition, the Commission would require sellers to comply with a renewable portfolio standard and disclose their fuel mix to customers.

[42]These numbers do not include self-generated electricity, nor NEPOOL net interchanges.

b. Renewable portfolio standard

All companies selling electric power in Maine should meet part of their customers' needs with renewable power. Companies could meet this renewable portfolio standard in several ways. They could generate renewable power. They could buy for resale the output of a renewable plant. Or, they could obtain renewable credits from companies that have renewable energy in excess of their portfolio requirement.[43] Companies with entitlements to renewable generation could compete to provide credits, and all power suppliers could try to minimize the cost of meeting the standard. If renewable generation becomes competitive with fossil-fuel generation, the value and the cost of the credits would decrease. Ultimately, the requirement could be eliminated as the cost of providing power using renewable resources approaches the cost of other production methods.

The Commission would adopt the renewable supply requirement before January 2000.[44] In establishing the requirement, the Commission would consider renewable provisions in other New England states,[45]

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[43]A market may develop for renewable credits, similar to that for trading of sulfur dioxide (SO_2) allowances under the Federal Clean Air Act.

[44]The Commission would also determine in the proceeding what energy sources would be considered "renewable."

[45]The Vermont Public Service Board recently proposed a portfolio requirement with tradable credits as part of its recommendations for restructuring.

evaluate whether the portfolio requirement remains the best method for Maine, and identify the effect on rates and the economy. After 2000, the Commission would reevaluate periodically the requirement and its level.

The renewable portfolio requirement and the credit trading will ensure the use and development of renewable generation with a flexible, market-based approach. The Commission could tailor the requirement to policy objectives, such as targeting a specific form of generation. By allowing the market, instead of regulators, to decide what renewable generation options thrive, the portfolio requirement satisfies the principle that restructuring should not diminish environmental quality and the principle that where viable markets exist, market mechanisms should be preferred over regulation.

Many commenters agreed with encouraging the development and use of power generated by renewable resources and the renewable portfolio requirement. These parties include the OPA, Maine's IPPs, and the CSE.

The utilities objected to the renewable portfolio requirement. They argued that the market ought to decide what resources meet consumers' electricity needs. They also emphasized that the same requirements ought to apply to electricity and other end-use fuels. As we have said, however, we believe the competitive market is unlikely, at least initially, to act in sufficient conformity to Maine's energy policy.

The Maine Municipal Utilities Group (MMUG) noted that suppliers could resist disclosing their resource mix or conforming to standards. As a result, they could be reluctant to enter Maine's market. However, other states are likely to have renewable provisions;[46] thus, Maine would be no less attractive than other states. Moreover, before placing requirements on companies selling power in Maine, the Commission would ensure that those requirements do not deter competitors from the Maine market.

CLF supported provisions to ensure environmental quality and renewable resources. CLF, however, asserted that the portfolio approach could be burdensome and complex and could impede the development of renewable technologies. CLF also suggested that potential litigation over Commerce Clause questions could delay execution of the portfolio requirement.[47]

As an alternative, CLF proposed a wires charge. We believe a wires charge is inferior to the portfolio requirement. A wires charge would require more regulatory oversight than the portfolio requirement, which counters the principle that where viable markets exist, market mechanisms should be preferred over regulation. Specifically, as the cost difference between

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[46]New Hampshire, Massachusetts, Vermont, and Rhode Island appear likely to include provisions to ensure renewable resource generation. California provides funding for renewable technologies.

[47]The Commission's view is that a renewable portfolio standard would not violate the Commerce Clause.

renewable and other forms of power generation change, the value and cost of meeting the minimum renewable portfolio standard would self-adjust, and not require regulatory intervention. Regulators would have to adjust the wires charge to reflect a changed market. For the portfolio requirement, regulatory action would be limited to adopting levels, reporting requirements and enforcing compliance.

CLF also argued that the portfolio requirement would be complex and therefore a burden. It is instructive that a similar system under the Federal Clean Air Act for SO_2 allowance trading works reasonably well.

c. Resource mix disclosure

Customers should be able to choose electric power providers based on what resources each provider uses to produce power. Customers may want to buy from suppliers based on production characteristics. For example, some customers may want to purchase energy generated with environmentally benign resources; some may want to exclude nuclear power, or power produced using coal or hydro. The Commission's survey on electricity issues suggests that more than 80% of Maine's residential customers and 75% of small businesses want to know how their electricity is generated, and a majority places a premium on clean power. Surveys in other states, such as Texas, reveal similar customer preferences. Sellers competing in New Hampshire's retail pilot have used environmental attributes as a marketing strategy.

To provide customers with information to make these choices, power suppliers should disclose their generation resource mix. The Commission would publish that information quarterly. The independent system operator (ISO) could oversee compliance. The ISO would have much information about production available in the normal course of business.

Commenters unanimously agreed that customers should have access to accurate information on the resource mix of potential suppliers. Except for CLF, CMP and MMUG, commenters supported a fuel disclosure requirement. CLF and CMP identified potential practical problems with the disclosure requirement and questioned the need. They asserted it could be difficult or impossible for energy suppliers to identify and report this information in a way that assists customers. We believe the benefits of disclosure outweigh the costs. Suppliers ought to know their resource mix; if they sell spot market power, they could provide system average mix data. If the market develops other means to provide credible data, the Commission would eliminate this requirement.

Some commenters suggested suppliers disclose other information, such as data about emissions and the geographical location of their power plants. We disagree. Such further disclosures would not provide sufficient additional useful information to justify the increased complexity and cost. We expect, however, that additional sources of information would become available in the marketplace.

3. Efficient Use of Electricity

Conservation and the efficient use of electricity can deliver value to customers at lower cost and with fewer adverse environmental impacts than producing more power. Federal and state policy has encouraged conservation and the efficient use of electricity. Utility regulators have often carried out these policies. In Maine, ratepayer-funded DSM has saved over six billion kilowatt-hours. The Commission required utilities to support DSM because it believed that customers may view the "payback" for DSM investments as too long; utilities may resist DSM because they may see their profits fall when customers save, rather than use, electricity.

The Commission would, at least initially, continue to ensure that consumers fund these programs through T&D rates. The Commission would set initial funding at a level comparable to that in 1999, and regularly review the need for funds, and their level. The T&D utilities, with Commission oversight, would solicit bids periodically to provide cost-effective efficiency services, select the vendor(s), and administer the contracts. T&D utilities could bid to provide energy services, even in their own service area.

Continuing to fund an appropriate level of DSM is consistent with the principles that restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize energy security. It is at best a possibility, and by no means a certainty, that markets would immediately yield an abundance of efficiency-related energy services.

The OPA, CLF, CSE and the IPPs supported requiring customers to pay for efficiency programs through the T&D utilities' rates, and endorsed bidding as a way to minimize the cost. Utilities and Madison Paper Industries do not believe that continued DSM funding through regulated rates is necessary. They believe the market would deliver appropriate energy efficiency services. The utilities further argued that imposing requirements and costs on electricity and not other fuels distorts markets and unfairly disadvantages providers of electricity. The Commission agrees that differences in the burdens placed on competitors in the energy market should be eliminated to the extent possible. Nevertheless, we are unwilling to entirely abandon regulatory requirements for conservation and the efficient use of electricity without clear legislative direction.

CLF and Ed Holt & Associates opined that setting initial funding at 1999 level would be inadequate. Holt also asserted that linking funding levels to a future year would give utilities an opportunity to reduce DSM spending. Holt offered no basis for the conclusion that regulatory oversight through 1999 would be inadequate to set DSM spending levels at an appropriate level; we believe that conclusion is unwarranted.

4. Long Term Resource Planning and Certification of Need

The Commission has executed state energy policy by regulating the utilities' power purchases and resource planning. Through its oversight, the Commission has sought to minimize electricity costs over the long term, encourage the use of indigenous renewable resources and energy efficiency, and ensure that generation-related decisions were in the public interest. Beginning in the year 2000, the Commission would no longer review power plant construction and other power acquisition decisions. The move to competition, and the accompanying shift of risk to private investors, would largely replace, and improve upon, regulatory oversight. However, there may remain matters regarding the construction and siting of power plants that warrant continuing government oversight. The Legislature should consider whether the Department of Environmental Protection or a newly formed entity such as a siting council or energy office should oversee these issues.

5. Air Quality Impacts of Restructuring

The Commission supports the application of emissions standards to minimize differences between old and new source generating plants. Because this matter extends beyond Maine's borders, the Commission could address it only through working with other states and Federal agencies. The Commission would not set up different standards for Maine generating facilities than are imposed on a regional or national basis.

Older, less efficient, and more polluting coal and oil plants could have a competitive advantage. These plants tend to have lower total costs, but higher heat rates and higher emission rates than newer plants. Many older plants were grandfathered with respect to New Source Performance Standards of the Clean Air Act (CAA), because at the time Congress enacted the CAA these plants were expected to retire soon. As competition develops, these plants may find new markets for their power, further contributing to delays in their being displaced by newer plants.

This creates two problems. First, it could exacerbate air quality problems. Second, the plants would have an unfair competitive advantage because they are grandfathered, and that could discourage the emergence of additional power suppliers. Thus, benefits of competition would lag, and air pollution would increase.

Maine and the rest of the northeast region would be particularly disadvantaged. The low-cost coal plants in the midwest are among those most likely to have increased demand for their power. If they expand their production, levels of NOX, SO_2, and CO_2 would increase, potentially degrading Maine's air and water quality, increasing Maine's cost of complying with the CAA. That would occur whether or not the power from the midwestern plants is sold into the northeast market.

All commenters agreed the presence of old and new source plants in the competitive market would create environmental and economic challenges for the northeast. Except for CLF and Maine's IPPs, parties agreed that regional or Federal solutions are necessary. They agreed that Maine ought not impose emission standards on its old source plants that are more stringent than standards required in other states.

Maine's IPPs recommended applying emission standards to those who sell power to retail customers. This approach, however, would be similar to, and perhaps duplicative of, a renewal portfolio standard. Therefore, imposing such emission standards could discourage companies from entering the Maine market. CLF proposed Maine require the older, fossil-fueled utility-owned plants within its borders to conform to emission standards comparable to those required for new plants, regardless of what other states do. They asserted this would allow Maine to argue more effectively for similar requirements in states up wind. We are not persuaded, however, that Maine acting alone is likely to have any significant effect on the operation of power plants in the midwest. On the other hand, such a requirement would further disadvantage Maine power producers subject to the standards. We prefer, therefore, to continue to seek regional and national solutions.

C. Further Proceedings

The Commission would begin a proceeding, in early 1998, to determine the appropriate level of renewable energy generation to be included in the production mix of all power sellers in Maine, and to establish the guidelines necessary to implement this renewable portfolio requirement. The proceeding would be concluded in early 1999.

The issues to be resolved in this proceeding would include the level of renewables to be required; the extent to which any Maine requirement should vary significantly from similar requirements (if any) elsewhere in New England; how renewable "credits" would be calculated and traded; what price impacts various renewable requirement levels would have, and the effect of those price impacts on consumers; and whether any particular level of renewable requirement would produce measurable benefits for Maine such as reducing the cost of complying with Federal Clean Air Act standards.

Beginning in mid-1998, the Commission would review the framework and substance of the demand-side management programs to be administered by the T&D utilities in the new competitive environment. These reviews would be concluded by mid-1999.

Issues in these proceedings would include how costs and kWh savings would be calculated; whether any costs should be deferred, and if so over what period; whether there should be a limit on the price impact of DSM programs; and how any costs should be included in rates.

VII. STRANDED COST

A. Recommendation

Electric utilities would have a reasonable opportunity to recover legitimate, verifiable, and unmitigatable costs stranded as a result of retail access. A reasonable opportunity is not a guarantee of cost recovery. Utilities should have only the opportunity for cost recovery comparable to that under current regulation. The Commission would not allow utilities to recover costs for which obligations were incurred after March 1995, unless the associated obligations were specifically mandated by the Commission or other public authority.

The Commission would require utilities to mitigate those costs aggressively, and would require utilities to obtain the highest possible value from their generation assets and contracts. The Commission would not reconcile stranded costs after-the-fact, but would review them periodically and, if warranted, adjust them on a going forward basis.

Stranded costs would be collected from customers through the regulated rates of the transmission and distribution (T&D) utilities. The Commission would establish the rate design for stranded cost recovery before the beginning of retail competition. The Commission would not establish exit fees or similar charges as a part of industry restructuring.

B. Discussion

1. Nature of Stranded Costs

Certain costs and obligations incurred by utilities to fulfill their legal obligation to provide electricity may become unrecoverable, or stranded, when retail competition begins. These costs fall into three general categories: (1) above-market costs associated with utility-owned generation plants; (2) above-market costs associated with generation-related contracts, most notably contracts with qualifying facilities (QFs); and (3) regulatory assets related to generation such as those associated with canceled plants and QF contract buyouts.[48] For the most part, current utility rates include these costs.

Traditional regulation provides utilities a reasonable opportunity to recover their costs, if prudently incurred, through the ratemaking process. In a retail market opened to competition, utilities may be able to recover only market value of their generation assets or power contracts; any remaining costs[49] associated with these assets in excess of the market value may be "stranded." A

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[48]Regulatory assets are not tangible, physical assets. They are essentially ratepayer obligations created by regulation. These assets represent costs that utilities have incurred in the past, but are recovered from ratepayers over time.

[49]Under traditional ratemaking, the cost of generation assets are recovered through the utility's rate base over their depreciable lives. The remaining costs of these assets are those that have not yet been recovered. The costs of purchased power contracts have generally been recovered as an expense. The remaining costs of these contracts refer to the payments for future deliveries of power under the terms of the contracts.

utility asset or contract could have a market value below or above the utility's remaining cost. The total stranded cost is the sum of the differences between remaining cost and market value, both positive and negative, of utility assets and contracts. Because regulatory assets represent only ratepayer obligations, they do not have a market value. The total of a utility's regulatory assets must therefore be added to other stranded costs.

Not all costs that become unrecoverable are "stranded" by retail competition. Customers may reduce or even eliminate electricity usage by self-generating, fuel switching, production cutbacks, energy conservation, and bypassing the utility's system entirely. All these activities result in fewer revenues available to the utility to pay the fixed costs of operations. These customer options, however, exist under current regulation as much as they would after retail competition begins.[50] The Commission would continue to consider whether the cost-shifting that may result from these reductions in usage warrants regulatory intervention.

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[50]The United States Supreme Court has recognized a Constitutional distinction between a reduction in economic value that results from governmental action as opposed to general economic forces. *Market St. Ry. Co. v. Calif. R.R. Comm'n*, 324 U.S. 548, 567 (1945).

2. Utility Recovery of Stranded Costs

a. Opportunity for recovery

The Commission would allow utilities a reasonable opportunity to recover legitimate, verifiable and unmitigatable stranded costs that result from retail competition. The Commission would design the rates to recover stranded costs so that the opportunities, risks and uncertainties for cost recovery would be comparable to those under the existing regulatory system. Industry restructuring would provide no additional guarantees or enhanced certainty for stranded cost recovery. Most commenters supported or did not oppose this approach to stranded cost recovery.

Historically, utilities have had a legal obligation to provide adequate and safe service at just and reasonable rates to all customers within their geographic service territories. These obligations prevented utilities from refusing to serve any customer, including those who might impose high costs on the system, and required utilities to have adequate generation capacity available to meet current and future demand. The obligation to provide service in return for the right to exclusive service territories is sometimes called the regulatory compact.

The Maine Law Court has long recognized the underlying principle of this compact:

> The whole body of public utility law has been developed here and elsewhere upon the concept of regulated monopoly. Implicit in this concept is an acceptance of the principle that a public utility offers its facilities and

> services to the public without discrimination and that it is obligated to extend its service as needed within its service area unless the supervisory agency determines that it is not practicable or economically feasible to do so. A public utility yields to the sovereign with respect to approval of rates, methods of financing and other matters of policy which are ordinarily within the sole province of management in private business. In return for relinquishing the right to determine without let or hindrance whom it will serve, what it will charge, or how it will finance or invest, it is usually given relative freedom from competition in its service area on the part of public utilities similarly regulated and controlled. The monopoly thus afforded as among competing public utilities is in effect a quid pro quo for the obligation to render public service and to submit to regulation and control.

Dickinson v. Maine Public Service Co., 223 A.2d 435, 438 (Me. 1966).

Opening a utility's franchise area to retail competition would effectively break the existing regulatory compact. The central issue for stranded cost recovery is whether, after the franchise for power sales is opened, utilities who invested in power supply to fulfill their franchise obligations should be given, in the restructured market, a reasonable opportunity to recover those investments. The Commission believes that utilities should be given that opportunity. In essence, utilities should have the same opportunity to recover the costs in a restructured industry as they had when they incurred the obligations under an earlier regulatory framework.[51] Moreover, changing the rules for cost

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[51]While not directly applicable, the recent United States Supreme Court decision in *United States v. Winstar Corp.*,____ U.S. ____, 116 S.Ct. 2432, 135 L.Ed 2nd 964 (1996) suggests, at least, that government should act responsibly in changing the

recovery after investments have been made to fulfill service obligations could impair government's credibility and deter long-term investment in Maine.

The opportunity to recover costs after retail competition begins should be equivalent, not superior, to the opportunity under the current system. Costs incurred imprudently, or costs that are not mitigated aggressively, have no place in any stranded cost recovery charge. The Commission would permit stranded cost recovery only to the extent consistent with strictures of prudent utility management.

One alternative to the recovery principles outlined above is to reduce the recovery by some specific portion, often described as "sharing" the burden among utility shareholders and customers. The Commission does not recommend that approach. Any portion selected could only be arbitrary and inevitably subject to a legal challenge that could delay the beginning of retail competition. It would also create substantial uncertainty in the electric and financial markets. If the Commission believed that curtailing the opportunity to recover prudently incurred costs were sound policy, and it does not, it could disallow recovery under current regulation without the travails of restructuring.

b. Mitigation

To minimize stranded costs, the Commission would require utilities to pursue all reasonable means to reduce uneconomic costs and to

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"rules of the game."

get the highest possible value for their generation assets and contracts.[52] The Commission would estimate a reasonable level of mitigation. Incentives might include price cap regulation, or sharing savings from cost reductions.

One important opportunity to reduce stranded costs is in the sale of generation assets. The Commission would rely on the market to ensure that ratepayers receive the maximum value for those assets. As the IECG and others observed, the utility should choose the method for any sale for its ability to obtain the highest possible price. In many cases, using an auction might produce the best result. In no case would the Commission rely entirely on a value determined administratively by calculating the net present value of the cash flow from the current use of a facility. In the case of a plant currently using oil as fuel, for example, the market might identify a higher value for the same plant if that plant were converted to gas. An administrative determination (or even relying on the sale price offered by an affiliate) in that case would be likely to understate the value significantly.

In addition, the Commission would continue to require that the T&D utility, as holder of the QF contracts, explore all reasonable and lawful opportunities to reduce the cost to ratepayers of those contracts.

[52]The Commission does not, however, encourage bankruptcy, strategic or otherwise, as a tool to reduce costs.

The Office of the Public Advocate (OPA) proposed a specific incentive to mitigate the costs associated with QF contracts. The allowance for stranded costs would assume that utilities can achieve a 10% saving in QF contract costs. Utility shareholders would retain savings in excess of 10%, but would not recover more than 90% of the original contract costs. We decline now to adopt the OPA's proposal. The specific incentives for cost mitigation should be addressed comprehensively in a proceeding.[53]

c. Cost recovery limitation

In an order issued in March, 1995, the Commission put utilities on notice that they would bear the primary market risks of costs incurred in the future. *Order Commencing Rulemaking, Re: Recovery of Stranded Cost Rulemaking*, Docket No. 95-055 at 10 (Feb. 27, 1995); *Order Terminating Rulemaking*, Docket No. 95-055 at 3-4 (April 8, 1995). To the extent generation-related costs incurred after March 1995 become uneconomic due to retail competition, the Commission would not include any recovery for those costs in the stranded cost recovery charge.

[53]Two jurisdictions, California and Pennsylvania, have enacted legislation that attempts to mitigate stranded costs, and thus reduce rates, through innovative financing mechanisms. Essentially, these jurisdictions have created a statutory right for the recovery of some types of costs through utility rates. This results in greater certainty of cost recovery that should lower the utilities' financing costs. The savings in financing cost would be passed onto ratepayers.

This limitation does not apply to regulatory assets created after March 1995, such as amortizations of QF buyout costs, and costs deferred pursuant to existing rate plans or for conservation. These regulatory assets result from utility efforts to reduce costs or to fulfill obligations imposed by the State. Therefore, utilities should have an opportunity to recover these costs.[54] Similarly, the limitation does not apply to new obligations over which utilities have no discretion. For example, Maine Public Service Company (MPS) may have to extend its contract with Wheelabrator-Sherman. If so, recovery of costs stranded as a result of the contract extension would not be subject to the March 1995 cut-off.

Bangor Hydro-Electric Company (BHE) and Eastern Maine Electric Cooperative (EMEC) opposed any recovery limitation because they still have an obligation to obtain generation resources to serve ratepayer demands. We disagree. Beginning in March 1995, utilities in Maine could no longer claim an expectation of an invulnerable franchise, and traditional opportunities for cost recovery, extending indefinitely into the future. Prudent management would, at that point, understand that potentially uneconomic burdens would be at their shareowners' risk.[55]

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[54]Consistent with Statement of Financial Accounting Standards No. 71, the Commission would establish rates that specifically allow for recovery of regulatory assets.

[55]In fact, BHE management appears to recognize this risk in its power purchases. It has bought relatively short-term power and has also begun hedging against the risk of fuel price volatility.

d. Constitutional authority

Central Maine Power Company (CMP) argued that, as a matter of law, states must allow utilities to recover any and all stranded costs. It rests the argument on restrictions against governmental takings of property in the United States and Maine Constitutions. We do not agree that the Constitution so rigidly constrains the Commission's discretion.

A commission may decline to allow the recovery of costs, even prudently incurred costs, without exceeding constitutional limits unless the result is confiscation of the utility's property, taken as a whole. Such confiscation will be found only where the utility's financial integrity is seriously jeopardized. *Duquesne Light Co. v. Barasch*, 448 U.S. 299 (1989).

Indeed, regulatory decisions that injure the utility's financial integrity may be lawful. For example, a state can continue to apply longstanding ratemaking principles even if it results in substantial financial harm or bankruptcy. *Appeal of Public Service of New Hampshire*, 547 A.2d 269 (N.H. 1988). If management imprudence compromises a utility's financial integrity, regulators are not constitutionally compelled to rescue its shareowners.

The Commission's conclusion that utilities should be allowed a reasonable opportunity to recover costs stranded by retail competition does not, therefore, rest solely upon constitutional principles. It rests also on the

Commission's belief that government and citizens are best served when decisions are made in a fair and consistent manner.

3. Determination of Stranded Cost Charges

a. Process

The Commission would estimate stranded costs for each electric utility. It would then use the estimates to develop the stranded cost rates to be charged by each T&D utility when retail competition begins. To reduce the risk of establishing rates that are grossly too high or too low, the Commission would, at a minimum, reexamine the stranded cost rates and correct for substantial inaccuracies in 2003 and again in 2006.

To determine the market value of generation-related assets and contracts, the Commission would rely to the greatest extent possible on market information. The Commission would consider factors including, but not limited to: market valuations that become known as plants and the rights to power from QF contract are sold, current and likely future regional market prices for power, and stranded cost determinations in other New England states.

The National Independent Energy Producers suggested that a competitive sale should determine an asset's market value. The Paradigm supported an auction approach. We agree that, to the extent possible, it is best to use market techniques to identify value. We depart only to the extent that we believe flexibility, instead of limits, on which market techniques T&D utilities use is likely to maximize the value of assets.

While CMP and BHE would be required to divest their generation assets no later than January 2006, utilities could propose to divest earlier. In the event a utility divests all or a significant amount of its assets prior to 2006, the Commission would review and, if warranted, modify that utility's stranded cost rates. When the utility completes the divestiture or sale, the Commission would finally decide the stranded costs associated with the asset. When the T&D utility no longer owns a power-producing asset, fluctuations in the value of that asset cannot be readily reflected in rates charged by the T&D utility. If the value of the asset increases, which would in theory reduce stranded costs, there is little chance of persuading the new owner to raise the price it already paid for the asset. If the value decreases, neither the T&D utility nor its ratepayers should be forced to help the unlucky buyer.

Any "final" stranded cost determination for divested assets creates a risk of inaccurate stranded cost charges if market values change. This risk would be reduced, to some extent, by the Commission's reexamining periodically the stranded cost associated with QF contracts and Maine Yankee. Because QF contracts and Maine Yankee ownership would remain with the T&D utilities, the Commission could review and modify associated stranded cost estimates at any time, including after 2006, until each of the contracts terminates and Maine Yankee ceases to operate. This should help to ensure stranded cost charges remain reasonable. Moreover, the total amount of stranded costs will decrease with the passage of time; mis-estimation of market value in 2005 or 2010 will necessarily have a smaller impact than mis-estimation in 1998 or 2000.

The Commission would adjust stranded cost charges on a prospective basis and not reconcile or true-up amounts to reflect past "actual" values. The purpose of periodic reviews is only to correct substantial estimation inaccuracies, not to guarantee dollar-for-dollar recovery or to reflect minor fluctuations in market value.

BHE and MPS supported a dollar-for-dollar reconciliation of stranded costs to account for any inaccuracy in estimates. However, such an approach could weaken incentives to mitigate stranded costs. With reconciliation, utilities would be financially indifferent with respect to mitigation. The regulatory lag created by a system of forward-looking rate adjustments has the additional benefit of giving T&D utilities a stake in the success of the competitive power market. A lower market price for power should stimulate T&D sales and, to the extent the stranded cost charge is based on usage, increase the T&D companies' revenues and profits. This stake would be lost, however, if past collections were somehow "reconciled."

b. Methodology

For utility-owned power plants, the Commission would estimate stranded costs by calculating the difference between net plant investment and the value of expected future profits. For purchased power contracts, it would calculate the difference between future contract payments and the market value of the power.[56] The stranded cost for each asset or contract could be positive or negative depending on whether the market value is less or greater than the remaining cost.

Another approach to calculating stranded costs, sometimes called the "revenues lost" approach, simply subtracts the costs the utility saved by the departure of a customer lost to a competitor from the revenues lost.[57] This methodology may be useful in certain circumstances, such as where an entire municipality leaves the utility's system. Conceptually, however, there is a closer match between uneconomic costs of generation and the introduction of competition in the retail generation market. For that reason, the Commission prefers to focus on generation-related assets.

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[56]All calculations would reflect present value where appropriate.

[57]FERC has asserted jurisdiction over stranded cost recovery associated with wholesale service and the formation of new retail utilities, such as municipalizations. *FERC* Order No. 888 (April 24, 1996). FERC has indicated that it will use the lost revenue approach to calculating stranded costs. Because of FERC's assertion of jurisdiction, the recommended plan does not address stranded cost recovery with respect to pre-existing wholesale arrangements or the creation of new retail utilities.

The Commission's range of stranded cost estimates together with a more detailed discussion of methods is contained in Appendix 5.

4. Recovery Mechanisms and Rate Design

The stranded cost liability associated with retail competition would lie with the T&D utilities and be recovered in regulated rates. Stranded costs result from obligations incurred by regulated utilities, and it is appropriate that they be recovered from the ratepayers of regulated entities. If stranded costs were recovered by unregulated power providers, those companies would have advantages and burdens neither available to nor imposed upon competitors. For example, if a generation company receives stranded cost payments, it would have an identifiable revenue stream that could provide cash flow advantages.

The Commission would design rates to recover stranded costs for each utility prior to retail competition. All customers using the services of the T&D utility would pay stranded cost charges. Because customers that buy power in a competitive market could be expected to buy the same amount of power they did from the utility before retail competition, it may be appropriate to impose a usage-sensitive rate for stranded costs. The Paradigm favored this approach. However, stranded costs rates should also be designed to satisfy other goals, such as economic efficiency, equity, rate stability, and should encourage choice among competitors based on their economic costs. Accordingly, the Commission would explore rate designs that are less usage sensitive, such as per maximum kW charges or flat access charges. To establish rate designs, the Commission would consider the amount to be recovered, the period over which recovery will occur, and rate designs adopted in other jurisdictions.

CMP proposed that the Commission allow CMP to impose limits on customers' opportunity to avoid paying their fair share of stranded costs. Non-utility commenters generally opposed exit fees. The Commission does not believe exit fees are either practical or appropriate. Proponents of exit fees claimed that the demand for electricity of particular customers has caused utilities to incur certain costs on their behalf, and that these same customers should pay these costs. This claim is doubtful. Power purchases are rarely customer-specific. Moreover, if the idea is to match cost-recovery with cost-causation, some daunting questions emerge. Should customers have to be on the system any particular length of time before any exit fee would apply? Should customers who entered the system last year be required to pay an exit fee if they leave the system next year? If so, should the amount of the exit fee be the same as for a customer that has been on the system for 30 years? Should exit fees apply to customers that enter the system in the future? None of these questions has a felicitous answer.

Exit fees could also adversely affect Maine's business climate. If exit fees applied to businesses who were utility customers on a specific date, only newer businesses could switch power suppliers without paying an exit fee. If exit fees applied to new customers, it could dissuade businesses from entering the

State. What business would move to Maine if its flexibility to move in the future were so constrained?

Exit fees are an extraordinary remedy. That approach might be justified where its absence would result in either extreme financial stress on the utility or unacceptable rate increases for utility ratepayers.[58] An exit fee or similar rate design should not be adopted without a substantial demonstration of ratepayer harm.

C. Further Proceedings

The Commission would establish initial estimates of stranded costs prior to 2000, using market information to the greatest extent possible. The Commission would also establish the rates that each T&D utility would be allowed to charge to recover the stranded costs subject to recovery. These proceedings are likely to be complex, both with respect to the proper calculation of stranded costs, and the rate design appropriate for their collection. Because an important component of the calculation of stranded costs is the market price for power, the Commission would conduct further proceedings after 2000 to update the stranded cost charges based on then current market conditions. In addition, there would be

[58]For example, the Massachusetts Commission imposed an exit fee for a large customer to avoid a significant impact on the utility and its remaining ratepayers. *Re: Cambridge Electric Light Co.,* 164 PUR 4th 69 (Sept. 28, 1995). The California Legislature has authorized charges to customers that bypass their utility's system as part of a comprehensive restructuring plan that includes innovative financing to obtain rate decreases for all to customers.

a link between this case and the bidding process for QF contracts, because the results of that process would have an effect on the level of stranded costs.

Some of the issues to be determined in these proceedings are whether sufficient efforts have been undertaken to mitigate stranded costs; the estimation of the future market price for power; the proper level of stranded cost recovery for each customer class; and the specific rate design for the stranded cost recovery charge.

Because the factors influencing the size of stranded costs are unique to each utility, the Commission would conduct separate proceedings for each investor- and consumer-owned utility. Under the Commission's Implementation Schedule, a nine-month proceeding for CMP would begin in late 1997, with the proceedings for BHE and MPS beginning in January 1998 and April 1998, respectively. The proceedings for the consumer-owned utilities would likely be less complex and would begin in April 1998. To ensure that rates reflect the most up-to-date information and analyses available, concurrent limited reviews may be needed between April and December 1999 for each of the utilities.

VIII. REGIONAL ISSUES

A. Recommendation

Maine cannot resolve all issues that will determine whether retail competition will succeed. Some issues must be addressed on a regional level or before the Federal Energy Regulatory Commission (FERC). Regional issues include the reliability of the bulk power and transmission systems, and the fair and efficient operation of the power market. The Commission, together with the New England Conference of Public Utility Commissioners (NECPUC), the New England Governor's Conference (NEGC) and others, would continue to work to resolve these issues.

Issues that affect Maine's ability to benefit from competition include governance reform of the New England Power Pool (NEPOOL) to allow fair and meaningful representation for all market participants; the existence of an Independent System Operator (ISO) for the transmission system that would be effectively independent and have no financial interest in any market participants; the creation and operation of a voluntary power exchange, either as an independent entity or as part of a reformed NEPOOL; and rules to ensure that providers meet the North American Electric Reliability Council (NERC) reliability standards.

B. Discussion

1. Perspective

FERC and state regulatory commissions regulate different aspects of electric transmission. FERC has authority over rates charged for interstate transmission and limited authority over reliability.[59] State commissions have authority over transmission facility siting within the state, and jurisdiction over retail rates.[60] This jurisdictional overlap creates challenges for restructuring, particularly in regions with tightly integrated, multi-state power systems. In New England, facilities owned by many different companies and located in six different states operate as a single system. NEPOOL coordinates and operates the system. Facility owners participate voluntarily in NEPOOL, and FERC oversees its governing agreements. Thus, a single state cannot mandate changes to the New England system necessary to accommodate competition.

In the New England region, power is regularly bought and sold in a wholesale market. The rules of NEPOOL, for the most part, govern this market. NEPOOL, which comprises more than 100 utilities in the region, has major responsibilities for planning and operating the region's generation and transmission facilities to ensure load is served reliably and economically. NEPOOL is

[59]Under section 202(c) of the Federal Power Act, FERC may require utility actions related to reliability if it determines that an emergency exists.

[60]FERC has indicated that it has jurisdiction to determine the rates for separated or unbundled retail transmission service. *FERC Order No. 888* (April 24, 1996).

organized and operates according to an agreement of the member companies, and is under FERC jurisdiction. Historically, NEPOOL's membership has been limited to utilities, and the largest utility members dominate its control.

State Commissions have two formal ways to influence NEPOOL: state regulation of the member companies within each state's jurisdiction and participation in FERC proceedings either individually or with other New England Commissions. The Commission can also communicate its views about regional issues to NEPOOL in less formal ways. The Commission would continue to pursue a variety of means to help bring satisfactory resolution of regional issues. Specifically, the Commission would continue to participate through informal and, if necessary, formal intervention at FERC, to reform NEPOOL, to form an ISO, and to develop a regional transmission group (RTG). As the restructuring proceeds in New England and elsewhere, the Commission would continue to be involved in regional issues to the extent consistent with Maine's interests.

2. Reliability

Maintaining the reliability of the electric power system is critically important. Restructuring should not be allowed to result in degradation of the regional power system's reliability. The current industry standard for bulk power system reliability, set by the NERC, provides that there should be no more than one day in 10 years that load cannot be served because of inadequate transmission or generation resources.

Traditionally, utilities in the region have cooperated to maintain system reliability. Utilities have shared information including expected load growth, system constraints, and construction plans. The vertical monopoly structure of the industry has aided this cooperation. In a competitive environment, companies may be less forthcoming with information. This could make maintaining sufficient reliability more difficult. The Commission would work to ensure that regional structures exist and have the authority to ensure system reliability. All competitors providing power to Maine customers would conform to appropriate regional and national reliability standards.

Commenters supported measures to ensure reliability of the region's power system. The Paradigm included regional reliability requirements.[61] Central Maine Power Company (CMP) suggested reliability could be more easily maintained if bilateral contracts were purely financial instruments and had no impact on system operation. Further, CMP asked the Commission to specify reliability standards that competitive providers in Maine would have to meet.

The Commission should not dictate particular reliability standards. CMP's concerns are best addressed through a reformed NEPOOL and an effective ISO, and through the requirement that all power providers who sell to

[61]In a survey recently conducted for the Commission, Maine's residential and small business customers identified reliability as the most important aspect of electric power.

Maine's consumers would have to conform to appropriate regional reliability standards.

3. Governance Issues in NEPOOL Reform

An essential feature for any entity that controls or coordinates regional market operation is meaningful and fair representation of all market participants. The recently expanded NEPOOL membership indicated the intent to file documents with FERC that would reform NEPOOL to accommodate a more competitive and open generation market, and to allow non-utility interests a voice within NEPOOL regarding how the market operates. The Commission has participated in and monitored the progress of NEPOOL restructuring discussions and will continue to work toward a system that provides appropriate representation for all market participants.

4. The Independent System Operator

The region's integrated bulk power and transmission systems require an operator to ensure the coordination of generation and load. In New England, the system operator oversees the generation and transmission resources of all companies within NEPOOL to ensure reliability and to minimize the costs of serving the aggregate pool load. Currently, the New England Power Exchange (NEPEX), an arm of NEPOOL, performs this function. To the extent system operation is linked directly to the financial interests of market participants, as it is now, the tasks may not be performed in a competitively neutral manner.

Therefore, the Commission supports creating an ISO with no financial interest in the success or failure of any particular market participant, or group of participants. It would continue to work toward that end. Commenters generally supported the ISO concept, but differed about the degree and form of independence necessary. The Paradigm included provisions for an ISO that would have no financial relationship to energy providers. The Commission would continue to work toward the creation of a truly independent ISO.

5. Transmission Pricing and Access

A healthy competitive market for generation depends on the availability of transmission services at non-discriminatory terms and prices. The FERC has made clear its requirements in this regard. There are ongoing efforts to establish the framework and rules for a RTG in New England to carry out FERC's mandates. The Commission has been and will continue to participate in these efforts and, if necessary, in related FERC proceedings.

Because there are separately owned transmission systems over which power flows in New England, there are difficult issues regarding how the region's transmission services should be administered and priced. As a general matter, prices for transmission should recover the transmission provider's cost of service and encourage the efficient use and expansion of the regional bulk power system. Existing pricing systems that discriminate or artificially favor the purchase of power from one generation unit above another (e.g., Pool Transmission Facility (PTF) rates)[62] should be eliminated over time. The Commission would continue to work to ensure that the rules and prices governing transmission in the region are consistent with fair and efficient market competition, and do not unduly disadvantage sellers or buyers in Maine.

Commenters generally agreed that transmission access and pricing must be open, fair, and efficient. The Paradigm reflected these same principles. Bangor Hydro-Electric Company (BHE) suggested the Commission not promote eliminating the PTF rate until a new method of pricing exists that ensures open access to regional transmission facilities at reasonable rates. According to BHE, eliminating PTF rates without reasonably priced open access transmission would limit competition and create opportunities for market power. The Commission expects the elimination of PTF-type rates would occur in the context of the RTG. Thus, the pool-wide rates and terms reflected in the RTG would replace PTF rates and, in principle, ensure fair and equal access to regional transmission. It may also be appropriate to phase-out PTF arrangements gradually to facilitate agreement on an RTG and minimize near-term disruptions for BHE and similarly situated utilities.

[62]The PTF rate was established by NEPOOL members to encourage joint ownership in large generating units distributed around the region.

6. The Power Exchange

Certain structures can help market operations and provide participants with information to make informed and economic choices. In the emerging electric power markets, a regional power exchange could perform these functions. The power exchange would be a spot market, allowing for market transactions in real time without the need for specific contracts between individual buyers and sellers. The exchange would receive and rank power supply bids, and determine and post market clearing prices. Participation in the exchange would be voluntary. Other power exchanges or similar mechanisms could evolve and coexist with or replace this exchange. The power exchange could be part of the same organization that provides the ISO services, though some have advanced theoretical arguments supporting a fully separate organization.

Enron Capital and Trade Resources (Enron) asserted there is no reason to create a power exchange. According to Enron, open transmission access and unbundled rates, together with the interplay of buyers, sellers, and merchants would achieve an effective and efficient market. In addition, Enron argued that the creation of a power exchange could hamper the development of a forward market. However, if established, Enron argued the exchange must be independent of the ISO and cease to exist by a certain date.

The Commission believes a power exchange is likely to perform an important role in the development of effective competition. If, as Enron asserted, the power exchange is unnecessary or uneconomic, buyers and sellers would use it little, or not at all. Thus, if Enron is correct, the market itself would eliminate the exchange. If it is voluntary, a power exchange should not hinder other transactions nor preclude the development of forward markets if such markets are efficient.

7. Horizontal Market Power Study

There is a risk that some market participants may control a large enough share of the region's power supply to allow them to exert undue influence over market prices. In that event, the benefits of restructuring would not flow to consumers.

To the extent possible, opportunities for market power should be minimized before retail competition. After-the-fact anti-trust enforcement would be expensive and likely ineffective, because the unlawful exercise of market power is difficult to detect and even more difficult to prove. The Commission recommends that the Legislature direct state agencies, including the Commission, to study regional power market and recommend steps to minimize market power opportunities before the date of retail access.

C. Further Proceedings

The Commission would continue its efforts at the regional level and, if needed, at FERC to resolve regional restructuring issues. The Commission does not currently anticipate proceedings before the Maine Commission to resolve the matters discussed in this section.

Appendix 1

STATE OF MAINE

IN THE YEAR OF OUR LORD NINETEEN HUNDRED AND NINETY-FIVE

S.P. 386 - L.D. 1063

Resolve, to Require a Study of Retail Competition in the Electric Industry

Emergency preamble. Whereas, Acts and resolves of the Legislature do not become effective until 90 days after adjournment unless enacted as emergencies; and

Whereas, it is immediately necessary to begin the study of an orderly transition to a competitive electric energy market to ensure that the transition is orderly and conducted in the best interests of the State; and

Whereas, in the judgment of the Legislature, these facts create an emergency within the meaning of the Constitution of Maine and require the following legislation as immediately necessary for the preservation of the public peace, health and safety; now, therefore, be it

Sec. 1. Study. Resolved: That the Public Utilities Commission and the Work Group on Electric Industry Restructuring, which is created by this resolve, shall conduct a study of the electric industry in order to develop plans, consistent with the public interest, that establish guidelines and requirements for an orderly transition to a competitive market for retail purchases and sales of electric energy; and be it further

Sec. 2. Issues. Resolved: That the Public Utilities Commission and the work group shall study the issues associated with the orderly transition to a competitive market for retail purchases and sales of electric energy, including at least the following:

1. How utility stranded investment is defined and calculated and how it will be dealt with;

2. How the regional marketplace and federal law affect the transition;

3. How the State's energy policy, including policies concerning conservation, use of renewable and indigenous resources and diversity of supply, will be affected;

4. How the State's environment and environmental policies will be affected;

5. How social policies, including low-income programs and universal service goals, will be affected;

6. How ratepayers, shareholders of investor-owned electric utilities, owners of consumer-owned electric utilities and other owners of energy resources will be affected;

7. How the State's economy will be affected;

8. How reliability of service will be affected;

9. How obligations of contracts will be affected;

10. How a system for the transmission, distribution and generation of electricity should be structured; and

11. To what extent protections against anticompetitive practices can be provided; and be it further

Sec. 3. Work group created. Resolved: That the Work Group on Electric Industry Restructuring, referred to in this resolve as the "work group," is established; and be it further

Sec. 4. Work group membership; meetings; chair. Resolved: That the work group consists of 18 members as follows:

1. Four Legislators who must be members of the Joint Standing Committee on Utilities and Energy, appointed jointly by the chairs of that committee;

2. One member representing the State Planning Office, appointed by the Governor;

3. The Public Advocate or the Public Advocate's designee;

4. One member representing the Public Utilities Commission, appointed by the chair of the commission;

5. One member representing Central Maine Power Company, designated by the president of the company;

6. One member representing Bangor Hydro-electric Company, designated by the president of the company;

7. One member representing Maine Public Service Company, designated by the president of the company;

8. One member representing the consumer-owned electric utilities, designated by Dirigo Electric Cooperative;

9. One member representing small business customers, appointed by the Governor;

10. One member representing the Industrial Energy Consumer Group, designated by that group;

11. One member representing the Conservation Law Foundation, appointed by the foundation;

12. One member representing the Independent Energy Producers of Maine, designated by that group;

13. One representative of Maine Yankee Atomic Power Company, designated by the president of the company; and

14. Two members appointed by the Governor representing the interests of low-income or elderly customers.

Appointments and designations must be made no later than 30 days following the effective date of this resolve. The appointing and designating entities shall notify the Executive Director of the Legislative Council upon making their appointments or designations.

When the appointment and designation of all members of the work group is completed, the chair of the Legislative Council shall call the work group together for its first meeting no later than July 30, 1995. The work group shall select a legislative member as chair; and be it further

Sec. 5. Work group study; duties. Resolved: That the work group shall examine at least the issues listed in section 2 of this resolve. To the extent the work group can reach agreement on how the issues should be dealt with, the work group shall develop a plan for the orderly transition to a competitive market for retail purchases and sales of electric energy. The plan must identify all necessary regulatory and statutory changes. Any plan developed by the work group must be supported by at least 12 members of the work group. The work group shall identify all issues on which the work group can not come to agreement; and be it further

Sec. 6. Staff. Resolved: That the work group may request staffing assistance from the Legislative Council. The work group may also request clerical assistance from the Legislative Council; and be it further

Sec. 7. Resources; procedures. Resolved: That the work group may:

1. Seek and receive funding from governmental entities or from nonprofit organizations for all or portions of the costs of conducting the study. The work group may accept and spend funds only if approved by the Legislative Council and a majority of the work group members approve of the funding source. The Executive Director of the Legislative Council shall administer the work group's budget;

2. Collect and analyze relevant information and data;

3. Conduct literature searches;

4. Conduct legal research and prepare legal opinions on questions within the scope of the study;

5. Hold meetings at convenient times and locations; and

6. Seek and receive assistance and information from any agency of State Government; and be it further

Sec. 8. Compensation. Resolved: That the members of the work group who are Legislators are entitled to the legislative per diem as defined in the Maine Revised Statutes, Title 3, section 2, for each day's attendance at the work group's meetings; and be it further

Sec. 9. Work group report. Resolved: That, unless an extension is approved by the Legislative Council, the work group shall present its findings in a report to the Second Regular Session of the 117th Legislature, the Joint Standing Committee on Utilities and Energy and the Public Utilities Commission no later than November 1, 1995; and be it further

Sec. 10. Public Utilities Commission investigation. Resolved: That the Public Utilities Commission shall conduct a study to develop at least 2 plans for the orderly transition to a competitive market for retail purchases and sales of electric energy as follows:

1. A plan to achieve full retail market competition for purchases and sales of electric energy by the year 2000. The plan must identify all necessary regulatory and statutory changes. The plan must be accompanied by a detailed critique of the plan addressing at least the issues identified in section 2 of this resolve; and

2. A plan to achieve retail market competition for purchases and sales of electric energy wherever effective competition is likely and to maintain appropriate regulation in areas where it is determined to be necessary. The plan must identify all necessary regulatory and statutory changes. The plan must be accompanied by a detailed critique addressing at least the issues identified in section 2 of this resolve.

In each plan, the commission shall provide a range of estimates of the costs of each affected utility's stranded investment.

The commission shall incorporate into at least one of the plans it develops all portions of any plan developed by the work group that was supported by at least 12 members of the work group.

The commission shall identify the plan which the commission believes to be in the best interests of the State; and be it further

Sec. 11. Commission process. Resolved: That in conducting its study, the Public Utilities Commission:

1. Shall begin no later than January 1, 1996;

2. Has discretion to distinguish issues of policy, to be resolved by discussion and briefing, from issues of fact, to be resolved by normal evidentiary proceedings, including by stipulation. With respect to any issue of fact, or otherwise as the commission determines necessary, consistent with the time deadlines contained in this resolve, the commission may streamline the discovery and the hearing process to efficiently utilize the resources of the commission and the parties while ensuring the determination of facts necessary for its decision-making and for substantiating recommendations to the Legislature;

3. Shall examine information related to the issues listed in section 2 of this resolve that is available from other states and other countries on electric utility restructuring;

4. Shall examine information related to the issues listed in section 2 of this resolve that is available on transitions in other industry sectors from a highly regulated market to a competitive market;

5. To the extent possible, pursuant to its authority under the Maine Revised Statutes, Title 35-A, section 118 and any other provision of law, shall seek input from and share information with regulatory bodies and other entities in the other New England states and other states of the northeastern United States; and

6. Shall conduct a minimum of 4 hearings at different locations throughout the State to receive public comment; and be it further

Sec. 12. Legal effect. Resolved: That none of the findings of the Public Utilities Commission has legal effect. The purpose of the study is to provide information to the commission in order to allow it to make informed decisions in developing its plans and to provide information to the Legislature in order to allow the Legislature to make informed decisions when it evaluates those plans; and be it further

Sec. 13. Report. Resolved: That no later than January 1, 1997, the Public Utilities Commission shall complete its study and submit a report of its findings, including the required plans and critiques, to the First Regular Session of the 118th Legislature and to the joint standing committee of the Legislature having jurisdiction over utilities matters; and be it further

Sec. 14. Committee authority. Resolved: That the joint standing committee of the Legislature having jurisdiction over utilities matters may, by unanimous or majority vote of the committee, report out legislation to the First Regular Session of the 118th Legislature on electric industry restructuring; and be it further

Sec. 15. Appropriation. Resolved: That the following funds are appropriated from the General Fund to carry out the purposes of this resolve.

1995-96

LEGISLATURE

Work Group on Electric Industry Restructuring

Personal Services	$1,100
All Other	1,500

Provides funds for the per diem and expenses of legislative members and miscellaneous costs of the Work Group on Electric Industry Restructuring.

LEGISLATURE TOTAL	$2,600

Emergency clause. In view of the emergency cited in the preamble, this resolve takes effect when approved.

Proposed Restructuring Legislation

This appendix contains proposed legislation to implement the Commission's Report and Recommended Plan on Electric Utility Industry Restructuring issued on December 31, 1996.

This proposed legislation is intentionally less specific than the Restructuring Report. As is discussed in detail in the Report, the full implementation of the Commission's recommendations is contingent on a variety of circumstances and developments. The proposed legislation is drafted in a way that, if enacted, would specify the limits of the Commission's authority to implement the restructuring plan while simultaneously providing sufficient flexibility to accommodate evolving circumstances that may arise during the implementation of the Plan.

This proposed legislation is not the only legislation that will ultimately be needed to restructure Maine's electric utility industry. This proposed legislation would only allow the Commission to begin the transition to retail competition. Many additional changes to Title 35-A and other titles in Maine statutes will have to be made before the process can be completed. At each step of the process, the Legislature will have the opportunity to review how events are unfolding and determine the proper next steps.

The Commission recognizes that the legislative role of setting the proper balance between allowing the flexibility essential to any effective regulatory process and articulating clear policy is especially complex where comprehensive change is proposed. The Commission is committed to assisting the Legislature in any way it can to find that balance for the future of electricity regulation in Maine.

Proposed Restructuring Legislation

AN ACT to Restructure Maine's Electric Industry

Sec. 1. 35-A M.R.S.A. ch. * is enacted to read:**

CHAPTER ***
ELECTRIC RESTRUCTURING

§ 1. Findings and purpose.

1. Findings. The Legislature finds that:

A. Where viable markets exist, market mechanisms should be preferred over regulation, and the risk of business decisions should fall on investors rather than consumers;

B. Customers' needs and preferences should be met with the lowest costs;

C. All customers should have a reasonable opportunity to benefit from a restructured electric industry;

D. Electric industry restructuring should not diminish environmental quality, compromise energy efficiency or jeopardize energy security;

E. All customers should have access to reliable, safe and reasonably priced electric service;

F. Electric industry restructuring should not diminish low-income assistance or other consumer protections;

G. The electric industry structure should be lawful, understandable to the public, and fair and perceived to be fair; and

H. Electric industry restructuring should improve the state's business climate.

2. Purpose. The purposes of this chapter are:

A. To promote efficient and effective competition in the market for the generation and sale of electricity in the state;

B. To ensure that all consumers of electricity are able to benefit from competition;

C. To provide an orderly transition from the current form of regulation to retail competition for electricity;

D. To continue to provide the public with opportunities to participate in decisions concerning electric restructuring; and

E. To ensure that the commission has all necessary authority to implement an electric restructuring plan consistent with the findings and purposes expressed in this chapter.

§ 2. Definitions

As used in this chapter, unless the context otherwise indicates, the following terms have the following meanings.

1. Affiliated interest. "Affiliated interest" has the same meaning as provided in section 707(1)(A).

2. Competitive generation provider. "Competitive generation provider" means generators, marketers, brokers, aggregators or any other entity producing or selling electric power to meet retail customers' demand.

3. Consumer owned transmission and distribution utility. "Consumer owned transmission and distributed utility" means any transmission and distribution utility which is wholly owned by its consumers, including, but not limited to:

A. The transmission and distribution portion of any rural electrification cooperative organized under chapter 37;

B. The transmission and distribution portion of any electrification cooperative organized on a cooperative plan under the laws of the state;

C. Any municipal or quasi-municipal transmission and distribution utility;

D. The transmission and distribution portion of any municipal or quasi-municipal entity providing generation and other services; and

E. Any transmission and distribution utility wholly owned by a municipality.

4. Divest. "Divest" means to legally transfer ownership and control to an entity that is not an affiliated interest.

5. Large investor owned transmission and distribution utility. "Large investor owned transmission and distribution utility" means an investor owned transmission and distribution utility serving more than 50,000 retail customers.

6. Qualifying facility. "Qualifying facility" has the same meaning as provided in section 3303.

7. Retail access. "Retail access" means the right of any retail consumer of electricity to purchase generation services from a competitive generation provider.

8. Small investor owned transmission and distribution utility. "Small investor owned transmission and distribution utility" means an investor owned transmission and distribution utility serving 50,000 or fewer retail customers.

9. Transmission and distribution plant. "Transmission and distribution plant" includes all real estate, fixtures and personal property owned, controlled, operated or managed in connection with or to facilitate the transmission, distribution or delivery of electricity for light, heat or power, for public use, and all conduits, ducts or other devices, materials, apparatus or property for containing, holding or carrying conductors used or to be used for the transmission or distribution of electricity for light, heat or power for public use.

10. Transmission and distribution utility. "Transmission and distribution utility" includes every person, its lessees, trustees, receivers or trustees appointed by any court owning, controlling, operating or managing any transmission and distribution plant.

§ 3. Retail access

1. Right to purchase generation service. Beginning on January 1, 2000, all consumers of electricity have the right to purchase generation service directly from competitive generation providers. The commission may advance or delay the date for retail access by not more than 90 days if necessary to achieve the purposes of this chapter.

2. Aggregation permitted. When retail access begins, all consumers of electricity may aggregate their purchases of generation services in any manner they choose.

3. Public agency may not restrict choice. If a public agency serves as an aggregator, it may not require consumers of electricity within its jurisdiction to purchase generation services from that agency.

§ 4. Deregulation of generation services

Except as otherwise provided in this chapter, competitive generation providers are not subject to regulation under this Title as of January 1, 2000.

§ 5. Structural separation and divestiture of generation

1. Structural separation required. On or before January 1, 2000, each investor owned electric utility shall transfer to a distinct corporate entity all generation assets and generation-related business activities, including electric energy sales activities, and generation-related contracts, except as provided in subsection 3. The commission shall determine the extent of separation between affiliates that is required under this subsection.

2. Interests in generation restricted. Except as otherwise provided in this section, on or after January 1, 2000, no investor owned transmission and distribution utility may:

A. Acquire or hold any financial or ownership interest in generation assets or generation-related business activities or contracts for generation; or

B. Produce, purchase, sell, market, aggregate customers, broker, or engage in any similar activity relating to generation capacity or energy.

3. Sale of capacity and energy required. Investor owned utilities may not be required to transfer to a distinct corporate entity contracts with a qualifying facility. Beginning January 1, 2000, each large investor owned transmission and distribution utility shall sell all rights to capacity and energy from its contracts with qualifying facilities. Beginning January 1, 2006, each large investor owned transmission and distribution utility shall sell all the rights to capacity and energy from any contracts with the Maine Yankee Atomic Power Company.

4. Divestiture required; exception. On or before January 1, 2006, each large investor owned transmission and distribution utility shall divest all generation assets and generation-related business activities, except contracts with qualifying facilities and the Maine Yankee Atomic Power Company. After divestiture, no large investor owned transmission and distribution utility may have any affiliated interest in a competitive generation provider.

5. Commission may require divestiture of Maine Yankee interests. Notwithstanding any other provision of this chapter, the commission may, if necessary to achieve the purposes of this chapter, require any investor owned transmission and distribution utility to divest its interest in the Maine Yankee Atomic Power Company on or after January 1, 2009.

6. Commission may require exempt utilities to divest. The commission may require any small investor owned transmission and distribution utility to divest, and thereafter have no affiliated interest in a competitive generation provider, except contracts with qualifying facilities and the Maine Yankee Atomic Power Company. In order to require divestiture under this subsection, the commission must find that divestiture is necessary to achieve the purposes of this chapter.

7. Generation assets permitted. On or after January 1, 2000, notwithstanding any other provision in this chapter, the commission may allow an investor owned transmission and distribution utility to own, have a financial interest in, or otherwise control generation and generation-related assets to the extent that the commission finds such ownership, interest or control is necessary for the utility to perform its obligations as a transmission and distribution utility in an efficient manner. The transmission and distribution utility may not sell the energy or capacity from generation that it owns, has a financial interest in, or otherwise controls to any retail customer.

8. Retail marketing restricted; wholesale marketing prohibited; exception. Except as provided in subsection 6, after January 1, 2006, consumer owned transmission and distribution utilities and affiliated interests of small investor owned transmission and distribution utilities:

A. May provide retail generation service only within their respective service territories; and

B. May not provide wholesale generation service except that incidental wholesale sales are permitted if necessary to reduce the cost of providing retail service.

§ 6. Regulation of transmission and distribution utilities

Nothing in this chapter limits the commission's authority to regulate electric transmission and distribution service and to ensure that all consumers of electricity are afforded transmission and distribution service at just and reasonable rates.

§ 7. Stranded cost recovery

Beginning with the implementation of retail access, the commission shall provide electric utilities a reasonable opportunity to recover, through the rates of the transmission and distribution utility, legitimate, verifiable and unmitigatable costs made unrecoverable as a result of retail access. Prior to the implementation of retail access, the commission shall determine the amount of these costs for each electric utility and may subsequently adjust these costs as necessary.

§ 8. Standard offer service

At the time retail access begins, the commission shall ensure that standard offer service is available to all consumers of electricity, except that the Commission may establish eligibility requirements that exclude consumers of electricity with demands above a specified amount if the Commission finds that these consumers do not need standard offer service and their eligibility for the service would increase its costs. The commission shall establish terms and conditions for standard offer service. Standard offer service must be available until January 1, 2005 and may be continued after that date if the commission finds it necessary. Nothing in this section precludes the commission from permitting or requiring different terms and conditions for standard offer service in different utility service territories and for different customer classes.

§ 9. Consumer protection

The commission shall ensure that all retail customers are protected to the greatest extent possible from unfair trade practices, fraud, and other unreasonable practices by competitive generation providers and transmission and distribution utilities.

1. Authority. In implementing this section, the commission, notwithstanding any other provision of this chapter:

A. Registration. Shall impose reasonable registration requirements on competitive generation providers;

B. Consumer protection standards. Shall establish consumer protection standards to protect retail consumers of electricity from fraud or other unreasonable business practices. Violations of the consumer protection standards shall be a civil violation for which the Commission may impose penalties, not exceeding $5,000 for each occurrence.

C. Dispute resolution. Shall resolve disputes between competitive generation providers and retail consumers of electricity with respect to Commission established customer protection standards;

D. Disconnection restricted. May forbid transmission and distribution utilities from disconnecting electric service to any consumer of electricity based on nonpayment of charges owed or alleged to be owed to any competitive generation provider. The commission may permit disconnection of electric service to consumers of electricity based on nonpayment of charges for standard offer service;

E. Disclosure. May require the disclosure, to the extent necessary to achieve the purposes of this chapter, of information about the competitive generation provider's services,including, but not limited to information about the characteristics of the generation assets used by the competitive generation provider. The Commission shall provide for reasonable confidentiality protections, if necessary;

F. Maine Unfair Trade Practices Act. Has concurrent authority with the Attorney General to act under the Maine Unfair Trade Practices Act with respect to retail sales activities of competitive generation providers; and

G. Additional actions. May impose any additional requirements necessary to carry out the purposes of this chapter, except that this section may not be construed to permit the commission to regulate the rates of any competitive generation provider.

§ 10. Energy policy

The commission shall, in a manner consistent with the requirements of an efficient and effective competitive market for electricity, promote the development and use of renewable resources in producing electric power and promote the use of conservation and load management.

1. Authority. In carrying out the requirements of this section, the commission may, without limitation on other actions it considers necessary:

A. Renewable resources. Require competitive generation providers to produce, or obtain credits for, a specified portion of their electric power sold to consumers of electricity in the state using renewable resources; and

B. Conservation programs. Require transmission and distribution utilities to implement energy conservation programs and include the cost of any such programs in rates.

§ 11. Consumer education and information

The commission shall take all steps necessary to ensure that, prior to the implementation of retail access, electricity consumers are aware, to the greatest extent practicable, of the opportunities and risks of electric restructuring.

1. Authority. In implementing this section, the commission may, without limitation on other actions it considers necessary:

A. Unbundled bills. Require electric utilities to issue bills which, to the extent practicable, state the current cost of electric capacity and energy separately from other charges for electric service; and

B. Publish information. Publish and disseminate, through whatever means it considers appropriate, information that will enhance customers' ability to exercise their choices in a competitive electricity market effectively.

§ 12. Commission proceedings and report

1. Commission proceedings. The commission shall conduct any proceedings necessary to implement this chapter. Nothing in this chapter is intended to exempt the commission from the requirements of Title 5, section 8071, to the extent the Commission adopts any major substantive rules.

2. Annual restructuring report. On December 31st of each calendar year, the commission shall submit to the Joint Standing Committee on Utilities and Energy, a report describing the commission's activities in carrying out the requirements of this chapter and further describing activities relating to changes in the regulation of electric utilities in other jurisdictions.

§ 13. Proposed changes

If the commission determines, after providing interested parties an opportunity to be heard, that any provision in this chapter is not in the public interest, the commission shall present a report to the joint standing committee of the Legislature having jurisdiction over utility matters stating the basis for the commission's conclusion and including draft legislation designed to modify this chapter consistent with the public interest.

Sec. 2. Recommendation for Low Income Program. On or before January 1, 1998, the commission and the State Planning Office shall provide to the Joint Standing Committee on Utilities and Energy, to the Joint Standing Committee on Appropriations and Financial Affairs, to the Joint Standing Committee on Taxation, and to any other committees of relevant jurisdiction, draft legislation that would fund assistance to low income consumers of electricity through the general fund or through a tax on all energy sources in the state.

Sec. 3. Market power report. On or before December 1, 1998, the commission shall submit a report to the Joint Standing Committee on Utilities and Energy, on whether market power exists or is likely to arise in the generation market in New England.

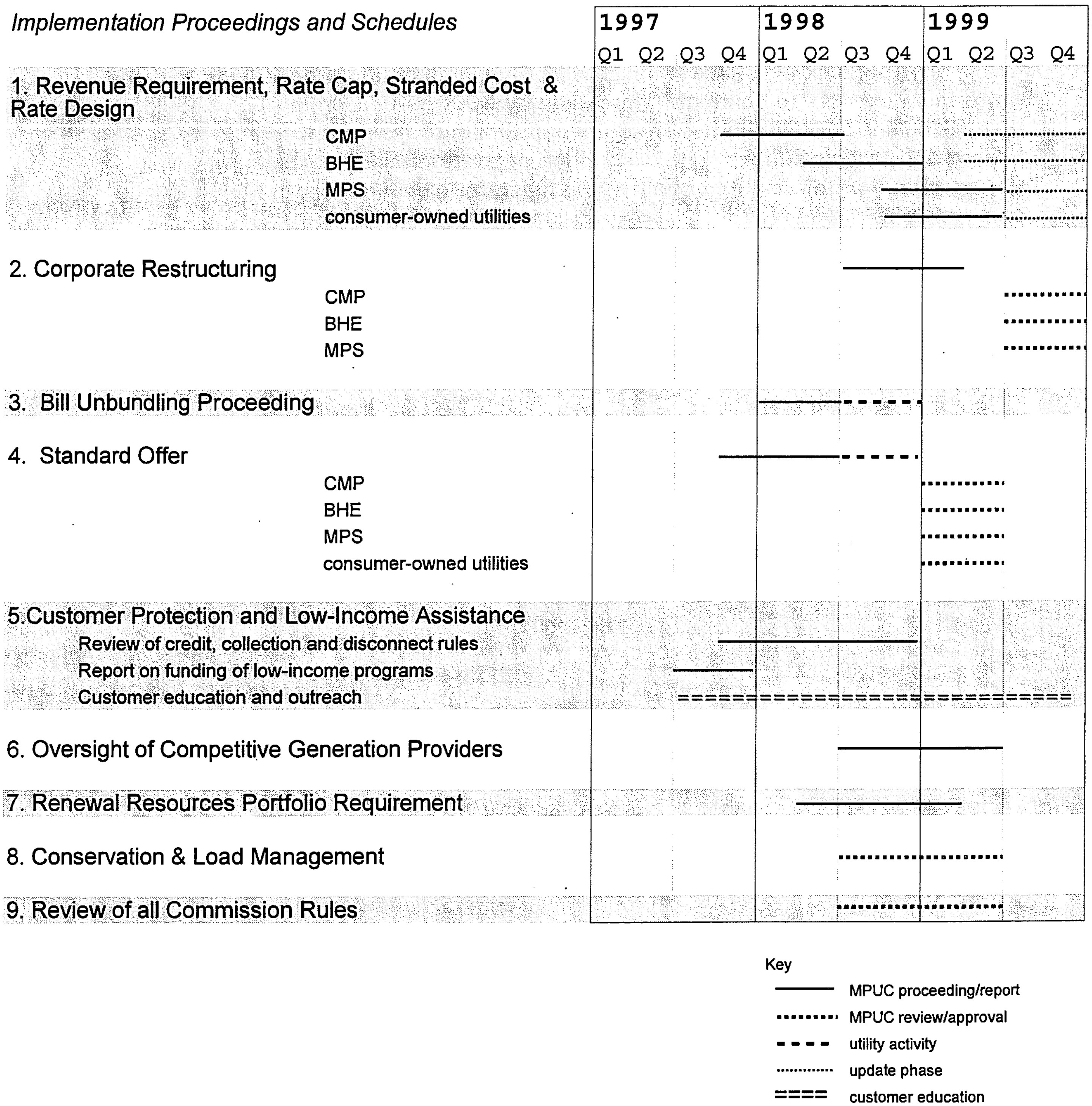
Sec. 4. Conforming amendments. The commission shall identify and submit to the Legislature by December 31, 1998, for enactment any amendments required to conform other statutes to the provisions of this Act.

IMPLEMENTATION PROCEEDINGS AND SCHEDULES

I. BACKGROUND

This Appendix describes the nine major implementation proceedings that the Commission expects to conduct before January 2000. The Commission should retain sufficient flexibility in the structure and timing of these proceedings to ensure efficient and fair resolutions. The description of these proceedings assumes that retail competition for electric power would begin for all customers in Maine in January 2000.

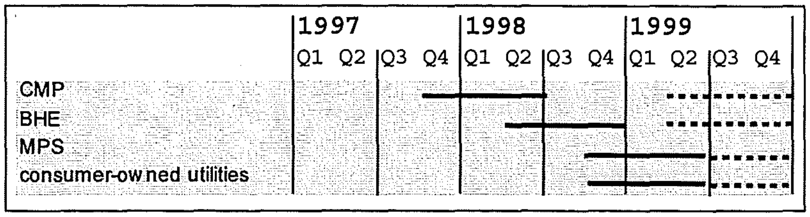
After that date, the Commission would continue to regulate the rates of the T&D utilities, but would no longer regulate the rates charged for electric power. The form (e.g., rulemaking, inquiry or adjudicatory) that any of these proceedings would take would be determined based upon the particular circumstances of the case.



Implementation Proceedings and Schedules
1997
1998
1999
Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4 Q1 Q2 Q3 Q4
1. Revenue Requirement, Rate Cap, Stranded Cost & Rate Design
CMP
BHE
MPS
consumer-owned utilities
2. Corporate Restructuring
CMP
BHE
MPS
3. Bill Unbundling Proceeding
4. Standard Offer
CMP
BHE
MPS
consumer-owned utilities
5.Customer Protection and Low-Income Assistance
Review of credit, collection and disconnect rules
Report on funding of low-income programs
Customer education and outreach
6. Oversight of Competitive Generation Providers
7. Renewal Resources Portfolio Requirement
8. Conservation & Load Management
9. Review of all Commission Rules
Key
MPUC proceeding/report
MPUC review/approval
utility activity
update phase
customer education

II. IMPLEMENTATION PROCEEDINGS

1. Rate Levels and Caps, Stranded Costs & Rate Design.



The Commission would need to establish the revenue requirements and rates to be charged by each T&D utility. This would require a Commission determination of:

- Appropriate T&D Charges. The Commission would establish the revenue requirements that the T&D utilities would be allowed to recover from ratepayers for their services. The Commission would also determine the appropriate design of rates for each T&D utility. While the Commission has traditionally set rates for vertically integrated utilities, these proceedings would also require that the T&D costs and rates be separated from the generation-related costs of the utility. Once the T&D utility's revenue requirement and rate design are determined, a price-cap plan or some other form of incentive regulation could be adopted to provide the T&D utilities with efficiency incentives and to provide ratepayers with stable and predictable rates.

  Significant issues to be determined in these proceedings are likely to include cost of capital, the value of any assets transferred to the generation subsidiary or other entity, rate design and marginal cost of service, and the proper form of regulation for T&D utilities.

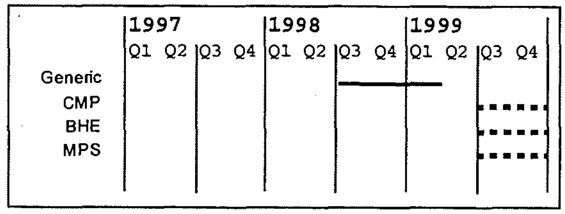
- Appropriate Stranded Cost Charges. The Commission would establish initial estimates of stranded costs in these proceedings, using market information to the greatest extent possible. These cases would also establish the rates that each T&D utility would be allowed to charge to recover the stranded costs subject to recovery. These proceedings are likely to be complex, both with respect to the proper calculation of stranded costs, and the rate design appropriate for their collection. Because an important component of the calculation of stranded costs is the market price for power, the Commission would conduct further proceedings after 2000 to update the stranded cost charges based on then current market conditions. In addition, there would be a link between this case and the bidding process for QF contracts, because the results of that process would have an effect on the level of stranded costs.

  Some of the issues to be determined in these proceedings are whether sufficient efforts have been undertaken to mitigate stranded costs; the estimation of the future market price for power; the proper level of stranded cost recovery for each customer class; and the specific rate design for the stranded cost recovery charge.

  Because the factors influencing the size of stranded costs are unique to each utility, the Commission would conduct separate proceedings for each investor- and consumer-owned utility. Under the Commission's Implementation Schedule, the nine-month proceeding for CMP would begin in late 1997, with the proceedings for BHE and MPS beginning in January 1998 and April 1998, respectively. The proceedings for the consumer-owned utilities would likely be less complex and would begin in April 1998. To ensure that rates reflect the most up-to-date information and analyses available, concurrent limited reviews may be needed between April and December 1999 for each of the utilities. Because of the complexity and interrelationship of these proceedings, they will begin relatively early in the implementation process.

2. Corporate Restructuring

By January 1, 2000, CMP, BHE and MPS would transfer their generation activities into separate subsidiaries, and CMP and BHE would be required to divest their generation assets and related functions from their T&D activities no later than the end of 2005.



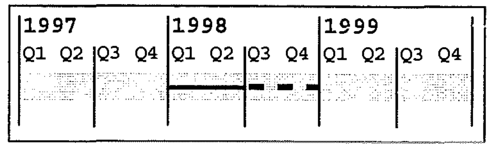
Utilities would not be required to divest their ownership interest in Maine Yankee, so long as the plant's operating life does not extend significantly beyond 2008.

The Commission would conduct a proceeding, beginning in mid-1998, to establish the requirements for structural separation between the T&D utilities and their generation-related activities. The Commission would precisely define the parameters of structural separation necessary to curb market power and cross-subsidization. Issues likely to arise concerning structural separation include what codes of conduct need to be established to ensure that the separation is effective, restrictions on employee activities, accounting standards, and information and service comparability requirements. Once several separation standards are established, each utility may be required to make a compliance filing.

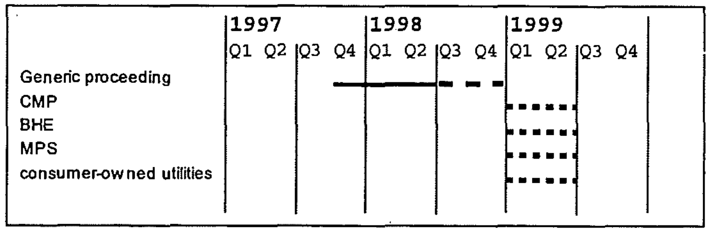
CMP and BHE would file their plans for full divestiture prior to 2006. The Commission would review the plans and ensure their consistency with the objectives of restructuring. A primary issue in these proceedings would likely be whether the plan is reasonably designed to capture the highest possible value.

3. Bill Unbundling Proceedings.

During January 1998, each electric utility would file a bill unbundling proposal for Commission review. The primary issue likely to be resolved is the "price" of power (i.e. energy and capacity) as distinct from other services. The Commission would complete its review by July 1998, so that utilities would have approximately six months to complete any needed computer system and procedure modifications. Utilities' bills would be unbundled beginning January 1999.



4. Standard Offer.



The Commission would, in proceedings beginning in late 1997, establish terms and conditions (including the rate design) for standard offer service, and would later (during 1999) review and approve the selection of bidders to provide standard offer services in each of the T&D utility service territories. There would be two groups of proceedings related to standard offer services:

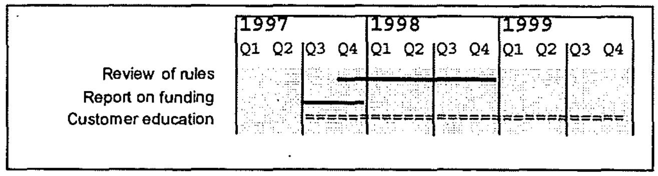
- Design of terms and conditions. The Commission would establish terms and conditions for standard offer service, including eligibility criteria, requirements for entering and exiting the service, and credit, collection, and disconnection provisions.

- Review of standard offer bids. Once the design of the terms and conditions of standard offer service has been established, the T&D utilities would request bids from power suppliers and would present the results of the bidding, together with a recommendation, to the Commission. The Commission would review the utilities' filings and would determine the winning bidders. These activities would be completed by mid-1999 so that the standard offer providers would have sufficient time to secure the necessary resources to provide the service, and to establish customer service programs. Issues in these proceedings would likely include whether the bidding process was fair, and whether the bidders met reasonable standards for reliability and financial security.

The Commission would review the winning bids for standard offer service to ensure that the price of power, when added to the price for other services (e.g., T&D) and the stranded cost charge would not, on average, be higher than the electricity rates paid during 1999. In the event that bids were too high to achieve this objective, the Commission would consider whether it should recommend modifications to the process of electric restructuring to ensure that regulation in Maine remains consistent with the public interest.

5. Customer Protection and Low-Income Assistance

Beginning in 1997, the Commission would address consumer protection and low-income issues..

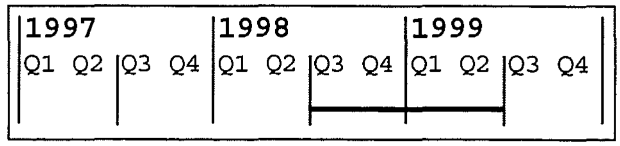


- Review of credit, collection and disconnection rules. This proceeding would determine what credit, collection and disconnection practices would be appropriate for T&D utilities. During 1997, the Commission would begin to review Chapters 81 and 86 of its rules, dealing with its disconnection and deposit regulations for residential and nonresidential customers respectively, and would complete new rules appropriate for a restructured electricity market by the end of 1998. Issues in this proceeding would include the implications of a T&D utility providing billing service for power providers, and whether existing rules concerning credit and collection continue to be appropriate.

- Report on funding of low-income programs. During 1997, the Commission, together with the State Planning Office, would prepare a recommendation, including proposed legislation, for funding assistance to low-income consumers of electricity through the general fund or through a tax on all energy sources ("all fuels") in Maine.

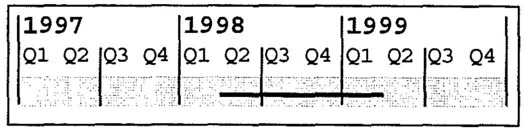
- Customer education and outreach. The Commission would establish a comprehensive customer education and outreach program beginning in 1997. The Commission would intensify its customer education efforts in 1999, as the January 2000 implementation date approaches, drawing on the experience in other states with electric restructuring.

6. Oversight of Competitive Generation Providers



In mid-1998, the Commission would begin one or more proceedings to determine what requirements should be imposed on companies selling electric power to retail customers in Maine. The issues to be addressed in these proceedings, which would be concluded by mid-1999, would likely include what registration requirements are appropriate; what jurisdiction the Commission should have over disputes between power sellers and their customers; what penalties should the Commission impose for violations of Commission rules; and what disclosures should power sellers make to their customers concerning the characteristics (e.g., fuel mix) of their production facilities. Other issues may be examined, including performance bonding; notice requirements for rate changes, other terms, and termination; and standardized billing.

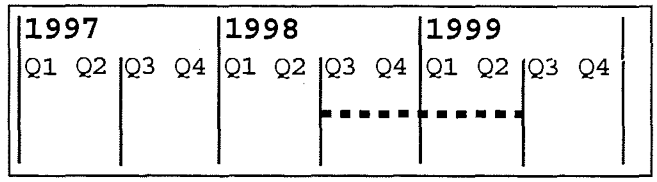
7. Renewable Resources Portfolio



The Commission would begin a proceeding, in early 1998, to determine the appropriate level of renewable energy generation to be included in the production mix of all power sellers in Maine, and to establish the ground rules necessary to implement this renewable portfolio requirement. The proceeding would be concluded in early 1999.

The issues to be resolved in this proceeding would include the level of renewables to be required; the extent to which any Maine requirement should vary significantly from similar requirements (if any) elsewhere in New England; how renewable "credits" would be calculated and traded; what price impacts various renewable requirement levels would have, and the effect of those price impacts on consumers; and whether any particular level of renewable requirement would produce measurable benefits for Maine (such as reducing the cost of complying with Federal Clean Air Act standards).

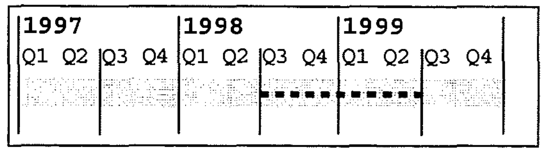
8. Conservation & Load Management



Beginning in mid-1998, the Commission would review the framework and substance of the demand-side management programs to be administered by the T&D utilities in the new competitive environment. These reviews would be concluded by mid-1999.

Issues in these proceedings would include how costs and kWh savings would be calculated; whether any costs should be deferred, and if so over what period; whether there should be a limit on the price impact of DSM programs; and how any costs should be included in rates.

9. Review of All Commission Rules



Beginning in mid-1998, the Commission will perform a comprehensive review of its rules to determine what rules should be added, amended or eliminated to conform to current and anticipated conditions in the electric industry in Maine. This review would continue through at least 2000, with the bulk of the effort completed by mid-1999. Rules enacted pursuant to authority granted by the enabling legislation for electric restructuring would be subject to 5 M.R.S.A. section 8071.

MPUC Customer Surveys

General Background:

During August and September of 1996 the Maine Public Utilities Commission conducted surveys of residential and small business customers. The purpose was to learn more about the attitudes, expectations, and information of small customers regarding the introduction of retail competition in the electric industry. The surveys were designed and administered by the Survey Research Center at the Muskie Institute of Public Affairs, University of Southern Maine.[1] The surveys were administered by phone to a random sample of 500 residential customers and a random sample of 500 small business customers (20 or fewer employees). The survey margin of error is +/- 4.4%. The survey questions and results are given in the pages that follow.

Customer Profiles:

The residential customers surveyed had an average household income between $34,000 and $35,000 per year (median). Fifty-five percent of the households had no member under 18. Twenty percent of the respondents (the person who handles the phone bill) were college graduates; 61% had some education beyond high school, and 5% had not completed high school.

The small business customers surveyed had average gross revenues of slightly over $100,000 per year (median). Twenty-four percent of these businesses had only one employee (self-employed), 59% had three or fewer employees, and 10% had ten or more employees. These businesses had an average of 16 years in operation (median), with only 7% reporting three or less years of operation. Eighty percent operate from only one site.

Cross-tabulation Analysis of Survey Results

Responses to nine selected questions were sorted 1) by utility (CMP, BHE, MPS), 2) by region (urban, north, coastal), and 3) by preference for deregulation vs. continued regulation.

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[1]These surveys should be distinguished from the non-scientific survey administered informally at our Electric Industry Restructuring Public Witness Hearings and described in our July Bulletin.

1. No statistically significant differences were found among the responses of customers of the different utilities for any of the nine questions examined.[2] This held for both the residential and the business surveys.

2. The north differed significantly from the other regions in willingness to accept less of their most important attribute in exchange for lower rates (residentials are more willing to trade - businesses less willing) and on the relative importance of rates.

3. Responses differed for both residential and business surveys when sorted by attitude towards regulation (would you prefer to deregulate or to continue regulation?). Business customers were more inclined towards deregulation.

<u>Residential Customer Survey</u>

1. Some people believe that electric companies should be deregulated to allow greater competition and possibly lower rates. Other people think that companies should continue to be closely regulated in an effort to protect consumers and the environment. Which is <u>closer</u> to how <u>you</u> feel?

Deregulation: 41.4% Continue Regulation: 54.5% Don't Know: 4.1%

2. Some people believe that if electric utilities are deregulated, consumers will benefit the most, because they will have more choices and lower rates. Other people think that the utility companies will benefit the most, because they will have fewer rules and requirements that they have to follow. Which is <u>closer</u> to how <u>you</u> feel?

Consumers: 49.9% Companies: 42.5% Both Equally: 2.9%
Nobody: 0.2% Don't Know: 4.5%

3. Are you aware that possible changes to the electric power industry would allow residential customers to shop around and choose among competing providers of electric power?

Yes: 55.5% No: 43.9% Don't Know: 0.6%

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[2]Chi-square test, significance level = .05.

4. Did you know that if customers could choose their supplier of electric power, that power would be delivered over the lines of their local electric utility?

Yes: 37.9% No: 62.1%

5. Do you believe that you, as a residential customer, would benefit from competition among providers of electric power?

Yes: 67.8% No: 24.6% Don't Know: 7.6%

6. Would you like to be able to choose your electric power provider if your rate under competition were likely to increase approximately 10 percent?

Yes: 33.1% No: 65.2% Don't Know: 1.8%

7. Would you like to be able to choose your electric power provider if your rates under competition were likely to stay approximately the same?

Yes: 56.0% No: 42.0% Don't Know: 2.0%

a. How about if your rate were likely to decrease approximately 10 percent?[3]

Yes: 75.0% No: 21.6% Don't Know: 3.4%

8. Would like to be able to choose your electric power provider if it meant the possibility of losing Maine-based utility companies to New England-based and nationally-based companies?

Yes: 37.7% No: 55.5% Don't Know: 6.8%

9. Have you ever spent any time trying to figure out which interstate long-distance phone service provider would be best for you?

Yes: 47.7% No: 52.3%

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[3]Asked only of those who answered *no* to question 7.

10. Have you ever purchased interstate long-distance service from one of the providers who compete with standard service from AT&T?

Yes: 47.1% No: 52.5% Don't Know: 0.4%

11. Do you believe that you as a residential customer have benefited from competition among providers of interstate long-distance phone service?

Yes: 51.6% No: 42.2% Don't Know: 6.2%

12. How much lower would electric power rates under competition have to be before you would spend time tying to figure out which electric power provider would be best for you?

(Median): 14%

13. Would you be willing to accept a 10% increase in the number and duration of power outages if doing so would result in a 10% decrease in your electric bill?

Yes: 30.7% No: 66.1% Don't Know: 3.1%

14. Would you be willing to pay 10% more for residential electric service if this would lower business and industry rates, possibly helping to improve Maine's economy?[4]

Yes: 40.7% No: 56.4% Don't Know: 2.9%

15. Next I am going to read you a list of factors that may be important to you regarding your electric service. For each one, please tell me how important it is to you. Is it very important, somewhat important, not very important, or not at all important?

a. Low rates

very	somewhat	not very	not at all	dk
72.5%	24.8%	2.3	0.4%	0.0%

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[4]Interviewers report that the wording of this question may have prompted some respondents to answer *yes* when their true preference was *no*.

b. Ability to choose power supplier

very	somewhat	not very	not at all	dk
29.9%	45.9%	19.3%	4.5%	0.4%

c. Rates don't change very much or very often

very	somewhat	not very	not at all	dk
56.5%	35.1%	6.8%	1.2%	0.4

d. Rate changes are predictable in amount and timing

very	somewhat	not very	not at all	dk
45.9%	42.8%	8.9%	1.9%	0.4%

e. Reliability

very	somewhat	not very	not at all	dk
88.1%	11.3%	0.2%	0.4%	0.0%

f. Minimizing environmental impact of electricity generation

very	somewhat	not very	not at all	dk
61.9%	31.4%	4.5%	1.8%	0.4%

g. Utilities develop programs to improve energy efficiency

very	somewhat	not very	not at all	dk
63.7%	31.4%	3.7%	0.8%	0.4%

h. Protection for low income customers

very	somewhat	not very	not at all	dk
50.9%	37.5%	7.8%	3.3%	0.6%

i. Getting complete service (generation, transmission, and distribution of electricity) all from only one company

very	somewhat	not very	not at all	dk
32.8%	34.8%	23.8%	7.4%	1.2%

16. Which item would you say is the most important to you?

a.	25.6%	Low Rates
b.	4.5%	Ability to choose power supplier
c.	5.3%	Rates don't change very much or very often
d.	3.7%	Rate changes are predictable in amount and timing
e.	27.8%	Reliability
f.	14.9%	Minimizing environmental impact of electricity generation
g.	7.6%	Utilities develop programs to improve energy efficiency
h.	7.2%	Protection for low income customers
i.	2.5%	Getting complete service (generation, transmission, and distribution of electricity) all from only one company
	0.8%	Don't Know

17. If it meant your rates would be about 10 percent lower, would you be willing to accept a lower level of the item you said was most important?

Yes: 29.4% No: 68.9% Don't Know: 1.7%

18. Electricity can be produced through many methods, some of which are less environmentally harmful than others. However, the "cleaner" method is often more expensive. Would you be willing to pay 10 percent more for your electricity if it could be produced by a cleaner method?

Yes: 72.0% No: 23.3% Depends: 1.2% Don't Know: 3.5%

19. Do you believe electricity companies should have to tell customers how their electricity is generated?

Yes: 85.9% No: 13.2% Don't Know: 1.0%

20. Would you purchase electricity from less clean sources if your rates were 10 percent lower?

Yes: 19.7% No: 75.6% Depends: 1.6% Don't Know: 3.1%

21. Do you think your electricity costs more than it should, less than it should, or is it about right?

More: 57.6% Less: 1.4% About Right: 39.3% Don't Know: 1.8%

Business Customer Survey

1. Some people believe that electric companies should be deregulated to allow greater competition and possibly lower rates. Other people think that electric companies should continue to be closely regulated in an effort to protect consumers and the environment. Which is closer to how you feel?

Deregulation: 50.0% Continue Regulation: 47.3%
Both Equally: 0.2% Don't Know: 2.5%

2. Some people believe that if electric utilities are deregulated, consumers will benefit the most, because they will have more choices and lower rates. Other people think that the utility companies will benefit the most, because they will have fewer rules and requirements that they have to follow. Which is closer to how you feel?

Consumers: 53.0% Companies: 38.6% Both Equally: 4.1%
Nobody: 0.8% Don't Know: 3.5%

3. Are you aware that possible changes to the electric power industry would allow business customers to shop around and choose among competing providers of electric power?

Yes: 64.2% No: 35.8%

4. Did you know that if customers could choose their supplier of electric power, that power would be delivered over the lines of their local electric utility?

Yes: 55.7% No: 44.3%

5. Did you know that if customers could choose their supplier of electric power, small businesses could form alliances and purchase their electricity as a group?

Yes: 24.5% No: 75.5%

6. Do you believe that you as a business customer would <u>benefit</u> from competition among providers of electric power?

Yes: 73.9% No: 19.3% Don't Know: 6.9%

7. Would you like to be able to choose your electric power provider if your rates under competition were likely to <u>increase</u> approximately 10 percent?

Yes: 45.1% No: 52.7% Don't Know: 2.2%

8. Would you like to be able to choose your electric power provider if your rate under competition were likely to stay approximately the same?

Yes: 49.8% No: 47.7% Don't Know: 2.5%

a. How about if your rates were likely to <u>decrease</u> approximately 10 percent?[5]

Yes: 71.3% No: 26.4% Don't Know: 2.3%

9. Would you like to be able to choose your electric power provider if it meant the possibility of losing <u>Maine-based</u> utility companies to <u>New England-based</u> and <u>nationally-based</u> companies?

Yes: 49.0% No: 46.5% Don't Know: 4.5%

10. Have you ever spent any time trying to figure out which interstate long-distance phone service provider would be best for your company?

Yes: 62.7% No: 36.9% Don't Know: 0.4%

11. Has your business ever purchased interstate long-distance service from one of the providers who compete with standard service from AT&T?

Yes: 65.5% No: 32.9% Don't Know: 1.6%

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[5]Asked only of those who answered *no* to question 8.

12. Do you believe that you as a business customer have benefited from competition among providers of interstate long-distance phone service?

Yes: 61.8% No: 30.5% Don't Know: 7.7%

13. How much lower would electric power rates under competition have to be before you would spend time trying to figure out which electric power provider would be best for your business?

(Median): 10%

14. Would you be willing to accept a 10% increase in the number and duration of power outages if doing so would result in a 10% decrease in your electricity bill?

Yes: 20.3% No: 77.4% Don't Know: 2.4%

15. Would you support increasing residential and small commercial electric rates by 10% if this would lower rates for larger business, possibly helping to improve Maine's economy?[6]

Yes: 16.1% No: 81.0% Don't Know: 2.9%

16. Next I am going to read you a list of factors that may be important to you regarding your electric service. For each one, please tell me how important it is to your business. Is it very important, somewhat important, not very important, or not at all important?

a. Low rates

very	somewhat	not very	not at all	dk
65.5%	30.2%	4.1%	0.2%	0.0%

b. Ability to choose power supplier

very	somewhat	not very	not at all	dk
29.4%	40.6%	20.4%	7.8%	1.8%

c. Rates don't change very much or very often

very	somewhat	not very	not at all	dk
52.4%	36.6%	8.7%	1.6%	0.8%

[6]Interviewers report that the wording of this question may have prompted some respondents to answer *yes* when their true preference was *no*.

d. Rate changes are predictable in amount and timing

very	somewhat	not very	not at all	dk
43.0%	40.4%	13.2%	3.0%	0.4%

e. Reliability

very	somewhat	not very	not at all	dk
91.0%	8.4%	0.6%	0.0%	0.0%

f. Minimizing environmental impact of electricity generation

very	somewhat	not very	not at all	dk
54.5%	34.3%	7.1%	3.5%	0.6%

g. Utilities develop programs to improve energy efficiency

very	somewhat	not very	not at all	dk
62.3%	29.0%	6.1%	2.2%	0.4%

h. Protection for low income customers

very	somewhat	not very	not at all	dk
33.5%	41.7%	13.6%	10.4%	0.8%

i. Getting complete service (generation, transmission, and distribution of electricity) all from only one company

very	somewhat	not very	not at all	dk
27.6%	28.0%	29.6%	12.9%	1.8%

17. Which item would you say is the <u>most</u> important to your business?

a.	28.4%	Low Rates
b.	3.7%	Ability to choose power supplier
c.	3.2%	Rates don't change very much or very often
d.	1.4%	Rate changes are predictable in amount and timing
e.	48.9%	Reliability
f.	6.9%	Minimizing environmental impact of electricity generation
g.	3.6%	Utilities develop programs to improve energy efficiency
h.	1.4%	Protection for low income customers
i.	2.4%	Getting complete service (generation, transmission, and distribution of electricity) all from one company
	0.2%	Don't Know

18. If it meant your rates would be about 10 percent lower, would you be willing to accept a lower level of the item you said was most important?

Yes: 14.0% No: 83.3% Don't Know: 2.6%

19. Electricity can be produced through many methods, some of which are less environmentally harmful than others. However, the "cleaner" method is often more expensive. Would your business be willing to pay 10 percent <u>more</u> for your electricity if it could be produced by a <u>cleaner</u> method?

Yes: 62.5% No: 28.5% Depends: 4.6% Don't Know: 4.4%

20. Do you believe electricity companies should have to tell customers how their electricity is generated?

75.1% Yes 24.7% No 0.2% Don't Know

21. Would you purchase electricity from <u>less clean</u> sources if your rates were 10 percent lower?

Yes: 20.3% No: 68.5% Depends: 4.4% Don't Know: 6.8%

22. Do you think your electricity costs more than it should, less than it should, or is it about right?

More: 68.3% Less: 1.0% About Right: 28.4% Don't Know: 2.3%

Estimates of Stranded Costs

I. INTRODUCTION AND SUMMARY OF ESTIMATES

Legislative Resolve 1995, ch. 48 "Resolve to Require a Study of Retail Competition in the Electric Industry" directed the Commission to provide a range of estimates of stranded costs for each electric utility affected by restructuring. On October 23, 1996, the Commission issued preliminary stranded cost estimates, seeking critical review and comment. Central Maine Power Company (CMP), Bangor Hydro-Electric Company (BHE), Maine Public Service (MPS), Eastern Maine Electric Cooperative (EMEC), Houlton Water Company (HWC), the Office of Public Advocate (OPA) and the Industrial Energy Consumer Group (IECG) provided comments. We have taken those comments into account in the analysis presented here.

Any estimate of stranded costs in Maine today will be highly uncertain, because it must rely on projections and assumptions about conditions extending many years, perhaps decades, into the future. Stranded cost estimates reflect projections of the future market for power in the region, and the operating characteristics and costs of numerous generating plants. Such projections are inherently uncertain; analyses and results that assume their accuracy should be viewed with skepticism. The level of uncertainty that surrounds stranded cost estimates, in our view, virtually eliminates their usefulness in guiding policy decisions about electric restructuring, and requires that policy makers exercise great care in designing any program for the recovery of "stranded costs."

In fact, the uncertain surrounding these estimates prompted, in large part, the Commission's recommendation that recovery of these costs be based on proceedings in 1999 and 2003 in which estimates of stranded costs would be developed, and another proceeding in 2006 in which a further calculation of these costs would be made. Any attempt in 1997 to finally determine these costs would be fraught with danger of ratepayers overpaying, on the one hand, or shareholders bearing an unfair burden, on the other.

The sensitivity of stranded costs to uncertainty, particularly of market value, results in estimates that range from well over $1 billion above zero to more than $300 million below zero. We estimate stranded costs for Maine's electric utilities to fall in the following ranges:

Company	Stranded Cost Range (M$) (NPV as of January, 2000)
CMP	(342) - 1069
BHE	65 - 242
MPS	(54) - 83
EMEC	10 - 15
Municipals (aggregate)[1]	- -
Total	(320) to 1,409

[1] Material provided by MMUG suggests there could be a small amount of stranded cost for some of its member utilities, and for others, there would be no stranded costs. We have not attempted to quantify stranded costs for the State's other municipal utilities.

Expressed another way, if the stranded costs estimated above were charged uniformly and collected over a ten-year period, the average rate per kWh would be a credit to customers of one-half cent at the low end, and a charge to customers of about two cents at the high end.[2]

To develop estimates, we relied on projections of plant operating and cost data provided by the utilities. Although we reviewed the material provided and, in some cases, replaced certain data or assumptions with our own, there must be significantly more review of these data and assumptions before stranded cost charges can be imposed on customers. Moreover, these estimates do not reflect other factors, including mitigation, market estimates of the value of assets, and land and salvage values. The IECG suggested several areas for further consideration, such as plant operational efficiencies and premiums for renewable plants and contracts.

[2] Stranded or uneconomic costs are currently recovered in bundled electric rates. The Commission does not expect that there would be a uniform per-kWh charge for stranded costs, either among customer groups or over time. The rate design for any stranded cost recovery charge would be developed in a Commission proceeding prior to retail competition and reviewed periodically thereafter.

II. METHODOLOGY

A. General Approach

The method we use to estimate stranded costs is straightforward. For utility-owned generating plants, stranded costs are the difference between the associated net plant investment (i.e., the amount invested in plants that has not yet been recovered from ratepayers) and the present value[3] of expected future profits from the plants' operation. For purchased power contracts, stranded costs are the present value of future contract payments less the market value of the purchased power. The sum of these two components, plus the sum of any generation-related regulatory assets, are a utility's total stranded cost. Commenters generally agreed with this overall approach.

For the market value of power from utility plants and purchase contracts, we used as a proxy the capital and operating costs of a newly constructed gas/oil combined cycle plant. Our estimates for market prices in the year 2000 range from \$.0392 to \$.0573/kWh.[4] These values reflect an

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[3] References to present value in this Appendix are to January 2000, the date of retail access.

[4] Actual market prices in the region may vary significantly throughout the year given variations in load and costs of plants used to meet that load. We have not modeled the regional market to capture this degree of precision; instead we have used the cost of a combined-cycle plant as an all-hours proxy for the market price of power.

assumption that the regional power market will require new generating resources in or around the year 2000 and that at that time, the cost of constructing and operating a new combined-cycle plant is a reasonable proxy for these new resources.[5] We used a range of assumptions for the capital, fixed O&M and fuel costs of a combined-cycle plant and, based on these, established the band of market prices described above.

The IECG argued that the values used in any stranded cost calculation should be identified by the market. We agree; when the Commission develops the stranded cost changes to be imposed on customers, it will rely on the market whenever possible to determine the appropriate value. For the purposes of this analysis, however, we have relied out of necessity on proxies for that future market.

B. Specific Issues

1. Multi-utility

The starting point for our estimates of stranded costs was the material provided by the utilities. The investor-owned utilities each provided estimates of their own stranded costs; the consumer-owned utilities did not provide estimates, but provided data from which estimates could be made. In developing our estimates, we adjusted, supplemented and corrected the data and calculations

[5] NEPOOL planning documents indicate the region would need new generating resources in the year 2000.

submitted by the utilities to make them accurate and consistent with our definition of stranded costs.

One difference between our estimates and those of the utilities arises from the treatment of regulatory assets, including deferred taxes. Unlike the utilities', our estimates include most, but not all, regulatory assets. Specifically, we include generation-related regulatory assets, such as those for cancelled generating plant, QF buyouts, deferred DSM and deferred taxes. We do not include T&D-related regulatory assets.[6]

Another difference between our approach and those of all three IOUs is the period over which we capture expected profits from utility-owned plants. Our estimates include expected profits through the year 2030; the IOUs truncate these in or around the year 2018. There appear to be substantial profits from utility-owned plants in the post-2018 period, most notably from hydro facilities. This additional value is likely to be identified by any market-based sale; it should not be ignored when estimating stranded costs.

2. CMP

We have estimated stranded costs by subtracting expected future operating profits of the plants from the net plant investment as of the beginning of retail competition. This approach captures expected costs and values

[6] The only T&D-related regulatory asset of any magnitude appears to be deferred taxes, e.g., estimated for CMP to be $134 million NPV as of January 2000.

directly attributable to the generation assets. CMP used a top-down, total revenue requirements approach. Specifically, CMP projected a revenue requirement for a generation company that would be disaggregated from today's integrated company. The revenue requirement of the resulting generation company includes in addition to costs directly associated with generation assets, other costs that would be incurred by today's integrated company not directly attributable to generation. From this revenue requirement, CMP subtracted the expected market price for a comparable amount of generation. Thus, CMP's stranded cost estimates include costs we include (i.e., those directly attributable to generation), and a pro-rata share of its general property and expense items that cannot be directly assigned to either the generation, transmission, or distribution function.

A relatively minor difference is in the modelling of future plant operation. CMP's stranded cost estimates reflect plant operation in future years based on the economics of an own-load dispatch for its existing service territory. This results in some plants projected to produce power even when the incremental costs of production exceed the estimated market price. Our estimates reflect that a plant would only operate if economic, that is, if its estimated productions costs were less than the expected market price at the time. CMP concured with our approach, and suggests further refinements to more precisely model plant operation and costs.[7]

Another difference is that CMP limited the extent to which the generation-related assets with a probable high market value would serve to offset stranded costs calculated from other assets. The failure to net valuable assets against those costs would inevitably lead to an over-estimation of stranded costs.[8]

3. BHE

Bangor Hydro estimated stranded costs in a manner conceptually similar to ours. The differences in the respective estimates are largely attributable to treatment of deferred taxes, the period over which we estimate stranded costs, and differences in assumptions. These differences are relatively minor. For example, the Company assumed the operating costs of its hydro plants grow at a constant annual rate of 2%; our estimates, derived from a BHE study of expected capital and operating costs at each of its hydro facilities, reflect somewhat different cost and growth assumptions.

[7] Several commenters raised related concerns regarding: (1) Wyman operation and O&M costs; and (2) our use of an all-hours market power price. A more detailed modelling of the regional market and Wyman operation would tend to decrease (relative to our estimates) stranded costs associated with the Wyman units.

[8] CMP failed to identify significant flaws in the method we employed, and, in fact, suggested that its method should produce comparable results.

BHE agrees that our methods are similar. BHE also provided corrections to its net plant data, which we have incorporated in our estimates.

4. MPS

Maine Public Service estimated its stranded costs as two components: (1) above market costs associated with its Wheelabrator-Sherman contract; and (2) unrecovered Seabrook investment. However, in the Company's analysis, Wheelabrator-Sherman contract payments extended only through 2000, even though the contract may obligate continued purchases by MPS through the year 2015. Our estimates reflect a purchase obligation through 2015, but because the contract prices have not yet been established for the period 2001-2015, we use a range of potential Wheelabrator-Sherman contract prices.

Another notable difference between our stranded cost estimates for MPS and the Company's own lies in how company-owned plants, including MPS's investment in Tinker Station and Maine Yankee, are treated. Our estimates reflect net investment in these plants or, in the case of Tinker Station and Maine Yankee, contractual payments, less the expected operating profit or market value associated with the output. MPS included neither the costs nor future value of these facilities, thereby omitting from its stranded cost estimates substantial generation-related amounts that should be captured.

MPS criticized our assumptions about future costs for power from Wheelabrator-Sherman and Tinker Station.[9] According to MPS, the former are too high; the latter, too low. We do not dispute MPS's observations. The assumptions cited by MPS were intended to reflect uncertainty inherent in future Wheelabrator-Sherman and Tinker Station costs. For Wheelabrator, the figures cited as too high by MPS are, in fact, intended to reflect the high end of this uncertainty, and, for Tinker, the low end.

5. EMEC

As discussed in section VII, stranded costs include costs or obligations incurred prior to March 1995. Consistent with this, our stranded cost estimates for EMEC exclude costs associated with any future power supply obligations, such as power to replace existing purchases from MPS and Maine Yankee. In addition, our estimates exclude any costs associated with purchases from New Brunswick Power (NB Power) after 2002, because EMEC's existing contract with NB Power allows EMEC to terminate its purchase obligation effective on November 30, 2002.

EMEC argued that it should be allowed to continue to purchase power for its members. The stranded cost assumptions described above do not suggest otherwise; rather this representation of EMEC's future power purchase

[9] In the case of Tinker, the price assumptions MPS now criticizes were provided by MPS.

activity is for the limited purpose of estimating stranded costs. It does not require or suggest that EMEC terminate any power supply contract, or that EMEC stop providing power to its members. Stranded costs, however, would not reflect costs associated with such future obligations.

III. UNCERTAINTY

It is difficult to overstate the uncertainty inherent in stranded cost estimates and the risks related to mis-estimations. Although the range of stranded cost estimates presented here reflect what appear to be reasonably broad ranges for various assumptions, actual stranded costs, or even estimates produced three years from now, may lie anywhere within this range, or fall above or below the range endpoints. It is because of this uncertainty, and the potential for substantial over or under-recovery from ratepayers, that stranded cost charges should be re-examined periodically, and adjusted if necessary.

Although we do not present a discussion of each and every source of potential mis-estimation, we identify and describe below some of the major sources of uncertainty surrounding stranded cost estimates for Maine's utilities.

A. Market Value

Our estimates of market value for utility-owned generation assets and purchased power contracts reflect that market prices received for the power from these assets and contracts will approach the cost of a newly constructed natural gas combined cycle plant. We acknowledge at least two levels of uncertainty inherent in this approach: the market may perceive a value for some or all assets/contracts that is not simply measurable by the cost of a combined cycle plant; and the expected costs for combined cycle generation may be wrong.

As an example of the former, if the future power market places a premium on renewable generation resources, simply using a combined-cycle proxy may understate the value of a significant portion of Maine's generation assets and contracts, thereby overstating associated stranded costs. As another example, it is possible that transmission constraints would render the cost of a combined cycle an inappropriate proxy for the market value of power in Maine.

In addition to the uncertainty associated with using the combined cycle as a proxy for market value, there is also uncertainty surrounding future combined-cycle costs. Although our stranded cost estimates reflect a range of combined-cycle costs, this range does not span all possible futures; rather, it provides a reasonably wide range given the world as we see it today. If the future unfolds differently (certainly a possibility given the structural changes occurring in the electric power industry), the costs associated with building and operating combined-cycle plants in New England could fall outside this range; we have not analyzed the likelihood nor quantified the effects of substantially different futures.

The magnitude of potential error from mis-estimating future market prices is substantial. For example, a difference in market prices equal to one cent per kWh changes the estimates of CMP's stranded costs by well over $500 million.

Commenters agree that the costs of a newly constructed combined cycle plant are a reasonable proxy for regional market prices. Many also cite factors that could render market prices higher or lower than this for particular plants, for groups of plants, in geographic regions, at times of the year, or due to transmission costs or constraints. In addition, the IECG notes several respects in which our combined cycle cost estimates appear understated.[10]

We have not adjusted our market price estimates to reflect issues raised in the comments. Some issues are already captured in our range of prices; others would merely increase or decrease the range endpoints.

B. Utility-owned Plants and Contracts

Our stranded costs also reflect projections of operating costs for utility-owned plants and, in some instances, purchase obligations, including forecasts of future fuel prices and O&M expenses, and estimates of prices yet to be established in certain contractual arrangements. The latter category includes MPS's Wheelabrator-Sherman contract, which may obligate the Company to purchase 126,582 MWh/year during the period 2001-2015 at prices not yet

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[10]No party has suggested that our combined cycle cost estimates are overstated.

established, and the current arrangement governing the cost to MPS of power from Tinker Station, which could be revised at the end of the current export license in June 2008.

Given these uncertainties, we used ranges for certain utility-owned plant and contractual power costs; for others we used base case forecast assumptions. We have not analyzed nor reflected in these stranded cost estimates the possibility that plants could be reconfigured or repowered, or shut down due to operational problems. Nor have we reflected how changing market conditions could affect plant operation. These, as well as other factors such as those raised by IECG, add to the uncertainty discussed above.

Stranded Cost Summary

Rates shown on this table are illustrative of a particular method and timing for recovery.
Actual recovery method and timing may differ.

	High Market Value		Low Market Value	
	Stranded Cost $ (NPV as of 1-2000)	Ilustrative $/kWh Charge (10 year levelized)	Stranded Cost $ (NPV as of 1-2000)	Ilustrative $/kWh Charge (10 year levelized)
CMP	(341,510,044)	-0.00621	1,069,157,609	0.01946
BHE	65,232,346	0.00582	241,580,367	0.02154
MPS	(53,914,536)	-0.01710	82,993,673	0.02632
EMEC	10,075,824	0.01488	15,114,716	0.02232
Municipals	*See note below*		*See note below*	
Total Utility	(320,116,410)	-0.00457	1,408,846,365	0.02013

Note : There could be a small amount of stranded costs for Municipals. These amounts would not materially affect totals shown above.

Resolve Transition Issues

In Section 2 of Legislative Resolve 1995, ch.48, the Legislature directed the Commission to study 11 transition issues in its report on retail competition in the electric industry. Throughout this report, the Commission addresses these issues in relevant sections. The table below provides a summary of how retail competition could affect each of the transition issues, and references the report sections or appendices that address each of the issues.

Issue	Summary and Reference
1. How utility stranded investment is defined and calculated and how it will be dealt with.	Utility stranded costs are above market generation costs rendered unrecoverable by retail competition, including costs associated with utility-owned plants, regulatory assets, and QF contracts. The Commission would allow utilities a reasonable opportunity to recover stranded costs. *Reference: Section VII, Appendix 5.*
2. How the regional marketplace and federal law affect the transition.	Maine's involvement in the regional bulk power and transmission system and evolving marketplace, as well as jurisdictional overlap with FERC, require that several restructuring issues be addressed regionally or before FERC. These issues relate to reliability and to the potential for regional market power. *Reference: Section II(B)(1), Section VIII.*
3. How the State's energy policy, including policies concerning conservation, use of renewable and indigenous resources and diversity of supply, will be affected.	Restructuring should not diminish environmental quality, compromise energy efficiency, or jeopardize energy security. *Reference: Section VI.*
4. How the State's environment and environmental policies will be affected.	*See* item 3, above. *Reference: Section VI.*

5. How social policies, including low-income programs and universal service goals, will be affected.	Restructuring should not diminish protections for low-income customers. The Commission strongly recommends low-income assistance program funding through taxes or broadly applied energy taxes. Standard offer service will promote universal service goals. *Reference: Section II(B)(2), Section IV, Section V(B)(2) (3).*
6. How ratepayers, shareholders of investor-owned electric utilities, owners of consumer-owned electric utilities and other owners of energy resources will be affected.	The impacts on these groups vary, and could encompass many facets of restructuring. The Commission addresses them throughout the report. *Reference: Section III, Section VII.*
7. How the State's economy will be affected.	Restructuring should improve Maine's business climate. Restructuring may also have impacts, both positive and negative, in some areas. *Reference: Section II(B)(2)(c).*
8. How reliability of service will be affected.	Restructuring should not change local reliability; electric T&D remain regulated monopoly-provided services. The regional and national bulk power systems must continue to develop ways to ensure reliability; companies selling retail electric power in Maine would adhere to those rules. *Reference: Section II(B)(2)(a)(b), Section VIII.*
9. How obligations of contracts will be affected.	Restructuring by itself should not affect existing contractual obligations. Contracts between QFs and electric utilities would remain with the T&D utility. *Reference: Section III(B)(4).*

10. How a system for the transmission, distribution and generation of electricity should be structured.	Essentially deregulated competitive markets would provide generation. T&D would remain regulated monopoly-provided service. The Commission addresses related structural issues throughout the report.
11. To what extent protections against anti-competitive practices can be provided.	Structural separation of generation assets and retail electric energy sales activities from T&D, coupled with subsequent divestiture by CMP and BHE, would limit vertical market power. *Reference: Section III.* Horizontal market power could remain a problem in the regional market. Appropriate State agencies, including the Commission, should continue to assess the possibilities for such market power, and develop an appropriate response. *Reference Section VIII(B)(7).* The Commission would enforce rules against consumer fraud committed by sellers of power in Maine. *Reference: Section V(B)(1).*

Customer Perspective

HOW WILL RESTRUCTURING AFFECT ME (AS A RESIDENTIAL CUSTOMER)?

When will I be able to start shopping for power?

You will be able to change your supplier of power in January of the year 2000. You are likely to be able to make arrangements or sign contracts for power up to a few months in advance of that date.

When I move to a new area, what company will I call to obtain service?

You will still call your local electric utility, which will be providing the wires and services needed to bring power to your residence. You will be asked, when you sign up, to select your power provider (much as today, you are asked to select a long distance telephone company).

What if I don't select a power provider, or I can't find one that will sell me power?

If you do not, or are unable to, find a company that will sell you power, you will receive power under the standard offer. The rates charged to you under the standard offer will be, on average, what you would have paid in 1999.

Who will bill me?

You may receive one bill, if your local utility and your power supplier have an agreement that they will bill you together; if you do get just one bill, it will show how much you are being billed for power, and how much for other services (such as distribution provided by the local utility, and any other charges collected by the local utility). You may also receive separate bills for power and for transmission and distribution service.

If I have a complaint, where can I go?

- If you have a complaint about the service provided by the local utility (for example, if there is a problem in the wires serving your residence that the utility has not fixed), you will be able to bring your complaint to the Public Utilities Commission.

- If you have a dispute with your power provider (for example, that company has made promises that it has not kept concerning the price you will pay), you may also be able to come to the Public Utilities Commission; for some disputes, however, you may have to rely on other enforcement agencies (such as the Attorney General's office) or private court action. Or you may decide to change providers.

- If you have a dispute with your power provider, your electricity will not be turned off; if you are unable to reach agreement with the power provider, or the power provider's side of the dispute is upheld by the Commission or the courts, you may either select another power supplier or be provided with service under the standard offer.

What happens if I do not pay my bill for the standard offer?

If you do not pay your bill for services from the T&D utility, or your bill for standard offer service, the T&D utility may disconnect your service. This could only be done, however, according to rules set by the Public Utilities Commission, and you would have the opportunity to bring your side of the story to the Commission before you were disconnected.

What if I simply cannot afford to pay my bill?

There will be assistance available to low income customers to help pay for their energy needs. This assistance may be administered through local Community Action (CAP) agencies, through the state, or by local utilities.

What will my choices for power look like?

No one knows exactly how power suppliers will market their power, but it is likely that some or all of the following options will be available:

- Short-term contracts at a relatively low price, with the risk that the price may increase;

- Longer term deals at a somewhat higher price, but with greater stability;

- "Spot market" deals, where the price varies from day to day or even hour to hour depending on the market;

- Deals available through brokers, marketers, and "aggregators" (i.e. groups you may belong to, or join, that would buy power as a group);
- Contracts where the power you buy is produced using renewable resources or using environmentally benign methods (i.e. "green power");
- The standard offer;
- Deals that combine electricity service with other energy services;
- Any combination of these, and no doubt many more.

Will my power be reliable?

Yes. The Commission recognizes that Maine's electricity supply and delivery must continue to be reliable and safe. If, at any point, it appears that reliability is threatened, the Commission, together with other state and Federal authorities, will intervene. The companies who will be providing electricity services are already working together to ensure that after competition begins reliability will remain at today's high levels.

Will I be able to have a say in how competition is implemented?

Yes. The Public Utilities Commission will have full, open processes in making all the decisions necessary to bring about this enormous change in the way you buy your power. The Commission will also develop programs to keep customers informed, at every step of the way, of what they need to know to become successful consumers in the competitive power market.

HOW WILL RESTRUCTURING AFFECT ME (AS A SMALL BUSINESS)?

When will I be able to start shopping for power?

You will be able to change your supplier of power in January of the year 2000. You are likely to be able to make arrangements or sign contracts for power up to a few months in advance of that date.

When my business moves to a new area, what company will I call to obtain service?

You will still call your local electric utility, which will be providing the wires and services needed to bring power to your business. You will be asked, when you sign up, to select your power provider (much as today, you are asked to select a long distance telephone company).

What if I don't select a power provider, or I can't find one that will sell me power?

If you do not, or are unable to, find a company that will sell you power, you will receive power under the standard offer. The rates charged to you under the standard offer will be, on average, what you would have paid in 1999.

Who will bill me?

You may receive one bill, if your local utility and your power supplier have an agreement that they will bill you together; if you do get just one bill, it will show how much you are being billed for power, and how much for other services (such as distribution provided by the local utility, and any other charges collected by the local utility). You may also receive separate bills for power and for transmission and distribution services.

If I have a complaint, where can I go?

- If you have a complaint about the service provided by the local utility (for example, if there is a problem in the wires serving your residence that the utility has not fixed), you will be able to bring your complaint to the Public Utilities Commission.

- If you have a dispute with your power provider (for example, that company has made promises that it has not kept concerning the price you will pay), you may also be able to come to the Public Utilities Commission; for some disputes, however, you may have to rely on other enforcement agencies (such as the Attorney General's office) or private court action.

- If you have a dispute with your power provider, your electricity will not be turned off; if you are unable to reach agreement with the power provider, or the power provider's side of the dispute is upheld by the Commission or the courts, you may either select another power supplier or be provided with service under the standard offer.

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- Short-term contracts at a relatively low price, with the risk that the price may increase;
- Longer term deals at a somewhat higher price, but with greater stability;
- "Spot market" deals, where the price varies from day to day or even hour to hour depending on the market;
- Deals available through brokers, marketers, and "aggregators" (i.e., groups you may belong to, or join, that would buy power as a group);
- Contracts where the power you buy is produced using renewable resources or using environmentally benign methods (i.e., "green power");
- The standard offer;
- Deals that combine electricity service with other energy services;
- Any combination of these, and no doubt many more.

Will my power be reliable?

Yes. The Commission recognizes that Maine's electricity supply and delivery must continue to be reliable and safe. If, at any point, it appears that reliability is threatened, the Commission, together with other state and Federal authorities, will intervene. The companies who will be providing electricity services are already working together to ensure that after competition begins reliability will remain at today's high levels.

Will I be able to have a say in how competition is implemented?

Yes. The Public Utilities Commission will have full, open processes in making all the decisions necessary to bring about this enormous change in the way you buy your power. The Commission will also develop programs to keep customers informed, at every step of the way, of what they need to know to become successful consumers in the competitive power market.

RESTRUCTURING ACTIVITIES IN OTHER STATES

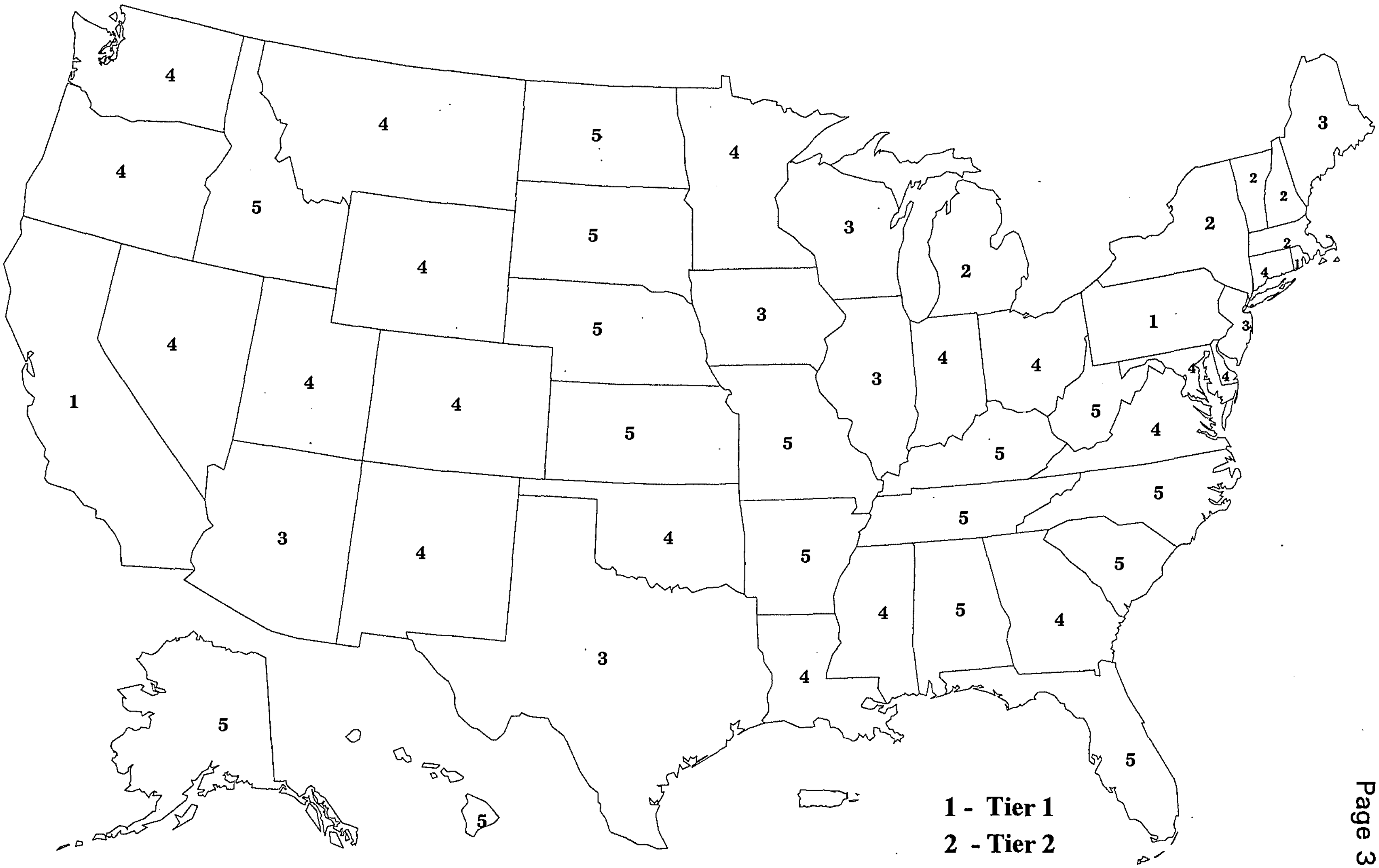
This appendix provides a survey of electric restructuring activities in other states. This survey has three parts:

- A map that provides a snap-shot view of restructuring activities in the United States. The states have been divided into five categories as follows:
    - Tier 1: A statewide restructuring plan has been adopted.
    - Tier 2: Companies have been ordered to file restructuring plans or general restructuring legislation has been enacted.
    - Tier 3: A commission or legislative investigation is underway that appears likely to lead to the adoption of a restructuring plan.
    - Tier 4: Informational or fact-finding activities are underway.
    - Tier 5: No substantive activity is underway or a decision has been made that no action is necessary.
- A three-page summary of regulatory commission and legislative activities in the various states.
- A more detailed state-by-state summary of commission and legislative activities. Activities in the other New England states and presented first, followed by the other states.

TABLE 1: CLASSIFICATION OF STATE RESTRUCTURING ACTIVITIES

Tier 1	Tier 2	Tier 3	Tier 4	Tier 5
California	Massachusetts	Arizona	Colorado	Alabama
Pennsylvania	Michigan	Illinois	Connecticut	Alaska
Rhode Island	New Hampshire	Iowa	Delaware	Arkansas
	New York	Maine	D.C.	Florida
	Vermont	New Jersey	Georgia	Hawaii
		Texas	Indiana	Idaho
		Wisconsin	Louisiana	Kansas
			Maryland	Kentucky
			Minnesota	Missouri
			Mississippi	Nebraska
			Montana	North Carolina
			Nevada	North Dakota
			New Mexico	South Carolina
			Ohio	South Dakota
			Oklahoma	Tennessee
			Oregon	West Virginia
			Utah	
			Virginia	
			Washington	
			Wyoming	

CLASSIFICATION OF STATE RESTRUCTURING ACTIVITIES



SUMMARY OF COMMISSION AND LEGISLATIVE ACTIVITIES

State	Regulatory Commission Actions	Legislative Actions	Comments/Other Activities
NEW ENGLAND			
Connecticut	Order 7/95 notes that Commission currently lacks authority to require retail wheeling	Study Bill passed 6/95	Study group final report due 1/97
Maine	Commission study on electric restructuring issues due December 31, 1996.	Legislature passed Resolve 48, which required a study of retail competition, in July 1995.	An 18-member Work Group investigated electric restructuring issues during fall 1995.
Massachusetts	DPU draft proposed restructuring rules 5/96; final rules due by 12/96; retail wheeling to begin 1/98	Study bill signed 7/96; study report mid-1997	Retail wheeling, discount & muni legislation pending
New Hampshire	PUC draft restructuring plan 9/96; retail wheeling pilot begins 5/96	Retail wheeling and restructuring law signed 5/96	Under law, retail wheeling to begin by 6/30/98
Rhode Island	PUC actions implementing legislation are expected	Restructuring bill to start begin retail wheeling by 7/1/98 was signed 8/96	
Vermont	PSC draft plan issued 10/16/96, final plan due 1/97	Study bill died 4/95	Retail wheeling to begin 1/98
OTHER STATES			
Alabama		Stranded cost recovery (e.g., "exit fee") law passed 5/96	Retail wheeling bill expected in next session
Alaska	None	None	
Arizona	ACC Staff released plan 8/96 that calls for full retail choose by 2003	Study committee report due 12/31/97	APS states conditions for retail wheeling
Arkansas	Discontinued IRP because of competiton,10/95		
California	PUC approves interim CTC; retail wheeling & restructuring order 12/95	Law affirming PUC's restructuring passed 9/96	FERC ISO & PX filings 4/96; direct access beginning 1/98
Colorado	PUC opens inquiry 6/96 PSC; report due to legislature 12/1/96		
Delaware	Opens DP&L competition forum 4/96; report to legislature due 12/96		
D.C.	Competition inquiry opened 10/95		No action since 12/15/95
Florida	PSC holds informal education sessions	Study Bill Died 5/95	

State	Regulatory Commission Actions	Legislative Actions	Comments/Other Activities
Georgia		Retail wheeling & study bills die 3/96	
Hawaii		Bill allowing NUG retail sales died 3/96	PUC to investigate restructuring in 1997
Idaho	PUC concludes that deregulation not feasible or desirable in Idaho (8/96)		WWP pilot for large load approved 9/96
Illinois	CILCO & IP retail wheeling pilots start 5/96	Study bill passed	Task force report filed 12/95; Final report 11/96
Indiana	Informal discussions on competition continue; PSI filed retail wheeling tariff	Alternative regulation and study bill became law 4/95	URC's report to regulatory flexibility committee due 11/96
Iowa	Utility Board adopts principles 5/96		Final UB action expected 10/96
Kansas	Restructuring inquiry is inactive	Law to study\defer retail wheeling for 3 yrs. signed 4/96; retail wheeling bill died 5/96	ER report from 23--member task force to legislature due 1/15/97
Kentucky	Considering alternative regulation; hearings scheduled for 9/96	Draft retail wheeling bill circulated by industrials	
Louisiana	Adopted principles 6/96		New Orleans competition inquiry cleared to continue 7/96
Maryland	PSC Order rejects retail wheeling 8/95		
Michigan	Retail whleeling for new loads to begin in early 1997. Detroit Edison and Consumers Power filed retail wheeling plans for new load with PSC	PSC proposal for legislation to allow retail competition deferred	
Minnesota	PUC adopts principles 5/96. Favors wholesale competetion, skeptical of retail wheeling		Study group reports due 9/96
Mississippi	PSC competition inquiry 8/96	Alternative regulation law signed 3/96	
Missouri	PSC informal discussions 8/96		UE to file retail wheeling pilot
Montana	PSC adopts principles 5/96		
Nebraska	None	None	
Nevada	PSC restructuring report 6/96	Study group to report 1/97	Retail wheeling law for 1 new plant 6/93

State	Regulatory Commission Actions	Legislative Actions	Comments/Other Activities
New Jersey	Restructuring inquiry opened 6/95; policy decision by 12/96		Energy Plan adopted 3/95
New Mexico	PSC opens inquiry 11/95	Bill favoring continued study passed 2/96. Report due 1/97	
New York	Final policy order for retail wheeling issued 5/96. Retail wheeling due early '98		Takeover of LILCO T&D proposed 12/95
N. Carolina	Commission suspends retail wheeling inquiry 5/96		
N. Dakota	PSC issued order in 9/96 stating competition was not an "immediate need"		
Ohio	Roundtable continues; proposed code of conduct 9/96	Reintroduction of retail wheeling bill 4/95, 1994 bill died	AEP restructuring proposal 10/95; Ohio Ed plan '96
Oklahoma	Rulemaking on special contracts and streamlining ordered 8/95	Study resolution signed 6/95. Study group to report 12/96	
Oregon	PUC informal workshops		
Pennsylvania	PUC policy report 7/96; retail wheeling petition pending	Consensus restructuring bill expected to be introduced 12/96	
S. Carolina	Rejected petition to open retail wheeling inquiry. Staff survey 1/96.		
S. Dakota	None	Alternative regulation law 2/96	
Tennessee	None	None	
Texas	PUC approves ERCOT ISO 8/96; stranded cost inquiries continue 5/96	Legislation signed expanding wholesale competition, setting competition report; retail wheel not included 7/95	Scope of competition report due 1/97; Leg. committee report 7/96
Utah	PSC opens restructuring inquiry '96		
Virginia	Staff report cautious on RW 7/96; rules muni needs approval to take utility assets 11/95	Alternative regulation, federal customer stranded cost authority	Legislative study committee meets 7/96
Washington	Final policy statement 12/95		Grid operator plan announced 7/96
W Virginia	None	None	
Wisconsin	Restructuring plan adopted 12/95; ISO plan due 10/96		PSC report to legislature 2/96
Wyoming	Informal discussions '96; PSC white paper expected 10/96	Alternative reg. law 3/95	Conference 10/94

ACTIVITIES IN OTHER NEW ENGLAND STATES

Connecticut

- **Legislative Task Force.** A legislative task force in Connecticut is expected to issue its final report and recommendations on electric restructuring issues in January 1997. The task force failed to reach consensus on a restructuring plan and is expected to issue a report in December 1996 that lists the opposing positions in 15 key policy issues, including timing of deregulation and stranded cost recovery.

- The legislative task force did agree to recommend that Connecticut set up a state-financing system to help utilities buy down high-cost power purchase contracts and reduce stranded costs.

- A group of task force participants, led by the Attorney General and the Office of Consumer Counsel, has submitted a proposal that retail wheeling be available to all electricity consumers in the state by July 1, 1998. The plan calls for deregulation of generation, separation of utility-owned generation from transmission and distribution followed by eventual divestiture of generation, creation of an independent system operator and the recovery of utility stranded costs after determination of the market value of generation assets through divestiture.

Massachusetts

- **Legislative Study Committee.** Legislation enacted in Massachusetts establishes a legislative study committee, which will report back to the legislature by mid-1997 on a number of issues including stranded cost recovery, environmental protection, low-income ratepayer protection and the property tax impact of restructuring (i.e., the impact on the revenues of towns and cities where generating plants are located).

- On May 1, 1996, the Massachusetts Department of Public Utilities (DPU) issued draft restructuring rules that would provide a direct-access competitive generation market by January 1, 1998. Final restructuring rules are expected by year-end 1996.

- Massachusett's Attorney General and the Massachusetts Electric Company, a subsidiary of the New England Electric System (NEES), have agreed to a restructuring plan, referred to as "Consumers First." This plan would allow retail access by January 1998, require that all customers be given a "standard offer" option that provides a 10 percent savings on their monthly bills, and would require older fossil-fired power units to meet the same emissions standards as new units. Massachusetts Electric would recover stranded investments through a 2.8 cents per kWh charge. Market valuation (sale, spinoff, etc.) of at least 15 percent of fossil-fuel and hydro units is required.

- Pilot "retail wheeling" programs have been approved for Commonwealth Electric Company and Massachusetts Electric.

New Hampshire

- **Legislative Action.** Legislation approved in New Hampshire requires retail wheeling as early as January 1, 1998 and no later than June 30, 1998. Under the legislation, the PUC must adopt restructuring rules before February 28, 1997 and the utilities must file retail wheeling tariffs and restructuring plans pursuant to the PUC's restructuring rules by June 30, 1997. The PUC issued a draft of its restructuring plan on September 10, 1996. Stakeholders filed comments on the plan on October 18.

- The PUC's draft plan ties stranded cost recovery to regional rates; those companies that are currently charging rates that are closer to the New England average would be allowed to recover a higher percentage of their stranded costs. (There is some indication that this feature of the plan would be subject to court challenge.) The draft plan would require utilities to unbundle service and transfer generation to separate affiliated companies. The Commission is seeking comments on ways to provide incentives for divestiture of generation.

- New Hampshire legislation requires that the six electric utilities in New Hampshire develop and implement pilot programs that provide retail wheeling services to three percent of electric load. Pilot programs are currently under way for all utilities except the New Hampshire Electric Cooperative (NHEC). NHEC is currently requesting a FERC ruling regarding the effect of the pilot program on its all-requirements contract with PSNH.

Rhode Island

- **Legislative Action.** Legislation approved in Rhode Island requires retail wheeling by July 1, 1998 and requires the restructuring of the electric industry.

- The legislation sets a nonbypassable stranded cost transition charge of 2.8 cents per kWh beginning when retail access begins, through the end of 2000, when it will be replaced by a PUC-determined stranded cost recovery charge. Most categories of stranded costs would be recovered by the end of 2009. Market valuation (sale, spinoff, etc.) is required for at least 15% of nonnuclear generating facilities. The legislation provides utilities with an incentive to renegotiate power purchase contracts, requires corporate functional unbundling and requires distribution companies to provide "standard offer" generation services to customers that do not choose to take power from a nonregulated power producer.

- The Rhode Island electric utilities have all filed to increase their rates by two percent, as permitted by the legislation.

Vermont

- The Vermont Public Service Board issued a draft of its restructuring plan on October 16, 1996. The Board is expected to submit its final plan to the legislature in January 1997. Under the plan, retail competition would begin in January 1998.

- The draft plan requires the functional separation of generation and transmission into distinct business units (smaller IOUs, municipal utilities, and cooperatives are not required to unbundle). Four additional features of the plan are notable. First, a portfolio standard for renewable resources would require all electric companies to dedicate a portion of their sales to renewable resources. Second, the draft plan includes a "Consumer Bill of Rights." Third, the plan includes an opportunity for full recovery of stranded costs provided that they are legitimate, verifiable, otherwise recoverable, prudently incurred and non-mitigatable. Finally, the draft plan supports federal legislation that would address the environmental effects of electric restructuring.

ACTIVITIES IN OTHER STATES

Alabama

- **Legislative Action.** Legislation was enacted that authorizes the PSC or the courts to review contracts for service to departing customers by new suppliers and to determine whether those contracts are in the public interest. If the PSC or the court approves the contract, it must require the departing customer to compensate its former supplier for stranded costs (e.g., "exit fees"). In the next legislative session, it is expected that retail wheeling legislation will be introduced.

Alaska

- None

Arizona

- **Legislative Study Committee.** A report is due from the legislature's 16-member committee on December 31, 1997. This committee is to develop a plan for the introduction of competition in generation no later than December 31, 1999.

- **Arizona Corporation Commission (ACC).** On August 28, ACC staff released a plan that calls for full retail choice by 2003; under staff's phase-in plan, 20% of customers would have choice by 1999, 50% by 2001 and 100% by 2003.

- Disputes have emerged between the legislature and the ACC regarding the Commission's authority to restructure the electric utility industry. (The ACC is an elected commission).

Arkansas

- None.

California

- **Legislative Action.** The Legislature unanimously approved and the governor signed into law comprehensive restructuring that affirms the PUC's restructuring policy decision and timetable as state energy policy. The law achieves at least a 10% reduction for residential and small commercial customers starting in 1998. One feature of the legislation authorizes the California Infrastructure and Economic Development Bank to issue "rate reduction bonds," which would be used to acquire transition property (i.e., stranded assets).

- Under the restructuring plan, direct access is to begin in January 1998 and most stranded costs are to be recovered by 2005.

- The PUC has begun the process of implementing electric restructuring by establishing working groups, one for each of four broad issue areas (market structure, consumer choice, ratesetting issues and environmental impact issues).

- The PUC has approved the imposition of a stranded cost recovery charge on retail customers departing Pacific Gas & Electric's system before January 1, 1998. The calculation of the charge has not been finalized.

Colorado

- The PUC has opened a notice of inquiry on electric restructuring issues. The PUC has sent a questionaire to utilities and interested parties in the western region. Results from the questionaire will be presented to the legislature before December 1, 1996.

Delaware

- The Public Service Commission (PSC) opened a proceeding to explore issues related to the "restructuring of Delmarva Power & Light Company's (DP&L's) electric business," at that utility's request. The PSC asked participants in this proceeding to submit a report by December 31, 1996 that addresses any changes in PSC rules or state laws that would be necessary to allow DP&L's customers to choose alternative suppliers.

District of Columbia

- The Public Service Commission (PSC) has not acted following the December 15, 1995 prehearing conference in its investigation of electric competition and regulatory policies.

- The Commission has asked for comments on certain electric restructuring issues in its review of the proposed merger between Potomac Electric Power Company (PEPCO) and Baltimore Gas & Electric (BG&E).

Florida

- **Legislative.** A bill calling for the creation of an Electric Utility Study committee to evaluate various issues related to the status of retail electric service competition in the state was defeated.

- The Florida PSC is holding a series of informational forums to educate the PSC and its staff on electric restructuring issues.

Georgia

- The PSC approved an alternative rate plan. The PSC noted in that order that nothing in the order precludes it or its staff from opening a study docket to examine electric restructuring issues. The PSC, however, has not begun a study.

Hawaii

- The PUC is expected to begin an investigation into electric restructuring issues in 1997.

Idaho

- The PUC concluded in its restructuring investigation that deregulation or opening up Idaho's distribution system "is not feasible or desirable at this time." The PUC cites three risks: (1) competition could increase rates for most ratepayers by requiring them to compete with others for Idaho's low-cost hydroelectricity; (2) quality of service could decline; and (3) restructuring could benefit a few large users of electricity at the expense of the majority.

Illinois

- **Legislative** - Various bills regarding retail wheeling and restructuring, which were introduced last year in both chambers of the legislature, lapsed. It is anticipated that activity on these bills will be deferred until the legislatively created Joint Committee, which is studying competition and restructuring, files its final report and legislative recommendation for restructuring the industry in November 1996.

- Illinois Power Company and Central Illinois Light Company currently have retail wheeling "pilot programs" underway.

Indiana

- **Report to Legislative Committee.** The Utility Regulatory Commission's report to the regulatory flexibility committee is expected to be completed in November 1996. That committee, in turn, is to report to the legislative council on the effects of competition, the effectiveness of traditional regulation and other energy utility issues before November 1997. This report is expected to be updated annually.

- The Utility Regulatory Commission (URC) has been holding informal "competition forum" meetings. The primary topics have been emerging issues in retail competition and the potential effects of retail competition on the state and its ratepayers.

Iowa

- In May, the Utilities Board (UB) adopted restructuring principles, which provide a general framework for evaluating proposed changes in the electric industry and for future discussions. In late 1996, the UB is scheduled to issue its final order and forward its recommendations to the Legislature regarding changes to the state's regulatory structure.

Kansas

- **Legislation.** The governor signed into law a bill that places a three-year moratorium on the State Corporation Commission (SCC) approving retail wheeling and also creates a task force of legislators and stakeholders to study retail competition issues. The moratorium on retail competition extends through July 1, 1999. The 23-member task force is to study electric restructuring issues and make a preliminary report of its activities and findings by January 15, 1997. A final report to the legislature is due in January 1998.

- The Kansas Corporation Commission's restructuring investigation has been inactive.

Kentucky

- The PSC began an informal, undocketed investigation into alternative regulatory approaches, with hearings scheduled for September 1996.

Lousisiana

- The PSC has adopted a set of principles that are intended to guide its restructuring investigation.

Maryland

- The PSC has opened a proceeding at Delmarva Power & Light's (DP&L's) request to explore issues related to restructuring DP&L's electric business, with a report by DP&L due in October 1996.

- In 1995, the PSC determined that retail wheeling was not in the public interest in Maryland at that time.

Michigan

- A December 1995 report by the State Jobs Commission found that lowering electric rates by introducing some form of competition was needed to improve Michigan's economic competitiveness. The State Jobs Commission plan would set up a poolco market structure and would allow retail wheeling by January 1, 1997 for new commercial and industrial loads. Under the State Jobs Commission plan, retail competition would be available to all customers beginning in 2001.

- In response to one of the State Jobs Commission's recommendations, the State PSC directed the utilities in the state to file plans that make retail wheeling available to new commercial and industrial load by the beginning of 1997. Detroit Edison and Consumers Power have filed plans with the state PSC.

Minnesota

- The PUC issued an order on May 14, 1996 that adopts principles and action steps for electric restructuring. The report embraced increased wholesale competition but was cautious regarding retail competition. Reports on rate flexibility/innovative regulation, unbundling, safety and reliability are due in late 1996.

- The PUC directed the competition working group in its restructuring proceeding to file a report on wholesale competition by September 1996. A subcommittee structure for the competition working group has been organized along the following issues: wholesale competition, unbundling, public information, safety and reliability, flexible and innovative ratemaking, and legislative and law related.

Mississippi

- The PSC rejected an "exit fee" proposal submitted by an Entergy Corporation subsidiary in August 1996 but opened a generic investigation to consider electric restructuring issues.

Missouri

- The PSC continues to sponsor occasional meetings of the "electricity issues round table." Most recently, stranded cost issues were discussed.

- Union Electric (UE) and others have proposed that UE begin an experimental retail wheeling pilot program.

Montana

- The Public Service Commission adopted final restructuring principles in its ongoing investigation and said it would focus on Montana Power Company's restructuring plan for a transition to retail competition and specifics to be filed by the Company as a way of addressing the public benefits of retail wheeling and restructuring. Montana Power intends to file its full restructuring plan by October 1996.

Nebraska

- None.

Nevada

- **Legislative.** A legislative study committee, comprised of 11 legislative members, continues to meet to develop recommendations for the 1997 legislative session.

- A PSC report found that Nevada should move away from a monopoly market structure but should not attempt to dictate the future industry structure in a prescriptive way.

- The PSC directed its staff to prepare a report on uneconomic bypass and stranded costs, which was due in September 1996. The PSC plans to distribute a policy statement on these issues in January 1997.

- The PSC plans to issue an order on unbundling issues in September 1996. The PSC has asked that working groups be formed and that tariffs be submitted by March 1997.

New Jersey.

- **Legislative.** Legislation was introduced that would direct the BPU to establish a pilot residential retail wheeling program.

- The BPU's staff plans to issue its recommendations on electric restructuring in November 1996, with a BPU decision expected by year-end 1996.

- The BPU has recommended that the legislature repeal the state's utility gross recepts tax.

New Mexico

- **Legislature.** The legislature adopted Joint Memorial 42, which directed the PUC to continue its current investigation into electric restructuring issues and to report back before electric restructuring is implemented. It also adopted Joint Memorial 43, which continues the interim study committee's work for another year; the study committee is to report to the legislature in January 1997.

- Comments were filed in February and April 1996 in the PUC investigation on electric restructuring.

New York

- In May 1996, the Public Service Commission issued its final policy decision in its competitive opportunities inquiry that would establish retail competition by early 1998. The PSC asked that the utilities file compliance plans by October 1, 1996. In November 1996, an appellate court (not the highest court in the state) upheld the PSC's retail competition decision.

North Carolina

- The Utilities Commission has postponed its retail competition investigation and has concluded that parties should instead concentrate their efforts on responding to the Utilities Commission investigation into the impacts of FERC Orders 888 and 889.

North Dakota

- In September 1996, the PSC issued an order in its restructuring proceeding, which stated that retail competition was not an "immediate need."

Ohio

- **Legislature.** A retail wheeling bill was introduced, which calls for retail competition to begin on January 1, 1998.

- The Ohio Electric Competition Roundtable continues to meet. The pricing committee of the roundtable has developed consensus codes of conduct for both utilities and third-party aggregators offering conjunctive electric services as part of a pilot program. This pilot program would allow customers to aggregate to negotiate special rates with their traditional utility or third-party aggregators.

- At the August 22 "Roundtable," Centerior Energy Corporation announced its intention to allow direct access for all customers by year-end 2002.

- The group of Midwest utilities that are developing an independent system operator proposal to be filed with federal regulators has expanded to include additional investor-owned, municipal, and cooperative utilities.

Oklahoma

- **Legislative.** A legislative study commission is meeting to study electric restructuring and, if appropriate, prepare legislation on retail competition. The study commission is expected to report in December 1996 and recommend legislative changes, if any.

- The Corporation Commission took comments on its restructuring inquiry in August 1996. A Corporation Commission decision is due in December 1996.

Oregon

- The PUC is hosting a series of workshops to discuss electric restructuring issues.

- The PUC will meet in November 1996 to review retail competition "pilot program" proposals by PacificCorp and Portland General Electric Company.

Pennsylvania

- **Legislation.** The legislature enacted the Electricity Generation Customer Choice and Competition Act. This comprehensive restructuring legislation was signed by the Governor on December 3, 1996. Beginning January 2001, electric generation will no longer be a regulated function. One-third of peak load demand will be provided on a reail competition basis by January 1999, two-thirds by January 2000 and full retail competition will be present by January 2001. The Commission will have some discretion to vary this schedule if necessary to preserve reliability or because of other specified considerations.

- The legislation allows utilities to seek PUC approval to securitize (refinance) stranded costs through the issuance of bonds. The legislation identifies property rights and a statutorily dedicated revenue stream for intangible transition charges (ITCs), which would include transition or stranded costs, recapitalization of existing debt or equity capital and related transaction costs. A "qualified rate order," using an expedited review process, would establish the ITCs and would provide an assurance that the ITC costs would be recovered.

- The competitive transition charge (CTC) would be calculated by the PUC so that they may recover just and reasonable amounts of stranded costs while allowing investors the opportunity to fully recover such amounts. A CTC would be paid by every T&D customer. The CTC would not last more than nine years. The CTC includes exit fees for customers that opt for self-generation and thereby bypass the system. If stranded assets are securitized, the CTC is to be reduced by an appropriate amount.

- The legislation caps rates at current levels. No increase in T&D charges could occur until full customer choice occurs (or up to 4.5 years). No increase in generation charges could occur while the CTC and ITC exist (or up to nine years).

- The PUC submitted a report on electric restructuring issues to the governor and legislature in July 1996.

South Carolina

- The PSC staff solicited comments through a questionaire on electric restructuring issues. The PSC staff compiled and released a summary of the responses to the questionaire but made no recommendations.

South Dakota

- None.

Tennessee

- None.

Texas

- **Legislation.** Legislation on retail competition is expected to be hotly contested during the 1997 session.

- The PUC staff issued draft reports on stranded costs and the scope of competition in the state in October 1996. The Draft report suggests that electric utilities will have $13 billion in stranded costs if retail competition begins in 1998, but suggests that a two-year delay could reduce stranded costs significantly. Final recommendations are due in December 1996.

- The PUC issued final rules for wholesale open-access transmission terms and conditions following up on its previously issued rules on wholesale transmission access and pricing. The PUC continues to meet and hold workshops on electric utility restructuring, stranded costs and the scope of competition in the electric industry. As a result of the workshops, the PUC has asked the state's electric utilities to estimate their stranded costs and file the estimates with the PUC.

Utah

- The PSC is considering experimenting with electric competition. Technical conferences have been held and comments were due in July 1996.

Virginia

- **Legislative Subcommittee.** The legislature established a seven-member joint subcommittee to study electric restructuring issues. The joint subcommittee is coordinating its study with the State Corporation Commission's (SCC's) investigation.

- **Legislation.** Legislation passed that allows the State Corporation Commission to approve alternative regulation and special contracts, allows utilities to recover stranded costs (e.g., through exit fees) from federal facilities that no longer take power from franchised retail utilities, grants the the SCC authority to approve municipality takeovers of services provided by an electric utility in that municipality, and grants SCC the authority to set for recovery stranded and other costs resulting from condemnations.

- The SCC's staff filed in a report its electric restructuring investigation in July 1996. The SCC staff report recommends that Virginia pursue "a cautious and measured approach" to adopting competitive initiatives.

Washington

- The Utilities and Transport Commission (UTC) issued final principles for electric restructuring in December 1995. The UTC plans to use these principles in exercising its general duties and responsibilities and in developing its opinion and judgments concerning specific regulatory issues.

- The UTC is considering establishing pilot projects initially targeted at industrial customers but which would eventually be geared toward small commercial and residential customers.

West Virginia

- None.

Wisconsin

- The Public Service Commission has opened proceedings to address ten of the 12 issue areas it said it would complete in 1996 toward its 32-step plan for starting retail wheeling by 2000 and restructuring the industry. Two proposals for independent system operators and one proposal for transferring transmission system ownership to a transco were filed in the PSC's case investigating the Independent System Operator issue.

Wyoming

- The PSC has formed study subcommittees to prepare reports on specific aspects of electric restructuring and direct access (i.e., legal issues, transition costs, reliability, rate unbundling, social concerns and implementation issues). The PSC is expected to release a white paper on restructuring during late 1996.

THE DEREGULATION EXPERIENCE: LESSONS FOR THE ELECTRIC POWER INDUSTRY

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August 1996

This paper was prepared by The National Regulatory Research Institute (NRRI) for the Maine Public Utilities Commission (MPUC). The views and opinions expressed herein do not necessarily state or reflect the views, opinions, or policies of the MPUC, the NRRI, the National Association of Regulatory Utility Commissioners (NARUC), or NARUC member commissions.

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INTRODUCTION

On July 3, 1995, the Governor of Maine approved Resolve 48. This Resolve, *inter alia*, requires that the state's Public Utilities Commission address several issues in its report to the Legislature on electric industry restructuring (see Table 1). These issues relate to the "orderly transition to a competitive market for retail purchases and sales of electric energy." This paper summarizes the experiences of five industry sectors that underwent transitions from a highly regulated market to a competitive market.

The "data" on deregulation[1] are abundant and originate from various sources. These sources include media accounts, anecdotal evidence, the activity of industry players, stock market results and activities, and scholarly studies.

The information drawn from these various sources points to two major conclusions. First, the more scholarly studies have shown that deregulation has generally been a successful story. Consumers have benefited greatly and the overall efficiency of the deregulated industries has improved greatly as well. Firms in these industries have reduced their costs, lowered their prices, introduced new services and reconfigured old services to better accommodate consumer preferences, and deployed new technologies and practices.[2] Further, distributional effects have not been dramatic. For sure, shareholders have not grown rich at the expense of consumers. In fact, in most instances, consumers have gained much more from deregulation than shareholders. Yet, shareholders have been able to earn adequate rates of return, attributed in part to the greater freedoms firms have enjoyed since deregulation.

On the downside, deregulation created certain problems. Some of these problems were short run in nature; after a period of time they were resolved or at least

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[1] Deregulation has many dimensions. This paper focuses on those that liberated both price and entry controls on the firms of a specific industry.

[2] Especially for the naturally competitive industries, such as land transportation, evidence shows that price regulation raised prices and reduced the number of competitors.

TABLE 1

TRANSITIONAL ISSUES IDENTIFIED IN RESOLVE 48

1. ***How utility stranded investment is defined and calculated and how it will be dealt with;***

2. ***How the regional marketplace and federal law affect the transition;***

3. ***How the State's energy policy, including policies concerning conservation, use of renewable and indigenous resources and diversity of supply, will be affected;***

4. ***How the State's environment and environmental policies will be affected;***

5. ***How social policies, including low-income programs and universal service goals, will be affected;***

6. ***How ratepayers, shareholders of investor-owned electric utilities, owners of consumer-owned electric utilities and other owners of energy resources will be affected;***

7. ***How the State's economy will be affected;***

8. ***How reliability of service will be affected;***

9. ***How obligations of contracts will be affected;***

10. ***How a system for the transmission, distribution and generation of electricity should be structured; and***

11. ***To what extent protections against anticompetitive practices can be provided.***

mitigated as industry players adjusted to the dramatically different market environment. One example is the uneven reductions in prices to customers with varying degrees of supplier-choice opportunities. Other problems appear more permanent; for example, mergers have created large firms that, in some instances, have had the effect of diminishing competitive forces.

Several industries in the United State and elsewhere in the world have undergone dramatic transformations over the last two decades.[3] This paper focuses on those industries that were once tightly controlled by price and entry regulation. Led by a combination of technological, economic, political, and ideological forces, these industries have become more competitive and less influenced by governmental control.[4] Different factors were responsible for the transformation of individual industries. For some, the impetus was the realization that regulation together with limited competition was incompatible with emerging market and technological forces. For others, the driving force was the erosion of benefits to those interest groups who previously supported regulation and barriers to competition. Other industries were performing so poorly that a political consensus developed for less governmental intervention and stronger market influence to manage the future structure and performance of these industries.[5]

The post-transformation experience of these industries can assist in predicting the effects on industries currently initiating major reforms. This paper summarizes these experiences for a number of industries, namely, transportation, natural gas,

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[3] See Robert W. Hahn and John A. Hird, "The Costs and Benefits of Regulation: Review and Synthesis," *Yale Journal on Regulation* 8, 1 (Winter 1991): 233-78; Clifford Winston, "Economic Deregulation: Days of Reckoning for Microeconomists," *Journal of Economic Literature* 31 (September 1993): 1263-89; and Jerry Ellig, "Regulatory Reform in Electricity: Precedents from Other Industries," unpublished paper, November 1994.

[4] Many analysts group these forces into two broad categories, political and economic.

[5] An analysis of driving forces behind industry transformation, particularly toward less regulation and more competition, is contained in Sam Peltzman, "The Economic Theory of Regulation After a Decade of Deregulation," in *Brookings Papers on Economic Activity: Microeconomics 1989*, Martin Neil Baily and Clifford Winston, eds. (Washington, D.C.: The Brookings Institution, 1989), 1-59.

telecommunications, financial, and United Kingdom's electric power. What implications they have for the restructuring of the U.S. electric power industry will be addressed. Particularly relevant are the experiences of the U.S. natural gas and telecommunications industries. These industries have already undergone dramatic transformation and, since the beginning of the century, have been subject to state public utility regulation.

MAJOR QUESTIONS AND ISSUES

Measuring the effect of tight price and entry regulation on the performance of an industry and on the economic welfare of individual stakeholders is a difficult task. For a particular transformed industry, an *ex post* analysis, for example, would require a comparison between actual performance and predicted performance under the previous market structure and regulatory regime.[6] Performance, of course, is multi-dimensional as typically it includes such elements as allocative and productive efficiency,[7] the availability of goods or services with varying attributes, and equity

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[6] Such an *ex post* "counterfactual" analysis requires predicting how the industry would have performed under the *status quo*. As an illustration, set $\Delta PER = PER_a - PER_r$, where the predicted change in performance, ΔPER, can be derived from observing actual performance, PER_a, and estimating how the industry would have performed under the old regulated regime, PER_r. In estimating PER_r, the analyst needs to assess the cost and demand conditions for the industry and include the effect of outside (exogenous) factors.

In an *ex ante* analysis, where one would try to predict the future effect of deregulation, a "counterfactual" prediction is also required. For example, the analyst would need to measure the performance of an industry under the condition that deregulation (or less regulation) would take place. A discussion of the methodological problems associated with measuring the effect of deregulation is contained in Hahn and Hird, "The Costs and Benefits of Regulation: Review and Synthesis;" and Paul L. Joskow and Nancy L. Rose, "The Effects of Economic Regulation," in Richard Schmalensee and Robert D. Willig, eds. *Handbook of Industrial Organization* (New York: Elsevier Science Publishers, Inc., 1989), 1449-1506.

[7] Allocative efficiency refers to a firm selling a service or good at the firm's marginal cost (assuming no harmful or beneficial effects on third parties). Productive efficiency refers to a firm providing a service or good with a given level of quality at the lowest possible resource cost.

effects. Different policy-makers and analysts, although they may assign dissimilar weights to these elements, would generally agree that they reflect the major indicators of how well or poorly an industry is performing.

The "economic welfare of the stakeholders" is intertwined with an industry's performance.[8] How an industry conducts its business in setting prices and in enriching equity holders directly affects customers and industry investors. In accordance with standard economic analysis, the performance of an industry should be evaluated on the basis of aggregate consumer and producer welfare. This criterion for assessing the performance of an industry is consistent with the social objective of advancing economic efficiency. The effects on individual stakeholders, such as workers, managers, and investors, are also important considerations in any evaluation of deregulation.

The pertinent issue with regard to restructuring of the U.S. electric power industry is, "*How will the industry perform under less regulation and more competition*?" Predicting the direction of prices for individual classes of customers, of profits, and of quality of service is difficult enough.[9] Trying to go one step farther by estimating the actual impacts is especially problematic.

Although conveying limited information, and requiring careful judgment in interpretation, the experiences of other industries undergoing dramatic transformation can be useful as a parameter in narrowing the expected outcomes of a restructured electric power industry. We should be able to predict more accurately what a more competitive and less regulated electric power industry holds for consumers and utilities

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[8] Most scholarly studies have shown that price regulation of most industries has produced a "deadweight welfare loss," which implies that the gains of regulation to some market players have been exceeded by the losses to others. For some industries, these "others" included producers who supported deregulation.

[9] Analysts have been "generally successful in predicting the direction and size of the effects of regulatory reform on prices and profits," (Winston, "Economic Deregulation: Days of Reckoning for Microeconomists," 1286).

by observing the performance of other industries undergoing major change. At least, that is the premise underlying this paper.

We will attempt here to identify "typical" outcomes for industries that became more competitive and less regulated. This goal is made difficult by the fact that industries were both regulated and deregulated for different reasons. For example, trucking was initially regulated to protect the railroads;[10] the wellhead price of natural gas was regulated to hold down the price for consumers.[11] We will therefore expect deregulation and more competition to produce different results as measured by major performance indicators.[12] Yet, we do observe a commonality of some major results. For example, most studies show that average prices have fallen after deregulation.[13] This outcome strongly suggests that regulation was instituted to serve interests other than consumers. One classic example of this is the regulation of the trucking industry. The empirical evidence clearly shows that economic gains under regulation accrued largely to trucking firms and labor at the cost of higher rates for shippers.[14]

In trying to predict how reform in the electric power industry or any industry will affect different stakeholders in addition to economic welfare as a whole, we need to know how regulation has affected the industry. Although there is disagreement among analysts on other points, they will generally agree that deregulation will ultimately cause average prices to fall. But even here it is not conceded that this outcome would be true for all consumers. Those consumers who were previously being subsidized or who

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[10] Prior to the Motor Carriers Act of 1935, which gave the Interstate Commerce Commission authority over pricing and entry into the bus and trucking industries, truckers had the flexibility to undercut railroads in the pricing of services to price-sensitive shippers.

[11] Paul W. MacAvoy, *The Regulated Industries and the Economy* (New York: W.W. Norton, 1979).

[12] See Joskow and Rose, "The Effects of Economic Regulation."

[13] Prices for individual groups of consumers, however, may increase. In this situation, the public-policy question is whether these price increases should be avoided even if economic efficiency suffers.

[14] Nancy L. Rose, "Labor Rent Sharing and Regulation: Evidence from the Trucking Industry," *Journal of Political Economy* 95 (1987): 1146-78.

may not have the ability to take advantage of market opportunities may, at least for a few or several years, endure higher prices.[15]

If one had to predict what will transpire in a restructured electric power industry based on the overall empirical evidence for deregulated industries, the following outcomes seem likely:

(1) the price of electricity averaged across all customer classes will fall;

(2) customers who do not have direct access to generators or marketers will benefit less than other customers or, at least in the short term, may actually be worse off;

(3) most of the benefits from industry restructuring will go to customers (i.e., most of the efficiency gains induced by competition will ultimately flow to customers);

(4) service quality will reflect, to a larger degree, the preferences of individual customers and may fall in the aggregate;

(5) price discrimination induced by competition will become more common;

(6) the productivity of the electric power industry will improve;

(7) bilateral contracts for electrical services with specified price and service obligation provisions will become more commonplace;

(8) the unbundling of old and new electrical services will evolve over time;

(9) the financial position of utilities and other firms will become more volatile, with bankruptcies and exiting of firms likely to occur;

(10) mergers and acquisitions will become more common as utilities and nonutilities try to strategically position themselves in the new competitive environment;

(11) electricity prices will be rebalanced to accommodate market forces, with the phasing out of cross-subsidies (e.g., interclass subsidizations, cost averaging) that previously benefited many customers;

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[15] For example, this has been the experience in the natural gas, railroad, and telecommunications industries.

(12) regulation/antitrust will assume a new role in assuring that (a) truly competitive ("level playing field") conditions exist and (b) customers have access to information needed for making intelligent decisions; and

(13) social objectives and transition costs will continue to be funded through regulatory channels, as long as utilities continue to possess monopoly power for some of their services that remain subject to some form of price regulation.

The above outcomes are compatible with the performance and activities in other restructured industries. The above predictions affirm a much more competitive, market-driven electric power industry than what exists today. One important lesson from the experience of transformed industries is that analysts and others tend to understate beforehand the changes in firm's activities and technology. In other words, the responses of firms and other market participants to a new environment are more dramatic than what anyone could ever have predicted. The transitional period to a highly-developed competitive environment may also require a number of years to complete. Analysts would therefore tend to truncate the benefits of deregulation by missing the *full* response of different market participants to these changes over an extended period of time. Although difficult to anticipate and more difficult to measure, these responses have been found after-the-fact to be significant in other industries. The experiences of deregulated industries generally show that firms respond quickly in changing their prices to correspond more closely to costs, but take much longer in undertaking major improvements in their operations.

During the transitional period, the different stakeholders will seek to "game" or strategically use the rules to their advantage. New entrants, for example, will want to handicap incumbent utilities, who in turn have an interest in raising barriers to market entry. Artificial constraints established by legislatures or regulators, either under current rules or new rules, that favor one group over others are likely to harm society at large. Such constraints often hurt those consumers or other groups that have little political clout. As a matter of public policy, legislatures and regulators should avoid showing favoritism toward special interest groups when it results in unfair or inefficient competition.

EVIDENCE FROM CERTAIN INDUSTRIES

Several studies have measured the effects of regulation on a particular industry.[16] These studies range widely in sophistication, from simple observation (comparison) of "pre-transformation and post-transformation" actual industry performance to econometric analysis that attempt to separate the effects of deregulation from exogenous factors in explaining changes in an industry's performance. The major problem with "observation" studies is that they cannot measure the effect of one particular event, such as deregulation, on an industry's performance. For example, at the same time that the United Kingdom privatized its electric power industry, it also radically restructured the industry to encourage competition and instituted a price-cap mechanism to regulate the prices of transmission, distribution, and bundled sales services. Subsequent to these changes in 1991, real prices for most U.K. electricity customers have fallen.[17] We cannot say, however, which of these factors was most important or even contributed to the decline in price. In any event, one must be cautious in interpreting the results of studies that attempt to measure the effect of deregulation *per se* for a specific industry.

The summary below highlights major outcomes and our observations of events for certain industries undergoing deregulation or major regulatory and restructuring reforms. These include the natural gas, transportation, U.K. electric power, financial, and telecommunications industries. Table 2 lists the major initiatives underlying

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[16] This paper will cite the more scholarly studies in its discussion of the evidence for individual industries.

[17] Nigel Evans, "UK Electricity: the Criticisms, the Changes, the Challenges," paper presented at the 1996 EPRI Conference on Innovative Approaches to Electricity Pricing, LaJolla, California, March 28, 1996.

TABLE 2

MAJOR DEREGULATION INITIATIVES

INDUSTRY	*INITIATIVES*
Natural Gas	• *Natural Gas Policy Act (1978)* • *FERC Order 436/500 (1985-87)* • *Natural Gas Wellhead Decontrol Act (1989)* • *FERC 636 Orders (1992)* • *Expansion of Retail Service Unbundling (1995-current)*
Transportation	• *Airline Deregulation Act (1978)* • *Motor Carrier Reform Act (1980)* • *Staggers Rail Act (1980)*
U.K. Electric Power	• *Privatization (1991)* • *Restructuring (1991)* • *Price-Cap Regulation (1991)*
Financial	• *Securities Acts Amendments (1975)* • *Depository Institutions Deregulation and Monetary Control Act (1980)* • *Garn-St. Germain Depository Institutions Act (1982)* • *Riegle-Neal Interstate Banking and Branching Efficiency Act (1994)*
Telecommunications	• *FCC Carterfone Decision (1968)* • *AT&T Settlement (1982)* • *FCC Computer III Decision (1986)* • *Telecommunications Act (1996)*

deregulation of these industries. Generally, deregulation has eliminated most of the inefficiencies under the old, heavily regulated regime (see Table 3).

Natural Gas

The U.S. natural gas industry has undergone a major transformation over the past two decades. Prior to the enactment of the Natural Gas Policy Act in 1978, the industry was comprehensively regulated from the wellhead to the burnertip. Federal regulation of the industry took a major step in 1938 with the passage of the Natural Gas Act. This legislation provided for the federal regulation of transportation and sales of gas in interstate commerce. In 1954, the Phillips decision by the U.S. Supreme Court extended federal authority to the regulation of wellhead gas prices. By the mid-1970s, the "old" natural gas industry started to encounter major shortages in the interstate gas market. Earlier in the 1970s, proven gas reserves began to decline. The apex of the gas-shortage problem occurred during the 1976-77 winter when severe curtailments disrupted thousands of businesses and led to the temporary unemployment of hundreds of thousands. A political consensus began to emerge in Washington, paving the way for wellhead price deregulation.

The Natural Gas Policy Act of 1978 provided for the phased deregulation of wellhead prices of most interstate gas drilled after October 1978. Later, the Natural Gas Wellhead Decontrol Act terminated all price controls beginning on January 1, 1993.

During the early 1980s, severe take-or-pay contract problems started to come to the surface. The market price for wellhead gas was frequently far below existing contract prices but pipelines were legally obligated to pay the contract prices. Take-or-pay provisions in producer-pipeline contracts were the product of wellhead price regulation that positioned producers favorably in negotiating nonprice terms and conditions with pipelines. Take-or-pay provisions placed most pipelines in a financial bind in addition to driving up the price of gas throughout the natural-gas network.

TABLE 3

INEFFICIENCIES IN OLD REGIME

INDUSTRY	*INEFFICIENCIES*
Natural Gas	• *Below-market price for wellhead gas* • *Market power exhibited by pipelines* • *Inaccessibility of gas distributors/ retail consumers to low-priced gas supplies*
Transportation	• *Cross-subsidies* • *Entry/exit barriers* • *Rigid pricing, service-provision and operation rules* • *Disincentives for productivity growth and operation/planning innovations*
U.K. Electric Power	• *Disincentives for productivity growth* • *Distorted prices* • *Highly monopolistic industry structure* • *Decisionmaking heavily influenced by politics*
Financial	• *Lack of price competition in brokerage services* • *Restrictions on the availability of banking services* • *Restrictions on interstate banking operations* • *Below-market ceilings on deposit interest rates*
Telecommunications	• *Rate averaging* • *Barriers to entry in long-distance market* • *Cross-subsidies between interstate rates and local service rates* • *Noncompetition in "equipment" markets*

Matters grew worse with the collapse of oil prices in 1985. As a consequence of these events, the demand for natural gas plummeted.

Pipeline reform began in 1985 with the Federal Energy Regulatory Commission (FERC) issuance of Order 436. This order was in response to a judicial interpretation of pipelines' Special Marketing Plans as unduly discriminatory. It provided a "carrot" to pipelines for open access by offering them an "optional" expedited certificate for new facilities.[18] Within months after the order, all the major pipelines applied for open-access status. The FERC permitted pipelines to convert contract-demand (CD) service to transportation-only service.[19]

In 1987, after judicial remand, the FERC issued Order 500.[20] This order addressed the take-or-pay problem by (a) requiring gas producers to credit against a pipeline's take-or-pay liability any gas transported for them, and (b) allowing pipelines to collect gas inventory charges for the provision of firm gas service.

As of that time, the FERC fell short of requiring pipelines to unbundle their services. Yet, for the first time, it gave pipeline customers the right to contract separately for gas supplies and transportation service. Although FERC actions in the 1980s helped to open up natural gas markets to competitive services, several problems emerged that the FERC later addressed in its 636 Orders. These problems included the "unfair" position of pipelines as gas merchants, inefficient transportation rate design, discriminatory storage access and upstream pipeline capacity access, and a nonfunctioning resale market for pipeline capacity rights. In response to these problems, the FERC issued the 636 Orders in 1992.[21]

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[18] "Regulation of Natural Gas Pipelines After Partial Wellhead Decontrol," Order No. 436, *FERC Statutes and Regulations*, 30,665 (1985).

[19] A contract demand refers to the level of firm service in terms of the maximum (daily or annual) volumes of natural gas sold (or moved) by the pipeline to the customer holding the contract.

[20] Order No. 500, *FERC Statutes and Regulations*, 30,761 (1987).

[21] Order 636 was issued on April 8, 1992, Order 636-A on August 3, 1992, and Order 636-B on November 27, 1992.

The Order prohibited pipelines from offering bundled sales service, established a capacity releasing program, redesigned pipeline rates on the basis of the straight fixed-variable (SFV) methodology,[22] and generally gave transportation customers nondiscriminatory access rights to the pipeline network. In return for required unbundling of pipeline services, pipelines are able to resell gas on an unbundled basis at market-determined prices.

State public utility commissions (PUCs) have now begun to allow the unbundling of gas services to small retail customers.[23] Service unbundling for a broader group of retail customers will be an important issue for state regulators in the coming years.

The "old" natural gas industry featured a rigid three-tier structure with long-term contracting as the dominant form of gas transactions. Three distinct markets (wellhead, citygate, and local distribution) existed. Under this industry structure, gas was provided as a delivered bundled service from wellhead to burnertip. Interstate pipelines played a critical role in the delivering process. Strong technical and economic reasons underlaid the prevalence of this particular market structure.[24] Under this three-tier structure, the natural gas industry performed satisfactorily over several decades. But, as noted earlier, this market structure led to major distortions and performed poorly during the mid-1970s' supply shortage and the early to mid-1980s' gas surplus.[25]

Over the last ten years, a four-market (commodity gas, interstate transportation, core distribution, and noncore distribution) structure centered around direct gas

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[22] Under SFV, all fixed costs are assigned to the reservation component of bills and all variable costs to the usage component.

[23] See, for example, Kenneth W. Costello and J. Rodney Lemon, *Unbundling the Retail Gas Market: Current Activities and Guidance for Serving Residential and Small Customers* (Columbus, OH: The National Regulatory Research Institute, 1996), Chapter 2.

[24] One economic reason was the existence of economies of scope — that is, the cost savings that resulted from one entity providing interrelated services and performing interrelated functions.

[25] A serious distortion of the mid-1980s was that gas supplies were plentiful but gas prices were rising.

purchases and spot contracts with flexible supply and take provisions has evolved. This four-market structure will likely remain over the next several years.

We observe widely different changes in prices across customer groups since the inception of wellhead deregulation in 1979 and pipeline reform in 1985. The nominal price of wellhead gas declined by 29 percent over the period of 1984 to 1994. Over the same period, prices to industrial costumers declined by almost 23 percent, prices to electric utilities declined by almost 36 percent; in comparison, prices to commercial customers decreased by a little over 1 percent, while residential prices actually increased by almost 5 percent.[26] If one adds up the decline in natural gas bills across all retail customers since 1984, however, the cost savings have been significant.[27]

Other major outcomes since the mid-1980s include major downsizing and productivity improvements by pipelines and distributors,[28] the entry of new marketeers engaging in various market functions, the introduction of new unbundled gas services, the sharing of transition costs,[29] no decline in firm gas service except for those customers who decided to take nonfirm service.[30]

Overall, the combination of wellhead deregulation starting in 1979 and pipeline reform starting in 1984 has engendered, as hoped for, a more dynamic competitive and less regulated natural gas industry. Prior to this period, the natural gas industry was

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[26] Historical prices for wellhead gas and individual retail customer classes can be found in United States Department of Energy, Energy Information Administration, *Monthly Energy Review* (Washington, D.C.: Energy Information Administration, November 1995), 125. It should be added that all retail customers have experienced large declines in gas prices when measured in *real* dollars.

[27] These cost savings have been estimated to be as high as $100 billion, assuming, perhaps simplistically, that gas prices would not have fallen in the absence of regulatory reform, namely FERC Order 436/500 and Order 636. During the 1984 to 1994 period, retail gas prices averaged across all customers declined by 42 percent in real dollars.

[28] See American Gas Association, "Efficiency Gains in Natural Gas Transmission and Distribution," *Energy Analysis* (Arlington, VA: American Gas Association, 1996). Between 1984 and 1993, fro example, operating and maintenance expenses of local gas distributors and gas pipelines collectively declined by 35 percent in real dollars.

[29] A more detailed discussion of transition costs follows later in this paper.

[30] Firm service refers to the provision of gas service on demand.

plagued with the twin problems of deficient wellhead price leading to severe gas shortages and excessive monopoly power exhibited by interstate pipelines in selling bundled sales service to local gas distributors. It should be pointed out that wellhead price regulation illustrates an example where regulation initially designed to benefit a particular group (consumers) ultimately ended up hurting them.[31] Contrary to what many people had predicted or advanced for self-serving reasons, open access in gas transportation has not jeopardized service reliability.

While the natural gas industry has undergone major changes over the last ten years, it has not completed its transformation process. Competition in wholesale gas markets has existed now for a number of years; while competition in retail markets is just now starting to emerge. Future activities will center on the retail gas market, where consumers will have more choices as local gas distributors unbundle their services. These activities will give a greater number of gas consumers the opportunity to directly benefit from competitive forces in the natural gas industry.[32] Marketeers/brokers and aggregators will play an important role in delivering natural gas to small retail consumers at competitive prices.

Transportation

Over the last twenty years, major deregulation reforms have taken place in the transportation industry. In 1978 Congress deregulated commercial air carriers; the Staggers Rail Act of 1980 deregulated most of the rail market;[33] also in 1980, Congress

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[31] Evidence in support of this outcome is contained in Stephen G. Breyer and Paul W. MacAvoy, *Energy Regulation by the Federal Power Commission* (Washington, D.C.: The Brookings Institution, 1974).

[32] See Kenneth W. Costello and Daniel J. Duann, "Turning Up the Heat in the Natural Gas Industry," *Regulation* 19, 1 (1996): 52-9.

[33] Regulation by the Interstate Commerce Commission still remained in markets where railroads exercised "market dominance." Railroad deregulation actually started with the Railroad Revitalization and Reform Act of 1976.

passed the Motor Carrier Reform Act, which led the way in lifting barriers for new carriers and in deregulating the trucking industry. Because these industries were regulated for different reasons, deregulation could be expected to have a diverse effect on the direction of prices, profit, and other performance indicators.

Several pieces of evidence warrant discussion. Most important, aggregate welfare gains from deregulation of the transportation sectors have been significant. One study estimated the annual economic cost of trucking regulation alone to be as high as $20 billion (in 1988 dollars).[34] Another study estimated that airline deregulation benefited consumers by roughly $10 billion annually (in 1977 dollars).[35] In the case of railroads, one study estimated that deregulation has produced efficiency gains as high as $17 billion annually (in 1988 dollars).[36]

These large welfare savings originate from various sources. For trucking, prices were set above marginal cost and regulation stifled productivity growth, technological change, and management ingenuity.[37] Additional sources of inefficiency include entry barriers and restrictions on certain truckers to carry specific commodities and to follow designated routes. Deregulation allowed truckers to tailor their services to accommodate the demands of individual shippers. A major benefit resulted from guaranteed delivery service that saved companies significant amounts of dollars in inventory costs.[38]

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[34] Hahn and Hird, "The Costs and Benefits of Regulation." The Motor Carriers Act of 1935 exempted agricultural commodities from regulation.

[35] Steven A. Morrison and Clifford Winston, *The Economic Effects of Airline Deregulation* (Washington, D.C.: The Brookings Institution, 1986). These savings derive from lower fares, more convenient flights, and shorter waiting times between flights.

[36] Christopher C. Barnekov and Andrew N. Kleit, "The Costs of Railroad Regulation: A Further Analysis," *Bureau of Economics Working Paper No. 164* (Washington, D.C.: Federal Trade Commission, 1988). Much of the efficiency gains derived from timelier and more reliable service.

[37] Trucking rates, in real dollars, decreased by 10 to 25 percent during the period 1975 to 1982. See Thomas Gale Moore, "Rail and Truck Reform—The Record So Far," *Regulation* 6, 4 (1983): 33-41.

[38] See, for example, Thomas Gale Moore, "Clearing the Track: The Remaining Transportation Regulations," *Regulation* 18, 2 (1995): 77-87.

The effects of airline deregulation have been more provocative. Some critics have argued that airline service has deteriorated, safety has fallen, discriminatory price has become rampant, and the financial condition of the industry has become unstable.[39] Although some of these allegations cannot be ignored, the most serious studies strongly suggest that airline deregulation has benefited passengers and society as a whole.[40]

Studies on the deregulation of the airline industry contain three major conclusions. First, deregulation has not jeopardized airline safety.[41] Second, price discrimination has become a dominant practice in the industry.[42] Some debate still exists over whether price differentiation in fares reflect outright price discrimination or cost differences in serving different passengers or different routes. Although deregulation has resulted in competition-driven price discrimination, less cross-subsidies have occurred. Prior to deregulation long-haul markets were subsidizing short-haul markets largely to encourage air service to low-density routes.[43] Third,

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[39] Price discrimination and market power in the airline industry, for example, are examined in Severin Borenstein, "Hubs and High Fares: Airport Dominance and Market Power in the U.S. Airline Industry," *Rand Journal of Economics* 20 (1989): 344-65.

[40] See Douglas Caves et al., "An Assessment of the Efficiency Effects of U.S. Airline Deregulation via an International Comparison," in *Public Regulation: New Perspectives on Institutions and Policies*, Elizabeth E. Bailey, ed. (Cambridge, MA: MIT Press, 1987); Thomas Gale Moore, "U.S. Airline Deregulation: Its Effect on Passengers, Capital, and Labor," *Journal of Law and Economics* 29 (1986): 1-28; Morrison and Winston, *The Economic Effects of Airline Deregulation*; and Elizabeth E. Bailey and Jeffrey R. Williams, "Sources of Economic Rent in the Deregulated Airline Industry," *Journal of Law and Economics* 31 (1988): 173-202.

[41] See, for example, A. Kanafani and Theodore E. Keeler, "New Entrants and Safety," in *Transportation Safety in an Age of Deregulation*, Leon N. Moses and Ian Savage, eds. (Oxford: Oxford University Press, 1989); and Richard B. McKenzie and Norman K. Womer, "The Impact of the Airline Deregulation Process on Air-Travel Safety," Working Paper 143 (St. Louis, MO: Washington University Center for the Study of American Business, 1991). Some observers would dispute this conclusion in light of the recent ValuJet crash and personnel changes at the Federal Aviation Administration.

[42] See, for example, Alfred E. Kahn, "Deregulation: Looking Backward and Looking Forward," *Yale Journal on Regulation* 7, 2 (Summer 1990): 325-354.

[43] To address the concern of small communities being harmed by airline deregulation, Congress enacted a program that subsidized these communities during a ten-year transition period.

deregulation allowed airlines to compete on the basis of price. Prior to deregulation, airlines competed vigorously with regard to service quality and other nonprice factors.[44] Although deregulation has arguably caused the quality of airline service to decline, this should not necessarily be interpreted as a loss in society's or passengers' welfare. In fact, it can be argued that passengers generally have been willing to sacrifice some frills (e.g., a full-course meal) in return for lower fares. Given the freedom to choose among different fare-quality of service menus, it can be inferred that the observed menus are compatible with consumer preferences.

The implication for restructuring of the electric power industry is that the pertinent issue is not whether quality of service would decline (which may happen) but whether the *net benefit* of any change would be positive or negative. One lesson from airline deregulation is that, as long as consumers have choices, they may be willing to accept lower quality of service in return for a lower price.

As is the case in some industries, deregulation may cause an increase in the quality of service. For example, a firm (e.g., Federal Express) could profit from offering higher quality service by charging a high price, which may not have been permitted under regulation. Further, as in the case of railroads, deregulation led to higher profits, which helped to fund long-neglected maintenance and capital improvements.[45] The staff of the Federal Trade Commission estimated that these activities have saved shippers a substantial amount of dollars from timelier and more reliable railroad service.[46]

Improvements in the performance of railroads since deregulation come from several sources. A major one was lifting of the restrictions imposed upon the railroads

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[44] Some analysts have argued that, by the time of deregulation, most of the industry's economic rents had been expended on promoting service quality.

[45] Robert D. Willig and William J. Baumol, "Railroad Deregulation: Using Competition as a Guide," *Regulation* 11 (1987): 28-35. Railroad deregulation was largely motivated by the dismal financial condition of railroads, including a wave of bankruptcies in the industry (e.g., Penn Central in 1976). Prior to deregulation most railroads were earning less than their cost of capital.

[46] Barnekov and Kleit, "The Costs of Railroad Regulation: A Further Analysis."

to enter or exit specific routes. Railroads, for example, previously could not abandon unprofitable routes. A second problem under regulation was the inability of the railroads to negotiate bilateral contracts with individual shippers or to quickly vary their rates in response to changed market conditions. Third, regulation placed the railroads in a financial pinch that affected their ability to offer high quality service.[47]

Railroad deregulation has affected shippers differently. Those shippers who were able to negotiate contracts have benefited the most.[48] Others who were still captive or price inelastic with respect to railroad transportation, such as electric utilities who had limited options in transporting coal, did not initially benefit as much from deregulation or from relaxed regulation. Regulation continued in circumstances where railroads were able to exercise "market dominance" by charging supercompetitive prices.

Overall, deregulation has greatly improved the economic performance of the railroad industry. Productivity and profits in the industry have increased. Along with greater rate freedom, which has helped to enhance the railroads' financial situation, came higher rates to those shippers who lack market choices. Taken together, however, shippers as a group have reaped large benefits from railroad deregulation.[49]

U.K. Electric Power

Much has been written on the experiences of the privatized U.K. electric power industry. The consensus is that, while privatization and restructuring of the industry has

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[47] These three sources of performance enhancements are discussed in Moore, "Clearing the Track: The Remaining Transportation Regulations."

[48] During the 1980 to 1990 period, railroad rates for commodities collectively (excluding primary forest products) fell by 34 percent. (See Ann F. Friedlaender et al., "Governance Structure, Managerial Characteristics, and Firm Performance in the Deregulated Rail Industry," *Brookings Paper on Economic Activity* [1992]: 95-169.)

[49] Willig and Baumol, "Railroad Deregulation: Using Competition as a Guide."

benefited electricity consumers and the U.K. as a whole, it could have been done better.[50] Since privatization of the industry in March 1991, inflation-adjusted electricity prices have fallen for all customer classes (except for the largest industrial customers who, under the old regime, were being subsidized).[51] The industry has also experienced a dramatic increase in productivity in all aspects of its operation.[52] Productivity gains resulted from the combination of private ownership, the strong incentives provided by price-cap regulation for cost cutting, and the competition in generation and power supplies to the nonfranchised power.[53]

The quality of service in the industry has improved greatly.[54] For example, since privatization, service disconnections fell by 95 percent. (Consumers are compensated by the utility for service failing the Guaranteed Standards of Service.)[55] The regulator, the Office of Electricity Regulation (OFFER), annually monitors and reports on the

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[50] See Stephen Littlechild, "The 'New' Electricity Industry: A Vision of the Role for Regulation in the 21st Century," paper presented at the "Carrots and Sticks" Conference: Innovative Incentive Rate Regulation for a Competitive Electric Utility Industry, Chicago, Illinois, April 28, 1994; Gordon MacKerron, "Problems of Regulation and Competition in the England and Wales Electricity System," paper presented at the Meeting of Harvard Electricity Policy Study Group, Dallas Texas, January 25, 1996; Derek W. Bunn, "Electricity Re-Structuring and Market-Based Pricing in the UK Electricity Industry During 1990-1995," paper presented at the 1996 EPRI Conference on Innovative Approaches to Electricity Pricing, LaJolla, California, March 28, 1996; and Vernon L. Smith, "Regulatory Reform in the Electric Power Industry, *Regulation* 19, 1 (1996), 37-40.

[51] Alex Henney, "Winners and Losers in Restructuring the Electricity Supply Industry in England and Wales," paper presented at the 1996 EPRI Conference on Innovative Approaches to Electricity Pricing, LaJolla, California, March 28, 1996.

[52] Ibid.

[53] The evidence suggests that competition in generation was the most powerful force in improving productivity in the U.K. electric power industry.

[54] The outcomes of increased productivity, lower prices in real terms, and higher quality of services have also occurred in the privatized Chilean and Argentinean electric industries. See R. Peter Lalor and Hernan Garcia, "Reshaping Power Markets—Lessons from Chile and Argentina," *Public Policy for the Private Sector*, Quarterly No. 6 (March 1996): 29-32.

[55] Littlechild, "The 'New' Electricity Industry: A Vision of the Role for Regulation in the 21st Century."

technical performance of the transmission and distribution system. The number of customer complaints has also fallen dramatically since privatization.[56]

On the negative side, much recent criticism has been directed at the disproportionate benefits of privatization accruing to utility shareholders. Since privatization, Regional Electricity Companies (RECs) have enjoyed, as the analyst Alex Henney phrases it, a "feast for shareholders." Between 1990/91 and 1994/95, operating profits have almost doubled, the return on capital has gone up from 15.7 percent to 25.7 percent and dividends have increased by over 300 percent.[57] In comparison, over the same period, electricity prices to domestic users decreased by about 5 percent (in real British pounds).

One analyst[58] identifies four major criticisms of the U.K. electric power industry experience: (1) excessive market power was initially granted to two generation companies, National Power and PowerGen (in 1991 their share of the generation market was around 74 percent),[59] (2) the terms of privatization were overly generous to the new owners, (3) regulation was excessively lax in controlling the prices of the distribution companies, and (4) customers have benefited too little.[60] Most observers of the U.K. electric power industry would agree with these criticisms.

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[56] Ibid. For example, since 1992 the number of complaints received by OFFER from dissatisfied customers has fallen by 50 percent.

[57] Henney, "Winners and Losers in Restructuring the Electricity Supply Industry in England and Wales," 3.

[58] Evans, "UK Electricity: the Criticisms, the Changes, the Challenges."

[59] One study concluded that dividing the generation sector into five firms would have created much more competitive conditions. See Richard J. Green and David M. Newbery, "Competition in the British Electricity Spot Market, *Journal of Political Economy* 100, 5 (October 1992): 929-53.

[60] The instituted price-cap regulation, especially during the initial years, allowed the distributors to retain most of the significant efficiency gains that were realized.

Financial

Major reforms in the financial industry include the abolition of fixed brokerage fees in 1975, the passage of the Depository Institutions Deregulation and Monetary Control Act in 1980, the Garn-St. Germain Depository Institutions Act in 1982, and the Riegle-Neal Interstate Banking and Branching Efficiency Act of 1994.[61] The transformation of the banking industry over the last two decades can be attributed to both major regulatory changes and innovations in technology and applied finance.[62]

Brokerage fees fell quickly and dramatically after deregulation. Soon after deregulation, for example, fees on average fell by 25 percent and fees for orders in excess of 10,000 shares fell by more than 50 percent. Prior to deregulation, fixed brokerage fees eliminated any price competition. Since deregulation, productivity in the brokerage industry has improved substantially, evident by the sharp drop of employees in the industry.[63]

Federal banking legislation in 1980 established the phase-out of regulation of all deposit rates except business demand deposits. Prior to this period, market interest rates rose far above the regulated rates on time deposits (as much as 500 basis points).[64] This divergence created a strong incentive for bank depositors to look elsewhere to place their money and for financial intermediaries to supply alternatives to

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[61] The 1980 legislation abolishes interest rate ceilings and permits savings and loans to offer interest-bearing checking accounts (the Banking Act of 1933 prohibited banks from paying interest on checking accounts); the 1982 legislation lifts restrictions on savings and loans in making loans; and the 1994 legislation allows bank holding companies to acquire banks in other states.

[62] See Allen N. Berger et al., "The Transformation of the U.S. Banking Industry: What a Long, Strange Trip It's Been," *Brookings Papers on Economic Activity* 2 (1995): 55-218.

[63] An *ex post* assessment of the deregulated brokerage industry is contained in Gregg A. Jarrell, "Change at the Exchange: The Causes and Effects of Deregulation," *Journal of Law and Economics* 27, 2 (October 1984): 273-312. One result of deregulation was the elimination of cross-subsidization favoring small transactions.

[64] Peltzman, "The Economic Theory of Regulation After a Decade of Deregulation," 34.

bank deposits.[65] As early as the late 1960s, it became obvious that interest-rate ceilings on bank time deposits were not sustainable.[66] Consequently, in 1970, the interest rates on time deposits were deregulated.

As with most other deregulated or less regulated industries, productivity in the banking industry grew dramatically. For example, between 1984 and 1993 the number of jobs in the industry fell by more than 20 percent, and more impressive, revenues per employee grew by more than 300 percent.[67]

Less government control also lifted restriction on a bank's asset investments, on the kinds of services it could offer consumers, and on interstate banking operations. For example, federal legislation enacted in 1994 allows bank holding companies to acquire banks in any state. This should have a major effect in intensifying competition in the banking industry.[68]

Discussion of deregulation of financial markets cannot end without mentioning the Savings and Loan (S&L) fiasco of the 1980s. One school of thought argues that deregulation was the culprit by giving S&L managers free rein to act irresponsibly. Another line of argument is that given the continuance of the Federal Deposit Insurance Corporation, S&L managers had strong incentives to deal in highly risky ventures. In such an environment, the government should have been more forceful in overseeing the S&Ls, in enforcing capital requirements that would mitigate against large financial losses, and in closing down insolvent S&Ls.[69] Some analysts have argued that many S&Ls were already insolvent by the late 1970s, prior to the period of financial

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[65] Much of the outflow from bank deposits went into money market accounts and mutual funds.

[66] Ibid.

[67] For a detailed analysis of the effects of banking deregulation, see Berger et al., "The Transformation of the U.S. Banking Industry."

[68] Ibid.

[69] Catherine England, "Banking on Free Markets," *Regulation* 18, 2 (1995): 32-39; and Kahn, "Deregulation: Looking Backward and Looking Forward."

deregulation.[70] Their insolvency, it is argued, can be traced to regulation itself, namely the interest-rate ceilings on savings deposits. When inflation and interest rates started to skyrocket in the mid-1970s, depositors in large numbers withdrew their deposits, placing the S&Ls in a financially distressed position.

Telecommunications

A qualitatively useful description of the history of the telecommunications industry is a cycle of regulation and deregulation running in parallel with a cycle of monopolization and competition. This history begins in 1876 with the issuance of U.S. Patent No. 174,465. This patent associated with Alexander Graham Bell's invention of the telephone set and another patent issued in 1877 generated the property rights that sustained the industry's first monopolization. The actual property rights were not secured until 1979, however. In that year, AT&T and Western Union reached a settlement with respect to AT&T's patent suit. This suit was terminated voluntary by AT&T when Western Union conceded the priority of AT&T's telephone patents and both companies agreed to licensing their patents to each other.[71] AT&T's ensuing patent monopoly lasted until 1894 when the two patents expired. During this fifteen- to sixteen-year period, AT&T was in the position to establish local telephone companies without fear of competition by leasing telephone instruments to companies and individuals that it had licensed to operate these instruments.[72] In fact, by 1979 AT&T

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[70] Ibid., England. In 1980, for example, only forty-three S&Ls were declared insolvent, while 434 S&Ls were declared insolvent in 1988.

[71] Federal Communications Commission, *Investigation of the Telephone Industry in the United States*, 76th Cong., 1st sess., 1939, H. Doc. 340, 123-5.

[72] Charles F. Phillips Jr., *The Regulation of Public Utilities* (Arlington, VA: Public Utilities Reports, Inc., 1993), 750.

had inked 185 contracts that amounted to control over local telephone service in the more lucrative areas of the United States.[73]

Coterminous with the patent awards that laid the foundation for AT&T's patent monopoly, the Supreme Court released its 1877 decision of *Munn v. Illinois*.[74] The specific issue was whether state of Illinois had the right to question and alter the rates that monopolistic grain operators charged for their elevator and warehousing services. The larger public policy issue was when is it appropriate for the government to intervene in the operation of an economic market, monopolistic or otherwise. The majority of the justices decided that intervention is proper and in the public interest when private property is put to use in a profit-making activity that has consequential effects on the economic well-being of the community. This decision established that the commonality of economic effects with respect to a large number of consumers is a necessary condition for the regulation of an economic market.

It is important to note that under *Munn v. Illinois* the monopolization of a market is not a necessary condition for the regulation of that market. However, the monopolization of a market certainly makes it easier for the government to conclude that the firm's profit-making activity has consequential effects on the economic well-being of the community. Therefore, AT&T's patent monopoly over local communications made it a target for regulation whenever the government decided that the price and availability of telephone service had consequential economic effects on the community. Massachusetts was the first and only state government to make this decision during the time period covering AT&T's patent monopoly. This event occurred

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[73] Irston R. Barnes, *The Economics of Public Utility Regulation* (New York: F.S. Crofts & Co., 1942), 8.

[74] *Munn v. Illinois*, 94 U.S. 113 (1877).

in 1885 when Massachusetts decided to regulate telephone services and other public utility services such as electricity.[75]

In the midst of AT&T's patent monopoly, the Congress of the United States decided to investigate the operation of a national market that it thought to be crucial to the country's economic well-being. The railroad industry during the 1870s and 1880s was at the center of the United State's economic growth and geographic expansion. The competition in this industry, however, was extremely rivalrous in a discriminatory fashion during this period. The Congress found that this industry was characterized by stable prices interspersed with episodes of price wars and price discrimination against customers with the more inelastic demands for railroad services.[76] The price wars certainly did not promote the economic well-being on the small community of railroad owners, nor did they promote the economic well-being of the larger community of railroad workers. Similarly, they did not promote the relative economic well-being of the community of railroad users with the more inelastic demands for railroad services. Such wars did, however, improve the economic well-being of the community of railroad users with the more elastic demands for services and the consumers of goods transported by rail.

When the Congress concluded its deliberation of the gains and loses associated with the operation of the railroad industry, it decided to pass the *Interstate Commerce Act of 1887* to allow the federal government to assist in the maintenance of stability and the minimization of discrimination in the prices of railroad services. Although the past price wars established that the railroad industry was not monopolistic, the Congress acted consistently with the theory of *Munn v. Illinois*. The diversified community directly affected adversely by the unregulated operation of the railroad industry was larger than

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[75] W. Kip Viscusi, John M. Vernon, and Joseph E. Harrington, Jr., *Economics of Regulation and Antitrust*, 2d ed. (Cambridge, MA: The MIT Press, 1995), 313. These authors note that the wave of state regulation of telephone services did not begin until 1907. It crested in 1916, and it ran its course by 1930.

[76] Ibid., 312.

the diversified community directly experiencing positive economic effects. Consequently, this federal law served as an appropriate basis under *Munn v. Illinois* for the federal regulation of interstate railroad rates by the Interstate Commerce Commission (ICC).

The Congress in 1887 apparently did not believe that the then existing operation of the national telephone service was harming the United States' economic well-being. This position is not unreasonable. AT&T was deploying local telecommunications facilities in an effort to take maximum advantage of its patent monopoly. Additionally, it was expanding the availability of long-distance telephone service in its efforts to compete with Western Union's telegraph services.[77] Obviously, the prices of telephone service was a strategic variable affecting AT&T's expansion policy. Competitive prices made its local telephone services comparable to the local mail and local face-to-face visits. Similarly, a competitive price in a viable long-distance market made this service comparable to telegrams. Therefore, economic regulation in 1887 of the monopolistic telephone industry did not appear to be necessary to promote the public interest.

A competitive period for the telephone industry was ushered in when AT&T's two patent expired in 1894. This period lasted until 1907. Its defining characteristic was that non-Bell companies entered various local markets.[78] Sometimes, these firms were in direct competition with AT&T's local companies. Other times, the settled service territories of AT&T did not have a prior market presence. Presumably, the Congress was not disturbed by the competition in the local telephone markets. It must have been happy to see the expansion of local service into areas not served by AT&T. These positive aspects of the end of AT&T's patent monopoly must have overshadowed the negative effect of AT&T's refusal to interconnect non-Bell firms to its long-distance

[77] Robert W. Garnet, *The Telephone Enterprise: The Evolution of the Bell System's Horizontal Structure, 1876-1909* (Baltimore, MD: Johns Hopkins University Press, 1985).

[78] John R. Meyer et al., *The Economics of Competition in the Telecommunications Industry* (Cambridge, MA: Oelgeschlager, Gunn & Hain, Publishers, Inc., 1980), 26.

network.[79] The non-Bell companies tried to enter the long-distance market by building their own long lines, but this effort failed in 1899.[80]

Although AT&T did not help its competitors after the expiration of its patent, AT&T did not try to eliminate its competition until 1907. Beginning in 1907 and lasting to 1913, AT&T aggressively sought to buy out the non-Bell companies.[81] This market strategy may have given the Congress a cause for concern. Perhaps, it feared that AT&T would raise the price of telephone services after it cornered the local and long-distance markets. Whatever the reason, Congress looked into the operation of the telephone industry. Its investigation resulted in the passage of the *Mann-Elkins Act of 1910* that gave the responsibility for the regulation of telephone services to the ICC. The regulatory boundaries of this federal law allowed the ICC to regulate rates and control entry into the market for interstate telephone services.

Perhaps fearful of the threat of regulation or the penalties associated with newly passed antitrust laws, AT&T agreed in 1913 to stop its acquisition program and interconnect the remaining and new local companies to its long-distance network.[82] One interpretation of this agreement is that it eliminated most incentives to build an alternate long-distance network for strategic reasons.[83] An opposing interpretation is that it prompted the ICC to use its authority over market entry to create a *de jure* long-distance monopoly for AT&T.[84] Whichever is correct, the ICC did not do much economic regulation under the Mann-Elkins Act.[85]

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[79] Ibid.

[80] Ibid.

[81] Ibid.

[82] Ibid., 27.

[83] Ibid.

[84] Viscusi et al., *Regulation and Antitrust*, 487.

[85] Meyer et al., *Competition in Telecommunications*, 27.

The ICC exercised its authority over the telephone industry until the Congress passed the *Communications Act of 1934.* This law created the Federal Communication Commission (FCC) with the regulatory charge to achieve universal and affordable telephone service.[86] Practically speaking, universal service means that every individual or family that wants "basic" telephone service will have access to this service. Affordability means that these individuals and families have a reasonable chance of paying for the service that is universally available. Economic circumstances in the 1930s suggest that the time was right for these public-policy objectives. Telephone service was part of the financial commerce of the United States. Influential money managers, corporate leaders, and private investors relied on this service for quick and private transfers of information. Meanwhile, the Great Depression was taking its toll on these groups and almost everyone else. After a period of growth in subscribership during the 1920s, AT&T and the government were confronted with a 6 percent decile in subscribers from 1930 to 1933.[87] Consequently, the price regulation of telephone service certainly appeared germane to the United States' economic well-being.

The dire economic circumstances of the 1930s also precipitated a departure from the price-stability and price-nondiscrimination objectives of the *Interstate Commerce Act*. Viscusi et. al. suggest that the ICC may have achieved price stability at near monopoly prices.[88] Such price outcomes would indicate that the regulation of price levels was not a primary focal point for the ICC. The price levels were a focal point in 1934, however. The Supreme Court addressed the issue of price level regulation in the public interest when it decided *Nebbia v. New York*.[89] In this case, the state of New

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[86] The Congress limited the FCC's authority to interstate telephone services and services ancillary to the production of interstate telephone services. One ancillary service was the interconnection of an interstate transmission network with local distribution networks for the purposes of originating and terminating an interstate telephone message.

[87] Meyer et al., *Competition in Telecommunications*, 27.

[88] Viscusi et al., *Regulation and Antitrust*, 312.

[89] *Nebbia v. New York*, 291 U.S. 502 (1934).

York was regulating the price that retailers could charge for milk. Although the 1934 retail market for milk was more competitive than monopolistic, the majority of the Supreme Court concluded that a state government has the right regardless of market structure to enforce any reasonable economic policy that it believes will improve the well-being of a large block of consumers.[90]

The FCC did not disturb AT&T's interstate monopoly until 1959, however, when it released its decision on the use of frequencies above 890 megacycles in its *Above 890 Decision*.[91] The commercialization of microwave technologies developed during World War II reduced the cost of interstate telephone services and reduced the minimum efficient size of a point-to-point interstate common carrier.[92] The FCC responded to these facts by allowing the construction of point-to-point private microwave networks that could be used only to transmit the interstate message of the network's owner.

AT&T responded with a substantial lag to this extremely limited competitive force that had been unleashed by the FCC and the commercialization of microwave technology. In 1961, AT&T introduced Telpak, which was a discounted tariff, in an apparent effort to stop the substitution of private networks for its private line services.[93] Although Telpak was based on volume discounts, it is likely that these discounts did not substantially affect AT&T's overall revenue and profit performance. Telpak arrived during a forty-seven-year period when the average growth rate in the number of Bell system telephones was 4.6 percent.[94] Additionally, Bell system revenue was growing at

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[90] *Nebbia v. New York* is not an extension of a monopoly-dependent *Munn v. Illinois* to competitive markets. The Supreme Court's touchstone is the same in both of these cases. Two majorities of justices, separated by the passage of approximately fifty years, opted to allow state governments to wade in on the side of consumers when the state has a reasonable basis for believing that a large block of consumers requires its assistance.

[91] *In re Allocation of Microwave Frequencies Above 890 Mc.*, Docket No. 11866, 27 FCC 359 (1959), aff'd on reh'g, 29 FCC 825 (1960).

[92] Viscusi et al., *Regulation and Antitrust*, 489.

[93] Ibid., 492.

[94] Meyer et al., *Competition in Telecommunications*, 30.

an annual real rate of 5.3 percent between 1959 and 1968.[95] These data suggest that shared-line customers would be affected by Telpak and private-line customers would make informed choices. Circumstances changed after the introduction of Telpak, however.

In 1963, four years after the *Above 890 Decision* and two years after Telpak, MCI requested permission to sell point-to-point private line service as a common carrier.[96] Telpak immediately became a thorn in MCI's side. Volume discounts made it harder for MCI to sell private line services to AT&T's customers. Concurrently, the FCC considered MCI's application and the legality of the Telpak tariff. MCI was eventually granted this authority, and the FCC rejected Telpak cost justification.[97] MCI became a common carrier in 1969.[98] Almost immediately thereafter, other companies requested the same authority to sell private lines services. In 1971, the FCC extended common carriage status to all these companies in *Specialized Common Carrier Decision.*[99]. AT&T responded in 1973 to the FCC's *Specialized Common Carrier Decision* with the HI-Lo tariff.[100] Another tariff battle ensued.[101] It and others came to some form of closure when AT&T revealed multiple schedule private line rates in 1977.[102]

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[95] Ibid., 37.

[96] Viscusi et al., *Regulation and Antitrust*, 492.

[97] Ibid.

[98] *In re Applications of Microwave Communications, Inc.*, Docket No. 16509, 18 FCC2d 953 (1969).

[99] *In re Specialized Common Carrier Services*, Docket No. 18920, Notice of Inquiry, 24 FCC2d 318 (1970), First Report and Order, 29 FCC2d 870, 920 (1971), reconsideration denied, 31 FCC2d 1106 (1971), aff'd *sub nom. Washington Utilities and Transportation Commission v. Federal Communications Commission*, 513 F.2d 1142 (9th Cir. 1974), cert. denied, 423 U.S. 836 (1975).

[100] Meyer et al., *Competition in Telecommunications*, 25.

[101] Viscusi et al., *Regulation and Antitrust*, 493, 516 n13.

[102] Meyer et al., *Competition in Telecommunications*, 25.

The introduction of microwave technology is an important watershed in the history of telecommunications because it is an economies-of-scale-busting technology. Prior to the commercialization of microwave technology, AT&T's "land-lines" technology had high fixed costs and low variable costs, especially when it came to adding another interstate caller. During the same period, the interstate market consisted primarily of voice-grade long-distance calls.[103] Importantly, the growth in these calls did not begin to trend upward at an appreciable rate in response to growth in real disposal income until 1949.[104] This mixture of demand and cost characteristics suggests the declining average costs of production that have been estimated for the period 1947 to 1976.[105] This mixture also suggests the possibility of economies of scale in the production of telephone services that were found to exist during the 1960s in the neighborhood of 1,000 to 1,200 circuits per intercity route.[106] Consequently, it would have been difficult for two or more interstate common carriers using "land-lines" technology to coexist before the 1950s, even if economies of scale did not extend to the cost subadditivity that is required of a natural monopoly.[107]

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[103] Viscusi et al., *Regulation and Antitrust*, 489.

[104] Ibid., 488.

[105] M. Ishaq Nadiri and Mark Schankerman, "The Structure of Production, Technological Change, and the Rate of Growth of Total Factor Productivity in the U.S. Bell System," in *Productivity Measurement in Regulated Industries*, Thomas Cowing and Rodney Stevenson, eds. (New York: Academic Press, 1981). See also, Laurtis Christensen, Diane Cummings, and Philip Schoeth, "Econometric Estimation of Scale Economies in Telecommunications," in *Economic Analysis of Telecommunications*, Leon Courville, Alain DeFontenay, and Rodney Dobell, eds. (Amsterdam: North-Holland, 1983).

[106] Leonard Waverman, "The Regulation of Intercity Telecommunications," in *Promoting Competition in Regulated Markets*, Almarin Phillips, ed. (Washington, D.C.: The Brooking Institution, 1975).

[107] Although it is unknown whether cost subadditivity existed before the commercialization of microwave technology developed during World War II, there is evidence that the multiproduct cost function of the largest interstate common carrier in the United States was not subadditive during the period 1958-1977. See David Evans and James Heckman, "Multiproduct Cost Function Estimates and Natural Monopoly Tests for the Bell System," in *Breaking Up Bell*, David Evans, ed. (New York: North-Holland, 1983).

The two largest specialized common carriers, MCI and Southern Pacific Communications Company, competed with AT&T exclusively in private line services from 1974 to 1976. Their competitive efforts were not profitable.[108] More than likely to stem these losses, both companies offered switched services over the same facilities that they used to provide their private line services. Subsequently in 1976, MCI presented the FCC with its Execunet tariff, which governed its sale of switched services. The FCC rejected this tariff on the grounds that Execunet was not a private line service. The D.C. Circuit Court concluded that the fact that Execunet was not a private lines service was not sufficient reason for the FCC foreclosure of this service to public, and therefore, it had to reverse the FCC's rejection of the MCI's Execunet tariff.[109] The basis of the appeals court decision was that the FCC had never concluded that the competitive supply of switched services was not in the public interest, and consequently, MCI could not be denied the use of its facilities for the purpose of providing such services to the public. The D.C. Circuit indicated, however, that the FCC could convene a hearing on the matter of whether the competitive supply of switched access services is in the public interest. The FCC did not shun this offer.

Shortly after the *Execunet I Decision*, the FCC opened a docket in 1978 to determine whether interstate toll services are a monopoly.[110] This docket remained open for two years, and the FCC concluded in 1980 that the sale of interstate toll services on a competitive basis was in the public interest.[111] During this two years, however, the FCC tried to limit the public's access to Execunet by ruling that AT&T did

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[108] Phillips, *Regulation*, 806 n126.

[109] *In Re MCI Telecommunications Corp.*, 60 FCC2d 25 (1976), rev'd 561 F.2d 365 (D.C. Cir. 1977), cert .denied *sub nom. U.S. Independent Telephone Ass'n v. Federal Communications Commission*, 434 U.S. 1040 (1978).

[110] *In re MTS and WATS Market Structure*, CC Docket. No. 78-72, Notice of Inquiry and Proposed Rulemaking, 678 FCC2d 757 (1978), Supplemental Notice, 73 FCC2d 222 (1979), Second Supplemental Notice, 77 FCC2d 224 (1980).

[111] *In re MTS and WATS Market Structure*, Report and Third Supplemental Notice, 81 FCC2d 177 (1980).

not have a current obligation to interconnect its competitors toll services to its local distribution facilities. The D.C. Circuit Court rebuked this decision, and it ordered interconnection without any further ado.[112] The public was becoming accustomed to competition in interstate toll services, and the appeals court had signaled quite clearly that it would not make any decisions that would limit the availability of competitive alternatives. Perhaps, the FCC's only conclusion was to find that the competitive supply of these services was in the public interest. Whatever the reason, the close of the docket on market structure for interstate toll services began the reseller era. These companies made money because of "capped" WATS tariffs and their technical ability to pack their leased WATS lines with interstate and intrastate toll calls. Not surprisingly, AT&T responded by proposing a restructuring of its interstate WATS rates. Once again, tariff battles ensued. During these fights, MCI and GTE Sprint began to deploy their own interstate telecommunications facilities. In 1984, United Telecommunications planned a large-scale entry into the interstate market using digital and fiber optic technologies. These activities marked the beginning of facilities-based competition in the interstate market.

A significant event in the history of telecommunications occurred before United Telecommunications' large-scale entry into the interstate market. AT&T settled a long-running antitrust suit.[113] The government's suit involved the business practices and relationships between AT&T's manufacturing company and AT&T's long-distance and local exchange companies. The government contended that AT&T was improperly excluding other companies manufacturing telecommunication equipment from making sales to its long-distance and local exchange companies. The suit was settled in 1982 when AT&T proposed the divestiture of its local exchange companies and agreed to

[112] *In re American Telephone and Telegraph Company Petition for Declaratory Relief*, 67 FCC2d 1455 (1978), rev'd *sub nom. MCI Telecommunications Corp. v. Federal Communications Commission*, 580 F.2d 590 (D.C. Cir, 1978), cert. denied, 439 U.S. 980 (1978).

[113] *United States v. Western Electric Company, 1982-2 Trade Cases*, sec. 64,900, 552 F. Supp. 131 (D.D.C. 1982), aff'd *sub nom. Maryland v. United States*, 460 U.S. 1001 (1983).

provide "equal access" to its facilities-based competitors.[114] The equal access condition opened a Pandora's Box of access and interconnection issues to be discussed subsequently.

The overriding issue associated with any antitrust suit is the promotion of competition. In 1974, the United States' government wanted to promote competition in the manufacturing and sale of telecommunications equipment. This is not surprising because competition in the interstate private line services market was just getting underway. Consequently, the government initially sought to require AT&T to divest itself of Western Electric and its local exchange companies.[115] Subsequently, the government changed its mind and wanted the divestiture of Western Electric and a portion of Bell Laboratories.[116] Meanwhile, MCI and other alternative interexchange carriers wanted to enhance their competitive chances in the interstate market for voice-grade telecommunications services after the *MTS and WATS Market Structure Decision* and the implementation of *inferior access* at negotiated rates for alternative interexchange carriers.[117] Consequently, the government could kill two birds with one stone if it settled its antitrust suit in return for the divestiture of the local exchange companies and the creation of equal access services that would be purchased by the alternative interexchange carriers. Finally, the FCC had become committed to bringing the benefits of competition to consumers, and it could use the implementation of equal access as one of the means to fulfill this objective.

The equal access mandate of the *Modification of the Final Judgment* required the creation of an equal access tariff. This tariff would be based on the cost of providing access service to alternative interexchange carriers that was "equal" to the

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[114] *Modification of the Final Judgment*, 47 *Fed. Reg.* 4166 (1982).

[115] Phillips, *Regulation*, 774.

[116] *Ibid.*, 810 n.154.

[117] *In re Exchange Network Facilities for Interexchange Access*, 71 FCC2d 440 (1979).

access available to AT&T.[118] No one knew the cost of this service, however, because such a service had never existed. The FCC with the support and assistance of all interstate carriers used this knowledge void to shift the responsibility for the recovery of nontraffic sensitive costs from interstate calls to intrastate and local calls. The initial position of what might be called the "incumbent coalition" was that the total cost of nontraffic sensitive facilities not directly assignable to the production of interstate calls should be recovered from the rates for local basic service. The initial position of the state regulatory commissions and consumer groups was that the implementation of equal access does not necessitate a change in the responsibility with respect to the recovery of nontraffic sensitive costs. A heated and vigorous battle ensured. In the end, neither side prevailed in its initial position. Instead, the FCC was able to shift some but not all of the responsibility for the recovery of nontraffic sensitive costs to local callers. This "victory" served to guarantee long-distance price reductions during the years immediately succeeding AT&T's divestiture of its local exchange companies. These price reductions merely amounted, however, to a rate redistribution. As the price per unit of interstate calling fell, the price of local basic service rose.

AT&T was regulated in the traditional fashion until the settlement of the antitrust suit and the emergence of plans for large-scale entry on a facilitates basis into the interstate market. AT&T's profits were regulated using the principles of ratebase/rate-of-return regulation. Its rates for interstate services were reviewed and approved by the FCC. These rates were set using cost-of-service principles. Changes to these rates were justified in terms of average embedded costs, while the competitive implications of

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[118] This access service was never really equal. A long-running debate arose over providing an equal-access 800 number interconnection arrangement to AT&T's competitors. AT&T's competitors complained about the "equality" of adjunct devices as substitutes for Feature Group D in geographic areas when the supply of Feature Group D was not economically feasible. The AT&T-instigated differences in call set-up times between Feature Group C and Feature Group D were a constant source of annoyance to AT&T's competitors and the regulators that had to hear their complaints. Feature Group C was the equal-access service that was available only to AT&T immediately after the divestiture. Feature Group D was the equal-access service that was available to AT&T's competitors immediately after the divestiture. The call set-up time for a Feature Group C call was slightly faster than the call set-up time for a Feature Group D call.

not changing these rates were placed in a subordinate role. The regulatory process did not move quickly as evidenced by the Telpak, Hi-Lo, WATS tariffs.

The nature of cost-based pricing changed around 1984. The previous focus on average embedded costs was switched to average incremental cost. This change meant that AT&T's rates had to provide revenues to cover at least the incremental cost of producing the affected services. The generation of revenues equal to or in excess of incremental cost, however, was only a threshold test of regulatory sufficiency. The new rates had to pass a "net revenue" test. The purpose of this test was to ensure that all customers benefited in one sense or another from the introduction of price decreases. In effect, the competitive implications of tariff proposals took on the primary role, while the cost justification of these proposals played the subordinate role.

This new tariff regime produced the "Reach out America" and "Pro-America" tariffs. Each of these tariffs involved volume discounts for residential customer with the Pro-America tariff introducing them to two-part tariffs. It also produced Tariff 12 and Tariff 16. Tariff 12 was available only to very large business users with seemingly special needs. It allowed AT&T to offer custom-designed volume discounts to specific customers without the requirement that similar discounts be offered to other customers. Tariff 16 was a competitive necessity tariff that permitted AT&T to respond on a targeted basis to the marketing efforts that its competitors had designed to win over medium-to-large-volume business customers. All four of these tariffs were vigorously opposed by AT&T's competitors on the grounds that they were anticompetitive.

An important aspect of extensive volume discounting in the interstate market is that this activity was predated by the availability of equal access for facilities-based competitors of AT&T. The purpose of equal access is to permit "full and fair" competition between AT&T and its competitors. The implementation strategy was to bring AT&T's competitors up to approximately the same level of interconnection enjoyed by AT&T with respect to the production of interstate toll services. Essentially, access and interconnection arrangements were neatly uniform for all interstate common carriers. Each carrier was paying the same prices for these arrangements. All of these companies were in the position to begin the customization of their access and interconnection arrangements. As a result, price competition began to spread across a wider range of telecommunications products. The expansion of price competition meant that AT&T needed to operate under a regulatory format that provided it with more pricing flexibility and an enhanced capability to respond rapidly to the pricing initiatives of its competitors. Therefore, the traditional regulation of AT&T ended when the FCC adopted price-cap regulation. This alternative form of regulation allows both of these activities. Price increases are not challenged by the FCC unless they exceed the relevant price caps. AT&T can lower its prices as long as they are not anticompetitive.

This history of the telecommunications industry supplies many lessons for state regulators dealing with the transition to a more competitive electricity market. First, it shows that *proactive and long-term* government intervention is required to diminish the market power of a regulated monopolist that had attained its market position on the strength of economies of scale. Although new scale-reducing technologies must contribute to the structural change of the marketplace, public policies have to permit these technologies to gain an economic foothold. For example, a pro-competition policy was adopted for the interstate telecommunication market in 1969 with the initiation of a series of long-running FCC's proceedings culminating in the entry of MCI into the market for voice-grade transmission. Subsequently, long-distance competition was institutionalized when AT&T, the Department of Justice, and a federal district court reached an agreement that resulted in AT&T's divestiture of its local companies. The pro-competition policy was extended to enhanced information services in 1986 and 1987 during the FCC's Computer III Inquiry that ended with a regulatory decision to implement open network architecture.[119] Recently, the passage of the

[119] *In re Amendment of Sections 64.702 of the Commission's Rules and Regulations*, Report and Order, 104 FCC2d 958 (1986).

Telecommunications Act of 1996 has extended the pro-competition policy to local telecommunications.[120]

Second, the deregulation of AT&T was not a prerequisite for the implementation of competition-enhancing policies for the interstate market. There was no change in the regulation of AT&T after the authorization of private microwave networks in 1959. Average embedded cost pricing principles survived the emergence of MCI as a specialized common carrier in 1969 and then as a common carrier in 1975. The demise of average embedded cost pricing in the early mid-1980s was not associated with the destruction of rate of return regulation. AT&T's profits remained regulated, and it still had to conform to the tariff procedures adopted in an earlier regulatory era. The major chance in the regulation of AT&T up until the implementation of price-cap regulation was that this traditionally regulated company was given the flexibility to change its prices more rapidly.

Third, rapid and flexible price changes by a traditionally regulated firm is made possible by either an explicit or implicit grant of permission for the regulated company to engage in market segmentation. In practice, market segmentation is another name for more price discrimination for competitive purposes. As shown as early as the 1870s with respect to the railroad industry, price discrimination for competitive purposes means the customers and customer classes with elastic demands for services

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[120] A pro-competition policy started to emerge in the electricity industry circa 1978 with the passage of the *Public Utilities Regulatory Policies Act* (PURPA). PURPA's support for conservation and energy efficiency created competition behind the meter at the electric wall plug. The extension of PURPA's conservation principles to support cogeneration and qualifying facilities created competition in the generation market. Essentially, PURPA furnished the groundwork for competition in generation market. The *Energy Policy Act* (EPAct) represented the next extension of pro-competition public policy for electricity. EPAct heralded an era of wholesale competition and open access to transmission services. The FERC contributed to the pro-competition movement with a series of Notice of Inquiry ending with the release of FERC Orders 888 and 889. These orders clearly anticipate robust retail competition in the future. See Federal Energy Regulatory Commission, *Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmitting Utilities: Order 888 — Final Rule*, (hereafter called, "The Final Rule") 75 FERC 61,080 (April 24, 1996); and Federal Energy Regulatory Commission, *Open Access Same-time Information System (formerly Real-Time Information Networks) and Standard of Conduct*, 75 FERC 61,078 (April 24, 1996).

experience price reductions, while those with inelastic demands for services experience price increases or less rapid price reductions. AT&T's volume discounting during the first half of the 1980s confirms this trend for the interstate telecommunications market.

Fourth, the FCC did not choose to change the regulatory format applicable to AT&T until it was convinced that facilities-bases competition was firmly established in the interstate market. MCI was in the process of upgrading its network when the FCC adopted price-cap regulation. US Telecom, the long-distance subsidiary of United Telecommunications, and GTE Sprint, the long-distance subsidiary of GTE Telephone Companies, had mergered to form US Sprint. In addition, the newly formed US Sprint was nearing the completion of the digital/fiber optic network planned by US Telecom and its predecessor company. In addition, other regional facility-based carriers were establishing themselves. Finally, AT&T's market share was falling and price competition was emerging for most of the customer classes that purchased services in the interstate market.

Fifth, the incumbent regulated monopolist should not be expected to take the introduction of competition agreeably. Throughout its history, AT&T has never backed down from an opportunity to stop, slow down, or elimination competition that was emerging in its markets. When its patent monopoly expired, AT&T tried to renew its patents. When that failed, it tried to modify its telephone equipment just enough to gain a new patent monopoly. When that failed, it refused to interconnection non-Bell local-exchange companies to its long-distance network. AT&T began a vigorous acquisition program when the non-Bell companies' efforts to build an alternate long-distance network failed. In fact, AT&T continued to buy up its local exchange competitors for three years after Congress passed the *Mann-Elkins Act*, which provided explicitly for the regulation of telephone service by the ICC. AT&T stopped these activities only after the Congress passed new antitrust laws threw into question the legality of AT&T's acquisition program. When the next round of competition began with the *Above 890 Decision*, AT&T introduce Telpak to stop or retard the construction of private microwave networks. It introduced the Hi-Lo tariff to stop or retard the growth of specialized common carriers. Finally, it introduced "Reach-Out America," "Pro-America," and other volume-discounted tariffs designed explicitly to stop the growth of facilities-based interexchange carriers.

Sixth, the divestiture of bottleneck and essential facilities by the incumbent monopolist does not guarantee the removal of all competitive problems in the market that relies on the nondiscriminatory availability of the bottleneck and essential facilities. As part of the settlement of the antitrust suit filed against it, AT&T chose to divest it local exchange companies and obligate the newly divested companies to provide the alternative interexchange carriers with an access service that was approximately equal to the access service that would be available to AT&T. Problems with access services persisted for many years after the initial Feature Group D equal access service was available to AT&T's competitors.

Seventh, a divested incumbent former monopolist is in the position to behave anticompetitively even if it does not control bottleneck and essential facilities. It was repeatedly argued by the alternative interexchange carriers that AT&T's series of volume-discounts tariffs for different market segments were predatory at worst and anticompetitive at best. These arguments were not completely specious, and they resulted in the institutionalization of the net revenue test. In addition to ensuring that all consumers benefited, in perhaps different ways, from the availability of volume discounts, the net revenue test greatly increased the probability that the volume discounts would not be predatory under normal operating conditions. When the FCC decided to remove its structural separation requirement for AT&T's enhanced and basic telecommunications services, nonaffiliated enhanced services providers and others argued that it would not be possible to police AT&T's incentive and capability to shift unregulated costs into regulated markets as it sought to expand into unregulated telecommunications services. A U.S. Appeals Court agreed with these arguments.[121]

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[121] *In re Amendment of Sections 64.702 of the Commission's Rules and Regulations*, CC Docket No. 85-229, Notice of Proposed Rulemaking, 50 Fed. Reg. 33,581 (1985), Report and Order, 104 FCC2d 958 (1986), Supplemental Notice of Proposed Rulemaking, FCC 86-253 (1986), on reconsideration, 2 FCCR 3035 (1987), on further reconsideration, 3 FCCR 1135 (1988), on second further reconsideration, 4 FCCR 5927 (1989), *Phase II*, 2 FCCR 3072 (1987), on reconsideration, 3 FCCR 1150 (1988), *on further reconsideration*, 4 FCCR 5927 (1989), vacated *sub nom . California v. Federal Communications Commission*, 905 F.2d 1217, 113 PUR4th 92 (9th Cir. 1990).

Eighth, it is possible to control the pace at which a new public policy is implemented. It is often heard that the interstate telecommunication industry is undergoing the transition to deregulation. History indicates that this transition began in the mid-1980s for the interstate market with the change in the focus of the FCC's review of AT&T's pricing. It is now 1996, and AT&T still is not deregulated with respect to its production and sale of interstate telecommunications services. AT&T's sale of telecommunications equipment and inside wiring was deregulated in about the same number of years. The deregulation of these services began with the *Carterfone Decision* in 1968.[122] This decision overturned those elements of AT&T's tariffs that prevented the attachment of non-Bell devices to telephone sets and those portions that did not allow customers to interconnect their communications systems directly to the Bell System network. Deregulation of customer premises equipment was finalized in 1980 when the FCC released its *Second Computer Inquiry Decision.*[123] These decisions and the subsequent judicial review show that an industry can be deregulated on a piece-meal basis. They also indicate, however, that when deregulation occurs in this manner that the first pieces of the industry to be deregulated are peripheral to the transmission and distribution of the regulated services.

Ninth, qualitative and quantitative data have to be mergered when examining the effects of changes in regulatory formats and focal points. The need for the dual consideration of both kinds of data is illustrated by the following examination of post-divestiture interstate toll prices. The analysis begins with the equal access that was provided to all interstate common carriers after AT&T's divestiture.[124] The rates for

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[122] *In re Use of the Carterfone Device in Message Toll Telephone Services*, 13 FCC2d 420, 423,426 (1968), reconsideration denied, 14 FCC2d 571 (1968).

[123] *In re Amendment of Section 64.702 of the Commission's Rules and Regulations*, Docket No. 20828 77 FCC2d 384, 35 PUR4th 143 (1980), modified on reconsideration, 84 FCC2d 50, 39 PUR4th 319 (1980), modified on further reconsideration, 88 FCC2d 512 (1981), aff'd *sub nom. Computer & Communications Industry Association v. Federal Communications Commission*, 693 F.2d 198 (D.C. Cir. 1982), cert. denied 461 U.S. 938 (1983), modified, 3 FCCR 22 (1988),

[124] *In re Investigation of Access and Divestiture Related Tariffs*, FCC 84-106, March 28, 1984.

these tariffs were set using traditional cost-of-service principles, which required the identification and separation of interstate and intrastate access costs. Since the FCC had never set access rates, it was able to start this exercise with a clean slate.

The major cost classifications in the years preceding the divestiture were local service, intrastate toll service, and interstate toll service. Each of these classifications made contributions to the recovery of traffic sensitive and nontraffic sensitive costs. Traffic sensitive costs, by definition, vary primarily with increases and decreases in the volume of telecommunications traffic that is carried by the firm. Nontraffic sensitive costs vary primarily with the number of customers that are served by the company in question. Nontraffic sensitive costs are associated with each of the three service classifications: these costs are heavily concentrated in the distribution facilities that connect individual homes and business to the rest of the world when they make and receive their local and long-distance calls. This fact did not go unnoticed in *Smith v. Illinois*, where it was established that the recovery of some of these nontraffic sensitive costs should be the responsibility of the interstate callers.[125] Prior to this Supreme Court decision, the rates for local service had been the tool for the recovery of all nontraffic sensitive costs. This decision also indicated that a usage-based allocation of nontraffic sensitive costs to local and long-distance services was acceptable to the justices, even though nontraffic sensitive costs, by definition, do not vary with telephone usage.

Smith v. Illinois set in motion a sequence of events that consistently resulted in the long-distance callers having more and more responsibility for the recovery of nontraffic sensitive costs. The increasing responsibility for the recovery of nontraffic sensitive costs laid on interstate rates was not a problem before the *Above 890 Decision*. AT&T had a complete monopoly over the long-distance market, and the FCC routinely approved interstate rates that would recover the nontraffic sensitive costs that were the responsibility of its long-distance subsidiary. The legalization of private

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[125] *Smith v. Illinois Bell Telephone Company*, 282 U.S. 133 (1930).

microwave networks, however, indicated that AT&T could not recklessly use the rates for private line services to recover nontraffic sensitive costs. Increases in these rates might induce one or more large corporations to build their own telecommunications networks.

The stage was set for AT&T to begin the process of "rebalancing" its rates for interstate private line services and interstate message toll service. Telpak was the first move in this direction. Its volume discounts implied that the large-volume users of private line services would contribute less to the recovery of nontraffic sensitive costs. This strategic move to keep corporations on its network, however, created another problem for AT&T. The principles of traditional regulation required that the unrecovered (actually unsupported) nontraffic sensitive costs had to be supported elsewhere. The support role fell to the remainder of the interstate users.

A portion of the remainder of the interstate users included those private line users whose usage levels were not large enough to justify the construction and ownership of private microwave networks under the existing private line rates. Consequently, AT&T with the approval of the FCC could raise the rates for these customers to just below the level that would induce these customers to build their own networks. MCI's 1983 application to sell private line services as a common carriers, however, put this population at risk as a source for the recovery of nontraffic sensitive costs. The switch-over rate for these customers was no longer the per unit cost of constructing a private network for their own use. Instead, it was the presumably lower per unit cost of constructing a private network for the shared use of multiple private line customers. Therefore, traditional regulation once again would forced AT&T to rebalance its interstate rates after the FCC approved MCI's application to be a common carrier of private line services.

After the *Specialized Common Carrier Decision*, competitive options became increasingly available to interstate private line users. Consequently, the interstate message toll service callers became the primary source for the recovery of nontraffic sensitive costs. Sufficient increases in the prices of interstate message toll services, however, would induce some of these users to switch to an alternative common carrier. MCI moved to take advantage of this opportunity because its private line service was not doing very well. After providing alternative voice-grade services for some time under its Execunet tariff, MCI petitioned to be an alternative common carrier. It was granted its petition in 1975. It also was provided with the right to resell AT&T's WATS lines, which meant that MCI did not have to build interstate transmission facilitates before it could sell a substitute for AT&T's interstate toll message service. With MCI and others selling private line and toll services, AT&T and the FCC had no place else to go in the interstate markets after the *Execunet* decisions when it came to rebalancing the responsibility for the recovery of nontraffic sensitive costs. Perhaps, it was at that time that the FCC decided that it had to reduce the amount of nontraffic sensitive costs that were subject to its jurisdiction.

Although it is not clear when this decision was made, the FCC elected to use the implementation of the access tariffs as the vehicle for reducing its cost recovery responsibility in the area of nontraffic sensitive costs. Traditional regulation and *Smith v. Illinois* required that the FCC find a way to separate nontraffic sensitive costs in a manner that reduced the allocation to the interstate jurisdiction. It took this problem to a Joint Board that consisted of state and federal regulators who were experienced in the regulation of telephone services. The Joint Board decided to change the means that were used to separate nontraffic sensitive costs. The new means, called the Gross Allocator, reduced the amount of nontraffic sensitive costs that came under the responsibility of the FCC. This decision reduced the cost of producing long-distance service. Of course, the long-distance cost reduction had to be reflected on the intrastate side of ledger as an increase in interstate toll and local basic service costs.

The FCC did not stop with the positive results that it achieved after the introduction of the Gross Allocator for the separation of nontraffic sensitive costs. The FCC with the support of AT&T and other telephone companies proposed a uniquely structured two-part access tariff. The usage-sensitive component of the tariff would be paid for by the interstate common carriers. The lump-sum monthly fee component of the tariff — the Subscriber Line Charge (SLC) — would be paid for by all subscribers to local basic service. The usage-sensitive rate would recover all usage-sensitive access costs. The SLC would recover the nontraffic sensitive access costs. State regulatory commissions and consumer advocates vigorously opposed this proposal. Both groups viewed the FCC's plan for the recovery of interstate nontraffic sensitive costs to be equivalent to an increase in the price of local basic service. After all, the SLC had to be paid even if a subscriber did not make any long-distance calls.

Despite the opposition, the FCC implemented its proposed two-part access tariff; but it was not successful in using the SLC to recover all of the nontraffic sensitive costs that were the FCC's responsibility. Instead, the FCC had to settle for recovery of half of these costs through the SLC. Still, the amount of nontrafffic sensitive costs that had found its way into the prices of interstate message toll services had been reduced a little further.

The SLC and the Gross Allocator were implemented after the divestiture of AT&T. Neither change in regulation practice was implemented on a "flash-cut" basis. Consequently, it took time for the full impact of these changes to be reflected in the prices of interstate toll service. This time lag meant that the prices of interstate toll services, set according to the principles of cost-of-service regulation, would fall steadily without any change or improvement in the process used to produce these services. Conversely, it meant that the price of local basic service would rise over the same time period if there were not any cost-saving changes to the process used to produce this telephone service.

The impact of the SLC was first felt by residential customers on interstate toll rates in June of 1985. Table 5.10 of the Joint Board's *Monitoring Report* indicates the SLC was $1.00 per month for the first twelve-month period after June of 1985.[126] The SLC for the next thirteen-month period was $2.00 per month. This fee for the next sixteen months was $2.60 per month. A SLC of $3.20 was charged for the following

[126] Joint Board, *Monitoring Report*, Common Carrier Docket No. 87-339, mimeo, May, 1996, 473.

four months. The transition was complete in April of 1989 when a fee of $3.50 per month was charged until the end of the year. In all, it took fifty-three months to fully implement the SLC for residential customers. During the same time period, the SLC was increasing for multi line business customers and Centrex customers.[127] The transition to the Gross Allocator took approximately the same length of time. Consequently, the "phase-in" of two important regulatory decisions concerning the recovery of nontraffic sensitive costs was complete by the end of 1989.

Table 4, a partial reproduction of Table 5.4 in the Joint Board Monitoring Report, shows the annual change in two price indices for interstate long-distance service from 1978 to 1996. The CPI index represents changes in prices for households. The PPI index represents price changes for residential and business customers. Both price indices considered show a substantial decline and reversal of trend in 1984. For the years 1984 through 1989, the data in the table trace a single-peak hilltop with the largest decline in both indices occurring in 1987. They generally continue their decline at a much slow pace until 1992. Both indices reversed trend and returned upward substantially in 1993. This upward trend in prices persists through 1996.

The data for 1984 and 1985 indicate that the phase-in of the Gross Allocator and the SLC cannot be the sole cause of the substantial price declines experienced in 1986 and 1987. Perhaps, part of the explanation lies in the voluntary retirements that AT&T offered its employees during this period. Another part of the explanation of these price declines might be the investment "write-offs" and "write-downs" that AT&T took to better its competitive position. Still, another part of the explanation might be productivity increases from those workers and managers that remained with AT&T. Finally, there were the optional calling plan, special needs, and competitive necessity tariffs that were introduced during this period.

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[127] Ibid.

TABLE 4

ANNUAL PERCENTAGE CHANGE IN
PRICE INDICES FOR
LONG-DISTANCE TELEPHONE SERVICE
(Interstate Service)

Year	CPI: Interstate Toll	PPI: Interstate MTS
1978	-0.8	0.0
1979	-0.7	-0.9
1980	3.4	5.5
1981	14.6	15.9
1982	2.6	3.9
1983	1.5	0.0
1984	-4.3	-5.1
1985	-3.7	-3.0
1986	-9.4	-10.0
1987	-12.4	-11.8
1988	-4.2	-2.1
1989	-1.3	-1.7
1990	-3.7	-0.1
1991	1.3	-1.3
1992	-1.3	1.0
1993	6.5	3.8
1994	5.4	6.1
1995	0.1	
1996	4.1	

Clearly, the phase-in of the SLC, the Gross Allocator and innovative tariffs cannot explain the price declines that occurred from 1988 forward. All of their effects had petered out by that time. However, the FCC introduced price-cap regulation in 1988. The dominant incentive of this alternative regulatory format is cost reduction. Nothing else occurred that could be expected to substantially alter the competitiveness of the interstate toll market from 1988 to 1992. Consequently, the explanation for the more modest price reductions experienced during this period appears to be productivity increases, lay offs, and pricing responses to competitive pressures.

The upsurge in interstate toll prices in 1993 and thereafter has been more substantial than the general increase in prices during the period 1993 through 1996. Table 5, a modified reproduction of Table 5.2 from the Joint Board Monitoring Report, shows the annual rate of changes in the more general price indices applicable to the telephone industry. The data show increases for these years in the price index for all items of around 2 to 3 percent. The data also show increases for the same year in the price index for all telephone services of around 0 to 2 percent. Meanwhile, the data (in Table 4) show increases in the CPI for interstate toll services for these years of around 4 to 6 percent.

The prices of interstate toll services have been increasing at one and one-half to two times the increases in the prices of all items. This trend suggests that the price increases in interstate toll services are being used to partly compensate for price reductions that are being offered to large-volume interstate customers that use services other than interstate toll.[128] They also suggest the possibility that interstate toll services are being used to support unregulated businesses that are owned or controlled by all of the three large domestic interstate carriers. These hypotheses are plausible because it is unlikely that AT&T and the other interstate carriers have exhausted all of their opportunities for cost reduction during this era of price-cap regulation. Therefore, these

[128] Joint Board, *Report*, 448.

TABLE 5

ANNUAL RATE OF PERCENTAGE CHANGE
IN THE CPI AND TELEPHONE SERVICES

Year	CPI: All Items	PPI: Telephone Services
1978	9.0	0.9
1979	13.3	0.7
1980	12.5	4.6
1981	8.9	11.7
1982	3.8	7.2
1983	3.8	3.6
1984	3.9	9.2
1985	3.8	4.7
1986	1.1	2.7
1987	4.4	-1.3
1988	4.4	1.3
1989	4.6	-0.3
1990	6.1	-0.4
1991	3.1	3.5
1992	2.9	-0.3
1993	2.7	1.8
1994	2.7	0.7
1995	2.5	1.2
1996	2.9	-0.2

hypothesis suggest that it would not be appropriate to deregulate interstate toll and other currently regulated services.

Tenth, the liberalization of interconnection policies is a powerful public-policy tool that can cut both ways for the regulated company.[129] AT&T's first liberalized its interconnection policies in 1913. This strategic decision enabled AT&T to comply with recently enacted antitrust laws and to solidify its monopoly over long-distance transmission. AT&T's second liberalization of its interconnection policies was part of a package designed to settle an antitrust suit. AT&T agreed to divest its local companies in return for the obligation of its divested companies to provide "equal access" to it and its competitors. Consequently, AT&T had to give up its long-distance monopoly and any competitive advantages it may have enjoyed from formerly being the long-distance monopolist.

Eleventh, the regulated firm enters into interconnection agreements for a variety of reasons. Some interconnection agreements occurring in the history of telecommunications have been win-win outcomes. Others have been more zero-sum in nature. There are no reported "horror stories" associated with AT&T's interconnection of independent telephone companies and rural cooperatives that started in 1913 after the "Kingsberry commitment." Similarly, the initial implementation of the Modification of Final Judgment (MFJ) "1 + dialing" equal-access provision came off without any major glitches.[130] Both were win-win types of agreements. In the first case, AT&T avoided any government scrutiny under then existing antitrust trust and simultaneously assured itself of a long-distance monopoly perceived to be in the public interest. In the second case, AT&T extracted itself from an antitrust suit and freed itself to compete vigorously in various unregulated telecommunication markets.

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[129] Alan Baughcum and Gerald R. Faulhaber, *Telecommunications Access and Public Policy* (Norwood, NJ: Ablex Publishing Corporation, 1984); Walter G. Bolter et al., *Telecommunications Policy for the 1980s* (Englewood Cliffs, NJ: Prentice Hall, Inc., 1984); and Marcelles S. Snow, *Marketplace for Telecommunications* (New York, NY: Langman, 1986).

[130] Gerald W. Brock, *Telecommunication Policy for the Information Age: From Monopoly to Competition* (Cambridge, MA: Harvard University Press, 1994).

Things did not go as well for those agreements that were required of telecommunications companies that also compete in the markets to which they are providing access. The implementation of open network architecture (ONA) has gone very slowly. The enhanced service providers and information service providers that are unaffiliated with the Bell Regional Holding Companies have encountered little difficulty in gaining access to ONA services that are also useful to the affiliated enhanced and information service providers. The unaffiliated companies find it tough going, however, to get ONA services that do not fit into the business plans of the affiliated companies.[131] For example, the unaffiliated companies have been seeking access to the local companies' operating and support systems for almost ten years.

Twelfth, the development of interconnection arrangements to solve the competitive-access problem occurs in fits and starts. This erratic approach to interconnection exists for a variety of reasons. It is never exactly clear on logical grounds that the owner of the interconnection facilities will encourage efficiency in either upstream or downstream competitive markets.[132] On practical grounds, efficient interconnection agreements would probably not be forthcoming when the "vertical foreclosure" of competition in either upstream or downstream markets through inefficient interconnection arrangements yields economic gains.[133] Furthermore, there is a long-standing public-interest worry associated with the solution of the competitive-access problem through unrestricted open access. Open access in the presence of

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[131] Robert J. Graniere, *Implementation of Open Network Architecture: Development, Tensions, Strategies* (Columbus, OH: The National Regulatory Research Institute, 1989).

[132] The argument against vertical foreclosure of either upstream or downstream markets by the owner of interconnections facilities is presented by Posner. See Richard A. Posner, "The Chicago School of Antitrust Analysis," *University of Pennsylvania Law Review* 127, (1978-1979): 925. Criticisms of this argument are presented by Blair and Kaserman, and Kaplow. See Roger D. Blair and David L. Kaserman, *Law and Economics of Vertical Integration and Control* (New York, NY: Academic Press, 1983); and Louis Kaplow, "Extension of Monopoly Power through Leverage," *Columbia Law Review* 23, 1 (1985): 515.

[133] J.A. Ordover and R.D. Willig, "The 1982 Department of Justice Merger Guidelines: An Economic Assessment," *California Law Review* 71 (1983): 571; and J.A. Ordover, A.O. Sikes, and R.D. Willig, "Nonprice Anticompetitive Behavior by Dominant Firms Toward Producers of Complementary Products," in *Antitrust and Regulation*, Franklin Fisher, ed. (Cambridge, MA: MIT Press, 1985).

sunk costs undermines regulatory options designed to protect captive customers. The reason for this is that the customers with options attempt to shift the responsibility for the recovery of sunk costs to customer classes without options.[134]

Thirteenth, interconnection arrangements spawn jurisdictional battles between federal and state regulators over the right to regulate the use of access facilities. Typically, the federal regulators have the stronger hand at the inception of the battle. Federal regulators can rely on the "interstate commerce clause" of the Constitution as a sturdy support for their policies.[135] In fact, the *Communications Act of 1934* gives the FCC the authority to regulate interstate communications and the ancillary services associated with interstate communications. Meanwhile, the state regulators often have to rely on statutory constructions which reserve for them everything that is not expressly given to the federal regulators.

Fourteenth, federal regulators can push forward their pro-competition policies without the cooperation of the state regulators. The interstate commerce clause provides a presumption that the FERC has the right to act unilaterally in the area of interstate transmission services. Furthermore, the federal courts in an important telecommunications case have decided that federal policies take precedence of state policies when state policies frustrate or impede the progress of a federal policy.[136]

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[134] Charles G. Stalon, "Some Thoughts and Concerns About FERC Wheeling Policies," address to the Federal Energy Bar Association, Washington, D.C., January 10, 1985; and William B. Tye et al., *The Transition to Deregulation* (New York, NY: Quorum Books, 1991).

[135] The interstate commerce clause has already reared its head in the electric power industry. EPAct gives control to the FERC over the rates, terms and conditions of wholesale sales. The right to regulate retail services is reserved for the states. EPAct did not draw a distinction between interstate and intrastate wholesale and retail services, however. EPAct gives control to the FERC over the rates, terms and conditions for transmission service used in both bundled and unbundled wholesale-sales service without any direction as to jurisdiction over transmission used in unbundled retail sales. The FERC leapt on this omission in "The Final Rule" by asserting jurisdiction over transmission service used in interstate commerce to complete an unbundled retail sale when the unbundled retail sale is offered voluntarily by the utility or mandated by the state regulatory commission.

[136] Louisiana Public Service Commission v. Federal Communications Commission, 106 S. Ct. 1890, 74 PUR 4th 1 (1986).

Fifteenth, competition is initially a transition to dominance. Monopoly is the pre-transition market structure, and the dissolution of the monopoly is not equivalent to the dissolution of the former monopolist. Typically, the former monopolist remains in the market as a formidable competitor with a relatively large market share.[137] Its pre-existing ties with customers provide it with several advantages, such as the benefits of customer inertia and name recognition. In addition, the former monopolist possesses market power over prices that it can exercise against large segments of its customer base because of the uneven introduction of competition across customer classes. Factors along these lines were sufficiently strong to cause AT&T to be a dominant firm even though it had relinquished its control over bottleneck facilities.[138]

TRANSITIONAL PROBLEMS

During the incipient periods of competition, newly deregulated industries have encountered adjustment or transitional problems. This is not surprising as new suppliers enter the industry, consumers, for the first time, are able to choose among different suppliers and the industry is rapidly pursuing higher efficiency. Empirical evidence across a wide range of circumstances shows that industry restructuring and deregulation greatly affect the behavior of market participants. Consequently, adjustment to the new environment takes time and, frequently, encounters major difficulties. It may well be the case that industries that initiated deregulation activities going as far back as twenty years have not yet completely adjusted to a competitive

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[137] William G. Shepherd, "Deregulation From Monopoly Only to Dominance? Telecommunications, Railroads and Electricity," *NRRI Quarterly Bulletin* 17, 2 (1996): 149.

[138] Pursuant to FERC Order 888, electric utilities are not required to divest themselves of their transmission and distribution facilities. These facilities constitute bottlenecks with respect to unbundled wholesale and retail electricity services. The electric utilities also are highly recognizable in the wholesale and retail markets; and they can exercise market power over large segments of their retail customers. Consequently, it is virtually certain that electric utilities will be dominant in the retail market regardless of whether they divest themselves of their generation assets.

environment. What we can say about these industries is that, as they approach a long-run competitive equilibrium, they become more efficient and responsive to consumer demands. It should not be surprising, however, to have losers as an industry undergoes these changes.

The long transitional period in many deregulated industries has inflicted pains on certain players. In the natural gas industry, for example, it took several years to resolve the take-or-pay gas contract problem. In the U.K. electric power industry, the market power of two generators kept wholesale prices above what they would be under competitive conditions. A common pattern of deregulated industries is that, for an indefinite time, some consumers benefit much more than others. In certain instances, some consumers may see an increase in their prices, especially if these consumers were the beneficiaries of cross-subsidies in the old regulatory regime.

One comment particularly pertinent to Maine is that rural areas did not become the victims of deregulation that some observers argued they would be. The fundamental argument was the deregulation would "skim the cream" off the profits that regulated firms had earned and used to provide affordable service to rural consumers. In other words, under deregulation firms would be forced to charge prices based on economic costs. At the worst, these firms may even be reluctant to serve unprofitable rural markets. Consequently, whatever subsidies were distributed to rural consumers would dissipate in a deregulated market.

The post-deregulation evidence has shown these claims to be exaggerated. In the trucking industry, for example, services to small communities have not declined. Because of free entry, new efficient carriers are now serving small communities. With regard to airline service, cities of all sizes have benefited from a better integrated air-service network that sprung up after deregulation. Airlines quickly developed route networks that better matched traffic patterns.

Overall, the deterioration service and price shocks to rural consumers have not transpired. New market institutions have evolved to play an important role in spreading the benefits of competition to rural markets. In fact, it is accurate to say that rural consumers have benefited from deregulation, although probably less than their urban counterparts.

Table 6 lists the major problems encountered by restructured industries during the transitional period. These problems reflect the dramatically different environment within which firms conduct their business. Consumers also have to make decisions that they were previously not required to make. Finally, regulators must change their policies and practices in response to a more competitive marketplace. In all, all players need to adapt to the new environment. In the transition, market players are striving to position themselves for the new equilibrium that will eventually transpire in the restructured industry.

TABLE 6

TRANSITIONAL PROBLEMS FOR RESTRUCTURED INDUSTRIES

- ***Regulatory lag in responding to competitive pressures***
- ***Partial regulation***
- ***Distribution effects on shareholders and certain consumers***
- ***Consumer transaction costs***
- ***Discontinuance of certain social activities***
- ***Retention of market power by incumbent firms***

Customer Confusion

One transitional problem revolves around the question of whether consumers will make wise decisions. In the tightly regulated regime consumers often had few choices, as their choice of suppliers and the menu of services were greatly limited. In the new environment, consumers will face more difficult decisions. For example, do they stay with their old supplier or do they switch to a new unknown supplier who promises them lower prices? In most market situations, consumers makes these decisions based on the information they acquire from various sources. Consumers are also accustomed to making such decisions since they have always had the ability to shop around for the "best deal."

A consumer may become perplexed when, for the fist time, she is given the opportunity to choose a supplier for a particular service or product. The consumer may not fully comprehend the new rules: What risk do I face? What is the service obligation (if any) of the old supplier? How can I be assured of reliable service? How often can I change suppliers? What up-front costs am I responsible for when I change suppliers? In addition, information about different suppliers may initially be unavailable or not transparent. In all, at the start-up of competition consumers may find it difficult to make intelligent decisions.

Regulation can play a vital role in assuring consumers that they know the new rules and have access to information needed for wise decisionmaking.[139] Especially for small consumers (it is assumed that the large customers can take care of themselves), regulators can require the local public utility to educate consumers about their rights and responsibilities and to disperse clear information that consumers can evaluate in

[139] A state regulator, for example, may want to establish a code of conduct that would specify rules for all concerned parties. These rules would in part protect against consumer deception and fraud.

choosing a supplier. Residential unbundling of natural gas and electricity services represents cases where these requirements seem applicable.[140]

Stranded Costs

Another potential problem encountered during the transitional period concerns the allocation of what are commonly called "stranded costs." In the deregulation of non-public utilities, firms were not compensated for any loss in revenues that may have resulted. Some industries actually increased their profits after deregulation (one notable example is the railroad industry). Of course, for the transportation industry capital assets are mobile, mitigating against a stranded-cost problem.

For the telecommunications and natural gas industries, stranded costs required special consideration by regulators. In the telecommunications industry, regulators allowed accelerated depreciation of deregulated customer premise equipment with the condition that the revenues received from the sale of rotary telephones be used to offset the cost of undepreciated capital. The depreciation rates for the obsolete capital caused by the divestiture of AT&T were generally allowed to increase. When, later, increasing competitive pressures penetrated all sectors of the telecommunications industry and, thereby, accelerated the obsolescence of existing investments, regulators commonly resorted to price caps. Under price caps, the telecommunications firms were responsible for the recovery of the undepreciated portion of obsolete capital.

Three major lessons can be learned from the experiences of the telecommunications industry with regard to stranded costs. First, the strength of competition has influenced the regulatory response. When competition is selective or narrowly-based, regulators tend to protect the shareholders. As competition becomes more pervasive, customers tend to be favored over shareholders. Growing competition

[140] See, for example, Costello and Lemon, *Unbundling the Retail Gas Market: Current Activities and Guidance for Serving Residential and Small Consumers.*

in the industry causes existing plant and equipment to become obsolete more rapidly. Second, the character of the stranded-cost problem has changed over time. Initially, it was concentrated on specific facets of the telecommunications business; later, it spread throughout the business. Third, regulators have chosen different ways to address the stranded-cost problem. They have realigned depreciation rates on both an *ad hoc* and generic basis, approved of pricing flexibility and discounts, convened rate cases, and instituted new regulatory formats.

Since the early 1980s, the natural gas industry has addressed stranded costs on two separate occasions in response to FERC's industry-restructuring orders. FERC Order 500 established a transition-cost recovery (TCR) methodology allowing pipelines to recover between 50 and 75 percent of their prudently-incurred take-or-pay costs associated with existing contracts with gas producers.[141] Most pipelines reached a settlement with their customers (mainly local gas distributors) that called for a 50-50 split of these costs. After some litigation, gas distributors were generally allowed by state regulators to recover their allocated share of the take-or-pay costs.

The FERC's position in Order 500 was that the burden of take-or-pay costs should be shared among gas producers, pipelines, and customers. One provision of Order 500 allowed pipelines to establish gas inventory charges (GICs) for firm gas service. GICs helped to avoid future take-or-pay problems and, at the same time allowed pipelines to directly bill customers for firm service.[142]

FERC Order 636 allowed pipelines to recover all "prudently-incurred" transition costs associated with restructuring.[143] Ten percent of these costs must be recovered from interruptible customers.

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[141] Pipelines commonly purchased new gas reserves under a take-or-pay stipulation of 75 percent to 95 percent of deliverable volumes.

[142] Another provision of Order 500 required gas producers to credit against a pipeline's take-or-pay liability any gas transported for them to third parties.

[143] Transition costs are grouped into four categories: (1) gas supply realignment, (2) unrecovered gas (Account 191), (3) stranded facility costs, and (4) new facilities costs. The FERC estimated these costs to be as high as $4.5 billion.

The natural gas experiences with stranded costs (or transition costs) also have three useful lessons applicable to the electric power industry. First, the possibility of large stranded costs should not unduly slow the movement toward restructuring and competition. The industry and regulators were able to move ahead in view of the contentious debate over how stranded costs should be allocated. Second, the efficiency gains arising from competition and restructuring can offset some portion of the stranded costs.[144] Some unknown share of the take-or-pay liabilities was "funded" by significant efficiency gains arising from wellhead price deregulation and open access of the pipeline system. Third, a political if not economic solution to the stranded-cost problem may require a sharing of these costs among all stakeholders. FERC took this position in its Order 500. It can be argued that sharing these costs is the only way to not violate generally-accepted equity standards.

Social Activities

Funding social activities (e.g.,.low-income programs, universal service) through the price mechanism is a rare occurrence in nonregulated industries. Firms in these industries attempt to remain competitive by holding down their cost of operation and by offering value-added services and products. In this environment, it becomes difficult for a firm to incur costs that neither makes it more productive nor adds to its revenues (i.e., makes it more profitable). This is especially true when competitors are not required to incur these costs. Such costs are ultimately unsustainable, as market pressures prevent the firm from earning normal profits in the long run.

Because restructured public utility industries will continue to have market power for some of their services (e.g., "wires" services) for the foreseeable future, they will be subject to some form of price regulation. Consequently, nonmarket social activities can

[144] In other words, the revenue losses for old services induced by competition can be counteracted by cost reductions and the introduction of new services.

continue to be funded through the pricing of these services.[145] It is expected, however, that regulators and legislatures will reassess these activities in terms of their scope and funding as competitive forces will make it more difficult for these activities to continue. To minimize economic distortions, a "surcharge" can be imposed on the access charges associated with regulated delivery services. Such a surcharge would require *all* electricity consumers to pay for social programs. Raising the user-sensitive bill component of transportation service, instead, would result in allocative inefficiencies (i.e., consumers demanding too little of the service at the margin because of an artificially high price).

Inefficient Competition

In a newly structured industry, incumbent firms may initially be in a position to stifle competition because of certain advantages they have over new entrants. For example, airline carriers with existing gates may prevent new carriers from entering lucrative markets; Baby Bells may keep out competition in their markets by restricting access to or inflating rates for local exchange services; and so forth. History has shown that as competition advances incumbent firms may resist this competition by using the regulatory process to impede it.

Anticompetitive practices include affiliate-transactions abuse, predatory pricing, cost shifting and cross-subsidization,[146] withholding of vital information to potential competitors, and discriminatory access to bottleneck facilities. Any of these practices would diminish the benefits of industry restructuring designed to promote competition. Most of these lost benefits would have gone to consumers in the form of lower prices.

[145] A discussion of funding social programs with electric utility revenues in a quasi-competitive environment is contained in Robert J. Graniere, *Post-Reform Continuation of Social Goals* (Columbus, OH: The National Regulatory Research Institute, 1996).

[146] For example, incumbent utilities have an incentive to cross-subsidize their competitive markets by redirecting the excess profits earned in monopoly markets.

State regulators can play an institutional role in assuring that regulated entities do not abuse their market position. They can go a long way in achieving this by establishing *fair rules* that show no partiality toward any firm. Fair rules mean that the successes and failures of individual firms will depend solely on their ability to offer value-added services at a profit that allows them to stay in business (i.e., on their merits). Fair rules, as those for athletic contests, attempt to achieve an outcome where the "best" come out as winners and the "worst" as losers. The "best," for example, can be defined as those firms who excel at providing value-added services to consumers at the lowest prices.

Fair rules may involve removing certain restrictions on the utility. If utilities, for example, are constrained from adjusting their prices in response to changed market conditions, they may lose customers to higher-cost competitors. Fair rules may therefore involve giving utilities more freedom in certain activities than what they currently have.[147] New competitors will try to burden incumbent utilities with old regulatory rules (e.g., embedded-cost pricing) that will limit their ability to compete.

SPECIFIC LESSONS FOR THE ELECTRIC POWER INDUSTRY

The empirical evidence for deregulated industries points to a pattern of outcomes that can be extrapolated to a restructured electric power industry. Extrapolating the outcomes to the electric power industry can be carried too far, however. After all, not all industries were regulated for the same reason. The regularity of the outcomes across widely different industries in terms of technology and the attributes of products or services do strongly suggest that we can predict — or at least make a good argument to try to predict — with reasonable accuracy the major outcomes of a restructured electric power industry. In the current context, "restructured" refers to a highly open

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[147]In addition to pricing, restrictions may apply to the offering of new services, service obligations, and planning activities.

industry characterized by a vigorously competitive generation market, nondiscriminatory access to the transmission network for both wholesale and retail transactions, a high degree of electrical service unbundling, and spot and futures electric power markets.[148] Regulation is assumed to remain in place for the pricing of transmission and distribution services, for "guiding" the transition, and for enforcing policies that guard against anticompetitive practices. The comments below reflect our predictions and observations with regard to the outcomes of a restructured electric power industry. These outcomes draw heavily from the empirical evidence on the effects of deregulation and greater competition for the five industries examined in this paper.

- First, we expect that electricity consumers as a group will experience lower prices and, over time, will benefit significantly.[149] This outcome will likely occur even if competition in the industry is imperfect and some firms have a high concentration of market power. At least initially, those consumers given the opportunity to make market choices will benefit the most; other consumers, when ultimately given market access and when competition spreads throughout the industry, will receive large gains as well. Regulation has generally deprived consumers of benefits from price competition and, as

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[148] This vision of a restructured electric power industry coincides with that of many industry experts.

[149] Large savings for consumers under a restructured electric power industry are estimated in Chitru Fernando et al., "Unbundling the U.S. Electric Power Industry: A Blueprint for Change," unpublished paper, March 1995; and Michael T. Maloney and Robert E. McCormick, *Customer Choice, Consumer Value: An Analysis of Retail Competition in America's Electric Industry* (Washington, D.C.: Citizens for a Sound Economy Foundation, 1996).

The first study estimates that electricity consumers could save $60 billion or more annually. The second study estimates that electricity consumers could realize economic gains as much as $108 billion annually, with the economy as a whole benefiting on net by $24 billion annually. These latter numbers suggest that restructuring of the electric power industry will result in large transfers among the different players in the electric power industry.

a whole, has increased prices above marginal costs. As an illustration, off-peak electricity should be expected to fall dramatically under a more competitive environment.[150]

- Second, we will be surprised to see "rate shock" for any group of customers or a noticeable deterioration of service quality. For a short time rates may increase for those customers who were being subsidized under the old regime. Over time, these customers should benefit from a more efficient electric power industry, especially if they are given the right to choose among different suppliers. Service quality as a whole, disputably, may somewhat decrease.[151] Rate-of-return regulation has probably inflated service quality beyond the level that would be observed in a less regulated industry. With greater competition, utilities would have a stronger incentive to control their costs of production and would be under intense pressure to offer prices below their current levels. For deregulated industries, service quality may have deteriorated in the airline industry but, as noted earlier, even in this instance consumers have "voted" their preference for lower service quality-lower fares compared to the service quality-fare offering previously dictated by regulation.[152] If there is concern over declining quality of service, state regulators can always resort to penalties, as in the case of the U.K. electric power industry, when utilities fail to achieve a specified standard of service.

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[150] See, for example, ibid., Maloney and McCormick.

[151] We are hesitant to make this prediction. The evidence points to an increase in service quality in most deregulated industries after a period of adjustment. Some analysts (e.g., Clifford Winston) have argued that consumers in deregulated industries have benefited as much from improved service as from lower prices.

[152] The word "may" is used here because, while airline deregulation has created more congestion at airports and less frills on airplanes, it has brought forth more frequent flights and more nonstop flights on heavily traveled routes. Surveys have shown no upward or downward trend in passenger complaints since deregulation.

- Third, many utilities will likely benefit from a restructured electric power industry. In almost all industries, the efficient firms have benefited (although less so than consumers) from deregulation.[153] Utilities will be expected to respond to competition by reducing their cost of operation, by more vigorously taking on innovations and new technologies, by developing new services, by tailoring their prices and services to individual consumers, and by entering new markets. All of these actions would be designed to increase profits. Utilities that fail to take such actions will either be financially distressed or prime candidates for take over by other firms. We expect electric utilities to operate, price, and invest for the future in a fundamentally different way from how they do today.[154] Less regulation, on net, will likely be good for well-managed electric utilities as it has been for well-managed firms in other industries undergoing dramatic changes because it liberalizes a firm's operating, planning, service-offering and pricing activities. The evidence for deregulated industries shows that regulation hinders the development of new services and regulated firms generally have higher costs.

- Fourth, current estimates of future benefits from less regulation of the electric power industry are probably too low.[155] It is extremely difficult to comprehend today how consumers and the industry will fully respond to a more competitive environment. For example, most *ex ante* studies fail to consider those technological changes that are likely to evolve under deregulation. As a case in point, the debate over privatization of the U.K. electric power

[153] At the industry level, profits have generally not increased because of strong competitive pressures.

[154] For example, restructuring will enhance the role of market forces and diminish the role of political/regulatory forces in pricing and planning practices.

[155] This position, as it pertains to deregulated industries in general, is supported by Hahn and Hird, "The Costs and Benefits of Regulation," 237-38.

industry could not even imagine the benefits that resulted from the substitution of combined-cycle gas turbines for new, much costlier coal plants that the old Central Electricity Generating Board was committed to build and, in most likelihood, would have built. This underestimation of benefits is not a criticism against the analyst but against the inherent difficulty of any study to predict the long-run benefits of future deregulation or to measure these benefits *ex post*.

The benefits of less regulation may also be estimated too low because of the failure to account for the reduction in unproductive rent-seeking/maintenance costs that will likely ensue.[156] These costs can be significant, as high as the efficiency losses under regulation plus twice the size of the wealth transfers induced by regulation.[157]

A third source of "benefits" underestimation, especially those accruing to consumers, is the omission of new services that competition would likely engender. These services would be the outgrowth of service unbundling, which is expected to proliferate under industry restructuring.[158]

- Fifth, over the long term, employees of a restructured electric power industry may actually benefit. Employees in many deregulated industries either lost

[156] These costs include the costs incurred by stakeholders in swaying regulators and legislatures to their self-interest positions. Consequently, such cost are intended to affect wealth distribution, rather than economic efficiency or wealth creation.

[157] See, for example, John T. Wenders, "On Perfect Rent Dissipation," *American Economic Review* 77 (June 1987): 456-59. Because of uncertainty over the benefits of rent-seeking\maintenance activities by individual interest groups and the so-called free-rider problem, the actual costs may be substantially less.

[158] As noted earlier, from the experiences of former comprehensively regulated industries, service unbundling is a major and anticipated feature of a competitive marketplace.

their jobs or had to accept lower wages/salaries;[159] the number of employees in other deregulated industries, such as airlines, actually increased because of the rise in demand for airline services. In the transition, as we have witnessed so far, utility employees will probably be harmed as utilities are under pressure to shed their costs quickly and substantially. In the longer term, however, if competition contributes to a more dynamic and faster-growing industry, employment and wages/salaries could conceivably be higher than what they would otherwise have been under the old highly-regulated regime.

- Sixth, as discussed earlier, industry restructuring will likely lead to more competition-driven price differentiation. Firms will be expected to offer special rates or provide services under bilateral contracts with special price and nonprice conditions that are tailored to the demands of individual consumers.[160] Such price differentiation is almost always economical from a societal perspective but may be discomforting to regulators and politicians, and those customers who receive a similar service at a higher price.

- Seventh, although restructuring implies less price and entry regulation, regulators as well as other government entities will assume a crucial role in assuring that consumers receive most of the benefits of competition and that the rules are fair to all service providers. Lax regulation or regulation showing favoritism toward one group of service providers can jeopardize the benefits

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[159] One conspicuous example is the trucking industry.

[160] On a modest scale, we have seen this so far in the electric power industry where many utilities have offered industrial customers special rates to relocate in their service areas, expand their manufacturing facilities, or to discourage self-generation. The accumulation of these rates over the last several years have widened the gap between electricity rates for small and large customers. During the period 1984-1994, for example, industrial electricity rates (in nominal dollars) fell by over 3 percent, while rates to residential customers rose by almost 17 percent (in nominal dollars). (Source: Edison Electric Institute, *Statistical Yearbook of the Electric Utility Industry 1994* [Washington, D.C.: Edison Electric Institute, 1995].) All consumers did, however, enjoy a decline in real electricity prices over this period.

of restructuring to consumers and the overall economic performance of the industry. This has been true in the airline industry, for example, where the federal government's failure to execute congestion pricing for landing and take-offs has reduced consumer welfare from airline travel. As noted earlier, consumers may face start-up problems in choosing among different service providers. Regulators can help to assure that consumers know their new rights and responsibilities and gain access to information needed to make intelligent decisions. Any new service obligations of the local utility, for example, will need to be conveyed to consumers. Importantly, regulation will still be required for those consumers who choose not to make, or are unable to make, market choices. Deregulating those services for which the incumbent utility still has dominant market power would be detrimental.

The following quote from Alfred Kahn perhaps best describes the changed role of regulation in a more competitive, restructured electric power industry:

> Our recent experience demonstrates. . .that free markets may demand governmental interventions just as pervasive and quite possibly more imaginative than direct [price] regulation; but its lesson is that those interventions should to the greatest extent possible preserve, supplement, and enhance competition, rather than suppress it. Finally, to the extent direct economic regulation continues to be required, it is preferable that it be of a kind compatible with competition, rather than obstructive of it.[161]

Kahn's observation speaks strongly for a continuing role for regulation as the electric power industry evolves into a more competitive market structure. As plainly shown from the experiences of deregulated industries, the transitional period can be arduous and long-lived. Regulation will have to undergo changes in its practices and

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[161] Kahn, "Deregulation: Looking Backward and Looking Forward," 353.

policies if it is to accommodate the newly created competitive forces. Laying out the "ground rules" during the transition will be a major function of state public utility regulators over the next several years as competition advances in the electric power industry. Appropriate "ground rules," in fact, will go a long way in ensuring success for a restructured electric power industry.

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Consumer Working Group: Recommendations on Consumer Protection Aspects of Electric Utility Restructuring for Residential and Small Commercial Customers

December 19, 1996

A. INTRODUCTION

Since October, a small group of utility employees, Public Utilities Commission (PUC) staffers and advocates for consumer and low-income interests have met on five occasions to consider aspects of utility restructuring that will directly affect residential and small commercial customers in Maine. Adopting the name "Consumer Working Group," the eight participants have attempted to reach consensus on some of the more significant elements of restructuring for regulated electric utilities and for competitive power suppliers alike. The Consumer Working Group attempted to agree on an approach to these issues in time to be incorporated in the PUC's final Report to the Maine Legislature on the restructuring of the electric industry in Maine. What follows are the points on which the participants reached general agreement in the course of negotiation and discussion. The working group members stress that this list is not exclusive and there are likely other consumer protection aspects that could have significant effects on residential and small commercial customers, particularly with respect to energy assistance for low-income households.

B. RECOMMENDATIONS

1. Consumer Bill of Rights

- Electricity should be affordable, with universal access to a necessity of life.
- Electricity should be reliable, with no deterioration in quality of service.
- All customers should have the opportunity to choose power suppliers as well as the opportunity not to choose and still receive competitively-priced Standard Offer service.

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- Disconnection and deposit protections at the PUC should be retained for transmission and distribution ("T&D") and extended to Standard Offer service.
- Customers should receive accurate and unbiased price comparisons and information about sources of electricity.
- No electricity supplier should be able to operate without state licensing approval and Secretary of State registration.
- Customers should receive privacy protections regarding electricity choices by means of reasonable licensing requirements.
- Customers should have reasonable ease of movement from one electricity supplier to another.
- The state should prosecute anti-competitive practices and seek to protect vigorous competition in all electricity markets.
- The state should create consumer protections for customers of electricity suppliers.
- Customers should retain current legal rights including the right to complain to the PUC.

2. <u>Requirements for the PUC's Licensing of Competitive Power Suppliers and Marketers</u>

- evidence of financial capability sufficient to cover obligations to T&D utilities and customers
- a finalized interconnection contract with one or more T&D utilities which may include billing, metering, service standards or other issues
- ability to satisfy renewables portfolio requirement, if any
- requirement for periodic informational filings with the PUC re:
  a. prices at typical usage levels in a recent 6 month period
  b. the term of pricing arrangements in a recent 6 month period
  c. degree of pricing volatility (fixed/variable) in a recent 6 month period
  d. % of energy supply from listed sources in a recent 6 month period
  e. % deviation from a benchmark level of emissions, if any, in a recent 6 month period (example attached)
  f. to be used by the PUC in consumer education efforts
- reasonable procedures to process billing disputes with customers

- disclosure of all pending legal actions and consumer complaints adjudicated by a regulatory body elsewhere, in the most recent twelve months.
- agreement by competitive suppliers to comply with standard consumer provisions for residential and small commercial customers:
  a. termination of service following no less than a 14-day notice but always on a regularly scheduled meter-reading date unless the competitive supplier pays for the special meter reading visit;
  b. initial service for a period of no less than 30 days;
  c. customer right to designate a competitive supplier or choose standard service at any time subject to payment of PUC-approved fees;
- Telemarketing should not occur to customers whose written request that no telemarketing occur is on file at the PUC.
- Electricity suppliers will send a written confirmation of prices and services with standard consumer protections available to customers no later than five days following a customer's designation of that supplier.
- The PUC will consider protections against unauthorized redesignation of suppliers ("slamming"), including but not limited to 3rd party verification.
- License revocation and renewal procedures, including enforcement proceedings at the PUC in instances of consumer fraud or violation of license conditions.

3. Regulation of T&D Companies

- In cases of bimonthly metering, customers requesting a redesignation are entitled to one meter reading, at no additional cost in the month with no scheduled meter reading, to enhance ease of movement between electricity suppliers.
- Deposit, disconnection, credit and collection requirements should be regulated by the PUC in a form substantially similar to Chapter 81 of the PUC Rules.
- Rates and fees for T&D services should be set by the PUC, including charges for establishing service.
- T&D companies shall continue to be regulated by the PUC with respect to consumer protection issues generally.

4. Regulation of Standard Offer

- Entry and exit to Standard Offer service should occur no more often than at the time of scheduled meter readings or once a month in the case of customers of T&D

companies that have bi-monthly meter reading, unless the customer (or a designated electricity supplier) pays for an unscheduled meter reading that is necessary to implement the redesignation.

- Charges for entering or exiting Standard Offer should be set by the PUC in periodic proceedings.
- Levelized budget payment plans should be allowed.
- There should be no deposit requirements for first-time Standard Offer customers on the date that restructuring is implemented (1/1/2000).
- Deposit, disconnection, credit and collection requirements should be set by the PUC in periodic proceedings in a manner that is substantially similar to Chapter 81 of the PUC rules.

C. MEMBERSHIP

The members of the Consumer Working Group included:

Betty Bero, Senior Consumer Assistance Specialist, PUC
Eric Bryant, Counsel, Public Advocate's Office
Geoff Green, Consumer Affairs, Central Maine Power Company
Mary Henderson, Director Attorney, Maine Equal Justice Project
Pat Kosma, Program Director, Kennebec Valley CAP
Chet Oiler, Manager, Kennebunk Light and Power District
Matt Thayer, Director, Consumer Assistance Division, PUC
Stephen Ward, Public Advocate

The Working Group met at the PUC's Augusta offices on October 30, November 13 and 26, December 3 and 16, 1996. Steve Ward served as facilitator for the Working Group's discussions and distributed minutes and summary conclusions following each meeting of the Working Group. PUC representatives participated in order to provide information to the group and therefore abstained from final adoption of these recommendations.

What Would an Environmental Disclosure for Sales of Electricity Look Like?

Fuel Facts

Your electricity is generated from	
Nuclear	XX%
Coal	XX%
Oil	XX%
Natural gas	XX%
Renewables	XX%

Air Emission Facts

Each of your kWh produces	% above or below reference
Sulfur Dioxides YYmg	XX%
Oxides of Nitrogen YYmg	XX%
Mercury YYmg	XX%
Fine Particulates YYmg	XX%
Carbon Dioxide YYmg	XX%

List of Commenters

The following individuals, companies, and organizations provided formal written comments or proposals during the Commission's study of electric industry restructuring:

Alliance to Benefit Consumers
American Association of Retired Persons
Applied Resources Group
Bangor Hydro-Electric Company
Barringer, Richard
Beaver Wood Power Project
Brassau Hydro Electric Limited Partnership,Greenville Steam Company and Wheelabrator Sherman Energy Co.
Callahan, Brian
Candage, Rufus
Central Maine Power Company
Chambers, Newty
Coalition for Sensible Energy
Coastal Enterprises
Conservation Law Foundation
Eastern Maine Electric Cooperative
Ed Holt & Associates
Endless Energy Corporation
Enron Capital & Trade Resources
Fox Island Electric Cooperative
Hacket, Sayward
Huber Wood Products
Independent Energy Producers of Maine
Industrial Energy Consumer Group
Kimberly-Clark Corporation
Lamb, Richard
Lippke, James
Madison Paper Industries
Maine Association of Interdependent Neighborhoods
Maine Community Action Association
Maine Equal Justice Project
Maine Farm Bureau Association
Maine Frozen Foods
Maine's Massachusetts House
Maine Municipal Utility Group
Maine Public Service Company
McLaughlin, William
Municipal Review Committee
National Association of Energy Service Companies
National Federation of Independent Business
National Independent Energy Producers
Nichols, Clark
Northeast Energy Efficiency Council
Office of Policy and Legal Analysis
Office of the Public Advocate
People's Regional Opportunity Program
Povich, Edward
Regional Waste Systems
Rippling Water Enterprises
Shaw's Supermarkets

In addition, the Commission received comments, both in writing and at public hearings, from hundreds of Maine citizens.

Glossary of Abbreviations

AARP	American Association of Retired Persons
ABC	Alliance to Benefit Consumers
ARP	Alternative rate plan
BHE	Bangor Hydro-Electric Company
CAA	Clean Air Act
CMP	Central Maine Power Company
CLF	Conservation Law Foundation
CO_2	Carbon dioxide
COUs	Consumer-owned utilities
CSE	Coalition for Sensible Energy
DSM	Demand-side management
EMEC	Eastern Maine Electric Cooperative
ENRON	Enron Capital and Trade Resources
EPAct	Energy Policy Act of 1992
EPRI	Electric Power Research Institute
ERRA	Electric Rate Reform Act
FERC	Federal Energy Regulatory Commission
HWC	Houlton Water Company
IECG	Industrial Energy Consumer Group
IPPs	Independent power producers
ISO	Independent system operator
kW	Kilowatt
kWh	Kilowatt-hour
MEJP	Maine Equal Justice Project
MEPA	Maine Energy Policy Act
MPS	Maine Public Service Company
MMUG	Maine Municipal Utilities Group
MSW	Municipal solid waste
NAFTA	North American Free Trade Agreement
NECPUC	New England Conference of Public Utility Commissioners
NEGC	New England Governor's Conference
NEPEX	New England Power Exchange
NEPOOL	New England Power Pool
NERC	North American Electric Reliability Council
NIEP	National Independent Energy Producers
NO_X	Nitrogen oxides
NPV	Net Present Value
OPA	Office of the Public Advocate
PTF	Pool Transmission Facility

PUHCA	Public Utility Holding Company Act
PURPA	Public Utility Regulatory Policies Act
QFs	Qualifying facilities
R&D	Research and development
RTG	Regional Transmission Group
SPPA	Small Power Production Act
SO_2	Sulfur dioxide
T&D	Transmission and distribution