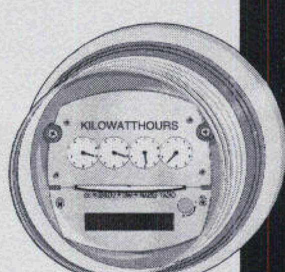
# States' Electric Restructuring Activities:

## An Initial Progress Report

Florida Public Service Commission
Tallahassee, Florida
October 1997



# STATES' ELECTRIC RESTRUCTURING ACTIVITIES: AN INITIAL PROGRESS REPORT

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**Report of the**
**Electricity Industry Work Group**

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# STATES' ELECTRIC RESTRUCTURING ACTIVITIES: AN INITIAL PROGRESS REPORT

## I. INTRODUCTION

Nineteen hundred and ninety-seven will be viewed as a transformative year for the regulated electric industry. Not a day elapses without some event occurring related to restructuring. The trade journals are awash with stories about the passage of a state bill to initiate retail choice, a merger or acquisition of a utility as it positions for competition, or some newly announced scheme to resolve the stranded cost issue. At the Federal level, at least three different bills have been introduced in this session of Congress mandating competition and the Federal Energy Regulatory Commission continues its implementation of Orders 888 and 889. While this transformation will be complex, will take a variety of paths, and will evolve over numerous years, enough states have already taken steps to warrant an interim evaluation of their progress.

The diversity of approaches taken by those states that have ventured farthest down this path may offer important lessons for Florida if the state pursues restructuring of its electric industry. The lessons learned by these early transitioning states may provide Florida with a virtual laboratory to evaluate the various merits of each approach, assess its applicability to our state, and identify the emerging issues and the types of competitive structures that can best meet the needs of Florida citizens.

A staff group under the moniker Electric Industry Work Group (EIWG) was appointed to evaluate those actions taken by other states to restructure their electric utility industry. This effort was a logical follow-up to the Public Utility Regulatory Conference workshops hosted by the Florida Public Service Commission (FPSC) in the summer and fall of 1996. The University of Florida's Public Utilities Research Center coordinated the workshops and gave staff and the public the opportunity to hear from some of the most notable authorities in the field. However, the one-day formats of the workshops did not afford an opportunity to delve very deeply into the complex regulatory issues underlying the restructuring phenomenon.

Thus, the primary objectives of the EIWG were to systemically gather information from selected sister states, organize it in a manner useful to this commission, and to explore in some detail the specific policy decisions adopted by these transitioning states. The Workgroup acknowledges at the onset that because most states are just in the embryonic stage of the process, our report often leads to more questions than answers, but even defining issues in a rigorous and thoughtful manner can be a useful addition to the Commission's institutional knowledge. Toward that end, we hope to have identified the range of issues that this commission may ultimately have to address.

Second, this project has resulted in a core of staff people well versed in the details of restructuring. In addition, we anticipate the information collected will be incorporated into an updatable and searchable database to ultimately track the activities of all fifty states. Lastly, the information garnered from this effort should allow the commission to be much more responsive and thorough in responding to inquiries from outside interests such as legislators and customer groups.

The second section of this report is a brief summary of the major issues that have confronted legislatures and regulatory commissions as they have proceeded with restructuring. More detailed state-by-state descriptions are contained in the subsequent chapters. One of the difficulties in attempting to draw conclusions at this point in time is that the specifics of the implementation plans vary tremendously across states and are often still in the formative stage. Consequently, while we summarize the number of states that have adopted some solution of strategy, the reader should carefully note the implementation details in the individual state analysis. For example, a state may have permitted stranded cost recovery, but how the commission defines and allows recovery is more substantively important.

The other problem with an interim report such as this is that any discussion of what the states are doing will be quickly outdated. The transformation of the electric industry is so complex and involves so many institutional decisions and reconsiderations, including judicial review, that a "snapshot" picture of what a state did or is about to do must be viewed as preliminary. In addition, as different approaches are tried and problems identified, the states will inevitably modify or rescind actions already taken. This simply reinforces the need for a systematic way to update the analysis as events unfold.

Finally, many commission staff people around the country were extraordinarily generous with their time as members of the EIWG called them or did site visits to their offices. In many cases, the key staff people we wanted to talk with were in the midst of detailed hearings and dockets addressing restructuring issues. Their patience in talking with the EIWG members, providing documents, and accommodating their schedules to meet with us, is fully acknowledged and appreciated. If there are any oversights or misinterpretations in this report, they are the responsibility of the FPSC workgroup, not of the staff of other commissions who so kindly assisted on this project.

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Difference in tastes, desires, incomes, and locations of buyers, and differences in the uses which they wish to make of commodities, all indicate the need for variety and the necessity of substituting for the concept of a "competitive ideal" an ideal involving both monopoly and competition.

Edward H. Chamberlin, *The Theory of Monopolistic Competition* (Cambridge: Harvard University Press, 1948), p. 214.

## II. OVERVIEW AND SUMMARY OF STUDY

### A. OVERVIEW

When this project began in the spring, 1997, the EIWG identified twelve states who had been the most aggressive in pursuing restructuring of their electric industries.[1] After an initial review of the implementation plans for these states, we eliminated one of them (Illinois) because restructuring legislation had failed to pass the legislature. Staff proceeded to analyze the relevant commission orders, statutes, and implementation plans of the remaining eleven states. On- site visits with key staff people were conducted in New York, New Hampshire, California, Arizona, Massachusetts, Vermont, and New Jersey. Phone interviews occurred for Michigan, Pennsylvania and Rhode Island and we reviewed the relevant documents for Maine. During the summer, three additional states – Nevada, Oklahoma, and Montana – passed restructuring legislation. Staff did an abbreviated review of these states, primarily synopsizing the implementing statutes. No interviews of commission staff were conducted for these latter states.

States have taken different approaches to restructuring and are in different stages of implementing plans. Some states have invested thousands of staff hours in conceptualizing, developing the rules for their transition, negotiating settlements, and litigating the specifics of their individual plans. On the other extreme, some states have just received legislative authority and the public utility commission (PUC) has done little in formulating the details of the plan and have not even begun administrative proceedings to adopt the necessary rules. The result is that many of the details on how restructuring will be implemented have not been decided. It is fair to say that even among the most aggressive of the fourteen states, only a small minority are in a position to begin implementation. Thus, while this report attempts to be thorough in describing what policy actions the key states have undertaken, many issues simply have not been addressed.

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[1]Arizona, California, Maine, Massachusetts, Michigan, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, and Illinois.

Second, anyone who understands the administrative procedures of most PUCs recognizes the commissions' actions are almost always subject to judicial review. Therefore, while we discuss what states have proposed, it should always be kept in mind that large portions of the implementation plans may be revised or rejected after administrative or judicial review. In fact, a number of state plans are already in abeyance awaiting either court challenges (New Hampshire and Pennsylvania) or, in some cases, awaiting explicit legislative authority to proceed. Massachusetts, New Jersey and Vermont, for example, have commission initiated restructuring proposals, but need specific enabling legislative authority. However, both New Jersey and Massachusetts are proceeding with implementation details anticipating the requisite legislation will be forthcoming.

The Workgroup developed nine topic categories that were used to frame the information gathered from each state. The topic areas are:

- Background
- Market Structure
- Stranded Cost
- Customer Issues
- Market Power
- Public Purpose Programs
- Reliability
- Reciprocity
- Tax Issues

Admittedly, there is not always a clear demarcation between subject categories, nor has every state addressed each of the topics. One cannot talk about independent system operators without dealing with both market power issues and reliability. Likewise, Customer Issues involve everything from competitive billing requirements to who do you call if the lights go out. The topic areas are simply a taxonomy to help structure the individual state analyses for the reader.

It is fair to say that as of late summer, 1997 there is a lot more talk about competition[2] than there are actually retail transactions taking place. Rhode Island is the only state allowing specific portions of their retail load the right of direct access. In addition, a number of pilots and experimental trials are underway.[3]

Map 1 shows states categorized into three groups based on where they are with respect

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[2]We will use the term restructuring and competition interchangeably. In either case, it implies the right of end-use, retail customers to have retail choice between alternative electric generation providers.

[3]For a review of some of these, see *Retail Pilot Programs: The First Six*. Edison Electric Institute. Washington, D.C. 1997.

to restructuring activities. Any assignment based on the level of state activity is admittedly subjective, but this represents a "snap-shot" of where the various states are in the process. In the most active group, the PUC has either proposed or adopted a restructuring plan, the legislature has passed a restructuring bill, or both. Some 18 states are studying the issue under the auspices of legislative study commissions or legislatively mandated task forces. The remaining 19 states show less legislative or commission activity, but most of them are monitoring the situation. In a few of these latter states, restructuring legislation has been introduced, but failed to pass.

## B. SUMMARY OF FINDINGS

### BACKGROUND

To no one's surprise , high electric rates were the primary drivers in initiating state action to restructure electric markets. For example, the eleven states that were initially selected for study had average rates of 9.56¢ in 1995. This was 38 percent above the national average of 6.89¢.[4] MAPS 2 - 5 show the average revenue per kWh for each rate class. The maps generally reflect that the northeastern states and California had higher than average rates for all customer classes. The southeast, midwest and extreme northwest states generally have average to below average rates. This data illustrates the rate levels that existed as those states began to restructure.

Recently, three lower cost states, Oklahoma, Montana, and Nevada, passed restructuring legislation. Their average revenue rate was 5.44¢ , some 21 percent below the national average. Clearly, different factors are motivating restructuring efforts in these low cost states. It is possible that these states see opportunities for their utilities to make out-of-state sales or they believe that competition affords other benefits for their states. It is also noteworthy that Nevada and Montana both have an extremely high percentage of industrial load as percent of their 1995 electric sales.

Our work indicates that electric rates were so high in some states that policy makers were very sensitive to the charge that economic development was being negatively affected (loss of jobs, industrial relocations, plant closings). We found in these states that large electric customers were often instrumental in encouraging the transition toward competition and the legislatures and governors' offices were particularly sensitive to their requests. For example, in Michigan the governor established a blue ribbon panel called the Michigan Jobs Commission to look at restructuring. The primary recommendation of this commission was that commercial and industrial customers have direct retail access as soon as possible, but the report did not mention access for residential customers. This pattern of commercial and industrial customers being catalysts for change was fairly typical.

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[4]All rates cited throughout this report are reported as revenue per kWh. All data are taken from the DOE/EIA *Electric Sales and Revenue 1995.* December, 1996.

## MARKET STRUCTURE

Market structure is a broad term referring to the game rules being developed by the states to define the role and responsibilities of new entrants to the electricity market and how the rules will be implemented. Most of the states are allowing retail access using a phase-in plan that gradually allows customers access to competitive power providers usually over a two to five year window. A few states like California, New Hampshire, Vermont and Massachusetts are going to go "cold turkey" and have proposed to allow all customers retail access on January 1, 1998. Rhode Island was the first state to pass restructuring legislation, preceding California's legislation by one month, and Rhode Island is permitting large industrial customers and state agencies retail access on July 1, 1997. All other Rhode Island customers will have retail choice by July, 1998. For the states following a phase-in or other transition approach, the proposed dates for full retail access for all customers are: Arizona (2003), Maine (2000), Michigan (2001), Montana (2002), Nevada (1999), New Jersey (1998-2000), New York (2001-2002), Oklahoma (2002), Pennsylvania (2001), and Rhode Island (1998).

Nearly all of these states are proposing the following structure. Distribution services will remain under a regulated electric company subject to the jurisdiction of the state utility commission. Most transmission services will remain under Federal jurisdiction via the Federal Energy Regulatory Commission (FERC). However, some portion of transmission dedicated to retail customers may remain under state jurisdiction. Only the generation portion of electric service, that is the production of the electricity will be competitive. Under the proposed systems, customers will be able to select an alternative electric provider who will deliver electricity to the incumbent transmission and distribution company, usually through an independent system operator (ISO). A number of states are exploring the notion of incorporating a mandatory power exchange (PX) as part of the market structure. A PX is a separate entity that will essentially act as the "market place" where the transaction prices will be determined. California is requiring a PX be established and the Vermont PUC has recommended to their legislature that the PX be part of their restructuring plan. Responsibility as the provider of last resort for those customers not electing an alternative supplier of power almost always remains with the incumbent utility.

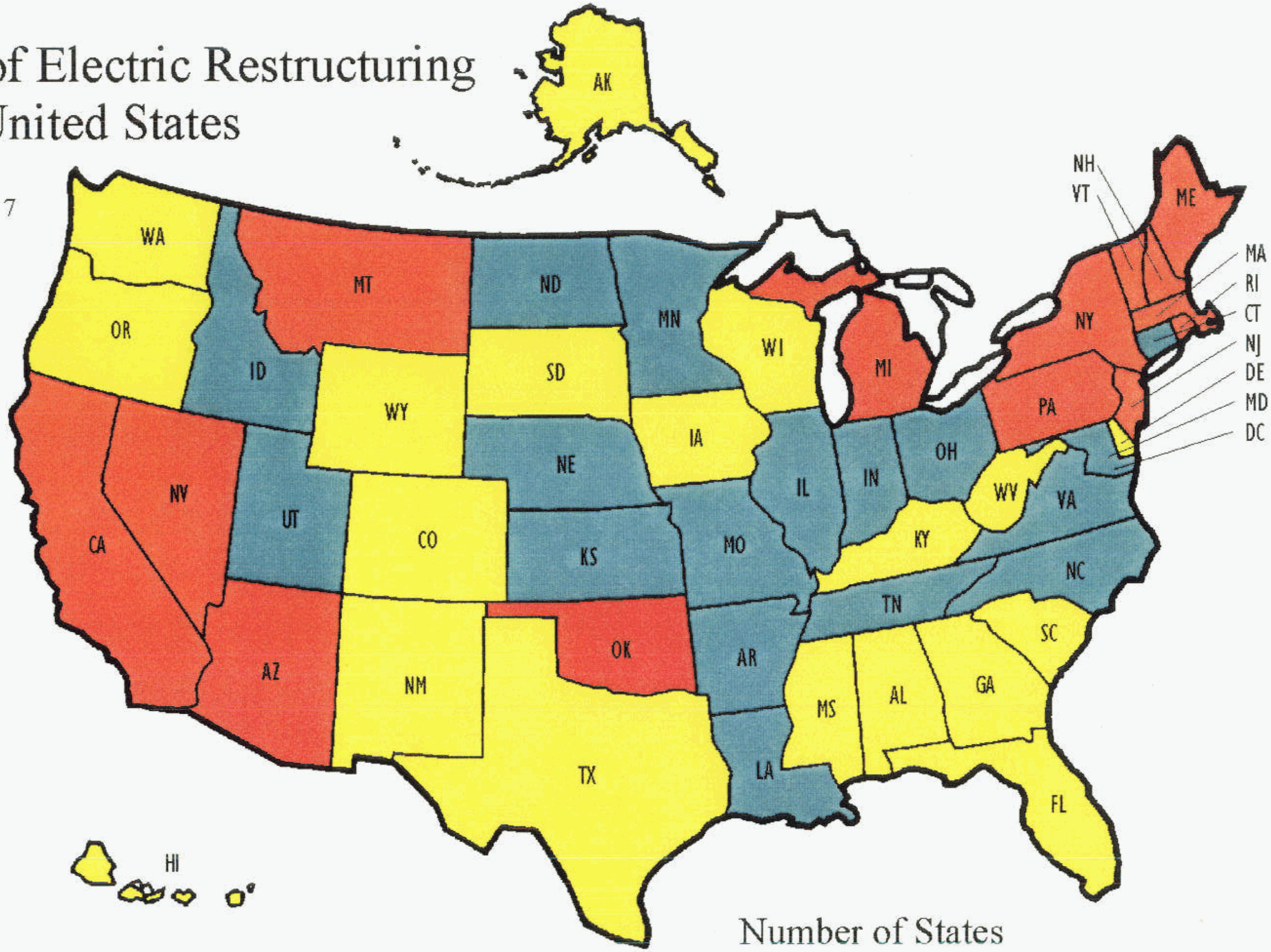
Nearly all states are requiring the components of electric service be "unbundled" and priced separately. A customer will have a power charge, potentially a transmission charge, a distribution charge, and perhaps a meter reading and billing charge all listed individually on the bill. Other potential charges include public purpose program surcharges (energy efficiency, renewables, low income), taxes, and competitive transition charges. The latter fee is earmarked as a payment toward the recovery of commission approved stranded costs.

While each state may have a slight variation on this model, most view the generation portion of the service becoming completely unregulated except for issues involving customer protection and information requirements. Most states are deferring to the FERC to set the transmission rate. However, there are a number of outstanding issues dealing

**MAP 1**

# Status of Electric Restructuring in the United States

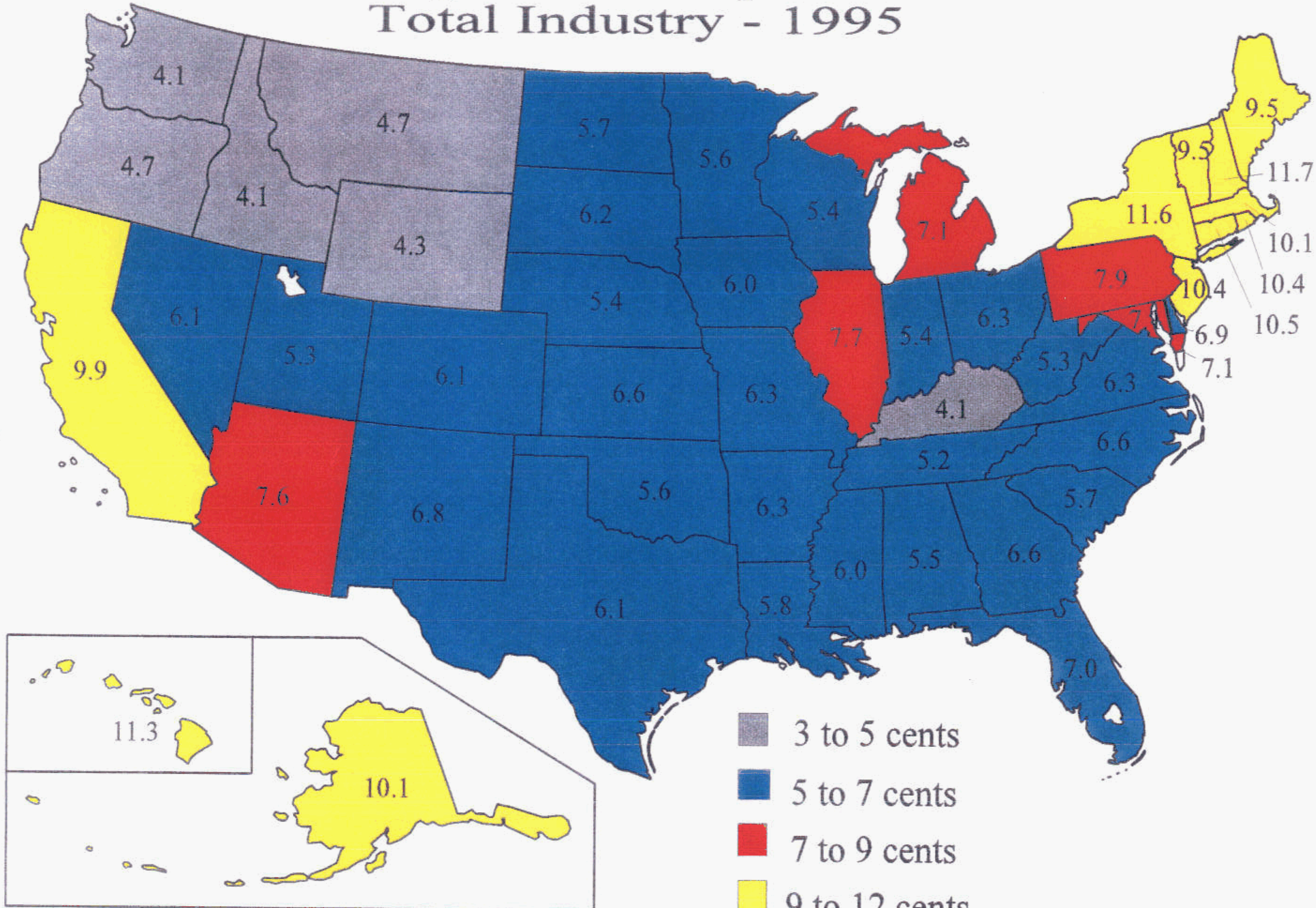
JUNE 1997




| | Number of States |
|---|---|
| Electric Restructuring | 14 |
| Electric Restructuring Being Studied | 18 |
| Actively Monitoring | 19 |

MAP 2

# Average Revenue per kWh - Total Industry - 1995

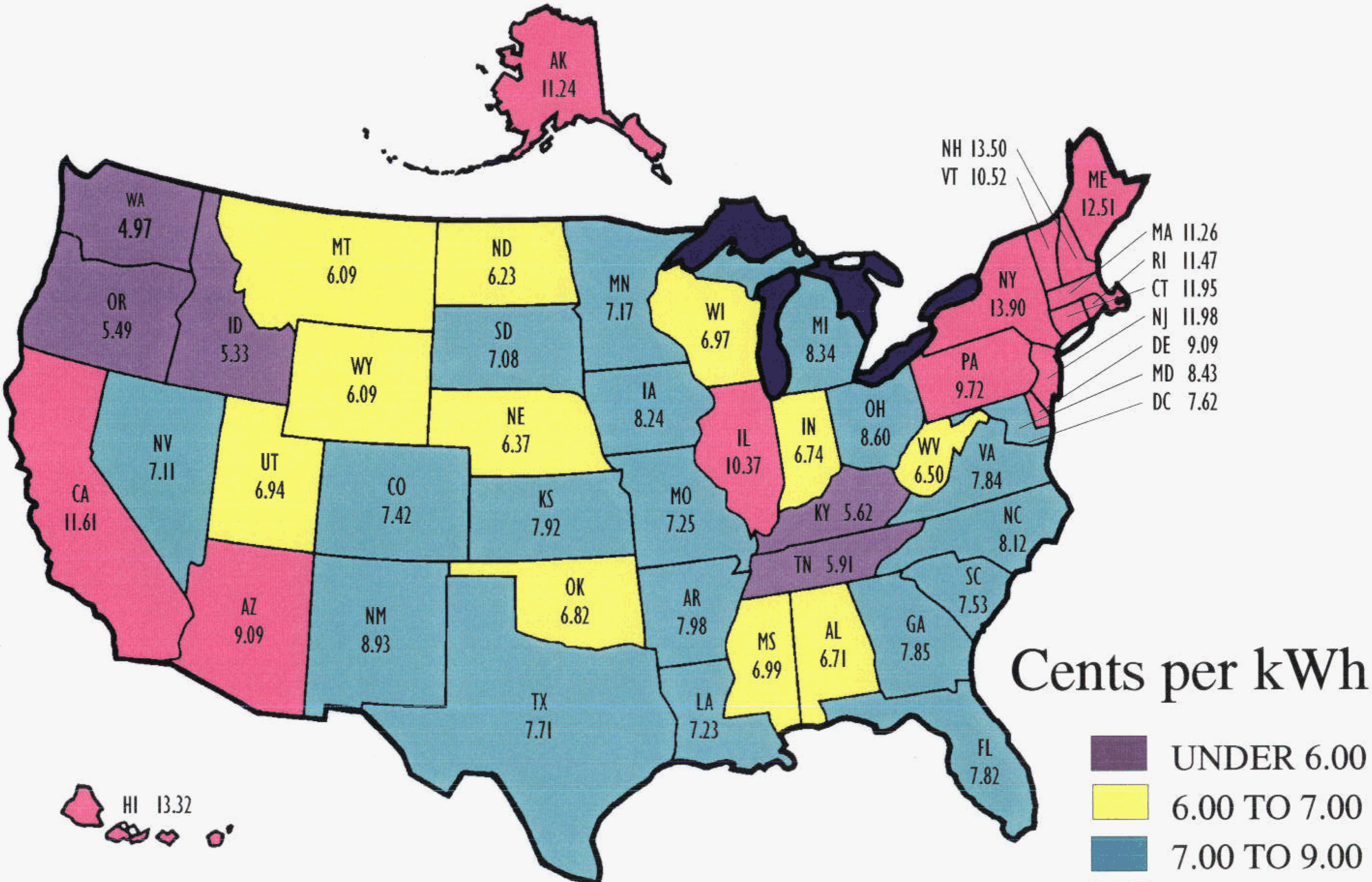



Source: Energy Information Administration, Electric Sales and Revenues, 1995.

MAP 3

## Average Revenue per Kilowatthour for the **Residential** Sector by State, 1995

(Average Residential = 8.40 cents)

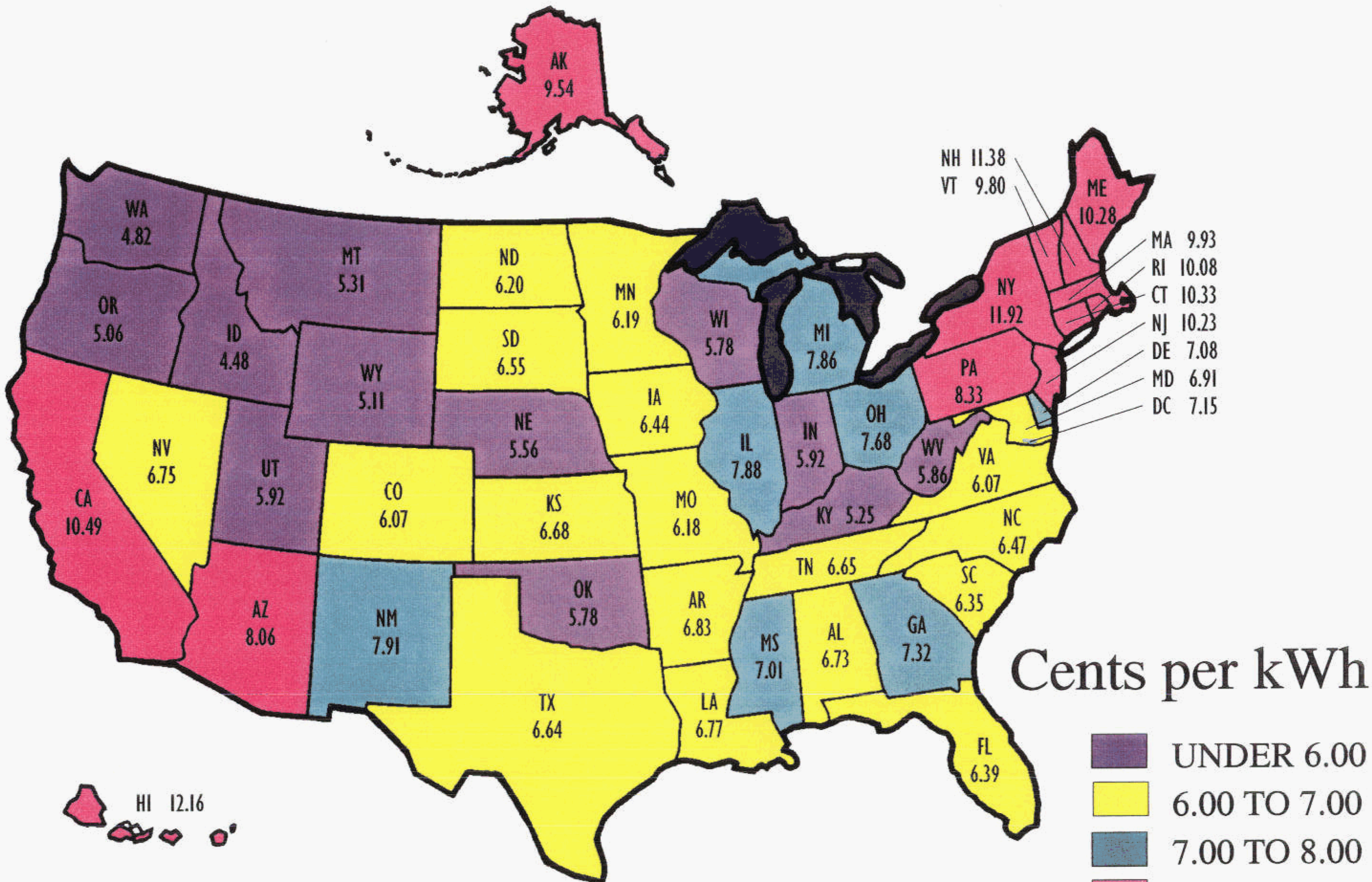



Source: Energy Information Administration, Electric Sales and Revenues, 1995.

MAP 4

## Average Revenue per Kilowatthour for the **Commercial** Sector by State, 1995

(Average Commercial = 7.69 cents)

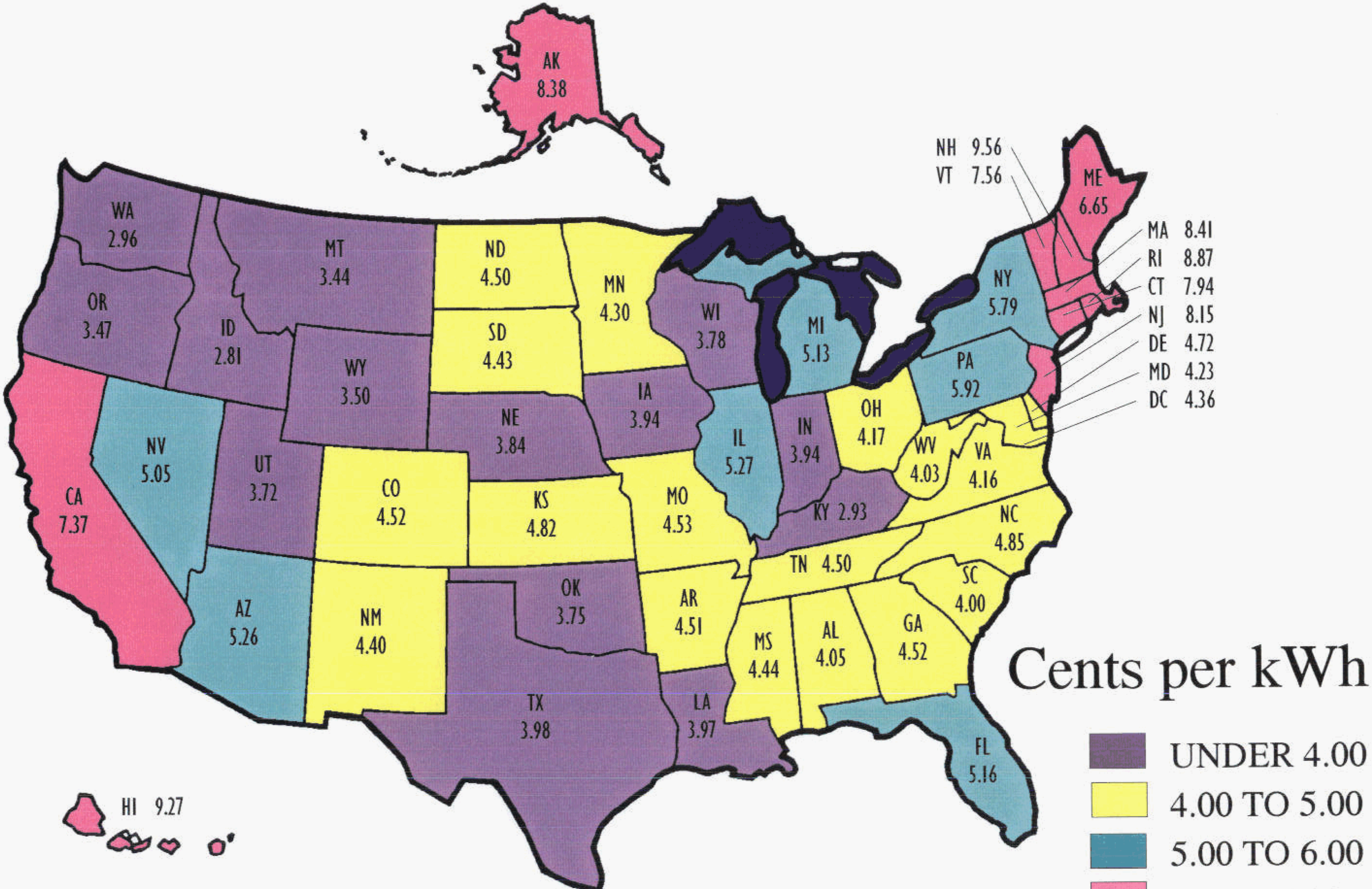



Source: Energy Information Administration, Electric Sales and Revenues, 1995

MAP 5

Average Revenue per Kilowatthour for the **Industrial** Sector by State, 1995

(Average Industrial = 4.66 cents)




Source: Energy Information Administration, Electric Sales and Revenues, 1995.

with what portion of transmission facilities dedicated to retail customers should be classified as jurisdictional to FERC and what portion is jurisdictional to states. FERC established a seven-part test in Order 888 to set standards for making such determinations. Interviews with public utility commission (PUC) staff indicated there is still much confusion surrounding this separation, but for now this is a relatively modest concern in the overall process of restructuring.

## STRANDED COSTS

Clearly, the most contentious issue addressed by any of the states is finding a fair and equitable solution to the stranded cost problem. Stranded costs are those utility assets that will become uneconomic after the introduction of competition. They usually include ancillary expenses that the utility will incur to transition to a competitive market such as employee retraining and costs directly associated with establishing an ISO, new billing systems, etc. All states thus far have adopted explicit provisions allowing some portion of stranded cost to be recovered by the incumbent utilities. Most are requiring the utilities to attempt various mitigation efforts such as buying down or renegotiating purchase power contracts, divesting or writing down uneconomic assets, or implementing other cost reduction strategies. All states are using an administratively determined value of stranded costs, with recovery based on some form of a competitive transition charge (CTC). This charge will be structured to be non-bypassable and generally applies to all customers who opt for service from an alternative power provider.

Beyond this broad framework, it is difficult to summarize how the states will handle this difficult issue. A number of states recognize that the value of the uneconomic assets will vary going forward based on future market prices for energy. Therefore, a number of states (California, Maine, Massachusetts, Michigan, New Jersey and Pennsylvania) have proposed periodically re-estimating the stranded costs and adjusting the CTC accordingly. Others are making an initial estimate that will remain in effect for a fixed period and will be revisited at a later date (Rhode Island). Most states have not addressed or have postponed the details of how to estimate stranded costs. New Hampshire probably has taken one of the most stringent positions on allowing recovery. Its PUC stated that utilities with rates above the regional average will not be authorized to recover all their costs. Furthermore, the NHPUC stated: 1) less than full stranded cost recovery is fair 2) less than full recovery is not economically inefficient and 3) full recovery of stranded costs has anti-competitive consequences. This position may partially explain the litigious nature of the restructuring process in New Hampshire.

### Securitization

A second but relatively recent mechanism to help ameliorate the rate impacts of stranded cost recovery is the so-called "securitization" of such costs. Most states are exploring this refinancing technique where the uneconomic assets of the utilities are packaged as a bond issue (or so-called asset backed securities) of which the interest and principal are paid through a surcharge on customers as part of the CTC. The state PUC determines the amount and type of assets that can be bonded and permits recovery of the CTC. Usually, a third party grantor is established who issues the bonds, transfers the proceeds to the utility in a lump sum, and is responsible for making payments of principal and interest. This grantor may be a state agency, as is the case with the California Economic Development Bank, but this is not required. It is the PUC's approval of the CTC pledged against the bonds that makes them highly attractive to investors. States do not normally guarantee the issuance itself.

The financial advantage of securitization is that it allows lower cost debt, instead of a combination of the utility's debt and equity capital structure, to be used to refinance the uneconomic assets. Several states have embraced this strategy with the expectation that it will allow an immediate reduction in rates. Most states do require legislative authority to proceed with securitization. To date, California, Pennsylvania, Rhode Island, and Montana have such authority. Other states seeking or expecting authority to permit the securitization of utility assets include Maine, Massachusetts, Michigan, New Hampshire, New Jersey, and New York.

## CUSTOMER ISSUES

All but the most recently approved restructuring plans pay significant attention to issues of customer protection and universal service. Here again, there is wide variation in the requirements imposed on alternative providers and distribution entities with respect to customer issues. Most states see billing and metering services being performed by the regulated distribution company. Although, California is explicitly preparing for these services to be deregulated by January 1, 1999 and New Hampshire will permit commercial and industrial customers to seek alternative billing and metering services. Nearly every state has made the incumbent distribution company the provider of last resort for those customers who do not elect an alternative provider, where competitive alternatives do not exist, or where the customer has had service discontinued from an alternative provider for non-payment. Generally, these customers will be served under a "standard offer contract" approved by the commission and offered by the distribution company. The rates and charges for these contracts will be regulated by the PUC except the energy portion of the service is often based on market prices.

Interestingly, a number of states including California and Nevada will use performance based regulation (PBR) for setting the rates for distribution services. Generally, performance based regulation allows rate increases based on an increase in some kind of price indicator. The rate of increase is often reduced by some efficiency or technology adjustment and is conditional on established service standards being met or exceeded. Michigan and New Jersey are also exploring PBR as an alternative to traditional rate based, cost of service regulation, and the Vermont commission has recommended to its legislature that PBR be permitted but not mandated.

## MARKET POWER

Another difficult question confronting transitioning states is identifying and mitigating undue market power on the part of incumbent utilities. In economic terms, market power exists when a single seller can influence prices. It is generally agreed that existing vertically integrated utilities providing all aspects of service (generation, transmission, and distribution) under a long standing monopoly environment, could easily exercise market power. The incumbent utilities' near complete ownership of generation and transmission in franchised service areas increases that probability. Likewise, there are opportunities for horizontal market power such as incumbent utilities having unfair access to customer billing records or having extensive and well established networks of customer service representatives. These assets may very well give them an unfair advantage under a deregulated market.

A number of remedies are being implemented to ensure that an incumbent utility does not exercise market dominance. Most states are requiring, as a minimum, functional unbundling between generation, transmission, and distribution services (Arizona, California, Massachusetts, Montana, New Jersey, Pennsylvania, Rhode Island and New York). Vermont has recommended to its legislature that functional separation be required. Two states, Maine and New Hampshire, are requiring divestiture of generation assets for those companies who want to make direct retail sales. Utilities in California and New York have voluntarily agreed to divest some portion of their generating assets. The other states have not yet defined what systems will be imposed to prevent undue market power.

The second widely accepted mitigation strategy is the requirement that transmission control and system reliability functions be performed by an independent system operator (ISO). The ISO is essentially the electric grid controller and gatekeeper and is responsible for ensuring short term bulk power is adequate and controls which transmission paths are available to carry the power. These functions have been traditionally performed by regulated utilities who either control their individual service grid or voluntarily form electric coordinating councils or dispatch pools to optimize the efficiency of multiple electric systems and to ensure wider system reliability. Clearly, whoever manages system operations or dispatch has inordinate power to affect prices by limiting transmission access or restricting generation. To prevent such undue market influence, the Federal Energy Regulatory Commission in Order 888 suggested, but did not require, that ISOs assume system operations. States have adopted this suggestion, but are making it mandatory. ISOs will not be affiliated with the utilities and are supposed to provide fair and non-discriminatory access to the transmission system for all market participants. Thus far, the following states are either requiring or recommending ISOs as a check on market power: California, Arizona, Maine, Massachusetts, New Hampshire, New Jersey, New York, Rhode Island, Pennsylvania and Vermont. Michigan will investigate the possibilities of a regional ISO. Montana, Nevada, and Oklahoma are still formulating their market power remediation strategies. California has imposed an additional separation to prevent market power abuses between system operations and economic dispatch by requiring a power exchange be established. Vermont has also recommended a PX be established.

## RELIABILITY

Reliability is a topic, not unlike mom and apple pie, that everyone unquestionably embraces and nearly every order or statute examined by the EIWG had the customary platitudes about "ensuring a safe and reliable electric system." We analyzed this issue from two perspectives -- operational reliability and system planning reliability. The first refers to the day-to-day operations of the electric system such as providing adequate short term, bulk power to cover contingencies and maintaining the integrity of the transmission system. The second refers to ensuring the timely identification and construction of new generation and transmission facilities.

The Workgroup's analyses indicate that while considerable thought has been given to operational reliability concerns, much work remains to be done in respect to planning reliability. Most states are relying on the newly developed ISOs to assure day to day, operational reliability. Since the coordinating councils and the National Electric Reliability Council have established long accepted standards, the assumption of operational control should go relatively smoothly. Moreover, a number of national organizations such as the U. S. Department of Energy's Task Force on Electric System Reliability are working diligently to coordinate the standards and market rules that will be adopted all across the country.

The states are giving far less attention to ensuring supply reliability. Traditionally, state PUCs or state energy offices have had a role in evaluating the adequacy of the generation expansion plans of the regulated utilities.[5] When the load and energy forecast indicated new transmission or generation was needed, the state commission frequently was required to evaluate the expansion plans and, if justified, issue a certificate of need for the new facility. The utilities after meeting applicable environmental and zoning requirements would construct the power plant or acquire right-of-way for transmission corridors to construct the new lines. Under a competitive market and absent rate-based regulation, it is unclear who will assume this responsibility. Interviews with staff around the country indicated that the operative assumption is "the market" would take care of the problem. In some yet unidentified manner, price signals would entice investors to construct both power plants and transmission lines. Those familiar with the difficulties of permitting such large and often environmentally controversial projects expressed concern that non-utility generators without the right of eminent domain and mandatory requirements to ensure system reliability imposed on them by most state statutes would find it difficult, if not impossible, to construct new facilities on a merchant or speculative basis. Only Nevada has directly addressed this concern. Its enabling legislation requires the commission to develop regular forecasts of demand and if it believes supplies will be inadequate, the commission may take action to

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[5]A recent NARUC Report indicated that some 40 states have authority to review load forecasts and resource plans. Approximately 30 states issue certificates of need. Karen Bauer, ed. *Utility Regulatory Policy in the Unites States and Canada: Compilation 1994-1995*. (National Association of Regulatory Utility Commissioners, 1995).

assign obligations to construct needed facilities to utilities, marketers, and system operators. California has asked the FERC to clarify that its ISO has the authority to mandate necessary facility additions.

## PUBLIC PURPOSE PROGRAMS

Public purpose programs refer to those non-essential utility services that have traditionally been required of regulated electric service providers. These programs include such services as offering energy audits and efficiency programs, funding renewable energy projects, providing assistance to low income customers, and performing research and development.

Nearly every state has included provisions to continue some or all of these programs through a non-bypassable system benefits charge. Funding for low income assistance programs is the most common public purpose program required in most restructuring plans. Nine states (Arizona, California, Maine, Massachusetts, Michigan, Montana, New Hampshire, Pennsylvania, Rhode Island) have specifically included some level of expenditures for continuing energy efficiency programs, although in most cases these expenditures are for a fixed period and will either be declining or eliminated sometime in the future. While four states (California, Massachusetts, Montana, Rhode Island), envision using a system benefits charge to continue to encourage renewable energy, Maine, Arizona, and Nevada have mandated a "renewable portfolio standard" which would require any generation provider in their states to have a certain percentage of their energy derived from renewable resources. Vermont has also advocated adoption of a portfolio standard as part of its legislative recommendations.

## TAX ISSUES

Electricity sales are often a basis for governmental units to collect taxes. Here in Florida, for example, it is possible for taxes to amount to 26 percent of a typical bill because of the gross receipts tax, sales tax for commercial customers, franchise fees, and municipal taxes. New Jersey imposes a gross receipts tax of 13%, the highest in the nation, on electric bills. In some communities, property taxes on nuclear or fossil units will be reduced if these assets are determined to have a lower market value. While generally not subject to Federal and state taxes, many municipally owned utilities receive a "payment in lieu of taxes" or make fund transfers to the municipal governments based on its electric sales. A recent report by Deloitte & Touche stated:

> First, absent changes in the tax laws, competition is likely to reduce state and local tax revenue, as economic activity shifts away from the highly taxed regulated utility sector into less highly taxed sectors. Second, the present tax structure tends to treat different providers of electricity differently, so that when they start to compete with each other, the differing tax treatments will affect the competitive balance

between them by reducing the cost of the more lightly taxed providers. These disparities could reduce or eliminate the economic benefits of competition, . . ..[6]

The Workgroup generally found most states are pursuing deregulation without fully understanding the profound and pervasive tax implications. Out of the fourteen states Nebraska, Nevada, Oklahoma, Montana, and Arizona will be studying the tax ramifications. The Massachusetts and New Jersey PUCs have made specific recommendations to their legislatures to address the issue. Vermont, California, Michigan and Maine apparently have not yet addressed the question. New York's legislature considered, but failed to pass tax reform. Only New Hampshire, Pennsylvania, and Rhode Island have revised their tax requirements in response to restructuring. States modifying their tax codes have as their objective to assure revenue neutrality so that tax revenues are not decreased and tax burdens are not unfairly shifted between customer groups.

## RECIPROCITY

Reciprocity is the condition that a utility will not be required to open its service area to retail competitors unless the competitors allow retail access in their service area. Usually utilities who are being required to open up their service to competition want similar access outside their service area. While there is some question under the Commerce Clause of the U.S. Constitution if such state imposed restrictions are legally permissible, the topic has been hotly debated. Thus far, only Michigan's plan has imposed "inter-state" reciprocity. In other words, any out-of-state utility that wants to sell to Michigan utilities must allow Michigan utilities access to their customers. Six states -- Arizona, California, Massachusetts, Pennsylvania, Montana, and Oklahoma -- have imposed "intra-state" reciprocity between investor-owned utilities and municipal and cooperatively owned utilities. In a number of cases, the state commission does not have authority to require retail access for public and cooperative utilities, but can restrict these non-regulated entities ability to engage in competition in the service areas of the deregulated investor-owned utilities. The other states either have not studied the issue or have not imposed any reciprocity requirements.

## CONCLUSION

This overall summary is not meant to be exhaustive. There is much more detailed information in the individual state reports that follow. However, it is clear that experimentation by and among the states on how best to proceed with this important process is alive and well. States have shown both enthusiasm and creativity in addressing some very complex issues. One important point should be made. Most of the Federal

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[6] *Federal, State and Local Tax Implications of Electric Utility Industry Restructuring*. Deloitte and Touche. October, 1996.

proposals being considered by Congress imposes a Federal mandate on how and when the states must deregulate their utilities. It would be unfortunate if a Federal, one-size-fits-all approach aborted the states' own innovative efforts to deregulate their electric industries in a manner most beneficial to their citizens.

We want to watch and learn from our sister states as they move down the path to restructuring. Here in Florida, we have the opportunity to learn from their mistakes and -- learn from their successes. To help keep current with restructuring activities in the future, Florida will participate with the Electricity Committee of the National Association of Regulatory Utility Commissioners (NARUC) to develop an ongoing state monitoring database. The objective is to establish a searchable database on the Internet so that legislatures, commissions, and other interested parties can have ready access to the latest information from the states. [7]

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[7]Many commission orders and decisions are already posted on state commission websites. The address of most states can be found at http://www.erols.com/naruc/statewebb.htm.

# III. INDIVIDUAL STATE ANALYSES

## ARIZONA

### BACKGROUND

In 1995, Arizona utilities generated some 48,600 gigawatt hours of electricity. Investor-owned utilities accounted for 58 percent of the state's total sales, municipals accounted for 37 percent, and cooperatives accounted for the remaining 5 percent. The residential class consumed 44 percent, commercials consumed 36 percent, and industrial/other classes consumed 21 percent. In respect to rates, average revenue per kWh was 7.60 cents in 1995 for all classes combined. Individual class breakouts were 9.09 ¢/kWh for residential, 8.06 ¢/kWh for commercial, and 5.26 ¢/kWh for industrial.

Restructuring has been a particularly controversial issue in Arizona. The Governor's office and the legislature have taken a position against restructuring, while the elected Arizona Corporation Commission (ACC) has advocated restructuring and taken formal steps to proceed with retail access. The ACC has authority over investor-owned and cooperative utilities, but the legislature exercises authority over municipals and the Salt River Project. The ACC cannot dictate statewide electric competition - that requires the action of the legislature - but can move forward with restructuring for the IOU's and cooperatives.

The utilities are reluctant to proceed with competition until several concerns are addressed first. They warn that reliability is of paramount importance, and they point to recent regional power outages as evidence that reliability must be insured before going forward with competition. They believe that the current rules passed by the ACC need further work in the area of reliability. Other areas requiring "additional work," according to the utilities, include: obligation to serve geographic markets, financial impact on various customer classes, and economic impact on state and local government.

In late 1994, the ACC conducted a preliminary workshop on restructuring. Nearly a year-long process involving a working group resulted in the October 1995 release of the Report of the Working Group on Retail Electric Competition. This was the initial blueprint for beginning the process. After a formal rule adoption process concluded, the ACC issued Decision No. 59943 introducing retail access for investor-owned and municipal utilities. Municipal utilities and the Salt River Project can participate if they choose.

Decision No. 59943 is a broad policy decision but is notably lacking in a specific implementation plan through which the policy will be achieved. Establishment of those implementation details is the role of the working groups, as referenced in the policy decision. The ACC's policy decision establishes working groups to address the various issue areas. Active working groups include the Stranded Cost Working Group, the

Unbundled Services and Standard Offer Working Group, the Electric System Reliability and Safety Working Group, and the Legal Working Group. Some of these working groups have subcommittees associated with them.

The policy rule states that the working groups will be coordinated by a staff division director or his or her designee. While the staff has been established as coordinators of the working groups, commissioners have informed at least one of the working groups (the Stranded Cost Working Group) that the parties, rather than staff, were expected to determine the eventual recommendations issued by the groups.

The process calls for subcommittees to forward their recommendations to the working groups. After due consideration, the working group may forward the recommendation, with or without modifications, to the full commission. In some cases the dates for receiving recommendations from workshops and working groups is specified within the policy decision. For example, the Stranded Cost Working Group is required by rule to submit their report on activities and their recommendations by September 30, 1997, as is the Legal Working Group. Likewise, the Unbundled Services and Standard Offer Working Group must report its recommendations to the commission by October 31, 1997. The Electric System Reliability and Safety Working Group must report to the Commission "regularly."

In February 1997, the utilities regulated by the ACC filed lawsuits against the ACC, in which they contested the ACC's statutory authority to mandate electric restructuring. The utilities claim that a constitutional amendment is required to restructure Arizona's electric industry. Four separate lawsuits may be consolidated depending upon court action. The utilities' primary concern is the risk of being denied full stranded cost recovery.

The ACC re-opened the rule docket and a re-hearing is imminent. ACC Staff believes there is a chance it will be concluded by March 1998. The working groups' reports will be reflected in the revisions to and the supplementation of Decision No. 59943 (see "Market Power" for discussion of working groups).

## MARKET STRUCTURE

The ACC intends to follow a gradual phase-in to allow access to retail load with full retail access scheduled for January 2003. During the transition the following actions have been ordered.

- By December 31, 1997, all utilities subject to ACC jurisdiction will propose for ACC review and approval a plan on how customers will be selected for participation in the competitive market prior to 2003.

- Each subject utility must file unbundled service tariffs. By January 1, 1999, all subject utilities must make 20% of their peak 1995 demand for all customer classes (including residential and small business) available for retail access. No more than half of the eligible demand may be allocated to large customers (i.e. customers with greater than 3 MW contract demand). Fifteen percent of the eligible demand must be reserved for residential customers, with aggregation of smaller loads permitted.

- By January 1, 2001, all utilities must make 50% of its 1995 system retail peak demand available for all customer classes (including residential and small business). Large customers are again limited to one-half of the eligible demand. Thirty percent of the eligible demand must be reserved for residential customers. Finally, by January 1, 2003, all jurisdictional load will have retail access.

## STRANDED COSTS

Stranded costs are the verifiable net difference between the value of prudent assets and obligations necessary to furnish electricity, acquired prior to December 26, 1996, and the market value of those assets and obligations directly attributable to the introduction of competition. Stranded costs includes generating plants, purchased power contracts, fuel contracts, employment transition costs, environmental mandates, and regulatory assets.

Although no method of calculating stranded costs has been officially selected, the Stranded Cost Working Group has voted to pursue the Net Revenue Lost method over other methods such as replacement cost valuation, auction and divestiture, and stock market valuation.

The working group has voted to allow periodic true-ups of the stranded cost amounts, but they were unable to agree upon a true-up interval.

### Recovery of Stranded Costs

The ACC has stated utilities must take every feasible, cost-effective step to mitigate or offset stranded costs by means such as expanding wholesale or retail markets, or offering a wider scope of services for profit. The ACC will allow recovery of unmitigated stranded cost by affected utilities, in accord with FERC Order 888. By September 30, 1997, the Stranded Cost Working Group, made up of representatives of ACC staff, Residential Utility Consumer Office, customers, utilities, and other electric service providers will present its recommendations to the ACC in a report. Recommendations will consider the following eleven items:

1. The impact of stranded cost recovery on the effectiveness of competition;
2. The impact of stranded cost recovery on customers of who do not participate in the competitive market;
3. The impact, if any, on the utilities ability to meet debt obligations;

4. The impact of stranded cost recovery on prices paid by consumers who participate in the competitive market;

5. The degree to which the utility has mitigated or offset stranded cost;

6. The degree to which some assets have values in excess of their book values;

7. An appropriate treatment of offsetting assets;
8. The time period over which such stranded cost charges may be recovered;

9. The ease of determining the amount of stranded cost;

10. The applicability of stranded cost changes to interruptible customers;

11. The amount of electricity generated by renewable generating resources owned by the subject utility.

After consideration of the above, the ACC will decide what actions to take regarding stranded costs. Affected Utilities will file estimates of unmitigated stranded cost. Cost recovery can be achieved through distribution charges or other means. The eleven considerations above must be utilized in determining the appropriate cost recovery mechanisms. Finally, stranded cost may not be recovered from reductions in electric purchases associated with self-generation, demand-side management, or other similar demand reductions.

The Stranded Cost Working Group has generally agreed that all customers should pay stranded costs, including Standard Offer customers. These are customers who elect to remain with the incumbent utility. This would represent a modification to the policy decision, since Decision No. 59943 indicates that recovery is limited to those customers who reduce or terminate service. The Commission will have to resolve on this in the future. However, since standard offer customers already have stranded costs built into their rates, such a change would not require the imposition of an additional rate element for recovery of stranded costs for those customers.

The working group has shown a preference for imposing a recovery mechanism that would be based upon a non-by passable kW/kWh wires charge, with an exit fee option. A lump sum payment amount option to exit the system was overwhelmingly supported. The group agreed that the recovery period should be as short as possible (between 3 and 7 years, depending upon the magnitude of stranded costs). Whatever the cost period, the group agrees that it should be fixed and known prior to its imposition, and it should have a defined termination date.

Co-ops are treated the same as investor-owned utilities with regards to stranded costs with one exception. Co-ops may request a modification of the competitive phase-in schedule as described in the rules in order to protect their tax-exempt status. This is necessary in some instances so that the co-ops will have the time necessary to modify the contractual arrangements pertaining to the delivery of power supplies and associated loans. The ACC makes its determination based on cost/benefit analysis. In regards to stranded cost recovery, municipal utilities would be treated the same as investor-owned if they choose to compete.

## CUSTOMER ISSUES

Each utility will make available Standard Offer bundled generation, transmission, ancillary, distribution, and other necessary services at regulated rates until substantial competition has been implemented. When stranded costs pertaining to a particular class have been recovered, then bundled generation can be discontinued through official Commission action. Utilities can request the ACC to make a determination of the existence of substantial competition.

## MARKET POWER

The ACC will require a number of remedies to address concerns about market power. The ISO appears to be the principle proposed solution. Divestiture is not being proposed, nor has it been advocated by the working group.

### Unbundling

Per ACC rule, unbundled service tariffs must be filed with the ACC no later than December 31, 1997 to provide the following services to all eligible purchasers on a nondiscriminatory basis:

- Distribution
- Metering and meter reading services
- Billing and collection services
- Open access transmission service (as approved by FERC, if applicable)
- Ancillary services in accordance with FERC Order 888.
- Information services such as customer information to other Electric Service Providers.
- Other ancillary services as needed for safe and reliable system operation.

On May 9, 1997, the Unbundled Services and Standard Offer Working Group met to discuss key issues. The group identified and classified 52 issues into the following categories: Standard Offer Service, Unbundled Services, System Benefits Charge, Measurement/Cost Issues, Solar Portfolio Standard, Customer Requirements, and Administrative Requirements.

**Independent System Operator**

According to Decision No. 59943, the ACC will conduct an inquiry into and support development of an independent system operator (ISO) for the transmission system. Also, the ACC may work with other entities to help establish an independent system operator.

An ISO named Desert STAR is currently being established in the Southwest, the purpose of which would be to provide reliable and nondiscriminatory open-access. Its full name is Desert Southwest Transmission and Reliability Operator. Desert STAR participants includes nine utilities from Arizona, New Mexico, Nevada, and West Texas. It was created via a memorandum of understanding between the utilities. Five public meetings were held in the various states during April, 1997. Four working groups are now coordinating a series of meetings with the goal of completing a feasibility study no later than September 30, 1997. Many questions remain unanswered, as this new structure is in its infancy. The four working groups include: (1) Governance and Regulatory Affairs; (2) Planning; (3) Operations and Implementation; and (4) Pricing and Tariff. The Governance Working Group has not established whether this entity will be for-profit or not-for-profit. Neither has it determined how board members will be selected, but it has established three straw men proposals for governance structure. The Pricing and Tariff Working Group has established some pricing criteria. The ACC staff is participating in the Desert STAR meetings. The internet website address for Desert STAR is WWW.swrta.org.

**Spot Market**

Decision No. 59943 establishes that the ACC will conduct an inquiry into spot market development and that it may support the development of a spot market or work with other entities to establish one. The ACC has not pursued issues regarding spot market development to date.

## PUBLIC PURPOSE PROGRAMS

Each utility will file for ACC review non-bypassable rates or related mechanisms to recover the applicable pro-rata costs of system benefits. The system benefit charge (SBC) will be charged to all consumers who participate in the competitive market. In addition, the utility may file for a change in the SBC at any time. The amount collected annually through the SBC will be sufficient to fund the existing ACC-approved low income, demand side management, environmental, renewables, and nuclear power plant decommissioning programs. Each utility must provide adequate supporting documentation for its proposed SBC and after administrative hearings and approval may recover such charges.

The Unbundling Services and Standard Offer Working Group met in June 1997 in an open meeting and discussed at length various issues related to the SBC. They reviewed the components which may be included in the SBC, but they made no final determination. They discussed the difficulty of establishing funding for all current system benefits while also maintaining or reducing current rates. At the July 1997 Working Group meeting, the consensus was reached that nuclear decommissioning costs will be included with the SBC.

### Solar Portfolio Standard

In an effort to promote renewables, the ACC ordered that Electric Service Providers (ESPs) selling electricity in Arizona must derive at least one half of one percent of the total retail energy sold competitively from new solar resources either generated or purchased. Solar resources include photovoltaic resources and solar thermal resources that generate electricity. New solar resources are those installed on or after January 1, 1997. This amount increases to one percent by January 1, 2002, unless the ACC changes this percentage based upon the costs of producing solar electricity, the costs of fossil fuel for conventional power plants, or similar factors. Any ESP will be able to credit twice the photovoltaic based or solar thermal based electric energy it generated, or caused to be generated under contract, before January 1, 1999 to the electric energy requirements of the ACC rule, for all such generation resource the ESP installed on or after January 1, 1997 in Arizona.

If an Electric Service Provider selling electricity fails to meet these requirements in any year, the ACC may impose a penalty on that provider up to 30 cents per kWh for deficiencies in the provision of solar energy. In addition, if the provision of solar energy is consistently deficient, the ACC may void any customer contracts negotiated under this Article. Photovoltaic or solar thermal resources that are located on the consumer's premises will count toward the solar portfolio standard applicable to the current Electric Service Provider serving that consumer. The solar portfolio standard described in this section is in addition to renewable resource goals for Affected Utilities established in Decision No. 58643.

The Solar Portfolio Subcommittee of the Unbundling Services Working Group met in July and considered a variety of issues, including which solar thermal resources may be used to satisfy the solar requirements of Decision No. 59943. No official action on these issues has yet been taken.

## RELIABILITY

### Operational

Currently, reliability of Arizona's electric system is achieved via reliability and coordinating councils (including the North American Reliability Council (NERC), the Western System Reliability Council (WSRC)), and neighboring utilities within Arizona and adjacent states. It is a system based on voluntary adherence to national, regional, and local industry standards and guidelines for interconnected system operation. However, as industry restructuring looms, the WSRC is currently in the process of developing procedures to ensure mandatory compliance with established criteria.

The ACC order requires each Electric Service Provider to be responsible for meeting applicable reliability standards. Each such company must work cooperatively with other companies with whom it has interconnections.

In its Decision No. 59869, the ACC established a working group to monitor and review system reliability and safety. Members of the working group include representatives of Staff, consumers, the Residential Utility Consumer Office, utilities, other Electric Service Providers and organizations promoting energy efficiency. In addition, the Executive and Legislative Branches are invited to send representatives to be members of the working group.

The Interim Report of the Electric System Reliability and Safety Working Group (issued 12/96), recommended 31 planning, operational, and administrative activities to be conducted by utilities to ensure system reliability in a competitive environment. For each such activity, two questions must be answered: (1) who is responsible for providing reliability-related services and (2) how are firms that provide such services appropriately compensated? The working group's objective for its November 15, 1997 report is to answer these questions and to develop a reliability rule or set of regulations necessary for reliability. The regulations will assign responsibility, ensure compensation, and provide for enforcement. These rules may be Arizona specific or they may simply defer authority to the WSCC or NERC.

In November 1996, Commissioner Renz Jennings stated in a discussion with a congressional committee that the WSCC or the FERC should undertake enforcement of reliability standards. Meanwhile, he believes the ACC's role regarding reliability includes working as a solutions broker for the various parties, since the parties sometimes have conflicting objectives. He stated that state and federal regulators can help develop a balance between system reliability obligations of non-WSCC members without allowing WSCC members to inhibit the transition to competition under the guise of reliability.

**Planning of Future Plant and Transmission Lines**

This issue will be addressed by the Electric System Reliability and Safety Working Group as part of the report due November 15, 1997 addressing 31 reliability-related activities (see "Reliability" section above).

The impact of the new rule upon planning reliability indicators is not known at this time. Currently, Arizona utilities operating reserve requirements are based on the greater of either seven percent of load (five percent if load is served by hydro) or the largest single hazard. The lost resource must be replaced within 10 minutes and the required operating reserve reestablished within 60 minutes.

An interim report is due on November 15, 1997 from the Electric System Reliability and Safety Working Group to the Commission which may address the issue of reliability indicators. This report will establish a proposed reliability "rule", which will assign responsibility, ensure compensation, and provide enforcement. The rules may be Arizona-specific or it may defer authority to the Western Systems Coordinating Council (WSCC) or the North American Reliability Council (NERC). The report will also define the potential impact of competition on 31 different reliability activities identified by the working group in November 1996.

## RECIPROCITY

The ACC is requiring intrastate reciprocity. The service territories of Arizona electric utilities not subject to the jurisdiction of the ACC may not be open to competition. Therefore, these non-jurisdictional utilities will not be able to compete for sales in the service territories of the subject utilities. However, if an Arizona electric utility not subject to the ACC submits to the ACC a statement that it voluntarily opens its service territory for competing sellers, along with the utilities Standard Offer Tariff and all documents as required of subject utilities per the rules adopted by the ACC, that utility may also compete for sales outside of its territory. This assumes that the utility obtains an appropriate certificate of convenience and necessity, agrees to abide by all applicable laws, and has entered into an intergovernmental agreement with the Commission.

No official policy has been adopted regarding inter-state reciprocity.

## TAX ISSUES

The Accounting, Tax, and Finance Committee of the Stranded Cost Working Group identified several key tax issues at its July 15, 1997 meeting. Primary among these was the effect of stranded investment quantification and recovery mechanisms on existing tax normalization rules in the Internal Revenue Code and IRS regulations. Another key issue is the effect of deregulating generation upon the existing definition of "public utility property" in the Internal Revenue Code. No estimates of the likely tax ramifications have been developed at this time.

The gas and electric utilities and Salt River project comprise 16% of the total property tax base in Arizona. According to the Arizona Department of Revenue, these utilities pay an estimated $400 million in property taxes to the various taxing jurisdictions. Rapid erosion of this tax base will occur if utilities are allowed accelerated depreciation. Similar erosion will take place if a lower cost basis is established for existing investment or if plant is taken out of service due to obsolescence. The working group believes that state and local governments should be made aware of these impacts.

Another obvious area of tax impact is the reduction in tax revenue associated with electricity price decreases. There is much debate over this issue, since some argue that much of consumers utility savings would be spent on other good and services, which are also taxed and would therefore offset any utility tax reductions.

# CALIFORNIA

## BACKGROUND

California utilities served an electric energy market in 1995 worth over $21 billion and requiring 212,000 gigawatt-hours of electricity. Investor-owned utilities served slightly more than 80% of this load and municipals served almost all of the remaining 20 percent. Market segments in terms of percent of load consumed are 38% residential, 40% commercial, 20% industrial, and about 2% other. California rates are among the highest in the nation. Average revenue per kWh for all classes of customer for 1995 was 9.9 ¢. Individual class revenue per kWh was 11.61¢ for residential customers, 10.49¢ for commercial customers, and 7.37¢ for industrial customers.

The political pressure for restructuring has come mainly from the large industrial customers. These customers believe restructuring will significantly lower their rates. While California has high residential rates relative to other states, the average residential bill in California is relatively low due to the fact that coastal California, site of the state's large population centers, has temperate winters and summers.

Additionally, with the anticipated termination of above market QF contracts many proponents believe this is an opportune time to introduce competitive market forces into the California power market. Anticipation of this favorable circumstance and the opportunity it represents to deal creatively with electric industry deregulation challenges, especially stranded costs, has motivated many interested parties to become advocates of industry deregulation.

The California Public Utilities Commission has been involved in electric restructuring efforts as far back as 1993 when it issued its first strategies for restructuring. The California Legislature became involved in 1996 and adopted most of the CPUC's plan for restructuring, known as the "Preferred Policy Decision," but made some notable changes to the basic blueprint. The result was a restructuring bill known as *AB 1890,* which was signed into law in September 1996. *AB 1890* is now in its implementation phase, and the CPUC is currently devoting substantial staff resources from its Energy Division and Legal Division to achieve the legislative objectives enumerated in the law. *AB 1890* directed the CPUC to make retail access available by January 1, 1998 for all customers.

The CPUC adopted a collaborative approach to implementing the requirements of *AB 1890.* In Decision No. 96-03-22 (the Roadmap), the CPUC indicated its preference for interested parties to negotiate the necessary changes to achieve a restructured electric market. These groups represent a broad cross section of interests and objectives, and their role was to assist the Commission in the procedural implementation of the Policy Decision. The Roadmap also identifies the process required to gain recognition as a working group. A working group is initiated via a proposal letter to the assigned coordinating commissioner from a proposed group of participants. The letter identifies the scope of the issues to be addressed by the group. The Roadmap identifies several key areas that require working groups, including direct access, consumer protection, public purpose programs, and unbundling. The direction taken by each of the working groups is determined primarily by the stakeholders (consumers, business entities) rather than CPUC staff. Working groups can avail themselves of CPUC and California Energy Commission (CEC) staff resources, and they can request a staff facilitator if so desired.

The CPUC's staffing plan for addressing electric restructuring issues includes designation of commissioners and CPUC staff to broad subject areas. Each area has an assigned commissioner and staff team with representatives from the various CPUC divisions. The Coordinating Commissioner has overall management responsibility for electric restructure efforts of the CPUC.

Utilities were required to submit their direct access implementation plan for Commission approval by July 1, 1997. In addition, they were required to describe procedures they will use to manage direct access requests. The Commission will issue an order accepting or rejecting such plans in October 1997.

## MARKET STRUCTURE

Retail customers have two basic electricity purchase options: direct access and full service. Direct access is power purchased directly from non-utility electric service providers (ESPs). ESPs can be suppliers, aggregators, brokers, or marketers. Direct access will commence simultaneously with the start of the Independent System Operator (ISO) and the Power Exchange (PX). The ISO and PX are mandated to begin operation not later than January 1, 1998. Remaining full service customers will receive energy from the PX, which itself purchases the energy on a wholesale basis from the utilities. Thus, California has fashioned a dual arrangement that allows for a "poolco" method and a "direct access" method of retail energy purchases.

In order to participate in a direct access transaction, those customers with a maximum demand equal to or greater than 20 KW must have hourly billing meters. Customers with maximum loads smaller than 20 KW may participate in direct access through installation of a meter at their own cost, or they may request statistical load profiling. Load profiling is a method of estimating a class of customers' hourly consumption over a given period of time. It is anticipated that load profiling will facilitate aggregation of small- to medium-size customers *who do not have hourly billing meters.*

Full service customers who have time-of-use (TOU) meters may participate in the hourly rate option, wherein they purchase energy from the PX at the hourly market price. This is known as virtual direct access. If they do not have a TOU meter, full-service customers cannot choose the hourly rate option.

Decision 97-05-040 (Direct Access Second Interim Opinion) mandated direct access availability to all customers of California's investor-owned electric companies on January 1, 1998, regardless of customer class or size of load. Access will be made available on a first-come, first-served basis. *Utilities* will begin accepting direct access requests on November 1, 1997.

If a 30-day backlog of unprocessed direct access requests occurs, the affected utility must notify the Commission immediately and then file within 5 days a backlog reduction plan designed to eliminate the backlog within 90 days.

During the first 12 months of operation, the ISO governing board, with the approval of the Oversight Board, has the authority to declare an "emergency" wherein a 10-day moratorium on processing of requests for direct access is granted. The moratorium can be extended by a ruling of the President of the Commission.

That portion of the regulated IOU operations associated with distribution will be known as the Utility Distribution Companies (UDCs). Distribution companies will provide regulated distribution service to all customers, both full service and direct access. They are required to provide nondiscriminatory distribution service to all customers in their respective service territories. During the transition period, the UDCs must bid all of their generation into the PX, and they must purchase power on behalf of their customers from the PX. UDCs are responsible for service connection and disconnection. The Commission will continue to regulate the terms, rates, and conditions of the distribution and electric services provided by the UDCs, using Performance Based Ratemaking (PBR). Customers who do not initiate the process to change energy providers will presume to be UDC power customers.

### Unbundling

The vertically-integrated IOUs are required to functionally unbundle generation, distribution, and transmission. The market will set the price for generation through the Power Exchange and direct access contracts; FERC will set the rates for transmission; and the CPUC will set rates for distribution services. CPUC Decision 96-10-074 directed the IOUs to separate their last authorized revenue requirements and rate base into generation, distribution, and transmission consistent with the anticipated FERC order on transmission revenue requirements. The IOU's unbundling applications were filed on December 6, 1996, including separation of the various rate components. On March 31, 1997, the ISO and PX trustee filed tariffs and other documents necessary to create the ISO and PX by January 1, 1998. The IOUs submitted proposals for their respective transmission revenue requirements at the FERC concurrently.

## STRANDED COSTS

The CPUC defines stranded costs as costs associated with generation facilities, generation-related regulatory assets, nuclear settlements, and purchase power contracts that were being collected in commission-approved rates on December 20, 1995 that may become uneconomic due to the advent of a competitive generation market. Uneconomic capital costs are those occurring when the market value at the time of divestiture, spin off, or appraisal was less than the net book value of the asset. For ongoing costs, uneconomic costs are those greater than the clearing price provided by the Power Exchange. Stranded costs also include the reasonable capital costs of early retirement and employee retraining programs associated with electric restructuring. The total amount of stranded costs is the subject of considerable disagreement and has not yet been determined.

**Calculation of Stranded Costs**

Stranded costs are calculated based on a mechanism that nets the negative value of all above market utility-owned generation-related assets against the positive value of all below market utility-owned generation-related assets. For utility-owned fossil generation capital investment, recovery of uneconomic costs is established as of January 1, 1998. Recovery of capital additions incurred after December 20, 1995, if necessary to maintain such investments through 2001, will be allowed. A "firewall" will be established between residential/small commercial classes and all other classes to prevent cost shifting between small and large customers. The basis of the stranded cost estimates will be adjusted each year through March 31, 2002 depending upon the true-up amount of transition costs and the agreed-upon market rate. The auditing and consulting firm of Mitchell & Titus, LLP has estimated sunk costs for this purpose. Additionally, the parties to the Stranded Cost Work Group have stipulated to a 1998 market price of 2.4¢.

**Recovery of Stranded Costs**

Stranded costs will be recovered through a non-bypassable competitive transition charge (CTC). Such costs will be applied on a per kWh basis, and the majority of these costs will be amortized over a four year period starting January 1, 1998 (the transition period). The CTC is "non-bypassable" since it applies to full service, direct access, and departing load customers.

The rate freeze imposed according to *AB 1890* is linked to the transition cost recovery. If generation-related uneconomic costs are recovered prior to December 31, 2001, the rate freeze will end.

Recovery will not extend beyond December 31, 2001, except for employee-related transition costs (extension of recovery for such costs through 2006), power purchase contracts (governed by the contract or buyout/buydown agreement), Biennial Resource Plan Update (80% of uncollected costs by the end of 2001 is eligible for recovery no later than March 31, 2002), and the San Onofre nuclear generating station (recovery allowed through 2003). Utilities are already accruing funds which are being credited to the CTC revenue account.

According to the Proposed Decision of Administrative Law Judge Malcolm (Agenda 8/1/97), the CTC is a charge that is set residually, on an hourly basis, after calculating all other costs. The CTC is the difference between the frozen rates (equal to the June, 1996 rate levels) and the PX price (generation), the distribution rate, the public purpose program surcharge, and the nuclear decommissioning surcharge. The differential is known as "headroom". Since the PX price is the only variable rate other than the CTC, the CTC varies inversely with the PX price.

The problem with this arrangement is that customers' total rate is equal to the frozen rate, regardless of the level of the PX rate. This pricing scheme has the unintended effect of masking important price signals, thereby creating system inefficiencies. For example, there is no customer incentive to load shift in order to get a lower PX rate if any gain which would be derived from that action were erased by an increase in the CTC. Likewise, there is no incentive to shop for a low-cost ESP. This price-masking effect is true for both direct access and full service customers. They both receive the same total rate, which is the frozen rate.

*AB 1890* requires the concurrent implementation of incongruous elements of restructure; rates are to be capped at the June 1996 levels, stranded cost recovery is required on a non-bypassable basis, and the direct access option is required to be available by January 1, 1998. Residual CTC may ultimately have the effect of restricting the demand for direct access during the transition period.

Commissioner P. Gregory Conlon provided an alternate order to ALJ Malcolm's proposed decision. In his proposed order, utilities would derive an averaged CTC residually by ex-post averaging of energy and other non-CTC functional rate components that vary over time. Thus, the CTC would be the same for all customers, whether they are full service, direct access, or departing load customers. This would basically ensure that there would be an incentive for customers to choose direct access; that is, they could take advantage of lower energy rates without concern that the imposition of a residual CTC would leave them no better off.

In Decision No. 97-08-056 approved August 1, 1997, the CPUC adopted the method of ex-post averaging as proposed by Commissioner Conlon.

**Securitization**

The IOUs can finance the CTC by applying concurrently for financing orders from the CPUC and for rate reduction bonds from the California Infrastructure and Economic Development Bank. The IOUs made their filings in May, 1997. The proposed bonds to be sold by the bank amount to $3.5 billion for PG&E, $3.0 billion for Southern California Edison, and $0.8 billion for San Diego Gas & Electric. In general, the utilities use of the funds will be to reduce capitalization. The decisions regarding these requested amounts were issued on September 3, 1997. The mandatory 10 percent rate reduction, credited to residential and small commercial customers' CTC charges, will be financed by the proceeds of these bonds. The interest and principal of the bonds will be paid via a fixed transition charge assessed to customers over a 10 year period.

### Public Power Utilities' Stranded Costs

*AB 1890* encourages publicly owned electric utilities to participate in electric restructuring by committing control of their transmission facilities to the ISO (Chapter 2.3.330.m). The bill directs public utilities to determine whether they will provide direct access, subject to non-bypassable transition charges. Collection of stranded costs are contingent upon transfer of transmission control to the ISO, in-state reciprocity, collection of a public goods charge, and allowing customers direct access to alternative providers. At this point, some of the public utilities are planning to fully participate in the restructure by January 1, 1998. In fact, the Sacramento Municipal Utility District (SMUD) plans to allow customers within its service territory to choose their electricity supplier even in advance of the *AB 1890* start date.

The CPUC does not have authority to regulate municipal utilities. However, the decisions made by the CPUC which influence the IOUs may, in many instances, be duplicated by the municipalities.

In order to prevent avoidance of stranded cost recovery, *AB 1890* mandated that the obligation to pay the competitive transition charges cannot be avoided by the formation of a publicly owned electrical corporation on or after December 20, 1995. Neither can the transition charge be avoided by annexation of any portion of an electrical corporation's service area by an existing local publicly owned utility.

## CUSTOMER ISSUES

### Aggregation

Aggregation of customer electrical load for direct access, via private market aggregators, cities, counties, etc., will be authorized by the CPUC for all customer classes. Each residential customer must do so by positive written declaration. This can be accomplished through third-party telephone verification for commercial customers. Public agencies acting as community aggregators must offer aggregation service to all residential customers in its jurisdiction.

### Billing and Metering

Per *AB 1890* (Section 392c.1), the IOUs are required to disclose each component of customers' electric bills. Each customer bill will have the following rate elements, or charges: energy (generation), distribution, transmission (ISO), public benefits, and the competitive transition charge (CTC). The utilities will reflect the mandatory ten percent rate reduction for residential and small commercial class customers, a requirement of *AB*

*1890*, as a decrease in the competitive transition charge. This ten percent rate reduction is actually a ten percent reduction in the average bill compared to average bills incurred as of June 1996 for each of these rate classes.

Per Decision 97-05-039 (Unbundling of Revenue Cycle Services), competing retail energy service companies may provide billing and related services for all customers and metering systems for their largest customers beginning January 1, 1998. Such firms may provide metering systems for small customers (less than 20 kW) beginning January 1, 1999. This one year delay was determined to be necessary in order to give the industry the opportunity for the development of standards for open architecture and the selection of appropriate technologies. Allowing entities other than the utility to provide metering services will promote competition and efficiency. The energy service providers must enter into a service agreement with the utility regarding the nature of the information collected, the means for sharing the data, and the method for ensuring that the metering equipment is installed, calibrated, and maintained properly.

Both billing and metering are now incorporated in the distribution charge. In Decision 97-05-039, the CPUC voted to require the three IOUs to provide retail energy service companies with three billing options: consolidated energy supplier billing, consolidated distribution company billing, and dual billing. A retail energy service company utilizing consolidated energy supplier billing is responsible for paying the distribution company's charges, even if the customer is delinquent or fails to pay. The goal is to itemize bills for all types of electric services.

No later than November 3, 1997, the IOUs will file cost studies and supporting testimony that separately identifies the net cost savings resulting when billing, metering, and related services are provided by another entity.

The CPUC considered allowing utilities to pursue automated meter reading since there are certain economies of scale associated with such service and since it may hasten customer adoption of real time pricing. However, in order to protect the development of a competitive market, the CPUC declined PG&E's request to pass on the increased costs of such technology to ratepayers (Decision 97-05-039). The CPUC's decision to initiate competitive opportunities for meter reading may be an indication that certain portions of distribution service may become competitive concurrently with generation competition.

ESPs, UDCs, and interested parties filed Open Architecture Agreement in July, 1997, wherein participants agreed upon open architecture standards for meters and meter communications to be implemented prior to 1998.

It is anticipated by CPUC staff that ESPs will have much more interest in providing meters to commercial customers rather than residential customers, at least during the early part of the transition period.

The issue of whether utilities and electric service providers will be required to perform identification of generation fuel type or generation source on customers bills (electron disclosure) is pending at this time.

**Universal Service**

Universal service obligations continue in the future for all utilities. The utility cannot refuse electric service to a customer in their service territory without just cause (e.g. nonpayment, rules violations, etc). To promote universal service, low income assistance programs are administered by the utility, but the method by which these programs will be administered is going to change in the restructured environment (see discussion below on Public Purpose Programs). The IOUs propose to maintain their exclusive authority for electric service cut-off for reasons of nonpayment or violations. This matter is still pending.

**Customer Rates**

It is anticipated that large industrial customers of IOUs will be the primary beneficiaries of the California restructuring process. However, with the imposition of a competitive transition charge to recover stranded utility assets, it is unclear if market driven rates will provide the anticipated savings.

Residential and small commercial customers are projected to see a 20 percent cumulative rate reduction off of current electric rates by not later than April 1, 2002. However, the formula for calculating this rate reduction excludes the costs associated with rate reduction bonds and competitively-procured electricity, so the actual rate reductions may be significantly less than 20 percent.

During the transition period (1998 through March 31, 2002), a rate freeze is in effect, with rates frozen at the June 10, 1996 level. Moreover, a mandatory 10 percent rate reduction is required for residential and small commercial service, per *AB 1890*, and will be credited on customer bills as an offset to the competitive transition charge. However, this credit amount will be paid from the proceeds of the rate reduction bond issue so that the full revenue reduction amount will still be credited to stranded cost recovery.

These rate levels will remain in effect until the earlier of March 31, 2002, or the date on which commission authorized uneconomic costs have been fully recovered. The only rates which may fluctuate within the limits prescribed above is the PX energy charges, subject to market based rates, and the CTC charge, which will be periodically adjusted to reflect updated estimates of stranded costs.

Individual rate components for energy, transmission, distribution, public benefit programs, and recovery of uneconomic costs will be included in the cost recovery plan. Customers of bundled and unbundled services will pay the same price for each component, with the exception of energy. Cost shifting among customer classes, rate schedules, and contracts is prohibited.

Both the generation and distribution components of the utilities regulated operations will be subject to Performance Based Ratemaking (PBR) rather than cost of service ratemaking during the transition period.

**Consumer Education Program (CEP)**

*AB 1890* mandates that all IOUs, in conjunction with the CPUC, devise and implement a customer education program. The purpose of the program will be to inform customers of the changes to the electric industry and to provide them with the information and resources necessary to help them make appropriate choices regarding electric service. The utilities are authorized by the CPUC to form a stakeholder group called the Electric Restructuring Education Group (EREG). The EREG is composed of 19 individuals representing widely diverse stakeholder groups. Their meetings are required to be open to the public. The EREG's role is to devise and implement the IOUs' joint CEP, with the assistant of a consultant, subject to the approval of the CPUC. The EREG is designed to exist for a limited period of time (from 9/1/97 through 5/31/98), after which all educational efforts will be taken over by the Electric Education Trust (EET).

The EET was proposed by the CPUC to ensure independent multi-cultural education, advocacy, and research for small business and residential customers. The EET will promote customer education regarding the advantages of direct access, and it will be targeted to those customer groups and communities where direct access participation is low. It will be administered by a 5 member committee comprised of representatives of consumer groups, the CPUC Consumer Division, and the utilities. The administrative committee has filed a work plan and the plan must be acted upon by the CPUC no later than October 1, 1997. The EET will conclude its work by June 1999 unless extended by the CPUC or by statute.

The total initial funding established for CEP efforts is $20 million. Utilities are allowed to recover their verified costs. The total initial funding for the EET is $3 million.

**MARKET POWER**

It is the CPUC's position that market power is the most critical issue facing electric industry restructuring and must be closely monitored during the transition. In doing so, the CPUC will not attempt to establish benchmarks for the purposes of determining when effective competition is achieved in the generation market. The CPUC believes that the formation of an ISO and power exchange will be critical to addressing market power concerns. However, many other aspects of the overall restructure plan address market power, including unbundling, divestiture, must take/must sell requirements, and direct access. Market power mitigation strategies comprised a large portion of the utilities' Phase II Filings submitted to the FERC on March 31, 1997 (Phase II is considered the implementation phase of California's restructure plan). The CPUC issued its comments regarding the Phase II Filings in June 1997 and the FERC will issue its decision regarding Phase II in the latter half of 1997. The mitigation of market power via these strategies are discussed below.

**Independent System Operator (ISO)**

The ISO functions as the "air traffic controller" of the electric grid. It takes on a myriad of duties in its role as the responsible agent for grid safety, dispatch, and reliability. Per *AB 1890,* the ISO will ensure efficient use and reliable operation of the transmission grid consistent with the planning and operating reserve criteria no less stringent than those established by the Western Systems Coordinating Council (WSCC) and the North American Reliability Council (NERC).

One of the ISO's duties is to ensure that sufficient ancillary services have been committed and are available for dispatch. The ISO must allocate these ancillary services to specified scheduling coordinators, including the PX, according to rules contained in the ISO Tariff filed with the FERC. The rates which may be charged for ancillary services are determined by the FERC. The CPUC has recommended that the utilities be allowed to charge no more than their cost of service rate for ancillary services. This is one example of how the CPUC and the FERC are coordinating efforts to mitigate market power and establish a workable ISO.

The ISO is controlled by a governing board. The ISO board was formed via the action of the Oversight Board. It has a majority of members who are unaffiliated with electric generation, transmission, or distribution corporations.

The CPUC proposed the establishment of the ISO in order to ensure that the owners of transmission cannot favor their own generation facilities over those of other utilities and non-utility generators by restricting transmission access. While the utilities will continue to own the transmission facilities, control of the facilities are scheduled to be turned over to the ISO by January 1, 1998. Both publicly owned and investor-owned utilities will commit control of their transmission facilities to the system operator. Publicly owned utilities will jointly propose a pricing methodology to the FERC that will result in an equitable return on investment in transmission facilities.

The ISO has adopted inspection, maintenance, repair, and replacement standards for the transmission facilities under its control. It has also adopted reliability and safety standards during periods of emergency or disaster. Annual compliance reports regarding all such standards are mandatory for all transmission facility owners. The CPUC will conduct a review to determine whether the standards have been met. If the standards have not been met, the Commission may order appropriate sanctions, including rate reductions and fines. In this regard, the CPUC will function as the enforcement arm of the ISO.

Within 6 months of approval of the ISO by the FERC, the ISO will provide a report to the legislature which will, among other things, recommend cost-beneficial improvements to electric system reliability.

In the event of a major outage that affects at least 10 percent of the customers of the entity providing local distribution service, the ISO will perform a review of the outage, especially the response time and effectiveness. If the ISO finds that the transmission facility owner or operator was responsible for the outage or prolonged the response time, the ISO may order appropriate sanctions (this authority is pending FERC approval).

Two public interest groups filed a federal legal protest against the proposed structure of the ISO and the PX on June 6, 1997. Towards Utility Rate Normalization (TURN) and Utility Consumers Action Network (UCAN) claim the ISO and PX boards lack adequate representation of consumer groups.

The CPUC recommended in its comments to the FERC that the FERC review the composition of the ISO and PX boards during the Mid-Course Review proceeding. Specifically, within three years of the start of operations, if any party or the CPUC notifies the FERC of market structure problems resulting from board composition, the CPUC recommends that the FERC initiate such a review.

While the CPUC stated that it generally supports the utilities ISO and PX filings, it recommends that the utilities augment their filings to include much more detail regarding the type and quantity of transmission capacity available to the ISO as a result of the proposed treatment of existing contracts. The ISO tariff does not adequately describe how the ISO will deal operationally with the each Company's dispatch priority for their existing contracts.

**Power Exchange (PX)**

According to *AB 1890*, "The Power Exchange will provide an efficient competitive auction, open on a nondiscriminatory basis to all suppliers, that meets the loads of all exchange customers at efficient prices." The PX is designed to be a spot market power pool for the wholesale of electricity, with hourly prices published and publicly available. Thus, in conjunction with the ISO, power deliveries will be scheduled by the ISO, available to the customer either from the PX (pool market) or from independent bilateral contracts (direct access sales). The market is to include transparent rules for power marketers and suppliers bidding into the exchange. These bids will be matched with purchase requests from utilities, marketers, and brokers. Least cost bids will be ranked according to established protocols. These protocols include provisions for unit commitment in the day-ahead schedule and for payment of minimum load not covered through market clearing prices for energy.

Participation in the PX is mandatory only for California IOUs. From 1998 through 2002, the IOUs must sell all the power necessary to meet the needs of their full service customers into the PX, and they must purchase the energy from the PX to satisfy their full service customers. After their service territories evolve from captive to open markets, they will be permitted to compete directly with neighboring public and private utilities and other power producers and providers.

The CPUC believes that the ISO and the PX should operate independently, as described in *AB 1890*. The California Energy Commission believes that any separation of these two entities is artificial and unnecessary. At the heart of this debate are the issues of market power and reliability. The need for intensive, real-time communication between the two entities in order to ensure grid reliability is undisputable, yet the potential for utilities to gain competitive advantage by gaming the system is a real concern. Ostensibly, the ISO and PX are currently administered as separate organizations, but it is not clear how these organizations will evolve as the deadline for ISO and PX operations approaches.

The CPUC admits that many technical hurdles remain in order for the ISO and the PX to become operational on January 1, 1998. Some of these technical issues are of great urgency and must be resolved prior to the start date. The CPUC has requested that the FERC set a series of technical/settlement conferences to address some of these concerns. In addition, the CPUC also recommends that the FERC conduct a Mid-Course Review three years after the start-up of the transition period in order to address market power and operational concerns.

**Divestiture**

The CPUC concluded that IOUs' voluntary divestiture of 50 percent of their gas-fired generation is consistent with *AB 1890*. As an incentive to promote divestiture, the policy to allow a utility an increase in the rate of return on equity of up to 10 percent of fossil generating capacity divested was established in the Preferred Policy Decision (Roadmap II).

PG&E has proposed divesting four fossil plants (3,074 MW, or 53% of PG&E's total fossil generation). SCE has proposed divesting twelve fossil plants (10,294 MW, or nearly 100% of its in-state fossil plant generation). Both IOUs will divest via auction. SDG&E is not yet required to divest.

**Must-Run Agreements**

The generation associated with California's "Must-Run" and "Must Take" Plants, as designated in the Phase 1 Filings, is so large that only a portion of California's electricity market is available for competitive PX power. The ISO will soon weigh-in on this issue, so that the amount of generation designated as "must-run" may be considerably reduced.

"Must Run" plants are those that must continue to operate in order to ensure system integrity; therefore, they cannot be easily cycled to match market conditions. These plants are mostly fossil plants, but also include nuclear units, purchased power contracts, and existing inter-utility contracts. "Must take" plants are facilities subject to existing contractual arrangements that preclude their dispatch in accordance with costs in a competitive environment. "Must Run" and "Must Take" plants were designated by the CPUC Policy Decision. The utilities' proposed must-run and must-take resources exceed SCE's minimum load more than 50% of the time. Load analysis reveals that, under average conditions, the PX market will be less than 1000 MW for Southern California Edison ( SCE), which represents only 14% of SCE's demand. Pacific Gas & Electric (PG&E) results are similar. If the utilities' proposed list of must run/must take requirements were to be recognized by the ISO, the competitive PX market would be quite small, at least during the transition period.

In its initial comments regarding market power issues, the CPUC expressed concern over the utilities' self-designation of large amounts of the fossil generation as "must-run." The CPUC recommended that the ISO determine which "must-run" services are required for system reliability, and that the ISO should be free to contract for reliability services with any source. In its December 18, 1996 order, the FERC agreed. The ISO is in the process of carrying out a technical study to identify which generating units it will require to be the subject of Reliability Must-Run Contracts. These contracts are far superior to the utilities' proposals in the Phase 1 Filings in mitigating locational market power.

**Utility Affiliates Guidelines**

The relationship between a utility and its affiliates requires certain safeguards in order to limit the market power of the UDC. Substantial provisions have been approved that will reduce the UDC's market power, including the creation of the ISO and PX, prohibition of UDC from entering into contracts to purchase power from its affiliates, and the buy-sell mandate. However, the concern remains that, despite these constructs, the UDC can use its market power in the distribution market to frustrate competition in the retail market. For instance, funds from the regulated affiliate could possibly be used to subsidize the unregulated affiliate. In order to prevent such problems, the Commission can impose conditions or regulations to ensure that the transactions between the affiliated marketer and the utility remain at arm's length. An abbreviated list of affiliate transaction guidelines, adopted by the CPUC in Decision 97-05-040 (Second Interim Opinion re: Direct Access), include:

1. No shared employees, expenses, or assets will exist between the UDC and its unregulated affiliates other than costs billed back by the holding company in compliance with existing affiliate transaction requirements.

2. Transactions between affiliate and the UDC are limited to generally available tariff items.

3. The UDC will not discriminate in favor of the affiliate in processing requests for direct access.

4. Customer information will be made available only with customer consent and under the same terms and conditions to affiliates and non-affiliates.

5. The affiliate will maintain its own book of accounts and have separate offices, personnel, equipment, etc.

6. Joint marketing is prohibited.

7. The UDC will not promote its affiliate.

A round of comments and reply comments by the IOUs and interested parties have been filed with the CPUC. A hearing regarding detailed implementation of these guidelines may be scheduled during the last quarter of 1997.

**Electric Service Providers: Registration and Rules**

Non-utility electric service providers (ESPs), which includes aggregators, marketers, brokers, are required by *AB 1890* to register with the CPUC if they intend to serve residential or small commercial customers. The CPUC has already established required registration information. ESPs may submit their registration forms to the Energy Division as early as July 1, 1997.

The CPUC is in the process of establishing market rules. The Commission may revoke the registration number of any registrant that fails to abide by the market rules or consumer protection rules adopted by the CPUC in the Direct Access Proceeding. Criminal and civil penalties will be brought by the Commission for serious infractions. In particular, warnings by the CPUC are being issued against the practice of "slamming". The CPUC may issue a code of conduct applying to ESPs in the future.

Each ESP must provide notice to all potential customers regarding the ESP's prices, terms, and conditions, as well as a notice describing the potential customer's right to rescind the contract. In regards to the price requirement, ESPs must identify the Competitive Transition Charge and explain the continuation of customer liability for this charge even if the customer should change providers.

## PUBLIC PURPOSE PROGRAMS

Per *AB 1890*, the CPUC will establish a non-bypassable rate component of the local distribution service called the Public Goods Charge (PGC), collected on the basis of usage, to fund public purpose programs. These programs include: (1) low-income assistance programs; (2) energy efficiency and conservation programs; (3) research, development, and demonstration programs only; (4) and existing, new, and emerging renewable resource technologies. For each of these areas of funding, *AB 1890* specifies minimum annual funding levels for the IOUs for the period of 1998-2001 (*AB 1890*, Article 7, Section 381).

The CPUC indicates that the funding for such programs should be approximately equal to current funding levels, but that the funding for renewables, set at $540 million for all the IOUs, spread over four years, is perhaps less than what would have otherwise been required. The legislature may be anticipating a future period when it will require renewables to be competitive on a cost basis with other generation sources.

**Low Income Programs**

*AB 1890* requires funding of low income programs at levels not less than 1996 levels ($106.9 million). Annual low income assistance will be allocated according to Commission determination. Such funding currently takes two forms: reduced rates of 15% provided by CARE (California Alternative Rates for Energy) and energy efficiency services. These programs will continue on into the transition period and beyond. The statute also establishes that funding will be collected by a non-bypassable rate component collected on the basis of usage. The CPUC is forming a Low Income Governing Board which will hire an administrator by January 1, 1998 and be accountable to the CPUC. The group will effectively replace the administrative function currently handled by the utilities; namely, collection and dispersal of low income funds, verifying customer eligibility, and making energy efficiency and education services available to low-income ratepayers.

Until the governing board and the new administrative entity is established, the utilities will continue to administer these programs.

**Energy Efficiency and Conservation**

Instead of continuing the energy efficiency and conservation programs through utility sponsored programs, the CPUC adopted a strategy which is designed to transform the market so that individual generation customers and suppliers will make rational energy service choices. Administration for energy efficiency will be achieved through an independent board and administrator, selected through a competitive bidding process. Rates for energy efficiency will no longer be embedded in electric rates, but will instead be identified as a line item on customer bills. This item will be a nonbypassable rate component of local distribution service. Until such time that this program is established, the utilities will continue to administer energy efficiency programs. Initial funding levels have been set by the legislature for the three IOUs. The total IOU funding for energy efficiency programs from 1998 through 2001 is $792 million. The CPUC recognizes the need to provide economic efficiency programs for both electricity and gas programs together. The Energy Division is recommending a gas surcharge mechanism, which ultimately will apply to all gas customers. Report of the Energy Efficiency Board regarding administrative structures was filed with the CPUC on July 1, 1997.

**Research, Development and Demonstration**

The legislature set funding for Research, Development and Demonstration (RD&D) at $62.5 M per year, allocated per AB 1890 between the three IOUs. Of this total amount, $61.8 M per year is allocated to the California Energy Commission for non-T&D related RD&D. The funding is available from 1998 through 2001.

## Renewables Resource Technologies

The California Energy Resources Conservation and Development Commission also known as the California Energy Commission (CEC) will receive all funding earmarked for "operation and development of existing and new and emerging renewable resource technologies". An aggregate level of funding of $540 million collected from the three IOUs is mandated by the legislature to be transferred to the CEC.

The CEC was mandated to report to the CPUC regarding the market-based mechanisms needed to allocate the available funds by March 31, 1997. *AB 1890* required each new and emerging resource technology providers and existing resource technology providers to receive a minimum of 40 percent of the funding levels prescribed in the bill. The allocation of the remaining 20 percent of funding is now being debated. Also, the CEC was charged with establishing a process for certifying eligible renewable resource providers and awarding financial incentives to the most cost-effective resource.

# RELIABILITY

## Oversight

*AB 1890* states that it is the intent of the legislature that California enter into a compact with the western region states that would require public and investor-owned utilities in those states to adhere to enforceable standards and protocols to protect reliability of the interconnected regional transmission and distribution systems. *AB 1890* confirms the CPUC's role of ensuring that the ISO conforms to Western Systems Coordinating Council (WSCC) and North American Reliability Council (NARC) criteria for planning and operating reserves. The bill also confirms the CPUC's role in ensuring that the facilities required to maintain the reliability of the system remain available and operational, consistent with maintaining open competition and avoiding an over-concentration of market power.

Additionally, reliability will be protected via the formation of a five-member Oversight Board as established per Sections 335 and 336 of *AB 1890.* The function of the board is to oversee the ISO and PX. In that regard, the board will appoint members to these entities and set terms of service. While *AB 1890* states that the board will also serve as an appeal board for ongoing majority decisions of the ISO, the FERC has held that many of the continuing functions envisioned by the bill to be preempted. The FERC sees the function of the oversight board to be one of initiating the formation of the ISO and PX.

## Transmission and Resource Planning

The ISO tariff provides that the transmission owner is obligated to build all transmission additions and upgrades within its service area. However, according to the CPUC, the transmission owners have an incentive to restrict transmission capacity in certain locations;

doing so will allow for increased profits for its own generation. Therefore, it is the CPUC's view that the ISO should be the entity authorized to assess the need for constrained area "relief" projects. This should include sponsoring projects to build, replace, or repower uneconomic must run facilities to the extent that market participants do not undertake to replace those uneconomic facilities. However, it is not certain at this time that the ISO has the authority to plan, permit, and construct transmission and generation projects. The CPUC has recommended that the FERC clarify the ISO's authority in this area.

Another issue is whether the transmission owners should have the exclusive right to engage in the construction of the planned addition. According to the ISO tariff, the transmission owner is the agent to construct needed expansion. The CPUC maintains that this limits the ISO's independence.

The ISO has authority regarding transmission standards and protocols. This authority is established by the FERC in Order 888, and confirmed in California's *AB 1890*. However, the ISO Technical Advisory Committee is vested with the authority to provide standards for operation, inspection, and maintenance per *AB 1890* (Section 347), and the composition of the Technical Advisory Committee could primarily be the transmission owner delegates. They could effectively block the revision of standards and protocols controlling the ISO's actions. Likewise, the ISO Tariff allows only the transmission owners the right to install and maintain required meters. This could limit the ISO's ability to independently operate the grid. The CPUC has advised the FERC to allow the ISO Board the authority to set any and all standards, without having to accept the ISO Technical Advisory Committee recommendations.

The ISO has authority over recovery of transmission costs. This issue was addressed within the Phase II Filings. The ISO tariff requires transference of the transmission facility recovery to the ISO. The FERC will set the revenue requirement for recovery of transmission facility costs between wholesale and retail. The CPUC will administer the recovery of the retail portion within the distribution rate element (allocation of the transmission revenue requirement among retail classes). The CPUC has worked closely with all stakeholders, attempting to draw a line between transmission and distribution facilities which will contain incentives and benefits for everyone. In addition, the CPUC has adopted an approach labeled "cooperative federalism" in its dealing with the FERC on this and related issues, wherein both agencies work to achieve common objectives.

The impact of restructuring on generation reliability indexes is not known at this time. Nor has responsibility to plan and construct new generation been assigned.

## RECIPROCITY

*AB 1890* contains no in-state reciprocity requirement for IOUs. However, the same cannot be said for municipalities. No publicly owned utility can sell power to retail customers of another publicly owned utility unless the first utility has agreed to let the second utility sell power to its customers.

No inter-state reciprocity requirements were enacted as part of *AB 1890*. In other words, each utility is required to allow sale of generation from out-of-state suppliers to retail customers in their service territory, regardless of whether the supplier accepts retail sales in its service territory from California utilities.

## TAX ISSUES

The CPUC has not addressed the tax impacts of restructuring the electricity market. It is likely, however, that municipal and cooperative power agencies, and the associated townships and customers, will experience significant tax effects.

# MAINE

## BACKGROUND

Maine is served by three investor-owned electric utilities: Central Maine Power Company (CMP), Bangor Hydro-Electric Company (BHE), and Maine Public Service Company (MPS). It is served by three cooperatives and five municipal or quasi-municipal utilities. Maine customers used some 11,500 gigawatt-hours of electricity during 1995. Thirty two percent of this power went to the residential class, 25% was commercial sales, 42% was industrial sales , and 1% was classified as "other." A large proportion of Maine's industrial load serves the paper industry. Maine generates a significant portion of its electricity from renewable sources. In 1995, wood, hydro, and municipal solid waste accounted for 47% of the state's generation. With respect to revenue per kWh generated, the state average across all customer classes was 9.49¢, relatively low by New England standards, but high by national standards. Revenue per kWh for the residential, commercial and industrial classes was 12.51¢, 10.28¢, and 6.65¢ respectively.

Maine's three IOUs have an ownership interest in Maine Yankee Atomic Power Company, which owns and operates the 920-MW Maine Yankee nuclear plant. CMP owns a 38% share, BHE owns a 7% share, and MPS owns 5%. The unit provided about 25% of the energy consumed by the state, and has been down since December 6, 1996, due to maintenance problems cited by the NRC. The unit was placed on the NRC watch list on January 29, 1997. On August 6, 1997, Maine Yankee's Board of Directors voted to permanently close Maine Yankee, after concluding that the plant could not be economically operated by its present owners. This decision followed unsuccessful attempts to sell the plant to PECO.

The prime mover of industry restructuring in Maine appears to be the high price of electricity, resulting from the current regulatory regime beginning in the late 1980s and early 1990s. These increases were caused in large part to above-market qualifying facility contract obligations and a reduction in demand for electricity due to economic recession. Because of high prices, Maine has adopted price cap regulation.

In July of 1995, the Maine Legislature directed the Maine Public Utilities Commission (MPUC) to devise a plan for the Legislature to consider which would achieve retail competition in the electricity market. The final report and plan were presented on December 31, 1996.

On May 29, 1997, the Governor signed into law L.D. 1804, "An Act to Restructure the State's Electric Industry" (the Act). It provides for full retail competition to begin on March 1, 2000. It directs the Maine Public Utilities Commission (the Commission) to conduct rulemaking on several issues that must be addressed to implement retail access. Between the fall of 1997 and the fall of 1999, the Commission will conduct 13 rulemakings on subjects such as unbundling, metering, consumer education, and renewable resources. The Commission will also conduct two adjudicatory proceedings for each utility. One proceeding will address divestiture, and the other will address stranded costs and ratemaking for transmission and distribution (T&D) companies.

## MARKET STRUCTURE

Under the provisions of the Act, all consumers of electricity will have the right to purchase generation services directly from competitive providers beginning on March 1, 2000. At that time, consumers will be allowed to aggregate their purchases in any manner they choose. If a public entity serves as aggregator, it may not require consumers within its jurisdiction to purchase from that entity.

Beginning March 1, 2002, the provision of metering and billing services will be subject to competition. The Commission is empowered to establish an earlier date for the provision of these services by rule, but the date can be no earlier than March 1, 2000.

Prior to October 1, 1999, the Commission will complete an adjudicatory proceeding to address the design of T&D rates to recover stranded costs, transmission and distribution costs, decommissioning expenses for nuclear units, and any other charge required by law.

**Large T&D companies (50,000 customers or more):** Following the beginning of retail access, large (50,000 customers or more) investor-owned T&D utilities may not sell electricity to any retail consumer. Entities affiliated with T&D utilities may, beginning with retail access, provide electricity outside the affiliated T&D service territories. In addition, they may provide electricity within the service territories provided they do not sell more than 33% of the total kilowatt hours within the territory. The need for this 33% market share limitation will be reviewed by the Commission by January 1, 2005.

The Act contains many provisions applicable to the large T&D companies that seek to insure that they do not afford any competitive advantage to affiliated electricity providers. For example, the Act prohibits joint marketing or advertising between T&D companies and their affiliates, and does not allow employees to be shared.

**Small T&D companies (less than 50,000 customers):** Small investor-owned T&D company affiliates will be allowed to sell electricity on an unrestricted basis both outside and within their service territories. By July 1, 1998 the Commission will open a rulemaking proceeding to determine the extent of separation required between small T&D companies and their affiliates. This rulemaking will be concluded no later than March 1, 1999.

The Commission is allowed by rule to limit or prohibit sales of electricity by competitive providers within the service territory of a municipal or cooperative utility if it is determined that allowing the sales would cause them to lose their tax-exempt status under state or federal law.

**<u>Municipal and Cooperative T&D Companies:</u>** Municipal and Cooperative utilities are allowed under the Act to sell retail generation service only within their respective territories. These utilities may not sell wholesale generation service except those incidental sales which are necessary to reduce the cost of retail service.

**Regulation of Competitive Providers**

To provide electricity for retail sale in the State, providers will be required to be licensed by the Commission. In filing for licensure, the applicant must provide the following to the Commission:

- evidence of financial capability sufficient to refund deposits to retail customers in the case of bankruptcy or nonperformance or for any other reason;

- evidence of the ability to enter into binding interconnection agreements with transmission and distribution utilities;

- disclosure of all pending legal actions and customer complaints filed against the competitive electricity provider at a regulatory body other than the Commission in the 12 months prior the date of license application;

- evidence of the ability to satisfy the renewable resource portfolio requirement;

- disclosure of the names and corporate addresses of all affiliates of the applicant.

**STRANDED COSTS**

The Act defines stranded costs as a utility's "legitimate, verifiable and unmitigatable costs made unrecoverable because of the restructuring of the electric industry required by this chapter and determined by the commission . . . " The determination of stranded costs is to be made by summing the following:

1. the cost of regulatory assets related to generation;

2. the difference between net book generation plant and its market value;

3. the difference between future contract payments and the market value of a utility's purchased power contracts.

The Commission is prohibited from including for recovery any costs for obligations incurred after April 1, 1995. There are exceptions to this prohibition for some regulatory assets created between April 1, 1995 and March 1, 2000 for costs associated with the restructuring of QF contracts, costs deferred pursuant to rate plans, and energy conservation costs. In addition, obligations incurred by utilities between April 1, 1995 and March 1, 2000 that are beyond their control are excepted, as are obligations incurred after April 1, 1995 that were devoted to reducing stranded costs.

The Act requires the utility to "pursue all reasonable means to reduce its potential stranded costs and to receive the highest possible value for generation assets and contracts, including the exploration of all reasonable and lawful opportunities to reduce the cost to ratepayers of contracts with qualifying facilities." The Commission is required to consider the utility's mitigation efforts when determining the amount of stranded costs.

Before the start of retail access, the Commission will estimate the stranded costs for each utility, and use those estimates to set a stranded cost charge to be collected by the T&D utilities when retail access begins. This will be done in Commission adjudicatory proceedings ending by July 1, 1999. In 2003 and every three years after that, the Commission will correct any substantial inaccuracies in the stranded cost estimates except for those stranded costs associated with divested generation assets, and change the T&D charge accordingly. The Commission may also adjust the charge at any other time. Any changes to the stranded cost charge are to be made on a prospective basis, and cannot address past inaccuracies in stranded cost estimates. In setting the stranded cost charges, the Commission may not shift cost recovery of stranded costs among customer classes in a manner inconsistent with existing law.

## CUSTOMER ISSUES

The Commission may require competitive energy providers to file a bond with the Commission as evidence of financial viability. The providers will also be required to file their generally available rates, terms and conditions with the Commission.

Providers will be required to provide the following consumer protections to those customers with demands of 100 kW or less:

- 30-day notice of termination of service (Note: customers cannot be disconnected for non-payment of the T&D portion of their bill);
- 30-day minimum service term;
- allow the customer to cancel selection of a provider orally or in writing within five days of selection;
- no telemarketing if the consumer has filed a request not to receive telemarketing with the Commission;

- must provide, within 30 days of contracting for service, the rates, terms and conditions filed with the Commission;

- must comply with any other provisions adopted by the Commission.

The Commission will resolve any disputes between providers and consumers. They will have the statutory authority to fine providers for violation of Commission rules and policies, and can order restitution for any party injured because of violations.

The Act provides that with the start of retail competition, electricity will be available to those customers not selecting a competitive provider pursuant to "standard-offer service." This service will serve as the provider of last resort for those customers who discontinue service with a competitive provider, or who do not choose a competitive provider. The Commission will initiate rulemaking on October 1, 1997 to establish the terms and conditions for this service, including entry and exit restrictions, rate design, and credit and disconnection practices.

Following the adoption of service standards, the Commission will administer a bid process that will select standard-offer providers for each T&D service territory by July 1, 1999. Affiliates of large (more than 50,000 customers) T&D utilities will be allowed to submit bids to provide standard-offer service to up to 20% of the load within its own service territory. The Commission will insure that affiliates will have no greater access to relevant information than is available to other potential bidders. Municipal, cooperative, and small investor-owned T&D companies will be allowed to bid for standard-offer service in their own service territories.

If the resulting qualifying bids for standard-offer service in any service territory, when combined with the regulated T&D rates and any stranded cost charges result in rates that exceed existing tariffed rates, the Commission is directed to investigate whether retail access remains in the public interest, or whether alternative mechanisms are needed.

Standard-offer service must be available until March 1, 2005. By January 1, 2004, the Commission will begin an investigation to decide whether standard-offer service should be continued.

## MARKET POWER

The Act requires that on or before March 1, 2000, investor-owned electric utilities must divest all generation assets and generation-related business activities. For the purposes of the Act, divestiture means the legal transfer of ownership and control to an entity that is not an affiliated interest. Certain assets are excluded from the divestiture requirement:

- contracts with qualifying facilities;

- contracts with demand-side management or conservation providers;

- ownership interest in nuclear units;

- ownership in facilities located outside the U.S. ;

- ownership interest in generation assets that the Commission determines is necessary for the utility to perform its obligations as a T&D utility.

The Act requires the utilities to submit divestiture plans by January 1, 1999. The plans will then be reviewed by the Commission in adjudicatory proceedings, with the issuance of orders approving or modifying the plans by July 1, 1999.

The Act states that the Commission may, on or after January 1, 2009, require divestiture of the utilities' ownership interests in the Maine Yankee nuclear facility. If requested by a utility, the Commission can grant an extension to allow divestiture of a particular generating asset, if it can be shown that such an extension will enhance the market value of the asset. Those assets for which an extension is granted must be transferred to a distinct corporate entity by March 1, 2000.

After February 28, 2000, the Commission will require that all investor-owned utilities sell the rights to capacity and energy from all those generation assets and purchased power contracts that were not required to be divested. The utilities will be allowed to retain the rights to capacity and energy that the Commission deems are necessary to allow them to perform their obligations as T&D utilities. Similarly, the Act allows T&D utilities to own or have a financial interest in generation and generation-related assets that are found necessary for T&D obligations.

On April 28, 1997, CMP announced that they planned to sell their generation assets immediately. The utility believes that an immediate sale will allow them to minimize the amount of stranded costs attributable to their generation assets.

The Act sets forth standards of conduct which address the relationship between a T&D company and an affiliated competitive provider of electricity. A T&D utility is not allowed to give its affiliate preference over nonaffiliated providers in matters related to any regulated product or service. The T&D must process requests for information in the same manner and within the same period of time for both affiliates and nonaffiliated. They may not provide preferential access to non-public information to affiliates, nor can they proprietary customer information without prior written authorization from the customer.

## PUBLIC PURPOSE PROGRAMS

### Renewable Portfolio Standard

To become a licensed electricity provider in Maine, an applicant must show to the satisfaction of the Commission that no less than 30% of its portfolio of supply sources for retail sales is accounted for by renewable resources. Recall, presently nearly half of Maine's power comes from renewables, including hydro.

A renewable resource is defined as electrical generation from three types of facilities:

1. Those facilities that qualify as small power production facilities as defined by the FERC;

2. Those facilities that qualify as qualifying facilities as defined by the FERC;

3. Those facilities with capacity no greater than 100 MW that rely on one or more of the following:
   a. fuel cells
   b. tidal power
   c. solar arrays and installations
   d. wind power installations
   e. geothermal installations
   f. hydroelectric generators
   g. biomass generators
   h. generators fueled by municipal waste in conjunction with recycling.

The 30% requirement will be reviewed by the Commission five years after the start of retail competition. The Act also directs the Commission to develop through rulemaking a program to allow retail ratepayers to make voluntary contributions to fund renewable resource research and development. Under the program, the T&D company would be responsible for collecting the contributions and forwarding them to the Commission.

### Energy Efficiency

The Act requires T&D utilities to implement energy conservation programs and include the costs of the programs in their rates. The Act calls for a "reasonable level of funding" of conservation programs, in an amount comparable to the amount expended for similar programs in 1999. The level of expenditures is to be reviewed regularly. By July 1, 1999, the Commission is to have enacted rules outlining the conservation programs to be funded.

### Low Income Assistance

The Act directs the Commission to continue existing levels of assistance to low-income households. The funding of this program will be through the rates of the T&D utilities, who will forward the revenue to the Commission.

## RECIPROCITY

The Act does not contain any provisions relating to reciprocity.

# MASSACHUSETTS

## BACKGROUND

In 1995, Massachusetts utilities produced more than 46,000 gigawatt-hours of electricity with a market value of $4.7 billion dollars. Consumption of this power was divided between residential customers at 34%, commercial accounts used 43%, industrial users consumed 21% and others account for the remaining 2%. Massachusetts is also considered a high cost state with an average revenue per kWh of 10.1¢. Individual class revenues are 11.26¢ per residential kWh, 9.93¢ per commercial kWh sales, and 8.41¢ for industrial accounts.

By early 1995 it became apparent to the Massachusetts Department of Public Utilities (MDPU) that its existing integrated resource planning (IRP) process had not been overly successful in promoting effective and timely decision making. Although the IRP process included regular, two-year planning cycles encompassing forecasting, need determination, negotiation, competitive solicitation, and contract approval, it was still a regulatory attempt to mimic a competitive market. In response to this situation, the MDPU opened docket D.P.U. 95-30 to seek comments on electric industry restructuring. As a result, the MDPU set forth seven principles as a guide to the development of a market structure that would realize their goal of lowering costs while respecting the other important public purposes of regulation. The principles are as follows:

1. Provide the broadest possible customer choice.
2. Provide all customers with an opportunity to share in the benefits of increased competition.
3. Ensure full and fair competition in generation markets.
4. Functionally separate generation, transmission, and distribution services.
5. Provide universal service.
6. Support and further the goals of environmental regulation.
7. Rely on incentive regulation where a fully competitive market cannot exist, or does not yet exist.

Based on the principles set forth in D.P.U. 95-30, docket D.P.U. 96-100 was opened in March 1996 with the purpose of developing an "efficient industry structure and regulatory framework that minimizes costs to consumers while maintaining safe and reliable electric service with minimum impact on the environment." D.P.U. 95-30, at 13. On December 30, 1996 the MDPU issued its *Model Rules and Legislative Proposal.* The draft legislation proposes that the legislature establish the framework of a restructured industry and authorize the MDPU to complete the details by rulemaking. The *Model Rules* indicate how the MDPU envisions implementing the restructuring principles. The major components of the *Model Rules* are addressed in subsequent sections of this report.

Under its existing authority, the MDPU also included two policy directives as part of its order in D.P.U. 96-100. First, the MDPU enacted standards of conduct for natural gas and electric distribution companies with affiliates engaged in competitive activities.[8] Second, as a means to educate consumers during the proposed transition to a competitive electricity market, the MDPU ordered that existing rates be unbundled, in a revenue neutral manner, into generation, transmission, and distribution components. These rates were to be filed with the MDPU by March 3, 1997. It is the goal of the MDPU to provide competitive choice to electricity consumers on January 1, 1998.

## MARKET STRUCTURE

### Generation Suppliers

Customers in a restructured competitive environment will have three types of electric generation choices. First, customers may enter into agreements with competitive suppliers for the provision of generation. The price for this type of service will not be regulated. Second, customers will retain the option of purchasing power directly from their electric distribution company at a price regulated by the MDPU. This option will be called standard offer service and will be made available for five years to customers who have never received generation from a competitive supplier. Third, customers who have received generation from a competitive supplier but who, for whatever reason, have stopped receiving such generation will be allowed to receive default generation service provided by a distribution company at a market price.

### Distribution Suppliers

At least during the initial stages of restructuring, the MDPU envisions continued regulation of distribution as it will remain a monopoly service offered exclusively by the local distribution company in a clearly defined territory. Distribution companies will have the following obligations within their service territories to:

1. connect all customers to their distribution system;

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[8]See D.P.U. 96-44 Order Commencing Rulemaking to establish standards of conduct governing the relationship between natural gas local distribution companies and their unregulated marketing affiliates.

2. operate their distribution system in a manner that maintains the current level of reliability; and

3. provide the same billing, metering, and other customer service functions that are currently provided by vertically integrated electric companies, with the exception that customers who purchase generation from competitive suppliers will have the option to receive a separate bill from their suppliers.

In addition, the *Model Rules* call for distribution companies to provide the following services that are required by the restructuring principles established in D.P.U. 95-30 to:

1. make generation available to customers, who, for whatever reason, are not receiving such service from a competitive supplier;

2. design low income tariffs that will provide the same level of discounts for low-income customers that are currently provided;

3. continue to provide energy efficiency programs to their customers; and

4. be responsible for collecting monies for a renewable energy resource fund.

Distribution companies must make available the following two types of generation: (1) standard offer generation service to those customers who have never received generation from a competitive supplier; and (2) default generation service, which will be available to those customers who have received generation from a competitive supplier but, who, for any reason, have stopped receiving such service.

Following the introduction of direct retail access, standard offer generation service will be available for a period of five years. Although this service will be unbundled, customers will receive a single bill that appears to show bundled electric service, with distribution companies replacing the integrated electric companies. The MDPU will regulate the price charged for standard offer service.

Initial standard offer service price proposals submitted to the MDPU must show service priced at a level no higher than current electric rates. In establishing standard offer prices, distribution companies should consider the need to balance between setting prices at levels that provide near-term rate reductions and establishing price paths for the five year period that encourage customers to participate in a competitive generation market. The provision of such service must be structured so that suppliers bear the risk of reduced standard offer load (i.e., stranded cost) due to customers moving to competitive suppliers.

Default generation service is intended to act as a safety net for all customers. The price for such service shall be based on the spot market clearing prices, as reported by the bulk power system operator. The MDPU will not preclude distribution companies from obtaining generation for default service from sources other than the spot market (e.g., through bilateral contracts).

On June 13, 1997 the MDPU issued proposed generic rules to regulate the relationships between distribution companies, competitive suppliers, and their customers. These rules are designed to complement the restructuring rules described above. The case is pending.

**STRANDED COSTS**

In D.P.U. 95-30, the MDPU defined stranded costs as:

1. the amount of the book cost or fixed cost associated with producing electricity from existing generation facilities that might not be recovered by the competitive market price for generation;

2. liabilities for future decommissioning and radioactive waste disposal associated with nuclear power plants that might not be recovered by the market price;

3. the amount by which the cost of existing contractual commitments for purchased power exceeds the competitive market price for generation; and

4. prudently incurred regulatory assets related to generation that were intended to be collected over time consistent with regulatory precedent or order.

Based on its opinion that electric companies should have a reasonable opportunity to recover, net non-mitigable stranded costs, the MDPU established standards to apply to requests for stranded cost recovery that it believes maintain the proper allocation of risks and rewards between electric companies and ratepayers. The standards are as follows:

1. In order to establish that stranded cost recovery is warranted, an electric company must demonstrate that net, non-mitigable stranded costs exist. It is not sufficient to demonstrate that certain costs are above market.

2. In order to establish that costs are stranded, an electric company must demonstrate that such costs have not been or would not be recovered.

3. An electric company must demonstrate that it has taken all available and reasonable means to maximize mitigation of stranded costs.

4. With reference to purchased power agreements (PPA), an electric company must demonstrate that the MDPU has approved the PPA for which stranded costs are claimed. Where such a demonstration cannot be made, the electric company must show the prudence of the contract at the time it was entered into based on what it knew or reasonably should have known.

In order to prove that an electric company has maximized its efforts to renegotiate contracts, it must present evidence to justify its management decisions and demonstrate that those decisions are not inconsistent with valid policies enforced by the MDPU.

**Stranded Cost Calculation and Recovery**

Stranded cost filings submitted by each company must be separated into two parts: (1) embedded costs which are known and may be verified using publicly available documents; and (2) mitigation efforts which consist of information on all company actions and occurrences that will reduce the level of embedded costs over time.

The *Model Rules* direct electric companies to subtract the total mitigation projection from the embedded costs to determine the net, non-mitigable stranded costs on a present value (PV) basis. This PV stranded cost calculation ensures that company assets with positive net value would offset, in part, the stranded costs associated with those company assets and obligations with negative net value.

Companies would be required to collect stranded costs through a stranded cost access charge that has fixed and variable components, applied to the distribution portion of customers' bills. This is consistent with the MDPU's restructuring principle that generation charges on customer bills reflect only the price of generation service as determined by the market.

The deregulation of generation and the introduction of competition will allow electric companies to profit from generation facilities that will have been paid for by ratepayers through the stranded cost charge. Therefore, for the purpose of addressing the residual plant value, the MDPU proposed that:

1. beginning with the initial setting of the stranded cost charge, mitigation projections estimate the residual value of retained generation facilities as well as the expected income from plant operation, and

2. stranded costs associated with owned generation facilities, regulatory assets, and minimum power purchase obligations be collected over

the expected economic life of the generating facility, the current amortization schedule of the regulatory asset, or the contractual term of the power purchase obligation, respectively.

The next step in determining the stranded cost charge would be to divide the PV stranded cost number into the component categories of stranded costs, and assign collection of each over time periods consistent with the above directives. Although electric companies shall be allowed to propose a rate of return, if any, to use in these calculations, the MDPU does not endorse any one particular method for spreading collection of stranded costs over time. In addition, the MDPU expects all companies to apply current MDPU cost allocation and rate design principles in order to determine the KW and KWH charges necessary to recover the approved level of stranded costs.

Once the original stranded cost charges are determined, the MDPU proposed to conduct periodic reviews of these charges to adjust them for deviations of actual market prices from those price projections used in the mitigation projections. Such a reconciliation would occur at the end of years two, five, and ten following the date of retail access.

## CUSTOMER ISSUES

With regard to consumer protections, the MDPU intends to apply its apply its billing regulations to both distribution companies and competitive suppliers who bill customers. In addition, the MDPU believes it is important to apply its registration and consumer protection requirements to competitive suppliers (i.e., marketers, brokers or aggregators) who do not fit the current definition of an electric company. In the absence of legislative changes to ensure the MDPU's jurisdiction over competitive suppliers, the MDPU may enforce compliance with its registration requirements for competitive suppliers by prohibiting regulated distribution companies from doing business with competitive suppliers not in good standing with the MDPU. However, the MDPU believes its registration requirements would be more effective if it had a range of sanctions available, such as the ability to impose fines. Therefore, the *Legislative Proposal* contains draft legislation to provide the MDPU with the authority to impose the above non-price regulations on competitive suppliers.

In general, all competitive suppliers will be required to register with the MDPU, provide basic information about themselves, pay an annual filing fee and provide a contact number. Specifically, each supplier must provide evidence of financial soundness such as surety bonds, a recent financial statement, appropriate market rating, a letter of credit or proof that the supplier has posted a bond with the ISO. In order to support the costs of reviewing each supplier's registration application, the MDPU's *Model Rules* contain a requirement that any competitive supplier pay a $500.00 fee. In addition, each supplier must maintain and publish in the telephone directories of each city and town in which it does business, as well as on its bills, an "800" or toll-free telephone number for customer service calls.

The MDPU did not envision the unbundling of metering and billing services until after the beginning of retail access. However, changes in metering technology as well as moves by other states to unbundle customer services prompted the MDPU in May 1997 to initiate a collaborative effort among interested parties to establish a consensus-based rules proposal governing metering, billing and information services. The MDPU indicated its willingness to provide expeditious treatment of any consensus-based proposal.

**Universal Service/Low Income Customers**

One of the MDPU's guiding restructuring principles is that restructuring must assure continuation of universal service with protections for low-income customers equivalent to that provided within the current industry structure. In this regard, the MDPU required each distribution company to offer a low-income tariff with the same eligibility criteria that are currently in place. The low-income discount would apply to the distribution charge, and during the transition period, the discount would also apply to the stranded cost charge.

In addition, during the transition period, the MDPU intends to apply its billing and termination regulations to both distribution companies and competitive suppliers who bill customers. However, in the restructured industry environment, a competitive supplier will only be able to terminate its generation contract with a customer; the distribution company will control power flow from the distribution grid to the customer's location. In this instance, a termination would result in the customer becoming a default generation customer of the distribution company. The customer would not lose electricity service but would receive default electric service priced at the spot market price.

**Electron Disclosure**

In order to facilitate consumer comparison of competing offers, the MDPU proposes to develop, through a collaborative process, a standard format for electricity labeling and pricing format for bills. The labels would appear on a competitive supplier's bills and marketing materials. Basic label information would include the fuel mix of the generating units being dispatched and the amount of air pollutants that are emitted from those units. This information would apply to both owned generation and long-term purchases. Competitive suppliers would also have to indicate to customers when a portion of the mix will be obtained through the spot market.

However, given the practical difficulties in assuring that a company or supplier could actually sell a particular type of generation from its supply mix to a specific retail customer, the MDPU proposed, at this time, to prohibit the marketing of any subsection of a supplier's mix. In the alternative, all competitive suppliers would be required to provide their customers and the MDPU with an annual report of the average resource mix of their owned generation and power purchases. This information would be updated quarterly and published on monthly bills.

Verifiability of fuel source and emissions data was viewed by the MDPU as critical to the success of any labeling system. Therefore, it advocated that the FERC, DOE, or the EPA establish the ISO as an information clearinghouse. The ISO would collect real-time information on generating unit dispatch and emissions in order to inform consumer choice and to assist environmental regulators in achieving environmental improvement.

### Performance-Based Regulation (PBR)

In Docket D.P.U. 94-158, the MDPU found that it was within their ratemaking authority to modify, refine, or supplement the existing cost-based, rate-of-return regulatory framework or to adopt new ratemaking approaches. PBR was viewed as one means to bring efficiency gains and lower rates to customers. The MDPU supports the use of PBR as an efficient method to regulate functions of electric companies where a fully competitive market cannot or does not yet exist. However, in order to provide the companies flexibility, the MDPU did not establish rules on PBR but rather provided the following three guidelines:

1. PBR plans should apply only to MDPU regulated functions at the time of the filing;

2. PBR plans should not involve the stranded cost issue; and

3. any proposal to convert a utility's distribution operations from a cost-based to a performance-based regulatory framework should include comprehensive service quality standards with significant financial incentives to guard against any degradation of service quality and reliability levels.

Given that the distribution function will remain a monopoly service, the MDPU expects PBR proposals to be included in each electric company's next base rate case submitted to the MDPU.

## MARKET POWER

### Vertical Market Power - Structural Reorganization

The MDPU contends that the minimum structural organization consistent with its competitive goals is the functional separation of generation, transmission, and distribution within one integrated company, and the establishment of a separate marketing affiliate if a company retains generation assets. However, the MDPU does not have the authority to order that such a structure be adopted or that companies divest themselves of generation assets. Therefore, the *Legislative Proposal* contains specific language to this effect. In addition, the MDPU is seeking authorization from the legislature to impose monetary penalties on any distribution company that violates the corporate rules of conduct established to govern the interactions between regulated and competitive divisions of a company.

Recently, the Joint Committee on Electric Utility Restructuring has been working to develop a final restructuring legislative package based on the Restructuring Committee's bill and a similar bill supported by the governor. This proposal includes provisions that require utilities to unbundle their generation, transmission and distribution assets into separate affiliates and encourages companies to divest all nonnuclear generation within one year of the starting date for retail access (i.e., January 1, 1998).[9]

**Bulk Power System**

The MDPU identified six essential features to the efficient operation of the New England bulk power system.

1. It should be operated as a single control area by an independent system operator (ISO).

2. The ISO should be responsible for maintaining current reliability standards.

3. The ISO should operate the bulk power system in a non-discriminatory manner to facilitate an efficient and competitive generation market.

4. The ISO should accommodate self-scheduling in the dispatch of generating units, but should retain the emergency capability to dispatch all generating units as necessary and feasible in order to maintain system reliability.

5. The ISO should be responsible for collecting information on power plant emissions associated with system dispatch

6. Open access to the transmission system and fair, economically efficient, and non-discriminatory pricing are prerequisites to the operation of an efficient bulk power system.

The MDPU intends to participate in regional efforts and in any FERC proceeding on proposed revisions to the New England Power Pool (NEPOOL) Agreement or an ISO to ensure that security and adequacy provisions are sufficient. NEPOOL has submitted a revised Agreement to the FERC which contains many of the items listed above.

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[9]New England Electric System, parent of Massachusetts Electric Company, has recently divested itself, by means of a bidding and auction process, of a number of generation assets located throughout New England. Similar efforts are underway by COM/Electric and Eastern Utilities Associates.

### Transmission Pricing

The MDPU believes that transmission pricing should be regulated by the FERC, including unbundled interstate transmission under state authorized consumer choice. This position, according to the MDPU, was confirmed by the courts in *United Distribution Companies v. Federal Energy Regulatory Commission*, 88 F.3d 1105 (D.C. Cir. 1996). The state would retain jurisdiction over distribution functions.

However, as a means to resolve jurisdictional questions, the FERC in Order 888 developed a seven part test to distinguish electric company transmission and distribution facilities. The FERC indicated that it would defer to recommendations of state regulators regarding the classification of transmission and distribution facilities based on its seven part test. Therefore, the MDPU ordered all electric companies to file, by March 3, 1997, analyses supporting their classifications of transmission and distribution facilities based on the FERC criteria.

Under the existing regulatory regime, the costs of transmission facilities and generation are rolled into a company's rate base and averaged across a company's customer classes. Although this pricing scheme covers fixed costs, it does not recognize that with the operation of the system comes congestion and location related costs. In a competitive environment, these costs must be reflected in rates in order to provide proper price signals to consumers. Such signals would also improve an investor's evaluation of the merits of siting a new generator, transmission upgrade, load management option, self generation and interruptible rates. The MDPU supports the development and submission of such a rate proposal to the FERC by Massachusetts electric companies.

### Horizontal Market Power

The MDPU stated in D.P.U. 95-30 that "horizontal market power in the electric industry could arise from undue concentration in the ownership of facilities at the same level in the chain of production [e.g., in generation]. Such concentration could enable one or a few market participants to influence prices to their own benefit." D.P.U. 95-30 at 20. However, the detection of horizontal market power and remedies for its abuse are difficult to establish given that the market has not yet been fully defined. In spite of this situation, the MDPU stated in its restructuring plan that it planned to assess the degree to which competition exists and will "take such actions as necessary to ensure that the full benefits of competition are achieved." D.P.U. 96-100 at 85.

Proposed mergers or acquisitions that have the potential to create market concentration on a regional basis or abuses of horizontal market power will be reviewed by the MDPU. The MDPU in Mergers and Acquisitions, D.P.U. 93-167 at 5, stated that:

> we expect utilities to explore thoroughly all cost-saving measures and opportunities to achieve efficiencies, including mergers and acquisitions, and

we encourage all companies to consider combinations that are consistent with our long-term goals of fostering effective competition and driving down rates.

## PUBLIC PURPOSE PROGRAMS

### Environmental Impact

Consumer access to information about available products and services is a crucial element in effective competition. To support this element, the MDPU intends to require suppliers when they register with the state to provide information on the sources and environmental impacts of power they propose to sell. In the future, all suppliers will be required to report on a quarterly basis information related to the fuel sources and emissions characteristics of their supplies on a portfolio-wide basis.

However, despite the MDPU's recognition that difficulties exist in the verification of environment-related marketing claims, it holds that, at a minimum, estimation and collection of emissions as a function of system dispatch will be required to inform customer choice and to validate such claims.

### Renewable Energy Resources

The MDPU believes that a low, non-bypassable renewables charge would foster competition and provide a market-based incentive to explore the viability of renewables. In its *Model Rules*, the MDPU proposed a charge of one mill per KWH, beginning January 1, 1998, to be collected on every KWH sold in Massachusetts through a non-bypassable access charge. Monies collected through the fund would then be distributed directly to eligible producers of renewable energy so that they can reduce the price they charge consumers while remaining commercially viable. After three years, the MDPU would review the results and reevaluate the need for and appropriate level of funding to support the commercialization of renewables.

The MDPU proposes to use a 4 percent addition of renewable energy to regional system sales of electricity over the next ten years as a benchmark to evaluate the efficacy of the approach described above. In addition, the MDPU encourages interested parties to form a renewables collaborative to examine all pertinent issues and to present its recommendations to the MDPU by July 1, 1997 for review and implementation by January 1, 1998.

### Energy Efficiency

During the transition to a competitive energy market, the MDPU believes that there is a role for distribution companies in providing energy efficiency services. The *Model Rules* require distribution companies to file energy efficiency plans that include:

1. an education component;
2. a proposal for support of market transformation initiatives;
3. a description of market-driven energy efficiency efforts;
4. proposed budgets and incentives;
5. a description of evaluation criteria; and
6. a proposal for coordinating delivery of energy efficiency to low income customers with appropriate community service agencies.

Determination of appropriate budget levels, incentives, and measurement of energy efficiency activities was left to a future proceeding. The MDPU encouraged electric companies to work in a collaborative fashion with affected stakeholders to develop their energy efficiency plans.

In recognition of the fact that changes within the electric industry and energy efficiency markets will not coincide, the MDPU adopted a two-plus-three year approach for review of energy efficiency plans. The *Model Rules* require each distribution company to file a detailed two-year plan accompanied by a projection of activities in the subsequent three years. The plan would be refined through a second filing after the first two years to provide details of activities for the following three years.

## RELIABILITY

In the past, reliable electric service in Massachusetts has been maintained pursuant to voluntary utility compliance with reliability criteria, planning policies and operating practices established by the National Electric Reliability Council (NERC). Similarly, through the NEPOOL Agreement, member utilities have maintained system security by designing and operating the bulk power system to a specified level related to the likelihood that reasonably foreseen circumstances would not result in a major outage.

The MDPU envisions future operation and system reliability[10] of the New England bulk

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[10]Reliability depends upon system security and resource adequacy. System security refers to the integrity of the interconnected transmission network and the avoidance of uncontrolled cascading failures which may result in widespread outages. Failures in service associated with system security arise from system operating practices, system design errors, control equipment capability, or system malfunctions. Resource adequacy refers to having sufficient generating capacity to be able at all times to meet the

power market as being the responsibility of the ISO. The ISO would have control over dispatch of generation and over system reliability through operation of the transmission grid. However, this vision of the future is premised upon the successful outcome of two important events. First, the development of mandatory NERC operating policies and reliability standards as well as implementation of mandatory mechanisms to ensure compliance with such standards. Second, changes to the NEPOOL Agreement to grant the ISO the authority and tools to maintain system security and the requirement that each NEPOOL participant bear a proportional responsibility for system security and adequacy.

With respect to resource adequacy, the MDPU envisions that in a mature and competitive generation market, there would not be a need for such standards. Adequacy could be ensured through the operation of market forces (e.g., price signals) that would foster a balance between supply and demand.

Finally, given that distribution companies would continue to remain under MDPU jurisdiction, they would be responsible for operating the distribution system in a manner that maintains the current level of reliability.

## RECIPROCITY

Within the *Model Rules*, the MDPU makes reference to supporting regional efforts to revise the NEPOOL Agreement and to establish an independent ISO. There is no mention of regional reciprocity. However, if a municipal power company decides to sell generation to consumers outside of its service territory, the MDPU proposed a policy of reciprocity. Investor owned electric companies would not be required to open their service territories to retail competition from a municipal company unless the municipal company extended reciprocal rights to all suppliers with respect to its service territory. The MDPU proposed that the legislature codify this policy of reciprocity.

## TAX ISSUES

Many municipalities are concerned that restructuring will reduce property tax revenues from electric companies, resulting in the redistribution of the tax burden to other taxpayers. This issue has two components: 1) the possible devaluation of utility plant; and 2) the possible reclassification of electric generating companies as manufacturers whose equipment is exempt from local property taxes.

With respect to the first component, the MDPU proposed that the legislature exempt

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aggregate peak loads of all customers. Failures in service associated with resource adequacy arise from an insufficient level of generating capacity that can be due to errors in load or capacity availability projections or to construction delays. D.P.U. 96-100 at 50-51.

existing regulated electric companies from personal property taxes. However, the MDPU recommended that these existing companies be legislatively required to enter into binding agreements to make payments in lieu of taxes to host municipalities during the transition period to a competitive market. These payments would be based on the greater of the fair cash value of utility property or the fair cash value plus the revenues an electric company receives as stranded cost recovery. In the case of independent power producers, the MDPU proposed to continue the practice of allowing such producers to enter into arrangements with municipalities for payments in lieu of taxes. With respect to new generators, the MDPU encouraged the voluntary negotiation of binding long-term tax agreements governing payments in lieu of taxes prior to the siting and construction of such plants or facilities.

With respect to the second component, the MDPU recommended that legislative changes to the statute be made because different forms of tax treatment for different types of generators could result in competitive distortions over time. For example, in the case of the *Board of Assessors of Holyoke v. State Tax Commission*, 3545 Mass. 244 (1969), the Supreme Judicial Court stated:

> We recognize that there may be some anomaly in taxing [Holyoke Water Power Company], now developed into predominantly a producer and distributor of electric power, in a manner different from the taxation of corporations wholly engaged in distributing electricity. We conclude, however, that the Legislature, by somewhat obscure enactments, and administrative officials, by interpretation, have established such a different method of taxation for [Holyoke Water Power Company].

# MICHIGAN

## BACKGROUND

The Michigan Public Service Commission (MPSC) regulates nine investor owned utilities with 1995 sales of some 86,00 gigawatt-hours. The two largest IOU's, Detroit Edison and Consumers Energy, make 91 percent of all IOU sales. Cooperative and publicly owned utilities make an additional 10,000 gWhs of sales. These sales generated some $6.67 billion in revenue. As of the end of 1995, average revenue per kWh for all utilities averaged across all customer classes was 7.05¢. This rate was slightly above the 1995 national average of 6.89¢. The breakout for kWh revenue by class in Michigan was residential 8.34¢, commercial 7.86¢, and industrial 5.78¢.

As early as early as April, 1994 the MPSC proposed an experimental, five-year pilot program to assess the potential for retail access for Michigan's ratepayers. Both Detroit Edison and Consumers Energy would have been subject to this five-year experiment. After a year of legal challenges and negotiations, the two utilities and intervenors appealed the MPSC's final order setting rates, terms and conditions of the retail wheeling experiment. The Michigan Court of Appeals ordered briefs to be filed in January, 1996.

Parallel with these actions, the Michigan Jobs Commission completed their recommendations entitled *A Framework for Electric and Gas Utility Reform* and Governor John Engler forwarded this report to the MPSC in January, 1996. The report recommended six near term objectives be achieved by January 1, 1997. These recommendations were 1) allowing direct retail access for commercial and industrial accounts 2) addressing stranded costs 3) exploring replacing rate of return regulation with rate cap regulation 4) allowing immediate file and use tariffs 5) eliminating prescriptive regulatory measures and 6) reorganizing the Public Service Commission. Public hearings were conducted on the recommendations during the summer of 1996, and MPSC staff submitted their *Staff Report* in December, 1996. The *Staff Report* recommended that 1) that all customers -- not just commercial and industrials -- should be permitted to participate in retail access and 2) rates should not increase for any customers and should decrease where possible.

The Commission directed the two affected utilities - Detroit Edison and Consumers Energy - to make informational filings on the Report and also permitted other parties to comment. Additional public hearings were conducted in March and April, 1997. On June 5, 1997 the MPSC voted to adopt, for the most part, the restructuring strategy outlined in the *Staff Report*. The reminder of this analysis will explore the recommendations adopted as the restructuring model for Michigan.

**Current Status**

While the substantive aspects of the Commission's implementation order have not been appealed, challenges based on jurisdictional issues have been filed. Staff believe that the courts will allow continued implementation of the plans, and will delay addressing the jurisdictional issue until the implementation issues have been resolved. Commissioner Shea dissented in the adoption of the order largely based on the belief that the MPSC did not have jurisdiction to require such a sweeping implementation order. In addition, he stated that the *Staff Report*, if adopted in its entirety, offered a more measured approach to restructuring and would permit timely reviews to see if its objectives were being achieved. Finally, there is still an outstanding challenge by Detroit Edison on jurisdictional grounds in a Federal court to a 1994 MPSC decision requiring a experimental retail access program.

On June 19th pursuant to the Commission's order, Detroit Edison and Consumers Energy submitted their proposed tariffs and requirements to begin restructuring. Interestingly, based in part on jurisdictional questions, both companies filed these tariffs as voluntary and conditional. Detroit Edison said it would proceed with the "voluntary" program if the Commission approved it and the legislature approved securitization and authorized recovery of stranded costs. The Commission has yet to resolve the jurisdictional authority to mandate implementation of its order.

There is discussion that the Michigan legislature will pass its own implementation plan as an alternative to the MPSC blueprint. The Commissions's order acknowledged such a possibility but it proffered that its implementation order would help guide the legislative deliberations. Governor Engler has publicly stated that he would veto any legislation that was inconsistent with the implementation process adopted by the Commission.

**MARKET STRUCTURE**

The *Staff Report* recommended a phase-in approach for retail access. Staff's recommendation would allow approximately 2½ percent of all customers to select their power supplier per year, but would allow primary voltage industrial and commercial customers full access by 2001 and all other customers full access by 2004. Intervenors argued against this approach from both an equity argument and on the grounds this was too long a phase-in period.

In their June 5th decision the MPSC kept the phase in of 2½ per annum for all classes and stated that <u>all</u> customers would have full retail access by 2001. The Commission expressed concern that a faster schedule would not allow time for the necessary infrastructure (ISO, billing systems, customer information, etc) to be developed and, an accelerated schedule could exacerbate the size of the potential stranded costs. Customers who do not choose an alternative power provider will continue to be served by the incumbent utility. The Order stated, "This schedule is sufficiently aggressive to keep

Michigan in the forefront of states moving toward competition while allowing adequate time to review and correct any deficiencies that may be found in the program."

Staff anticipates that there will be more customer load requesting retail access than the 2½ percent allowed during the transition. While the *Staff Report* suggested that either a lottery, bidding, or first-come first-served approach could be used for allocating this load, the Commission adopted a bidding system as a means to allocate the portion of load that would be subject to retail access. Basically, for the first year of the transition all customers requesting retail access will submit sealed bids for an amount they are willing to pay as a transition charge. The 2½% block will be assigned to the high bidders who will then have the right to seek competitive power. While the transition charge that will be ultimately adopted is not known, the Commission emphasized it will periodically adjust this figure based on market data. (See the discussion of stranded costs below).

The Commission did examine the issue of aggregation for smaller loads. The *Staff Report* stated that since 1 Mw block was the minimum load block that could be schedule as part of the system dispatch, any smaller customers would be required to aggregate loads up to this minimum amount to be eligible for retail access. While the Commission did not generically deal with all the issues of aggregation such as multiple load centers, it did set aside 10 Mws of the eligible retail load specifically for aggregators. Further, the Commission will look at aggregation issues as they review the implementation tariff filings for each utility.

**STRANDED COSTS**

As in most states, the stranded cost issue was most contentious. The *Staff Report* defined five classes of stranded costs. They were: 1) regulatory assets 2) capital costs of certain generating assets 3) capacity costs of purchased power contracts 4) employee related restructuring costs (i.e. retraining and repositioning utility workers) and 5) direct implementation costs of restructuring (i.e. establishing an ISO, changing billing systems, new meters, and other associated expenses of restructuring). Staff recommended that the appropriate stranded costs be recovered through securitization and through a transition charge applicable to all customers through 2007. Informational filings by the investor owned utilities indicated that Detroit Edison estimated their stranded costs at more than $3 billion; Consumers Energy estimated its stranded cost at $2 billion with most of this contracted capacity costs from purchase power agreements. Intervenors questioned these amounts with the Commission admitting actual stranded costs are primarily dependent on the existing and future market price of energy.

A number of confounding factors were discussed in the Commission's order. First, it stated that no imprudent costs would even be considered for recovery. Second, it noted implicitly that "netting out" so called stranded benefits would also be a difficult task since it also involved using the base market price of energy. Therefore, as a solution to these estimation hurdles and to overcome the inherent problems of forecasting future energy prices, the Commission adopted an annual "true-up" process. This periodic true-up procedure will recalculate the difference between market assets and stranded costs to develop the transition charge. This approach should provide a more accurate estimate of the stranded costs and therefore yield a more accurate transition charge. It will also tend to ensure that customers electing to remain with the incumbent utility do not experience inequitable shifting of costs to them.

### Securitization

The *Staff Report* offered securitization as one alternative to mitigate stranded costs. While the Commission expressed a favorable disposition to this approach, it admitted that expressed legislative authority would be necessary and that questions remained about the tax treatment of such proceeds. Thus, securitization is not being implemented at this time.

## CONSUMER ISSUES

The Commission ordered staff to examine the existing billing and information disclosure requirements and determine what new or revised procedures would be needed under retail access. Areas to investigate included 1) general information about direct access 2) details regarding prices and the kinds of services that would be offered and 3) the sources of power generation and other information customers may need about the supplier. Staff is to report back in 120 days.

### Regulation of Distribution Utilities

The *Staff Report* addressed the issue of protecting non-participating customers during the transition to a competitive market. They offered three proposals to accomplish this. First, staff recommended a rate freeze for all incumbent utilities. Second, staff proposed that the unbundled distribution service of the incumbents be regulated using a performance based regulation model (PBR). Third, the staff recommended that the Power Supply Cost Recovery (fuel adjustment) process be suspended during the transition.

The Commission considered each of these proposals. In respect to the rate freeze, the rate freeze was opposed by several parties including the Michigan Attorney General who argued that a previous Detroit Edison rate case agreement assured customers of rate reductions in 1998 and 1999. Detroit Edison disputed this interpretation of the agreement. Therefore, the Commission initiated a separate proceeding to "determine what actions, if any, are necessary to implement the settlement agreement." The order did not discuss rate freezes for Consumers Energy.

The *Staff Report* suggested that distribution utility services be subject to PBR such that rates for services could not escalate more than an annual percentage rate equal to the Consumer Price Index less 1 percent and that specific quality of service standards be established. While the parties debated the appropriate index to use, generally the parties supported the use of PBR as a reasonable regulatory alternative. However, the Commission noted that in the absence of enforceable service standards a PBR model would not work. Since no such standards have been proposed at this time, the Commission said it would like to entertain specific PBR proposals, but would not act until such proposals had been fully developed.

Finally, in respect to the suspending the fuel adjustment clause the Commission indicated it had not developed a record for making such a decision and that many public interest factors needed to be considered. Therefore, it would consider PSCR suspensions when asked to do so on a case by case basis.

**MARKET POWER**

Consumers Energy and Detroit Edison have begun discussions about forming a Michigan based independent system operator (ISO) as one method to mitigate market power concerns. Detroit Edison indicated that it had discussed forming a Midwest ISO, but that prospects for such a regional system had dimmed with the withdrawal of Indianapolis Power & Light. Both Michigan utilities suggested that partial operation of a Michigan ISO could begin in 1998 and be fully operational by 2000, if the existing Michigan Electric Power Coordinating Center was used as the foundation of the new ISO. While both utilities indicated seasonal transmission constraints for importing power, neither believed that market power conditions existed. However, intervenors expressed strong concerns about market power.

In its order the Commission said:

> The basic facts regarding market power are as follows. First, between them Consumers and Detroit Edison control approximately 90% of the generation in their service territories. Second, transmission into their interconnected system is severely constrained. Specifically, Consumers and Detroit Edison report that they zero available transfer capability to import firm power during four on-peak months. Third, Consumers and Detroit Edison own, control, and operate the transmission system. From the above it is clear that market power is an essential issue that must be addressed in the direct access program.

The Commission concluded by stating that the existing record did not allow an adequate basis to resolve this issue. The standby power issue discussed below was a partial answer but that further work needed to be done. Therefore, they ordered the MPSC staff to conduct a series of public meetings with all participants to develop a proposal for a Michigan ISO and "to explore other methods of addressing market power issues, including the adoption of standards of conduct consistent with FERC Order No. 889-A. The staff was given one year to file a report.

**Standby Service**

Standby service traditionally has been backup service for industrial customers who own their own generation facilities. The incumbent utility would normally provide tariff based standby service during outages of the customers equipment. Under a competitive market, it is anticipated during the first few years of the transition that standby service will be necessary for direct access customers who need such service when their alternative provider fails to serve. After reviewing the utilities informational filings on their proposed standby rates, the Commission agreed to conduct future hearings to more fully develop a record to make a decision.

The Commission went on to say that even in the absence of resolving market power issues the direct access transition should continue. Because it was a voluntary customer choice program, there was no harm in allowing customers who could benefit from retail choice from making that decision even with market power issues unresolved.

## PUBLIC PURPOSE PROGRAMS

The MPSC order is largely silent regarding public purpose programs. As noted in the *Staff Report*, most utility sponsored demand side management programs had already been discontinued on grounds that they were no longer cost effective. It is expected that the consumer issues workgroup may address some issues involving low income programs. Other public benefit type programs are not discussed.

## RELIABILITY

It is anticipated that most issues involving operational reliability will be handled under the auspices of the ISO. The implementation order is silent with respect to planning reliability. Discussions with MPSC staff indicate that the MPSC does not have a statutory requirement to issue certificates of need for new transmission or generation facilities. Therefore the opportunity exist for incumbent utilities or others to construct such speculative or merchant facilities in response to market prices under a competitive environment.

## RECIPROCITY

The Michigan PSC specifically addressed the issue of reciprocity by requiring that any utility or utility affiliate that offered direct retail power to Michigan customers must open their own system to retail access from Michigan utilities. An open exception was made for unaffiliated brokers and marketers. On January 1, 2002 all providers - both utilities and brokers - must offer reciprocity to be able to serve retail load in Michigan.

## TAX ISSUES

Neither the staff report or the commission's restructuring order directly address the tax ramifications of restructuring.

# MONTANA

## BACKGROUND

In 1995, Montana consumed 13,429 gigawatt-hours of electricity with investor-owned utilities providing 64 percent of this energy. Cooperatives and Federally owned power authorities provided nearly all of the remaining power. Market share was divided between the residential class with 27 percent, commercial class with 23 percent, and 47 percent going to industrial customers. This is by far the highest percentage of industrial load of the fourteen states under study.

Montana has exceedingly low rates. Revenue for all classes per kWh was 4.65¢. Residential rates were highest at 6.09¢ and industrial the lowest at 3.44¢. These are 27 percent and 26 percent below the national class averages. Commercial customers paid 5.31¢ per kWh.

SB 390 (the Electric Utility Industry Restructuring and Customer Choice Act) was approved by the legislature and signed into law on May 2, 1997. The new law calls for retail choice for larger customers and pilot programs for smaller customers to begin on July 1, 1998. As soon as administratively feasible, but before July 1, 2002, all other customers must have retail choice. The Public Service Commission may extend the date for 2 years if it finds that it is not administratively feasible or that there isn't workable competition. Utilities must file restructuring plans by July 1, 1997.

Investor-owned utilities (IOUs) must file a transition plan with the Public Service Commission (PSC) one year before any customer is entitled to retail choice. SB 390 states:

> The plan must include an outline for an orderly transition to choice for all customers, a method for assigning customers that do not choose suppliers, an educational program for their customers, and a plan for implementing universal system benefits programs.

On July 1, 1997, Montana Power filed its proposed restructuring plan. The plan called for a phase-in to achieve full retail access by July 1, 2002. The plan was rejected by the Commission and the company was ordered to refile by August 26, 1997.

## MARKET STRUCTURE

To the extent that a public utility is vertically integrated, a public utility must functionally separate the utility's electric supply, retail transmission and distribution, and unregulated retail energy services operations. The PSC may not order a public utility to divest itself of any generation assets or prohibit a public utility from voluntarily making such a divestiture.

Public utilities must make their transmission and distribution facilities available for all electricity suppliers and customers on a nondiscriminatory and comparable basis. The utility must adopt and comply with a code of conduct consistent with the FERC's code of conduct.

Distribution services providers are required to provide the following:

1. tariffs that make distribution facilities available to all electricity suppliers, transmission services providers, and customers;

2. build and maintain distribution facilities; and

3. be an emergency supplier of electricity and related services.

**STRANDED COSTS**

The PSC shall allow recovery of the following categories of transition costs:

1. the unmitigable costs of qualifying facility contracts, including reasonable buyout or buydown costs for which the contract price of generation is above the market price for generation;

2. the unmitigable costs of energy supply related regulatory assets and deferred charges; and

3. for a 4 year period, the unmitigable costs of IOU owned generation and power purchase contracts.

Upon PSC approval of these costs, they can be recovered through a non-bypassable charge on all customers.

A utility may, after July 1, 1997, apply to the PSC for a determination that certain transition costs may be recovered through issuance of transition bonds. If transition bonds are issued, cost savings associated with the bonds must benefit customers. The utility retains sole discretion whether to sell, assign, or otherwise transfer or pledge transition property.

**CUSTOMER ISSUES**

During the transition to competition, IOUs will be required to institute a rate moratorium for all customers beginning on July 1, 1998 that shall extend for 2 years. After June 30, 2000, rates for customers that do not have choice, as of July 1, 1998, cannot be increased, except for transmission and distribution rates subject to PSC approval.

## MARKET POWER

As stated in the market structure section above, utilities must functionally their supply, transmission and distribution functions. However, SB 390 does not speak directly to the issue of the need for an ISO or other market power concerns.

## PUBLIC PURPOSE PROGRAMS

Beginning January 1, 1999, 2.4% of each utility's annual retail sales revenue for the calendar year ending December 31, 1995, is established as the annual funding level for universal system benefits programs. This funding level remains in effect until July 1, 2003. These funds will be used to ensure continued funding of and new expenditures for energy conservation, renewable resource projects, and low-income energy assistance during the transition period and into the future.

## RELIABILITY

SB 390 requires utilities to "maintain standards of safety and reliability of the electric delivery system and existing customer service requirements."

## RECIPROCITY

Except for utility cooperatives that explicitly inform the PSC of their intent not to open their facilities to competitive suppliers as allowed by SB 390, all electricity suppliers must be afforded open, fair, and nondiscriminatory access to customers of other utilities.

## TAX ISSUES

The revenue oversight committee will analyze the amount of state and local tax revenue derived from previously regulated electricity suppliers that enter the competitive market and make a recommendation to the legislature as to how to adjust state and local tax burdens on all market participants.

# NEVADA

## BACKGROUND

Total sales to ultimate consumers in Nevada were 20,659 gigawatt-hours for 1995. Residential customers used 32 percent, commercial used 23 percent, industrials used 41 percent, and others used the remaining 0.3 percent. Nevada is also considered a low cost electric state. Total system revenue per kWh was 6.10¢ (11% below the national average). Individual revenue per class was 7.11¢, 6.75¢, and 5.05¢ for the residential, commercial, and industrial classes. Total revenue generated in 1995 was $1.2 billion.

On June 24, 1995 the Nevada Legislature passed Assembly Concurrent Resolution (ACR) No. 49. This resolution created a legislative committee to review competition in the generation, sale and transmission of electricity in Nevada. During the balance of 1995 this committee held workshops to gather information on restructuring.

In January 1996, the Nevada Public Service Commission (Commission) initiated Docket No. 95-9022 to investigate the structure of Nevada's electric utility industry in an era of competition. Following a series of workshops during the first half of 1996, the Commission issued a report entitled "The Structure of Nevada's Electric Industry: Promoting the Public Interest." This report was intended to supplement the legislative committee's efforts on restructuring. The report concluded that the monopoly structure of the electric utility industry is a "one-size fits all product ill suited to the diversity of Nevada's needs." The Commission cautioned that while it encouraged movement away from traditional utility structure and regulation, "Nevada must avoid the California path of dictating market structure." The report called for the identification of market barriers, retention of universal service, a role for government in resource selection, and new authority for the Commission to design an appropriate stranded cost recovery mechanism.

In early 1997, Assembly Concurrent Resolution No. 4 was introduced and referred to committee. This resolution was intended to continue the legislative study committee's work on restructuring initiated by ACR No. 49 in 1995. The resolution called for the assessment of specific issues including the timing of retail competition, whether divestiture should be required, whether an ISO is necessary, whether stranded costs should be recovered, and whether the Commission should regulate prices during the transition to competition.

The Commission prepared a draft bill on restructuring on February 6, 1997. This bill required the Commission to adopt restructuring rules within 18 months of approval and to oversee the restructuring process. This draft bill was formally introduced as Assembly Bill (A.B.) 366 on April 15, 1997. The Nevada Legislature ultimately passed A.B. 366 with amendments on July 6, 1997, and the Governor signed the bill on July 16, 1997. The law provides for retail access on December 31, 1999. The law also includes stranded cost recovery standards, competition guidelines for utility affiliates, distribution utility performance-based regulation, renewable portfolio standard, consumer protections, and alternative supplier licensing. A.B. 366 also reorganizes the Commission from a five-member panel to a three-member Public Utilities Commission. The law also restructures and makes the natural gas industry competitive. A description of the new law follows.

## MARKET STRUCTURE

Customers may begin receiving "generation, aggregation, and any other potentially competitive services" from competitive suppliers no later than December 31, 1999. The Commission however, may extend that date "to protect the public interest." The Commission has the latitude to phase-in retail access for different classes of customers. The law gives the Commission great leeway in directing the course of competition in Nevada.

## STRANDED COST

The Commission will determine the recoverable costs associated with potentially competitive service as of the date on which alternative sellers begin providing the service. The Commission will consider, in determining stranded costs, 1) the extent to which the utility was legally required to incur the cost; 2) the extent to which the market value exceeds the cost; 3) the utility's efforts to mitigate the costs; 4) the extent to which rates previously set compensated shareholders for the risk of nonrecovery of the costs; 5) the effects of the difference between the market value and the cost; and 6) the utility's management practices compared to other utilities with similar obligations to serve.

## CUSTOMER ISSUES

The Commission is to establish anti-slamming procedures for alternative energy suppliers, minimum standards for competitive sales information, and carry out an educational program for customers prior to the start of retail access. The Commission is authorized to conduct an investigation to determine whether markets are functioning in a competitive manner pursuant to the new law.

The Commission will also license alternate energy suppliers. The Commission will establish alternate energy supplier standards for safety and reliability of service, financial and operational fitness, and billing practices and customers service, including the initiation and termination of service.

Distribution utilities will remain under the jurisdiction of the Commission using performance-based regulation (PBR). Distribution utilities are required to "provide electric service to customers who are unable to obtain electric service from an alternative seller or who fail to select an alternative seller." Distribution utilities are also required to provide all non-competitive services in its service area unless the Commission authorizes otherwise.

The new law states that residential rates may not exceed rates in effect on July 1, 1997, for a period lasting until two years after the date the Commission repeals price regulation. The law, however, provides that the Commission may approve rate increases to ensure recovery by the vertically integrated utility of just and reasonable costs.

## MARKET POWER

The Commission must establish standards of conduct for competitive markets and monitor the markets for anticompetitive or discriminatory practices. The law also gives the Commission authority to set conditions and limitations on the ownership, operation, and control of a service providers assets in order to prevent anticompetitive behavior. The Commission also must conduct investigations to assess the effect of mergers, disposition of ownership or control of assets, transmission congestion, and anticompetitive behavior.

## PUBLIC PURPOSE PROGRAMS

The law establishes a renewable portfolio standard for wind, solar, geothermal, and biomass. The goal is for renewables to provide one percent of Nevada's total electric needs. The standard must be derived from not less than 50 percent renewable, and not less than 50 percent solar. The Commission may establish a system of credits to facilitate compliance. Credits must be issued for each kWh of renewable energy produced, and holders may trade or sell the credits.

## RELIABILITY

The new law requires the Commission to develop regular forecasts of electric capacity and energy. Providers of competitive services (i.e., end-use electricity provision) are to annually submit information to the Commission allowing it to monitor the development of competition, and to ensure the availability of adequate, reliable, efficient and economic electric service. If the Commission determines that insufficient capacity is forecasted, it may take remedial actions. The Commission may establish equitable, non-discriminatory obligations for customers, electric distribution utilities, or alternative sellers to insure sufficient capacity is available.

## RECIPROCITY

No information available at this time.

**TAX ISSUES**

A.B. 366 provides that future taxation of restructured industry property will be treated the same as under the current unitary integrated tax system. The law also requires the Nevada Department of Taxation to file a report with the Legislature on the implications of restructuring on state tax revenues.

## NEW HAMPSHIRE

### BACKGROUND

New Hampshire (NH) customers consumed approximately 9,000 gigawatt-hours of electricity in 1995. Nearly 88 percent of this power was provided by investor owned utilities. Market division of this load was 41% residential, 33% commercial, 20% industrial, and 6% other. NH is considered a very high cost state with an average revenue per kWh for all classes of customers of 11.72¢ for 1995. Individual class revenues per kWh were 13.5¢ for residential, 11.38¢ for commercial, and 9.56¢ for industrial.

In June 1995, the Legislature enacted House Bill 168 which directed the New Hampshire Public Utilities Commission (NHPUC) to establish a pilot program, providing approximately 17,000 retail customers with the opportunity to purchase electricity from competitive non-utility power suppliers. The pilot program began on May 28, 1996 and is scheduled to operate for up to two years. Only the source and price of electricity supply is open to competition. A recent survey of 400 pilot program participants showed that price was the single most important factor in a customer's choice to switch to a new electric supplier. However, it should be noted that NH's retail electric rates are the highest in the country.

The Legislature passed House Bill 1392 in May, 1996. This bill was codified at RSA 374-F and was the result of the work of several legislative committees and the NHPUC. The statute directed the NHPUC to develop a statewide restructuring plan. Its broad public policy directive reads as follows:

> The most compelling reason to restructure the New Hampshire electric utility industry is to reduce costs for all consumers of electricity by harnessing the power of competitive markets. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment.

The statute also called for full retail access by January 1, 1998. In response, the NHPUC issued its *Final Plan* on February 28, 1997. This plan is the blueprint of the market and institutional structures necessary to provide customers with energy service choices and to ensure fair and efficient competition among retail market participants. Supplemental orders establish utility specific interim stranded cost charges. The *Final Plan* directs each utility to file comprehensive plans, no later than June 30, 1997, which comply with the *Final Plan* and the supplemental orders.

In response to the *Final Plan*, Northeast Utilities (NU), parent of Public Service Company of New Hampshire (PSNH), filed suit in federal court on March 3, 1997.[11] NU claimed that the restructuring order would illegally impose economic losses on PSNH and violate a 1989 rate agreement with the state. A federal judge agreed in part with the NU claims and issued a temporary restraining order limited to the issue of stranded cost recovery for PSNH. The judge also ordered the parties (i.e., the mediator, governor, state attorney general and PSNH representatives) into a mediation process with a September 2, 1997 resolution deadline. However, the parties were unable to reach agreement. The federal court will now reconvene hearings on the outstanding legal issues of the NU suit. Similarly, the NHPUC will reconvene its hearings on implementation details of the *Final Plan*.

## MARKET STRUCTURE

The majority of NH customers purchase bundled electric service from regulated, vertically integrated utilities. The rates for this service recover test year fixed and variable costs plus a return on capital. Although each utility must own or purchase sufficient generating capacity to meet the peak demands of its own customers, these generating sources are centrally dispatched by the New England Power Exchange, the operating arm of the New England Power Pool (NEPOOL). The costs savings generated by central economic dispatch are shared by NEPOOL members and typically passed to customers through fuel and purchased power adjustment mechanisms. Each transmission-owning utility provides transmission services on its own system and, with the exception of pool-planned facilities, recovers the associated capital and operating costs through utility-specific rates.

The NHPUC found that a hybrid market model was the most appropriate competitive structure for its state. This approach which allows bilateral contracts as well as pool or spot market power purchases was the most desirable because it brought greater benefits to NH in the long run. Under the hybrid model, the independent system operator (ISO) acts as the grid operator, accepting and transporting energy supplied through bilateral contracts and one or more spot markets. Large volume customers may receive the economic gains of lower prices through negotiations, while smaller volume consumers may benefit by purchasing from a power exchange, thus minimizing the complexity and cost of their transactions. Small customers may also negotiate directly with a power supplier or through a marketer or broker. Aggregation of small customer loads may also be employed to increase buying power. Aggregation may include the loads of multiple customers from different rate classes or a customer may aggregate loads at several sites. The *Final Plan* states:

> We (the NHPUC) believe that the ability to sell power directly to a spot market or pool distinctly benefits small producers who may find tepid demand

[11]No other NH regulated electric utilities joined the NU lawsuit. However, Connecticut Valley Electric Company said it would seek to block the NHPUC order through an appeal to the Federal Energy Regulatory Commission based on jurisdictional grounds.

in a purely bilateral contract market. In addition, this hybrid approach allows individual market participants to determine which of the two trading mechanisms provides greatest value to each.

## STRANDED COSTS

RSA 374-F:2, IV. states:

> "Stranded costs" means costs, liabilities, and investments, such as uneconomic assets, that electric utilities would reasonably expect to recover if the existing regulatory structure with retail rates for the bundled provision of electric service continued and that will not be recovered as a result of restructured industry regulation that allows retail choice of electricity suppliers, unless a specific mechanism for such cost recovery is provided. Stranded costs may only include the costs of:
>
> (a) existing commitments or obligations incurred prior to the effective date of this chapter;
>
> (b) renegotiated commitments approved by the commission; and
>
> (c) new mandated commitments approved by the commission.

The NHPUC found that the most appropriate definition of stranded cost to be "net" sunk generation cost (including generation related regulatory assets) that ordinarily would not be recovered if retail customers were allowed access to alternative generation resources. Responsibility for the resource decisions which led utilities to acquire assets which are now or may become uneconomic must be determined on a utility specific basis. Where utility management is found to be responsible for such resource decisions, recovery of stranded costs will be limited. On the other hand, where it is found that management discretion over resource decisions was limited by regulatory mandate, utilities will be allowed an appropriate opportunity for full recovery of related stranded costs.

With regard to the value of generation assets, the NHPUC found that the sale or spin off of such assets to be the most accurate method to determine their worth and a reasonable means to avoid any exercise of vertical market power. However, in the event that a utility chooses to spin-off assets rather than make a sale, its plan must provide a mechanism whereby stranded costs borne by the distribution company after the spin-off are minimized and capture the appropriate level of value from the generation company. Plans to auction, lease, or spin-off generation assets and contracts will be reviewed by the NHPUC.[12] The *Final Plan* also requires the complete separation of competitive and non-competitive services by the year 2000.

Finally, for purchased power contracts, after all cost-effective and legally permissible buydowns or buyouts have been completed, any residual costs must be reduced to minimum practical levels. To the extent that more lucrative options have not been exercised, stranded cost mitigation will be deemed incomplete.

**Stranded Cost Recovery**

According to RSA 374-F:3, the NHPUC must establish the value of stranded costs and determine an appropriate level of recovery. Such stranded cost charges must produce rates that "to the extent practicable...approach competitive regional electric rates." Utilities with rates exceeding the regional average will not be authorized to recover all their costs. Specifically, the NHPUC reached the following conclusions:

1. less than full stranded cost recovery is fair;

2. less than full stranded cost recovery is not economically inefficient; and

3. full recovery of stranded costs has anti-competitive consequences.

Although the Legislature is reviewing the issue of how to treat the nuclear power plant decommissioning costs currently paid by ratepayers, the *Final Plan* includes a provision that such charges should be included as part of the total stranded cost charges.

In general, cost recovery mechanisms must allocate costs fairly between rate classes. Utilities are authorized under RSA 374-F:4, V to collect a stranded cost recovery charge, subject to its determination in the context of a rate case proceeding that such a charge is "equitable, appropriate, and balanced, is in the public interest...." The burden of proof for any stranded cost recovery lies with the utility making such a claim. Consistent with RSA 374-F:3, XII(d), utilities shall allocate recoverable stranded costs to all customer classes using existing cost allocation methodologies for generation assets. The resulting class costs shall be recovered from all customers, including new businesses, who receive delivery services from local distribution companies through usage based surcharges. These non-bypassable usage based surcharges represent recovery of the stranded costs that remain net of any proceeds from cost mitigation and generation asset divestiture. It is important to note that the legislation (i.e., RSA 374-F:3, XII(d)) discourages the use of exit fees to recover stranded costs.

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[12]New England Electric System (NEES), parent of New Hampshire based Granite State Electric Company, has recently divested itself, through an auction process, of a number of generating assets located throughout New England. This effort was undertaken in response to restructuring initiatives in Massachusetts, New Hampshire and Rhode Island.

Interim stranded cost charges will be calculated based on the application of the regional average rate method which comprises an independent estimation of regional market prices. These interim charges will be effective for two years from the implementation of utility compliance filings. Utilities may seek adjustment to such charges at any time based on severe financial hardship as determined by the NHPUC or upon the outcome of the rate case proceedings to adjudicate claims for stranded cost recovery.

## CUSTOMER ISSUES

The local distribution company has the continued obligation to provide default power service as well as the obligation to connect any customer requesting service. The distribution company shall be allowed to satisfy their contractual obligations for qualifying facility (QF) power purchases by using the output generated by QFs to meet the load of default customers. Any additional load needed to meet the needs of default customers will be obtained through a competitive bidding process. In order to avoid the above market costs associated with QF contracts, default customers will only bear that portion of the QF contract price which would be equal to the then current market price for power. The remainder of the contract price shall be recovered as stranded costs. Distribution companies will be allowed to recover between 10% and 20% of the savings realized from any additional mitigation efforts designed to reduce the stranded costs associated with QF contracts.

Default power service will be available to all residential and small commercial customers. Large commercial and industrial customers will be eligible to receive default service during a six month transition period following the outset of competition. After the transition period ends, large commercial and industrial customers who find themselves temporarily between suppliers will be allowed to access default service for a period of up to sixty days.

The NHPUC opened a rulemaking docket (DRM 97-082) on May 13, 1997 for the purpose of establishing registration requirements for competitive suppliers and consumer protection rules that all competitive suppliers will have to comply with.

## MARKET POWER

### Restructuring and an Independent System Operator

In compliance with FERC's Open Access Rule, NEPOOL filed an integrated package of arrangements with the FERC on December 31, 1996. This package included an open access tariff, agreements to transfer control of the region's transmission grid and generation operation to an ISO, qualify NEPOOL as a Regional Transmission Group, and facilitate wholesale competition through a combination of a bilateral market and a regional power exchange.

NEPOOL proposed to enter into an Interim ISO Agreement following initial acceptance of its filing by the FERC. The Interim ISO Agreement describes the respective rights and obligations of the ISO and NEPOOL participants and discusses the ISO budget process, indemnification, liability, insurance, ISO termination, dispute resolution, and governing law.

Although the NHPUC believes that the Interim ISO Agreement is a reasonable starting point for industry restructuring, it does not believe that the proposed ISO complies fully with the FERC's Open Access rule. With respect to NEPOOL's transmission tariff, the NHPUC believes that it fails to adequately address or provide necessary support for issues such as congestion rights and pricing and discriminatory requirements regarding scheduling pool transactions and internal self-scheduled transactions.

**Transmission Company Responsibilities**

The issue of state and federal jurisdiction over retail transmission service remains highly contentious. Therefore, the *Final Plan* makes two assumptions: 1) that the Federal Energy Regulatory Commission (FERC) has jurisdiction over the terms and conditions of the service of transmitting retail power; and 2) the NHPUC may direct its jurisdictional utilities to file at FERC tariffs for such service, which contain specific terms and conditions determined by the NHPUC, for ultimate disposition by FERC. The basis for assumption one is that in Order No. 888, the FERC found that "when a bundled retail sale is unbundled and becomes separate transmission and power sales transactions, the resulting transmission transaction falls within the Federal sphere of regulation." (61 Fed. Reg. 21,505.)

**Distribution Company Responsibilities**

As stated in RSA 374-F:3, II, vertically integrated utilities must unbundle their retail services into generation, transmission, and distribution sub-components. Distribution can be further sub-divided into basic distribution service, metering, billing, customer service, and aggregation/marketing. Distribution companies will be responsible for providing non-discriminatory unbundled distribution service to all customers in their franchise territories. Rates for such service will continue to be regulated by the NHPUC. In addition, distribution companies must assume the Qualifying Facilities (QF) power purchase obligations of existing utilities. However, if a jurisdictional utility chooses to be a distribution company, the NHPUC believes that in order to avoid any exercise of market power, such a utility must divest itself of its generation and aggregation/marketing services by the end of the two year period following the initiation of competition. Such a utility must also sell off any rights to obtain power under existing power purchase contracts. Finally, a distribution company may not be an affiliate of any company which sells a competitive service in its service territory. Jurisdictional utilities must submit plans to accomplish these requirements by December 31, 1997.

Distribution companies are directed to continue the pilot program practice of estimating hourly loads using load profiles for residential and small commercial customers rather than installing hourly meters and related communications equipment. Each utility will perform a detailed operational review of the Pilot Program load estimation procedure in order to identify ways to improve accuracy and include the results of that analysis in their compliance filing.

**Divestiture Compliance Filing Requirements**

In order to accomplish divestiture within the allowed two year period, each utility shall include in its compliance filing a plan to separate generation and aggregation/marketing from transmission and distribution. The transmission and distribution company shall not perform aggregation/marketing services for its affiliated generation company. The generation (and aggregation/marketing, if any) affiliate shall at a minimum be located in a different part of the building than the transmission and distribution company. In addition, the name of the generation/marketing affiliate shall bear no resemblance or relationship to the name of the transmission and distribution company or the holding company. Finally, each affiliate shall keep separate finances and books of accounts subject to FERC requirements. These compliance filing requirements are intended to mitigate the potential exercise of market power by affiliate companies.

**Unbundled Electric Service**

Retail electric services and rates must be unbundled in order for customers to choose their electricity suppliers. This requires segregating the service components and pricing each regulated component separately. Although the NHPUC finds that it is appropriate to allow large commercial and industrial customers to obtain metering, billing and customers services from competitive suppliers in 1998, a more comprehensive separation of services will be deferred until a later date.

Jurisdictional utilities are directed to submit cost of service studies which unbundle 1996 test year revenue requirements into generation, transmission, and distribution respectively. The distribution revenue requirement must be further subdivided into the revenue requirement for each rate class. Compliance plans must also include an embedded cost of service study based on 1996 calendar year data that identifies total cost by function.

**Special Contracts**

All existing special contracts will be unbundled. Price discounts will not be applied to the transmission or distribution components of the unbundled rates but will be reflected in the stranded cost component of the equivalent unbundled rate. After the implementation of competition, any contractual obligations and the obligation to supply the energy requirements of special contract customers will remain with the distribution company. Distribution company compliance filings shall include procurement plans to meet the energy requirements of special contract customers.

In order to avoid non-contract customers from paying the discount afforded special contract customers, the difference between the regular unbundled tariffed rate and the special contract rate will not be recovered from non-contract customers.

## PUBLIC PURPOSE PROGRAMS

### Low Income

A low income assistance program will be funded through a systems benefit charge designed to raise up to $13.2 million. The program is intended to accomplish three goals: first, to bring electric bills into the range of affordability; second, to encourage conservation and the use of energy efficiency mechanisms to make electric bills manageable; and third, to make the most effective use of limited funding. A working group will submit a program to the NHPUC by August 30, 1997.

### Energy Efficiency

Experience to date has shown that most utility sponsored energy efficiency programs have been marginally cost effective at best. Given this situation, the NHPUC believes that it is appropriate to phase out the existing programs. However, rather than abruptly ending them when retail competition is implemented, the NHPUC will cap the level of energy efficiency spending for each utility at its latest approved level. As utilities prepare their next annual energy efficiency filings, the NHPUC directed them to include plans on how to phase out their programs within two years from the implementation of retail choice.

### Environmental Impact

Continued environmental improvement was also addressed by the NHPUC. The Commission concluded that existing federal and state agencies are adequately empowered to undertake appropriate enforcement activities. However, a working group will be established to consider the feasibility of requiring suppliers to disclose the environmental emission impact of the power in their resource mix. NH House Bill 406 was re-referred back to committee for further study on March 18, 1997. The bill would have required owners of electric generating facilities to report information on the fuel sources and air pollutant profiles for each significant generator.

### Renewable Energy Resources

Requiring suppliers to disclose the nature of their resource mix is the most effective method of providing support for the development of a competitive renewable resource market. A working group has been established to develop standards for the disclosure of resource mix information.

## RELIABILITY

### Operational Reliability

RSA 374-F:3, I simply states: "Reliable electricity service must be maintained while ensuring public health, safety, and quality of life." Although under competition customers may negotiate lower levels of service reliability in return for a lower price, this situation is distinct from the concept of system reliability which can, according to the NHPUC, be maintained by a properly structured ISO. An ISO should have the ability and authority to:

1. balance load with resources under its control;
2. allocate curtailments related to transmission constraints based on market price;
3. redispatch to relieve transmission constraints; and
4. control sufficient assets to provide backup service if an unscheduled outage occurs.

According to the *Final plan*, short-term reliability can be ensured through ISO enforcement of applicable standards set by NERC and NPCC, while long-term reliability requires an effective Regional Transmission Group and an active futures market. The NHPUC intends to monitor and comment on these issues through their participation in the New England Conference of Public Utility Commissioners and through appropriate intervention at the FERC.

### Integrated Resource Planning

Integrated resource planning (IRP), RSA 378:38, requires utilities to evaluate all supply and demand resource options to meet customer needs. Although IRP's importance appears to diminish once generation is separated from transmission and distribution, it is still appropriate for distribution companies to conduct overall system planning. Therefore, utilities are required to include in their compliance filing a proposal on how to address system planning in the restructured environment. The NHPUC will work with the Legislature to repeal or modify RSA 378:38 as well as RSA 162-H, which requires the Site Evaluation Committee to determine the need for generation.

## RECIPROCITY

The *Final Plan* does not directly address the issue of reciprocity. Within the context of New England state cooperation, the NHPUC supports regional efforts to reform NEPOOL and enhance competition through industry restructuring. However, RSA 374-F:3 XIII. states in part:

> New Hampshire should work with other New England and northeastern states to accomplish the goals of restructuring. Working with other regional states, New Hampshire should assert maximum state authority over the entire electric industry restructuring process.

With respect to municipal utilities, a new law (HB 528) requires that any municipal utility formed after July 1, 1997 to provide open access. The interesting aspect of this law is that it applies to water, gas and electric utilities. Thus, it appears that in New Hampshire reciprocity has been extended to include other municipal utility services.

## TAX ISSUES

The NHPUC believes the legislature should consider the tax implications of the *Final Plan* and determine whether legislative change to address tax receipts is necessary or appropriate. The NHPUC recommends that any taxes levied on market participants be competitively neutral.

With respect to utility franchise taxes, HB 602 was signed by the governor on June 24, 1997 and becomes effective on January 1, 1998. HB 602 repeals the franchise tax and replaces it with a tax on the consumption of electricity. The consumption tax is set at .00055 cents per kWh and is designed to be revenue neutral. Existing municipal utilities are exempt from the consumption tax.

With respect to local property taxes, HB 566 was signed by the governor on June 20, 1997 and became effective on March 1, 1997. This bill provides that property used in the generation of electricity be subject to local property tax regardless of its ownership and repeals the exemption of independent power producers from taxes that otherwise would be applicable only to public utilities. The bill preserves a municipality's right to tax an electric generation plant as real estate when the plant is unregulated.

# NEW JERSEY

## BACKGROUND

During 1995, New Jersey electric customers consumed nearly 67,000 gigawatt-hours of electricity which generated total revenues to the utilities of $6.9 billion. The residential customer class consumed 34% of this power; the commercial sector used 45% and the industrial class was responsible for over 21 percent with a slight residual of 0.8% consumed by other customers. In respect to electric rates, New Jersey is a high cost state with average revenues per kilowatt-hour for all customers at 10.44¢ per kWh. Revenue for the other individual classes was 11.98 ¢/kWh (residential), 10.23¢ (commercial) and 8.15¢ (industrial).

Electric utility rates in New Jersey have consistently been among the highest average rates in the nation for many years. New Jersey is concerned that high rates are not only a burden on the residents of the State, but have hindered New Jersey's ability to retain and attract business. Reducing historically high rates was believed to be critical to the efforts to improve the climate for economic development in New Jersey and to ease the burden on consumers and small business. The restructuring of the power industry in the State focuses on increasing competition in both the wholesale and retail markets for three primary reasons: 1) to reduce electric rates for all ratepayers; 2) to expand the choice of services and products for all consumers; and 3) to ensure that New Jersey remains competitive in the regional, national and international markets.

Electric utility restructuring was first set forth in March 1995 with the release of the New Jersey Energy Master Plan Phase I Report by the New Jersey Energy Master Plan Committee, under the auspices of Governor Christine Todd Whitman and Herbert H. Tate, President of the New Jersey Board of Public Utilities (BPU or the Board) and Chair of the Committee. Energy Master Plans are required every three years, and are generally integrated resource planning exercises. However, the Board initiated an expansion of the Energy Master Plan exercise into an investigation of electric restructuring. Advisory groups made up of utilities, large consumers, residential representatives, contractors, and others participated in the Energy Master Plan process.

The Phase I Report made several policy recommendations to be implemented in the short-term, to address immediate competitive pressures in the State caused by high energy prices, and to prepare for the transition to competition. These identified measures included passage of legislation providing standards for rate flexibility as an interim measure to allow New Jersey's electric utilities to compete to retain "at risk" customers and attract new customers, and legislation permitting alternative (non-traditional rate base/rate of return) regulation to align the interests of customers and utility shareholders, and to stimulate efficiency and innovation. In addition to the recommendations for interim action to address the changing marketplace and economy, the Phase I Report also explicitly directed the BPU to investigate possible changes to the structure of the electric power industry in New Jersey as a more longer term means of achieving a lowering of the cost of electricity in the State.

Beginning with the release of the Phase I Report, the State embarked on the goal of achieving increased competition. In July 1995, the State Legislature adopted, and Governor Whitman signed into law, a Bill that allowed the State's electric utilities to offer electric rate discounts to individual customers under specific extenuating circumstances. This was enacted as a short-term measure to address competitive threats caused by high electric rates, including possible business relocation out of State, with a concomitant loss of jobs, and decisions by in-State customers to build on-site generation and by-pass the native utilities.

In January 1997 proposed findings and recommendations were made in a report as part of the Energy Master Plan Phase II. The Board issued its findings and recommendations on April 30, 1997 following consideration of comments filed by participants. This report provides specific proposals to restructure the electric power industry in New Jersey. The primary recommendation is that, by October 1998, a percentage of retail electric customers in New Jersey will be given the ability to directly choose their electric power supplier, and that by July 2000 all New Jersey retail customers will have the freedom to exercise that choice. This report also recommends near-term electric rate reduction in the range of five to ten percent, in connection with the phase-in of retail competition.

There is currently no state legislation on restructuring. The Board is proceeding in what it hopes will be a parallel path with the Legislature. In order for the Board's restructuring plans to be realized, the Legislature must act to end monopoly provision of electricity, and other issues, including power plant siting. The Board will be receiving restructuring filings during the summer of 1997 and begin its analysis and hearing process. Work schedules are based on meeting the October 1998 target for initiating open access. There appears to be general acceptance of restructuring by all parties in New Jersey. The Board staff hope the Legislature will take actions necessary to approve restructuring by the summer of 1998. This summary is based on the findings and recommendations of the Board as filed in April 1997.

## MARKET STRUCTURE

The Phase II Report recommends that retail competition not be introduced simultaneous with the implementation of full wholesale competition as provided by FERC Order 888. It is believed that it would be a wise and prudent approach to allow a period of time for the new marketplace featuring wholesale competition, once approved and fully implemented, to mature and work out the inevitable kinks before introducing the additional complexities associated with supplier choice for retail customers, numbering many times the quantity of wholesale market participants. The Phase II Report recommends that retail competition be phased in over a period of years. The Report recommends that beginning in October 1998, retail competition would be introduced to a small percentage of total customer load. It would proceed along the following timetable:

| Date | % of Total Customer Load |
|---|---|
| Oct. 1998 | 10% |
| Jan. 1999 | 20% |
| Apr. 1999 | 35% |
| Oct. 1999 | 50% |
| Apr. 2000 | 75% |
| Jul. 2000 | 100% |

Consumers have for decades received what is referred to as "bundled" electric service at one price. This bundled service actually has encompassed a number of discrete services. Because utilities have operated as vertically-integrated, regulated monopolies, these discrete services have been virtually indistinguishable to the consumer. The consumer receives one package of delivered power to the meter. That package of "bundled" power services is delivered at a price which is regulated by the BPU, based upon the cost of providing service.

As competition is introduced into various sectors of the electric industry, these services will have to be separately identified and billed. Particularly, competitive services will have to be separated from those which will continue to be provided on a monopoly basis by the electric utilities, in order that customers may be able to clearly identify where they have the ability to choose. The separate services that are currently encompassed in "bundled" electric utility service and rates include generation service, transmission service, distribution service, and customer services. In addition, a number of "customer-side" services are currently offered by utilities, at a separate charge, in competition with independent contractors.

The Phase II Report recommends that generation service be opened to competition, and the price for that service would no longer be regulated. Rather, consumers will be able to shop for that service, and will pay market prices. Transmission service will be provided on a regulated basis from a regional Independent System Operator; transmission services will be regulated by the FERC. Distribution services will continue to be provided on a monopoly basis by the electric utility, regulated by the BPU. Customer services, at least initially, will be provided by the electric utility at prices regulated by the BPU.

The specific industry model for the introduction of retail competition was hotly debated in the New Jersey restructuring proceeding. The Board concluded that the generation (production) function is no longer a natural monopoly, and that power suppliers can and should compete directly against one another. For this to occur, the current vertically-integrated industry structure should be unbundled at a minimum into separate generation, transmission, and distribution functions.

Three principal industry models for the introduction of retail competition have been proposed and debated: the poolco model, bilateral contracts model and a hybrid of the two. All of these models rely upon an ISO to provide transmission service on a fair and equal basis and manage the flow of electrons over the transmission system and to ensure overall system reliability; however, the nature and degree of control of market participants varies significantly among the models, with poolco generally imparting the greatest degree of control over market participants and the bilateral model generally the least.

In the poolco model, there is a central power pool (Pool), commonly referred to as the "power exchange" or "energy market", for which membership is mandatory for all generators. In the poolco retail model, all buyers are required to purchase power directly from the Pool. In essence then, the Pool represents a competitive wholesale market and the retail customer remains captive to the local utility for the supply of power (albeit at a competitive market price rather than a regulated, cost-based rate as is currently the case).

In the bilateral contract model also referred to as "direct access" or "customer choice," retail customers negotiate directly with sellers in the marketplace for terms of delivery and price of electric energy and capacity. The role of the ISO is much more limited than with poolco: it receives from the suppliers information related to the transactions, including the location and dispatch schedule of generators, and the delivery point(s) (the price of the transaction is not considered relevant to the ISO). The ISO would have the ability to procure capacity and energy on a short term basis to maintain system balance and relieve transmission constraints.

The hybrid model, which consists of bilateral contracts as well as a voluntary Pool, combines many of the features of poolco and direct access as previously described. Retail customers would have the ability to negotiate a power supply agreement directly with a supplier of their choice, or may simply choose to accept Pool-supplied power at the market clearing price (or as hedged via a contracts-for-differences or CFD). CFDs are financial instruments that provide retail customers the ability to hedge the fluctuations in Pool prices and otherwise establish a known price around power physically delivered through the Pool. In the hybrid model, participation in the power exchange is voluntary for both generators and customers (or their aggregators).

The Phase II Report recommends that the hybrid model for retail competition providing for both bilateral contracts and a voluntary power exchange, will best serve the interests of the State. The hybrid model combines the attributes of both the poolco and the straight bilateral contract approach and, conversely, mitigates the alleged shortcomings of both. By permitting customers the freedom to negotiate power purchase arrangements directly with suppliers, there will truly be customer choice, providing the impetus for the creation of a wide range of services and pricing options to best meet individual customer needs.

## STRANDED COSTS

The issue of stranded cost was studied extensively and the following potential causes of stranded costs were identified:

* **Regulatory actions**- these would include actions by regulators to permit retail customers to bypass utility generation to choose their supplier of power, as well as mandates that may change utility pricing from cost-based to market-based.

* **Customer-installed self generation and demand side management (DSM)**- these actions by customers could reduce customer consumption, thereby reducing overall revenue contribution towards utility assets.

* **Customer relocation out of the utility's service territory**- such actions by customers result in a loss of contribution towards utility assets. Under current regulation, such lost revenues are netted against net revenue increases from new customers and prospectively recovered from remaining customers in future rate cases.

With respect to the potential causes of stranded costs, for purposes of the Phase II Report it was deemed appropriate to focus primarily on regulatory actions. Specifically, the BPU felt it must address those stranded costs which are or may be created as a result of the recommendations in the report to open the power generation and supply market up to competition.

The report identified the following potential sources of stranded costs:

* Utility-owned generation;

* Long and short term power purchase agreements with other utilities;

* Long term power purchase contracts with non-utility generators;

* Utility regulatory assets; and

* Other: down-sizing and restructuring costs, social policy programs and stranded benefits.

Because of the current high level of electric utility costs, the magnitude of the potential stranded costs of New Jersey electric utilities is substantial. The report provided a range of estimates of the stranded costs for each utility by major category. The range is quite wide, depending most specifically on the assumed future market price for power. For the reasons described previously, the magnitude of a utility's stranded cost is inversely related to the actual market price for power; i.e. the lower the market price, the more of the utility's current costs will be "uneconomic." The range of State-wide stranded costs, broken down by major category, was as follows:

| | Low | High |
|---|---|---|
| Utility Plants: | | |
| Nuclear | $4.0 billion | $7.0 billion |
| Steam & Other | (2.0)billion | $2.9 billion |
| Purchase Contracts: | | |
| Non-Utility | $3.5 billion | $5.3 billion |
| Utility | $0.1 billion | $0.1 billion |
| Regulatory Assets: | $1.5 billion | $1.5 billion |
| Total: | $7.1 billion | $16.8 billion |

What is evident from the table above is that the potential magnitude of utility stranded costs in the State is driven to a large extent by two factors: high cost utility-owned nuclear power plants and high-priced supply contracts with non-utility generators, (otherwise referred to as independent power producers (IPPs)). Depending on whether the low or high end range of estimates is used, nuclear power accounts for about 40-55% of the total stranded cost problem; IPP contracts account for anywhere from one-third to one-half of the estimated stranded costs.

It is the BPU's opinion that eligibility for stranded cost recovery, should be limited to those costs which would otherwise be unrecoverable as a direct result of New Jersey's decision to open the power generation market up to competition. As a result, eligibility for stranded cost surcharge recovery would be limited to costs related directly to utility power supply. More specifically, the following would be included as eligible costs for inclusion in a stranded cost charge:

* Utility generation plant.
* Long and short-term power purchase contracts with other utilities.
* Long term power purchases contracts with non-utility generators.

The BPU concluded that the other identified potential sources of stranded costs, including regulatory assets, down-sizing and restructuring costs and social program costs, are not directly put at risk through the introduction of competition into the retail power generation market, and can be addressed through more traditional ratemaking techniques. Moreover, as generation-related stranded cost charges will be a transitional, non-permanent tool, as opposed to these other categories which may require longer term commitments, this is further basis for concluding that identified "other" categories are not appropriately recovered in a stranded cost charge.

The Report proposes that for a limited number of years, utilities would have an opportunity to recover stranded costs associated with generating capacity commitments made prior to competition. The BPU recommends the opportunity for full recovery of stranded costs contingent upon the utility meeting conditions, including a near term 5 to 10 percent rate reduction. The report encourages all stakeholders to explore all reasonable means to mitigate IPP contracts. "Securitization" of stranded cost is considered in the Report, as a means of lowering interest rates and providing savings to ratepayers. A market transition charge (MTC) would be established to recover allowable stranded costs. The MTC would be established for each utility through the 7/15/97 filing which must include MTC composition, magnitude, and duration.

**Securitization**

A relatively recent mechanism to help address the stranded cost issue, which is now being explored in a number of other states, is the so-called "securitization" of such costs. The Board, in its findings and recommendations, states, "Securitization essentially entails the financing of stranded costs, up to a defined limit, by issuing debt (so-called :asset backed securities, or ABS), and paying the interest and principal associated with the ABS through a surcharge levied on the utility's customers."

The BPU does not be regard securitization as a panacea, only as part of a solution to the stranded cost problem. Moreover, securitization, as a relatively risk-free mitigation tool for utilities, cannot serve as the sole source of potential rate reductions. In addition, because of the nature of securitization, whereby proceeds may be utilized in rather large up-front lump sums, to buydown contracts or retire debt and equity on the basis of market price projections, the BPU believes it advisable to put a limit on the amount of securitized debt which can be issued by each utility. It is further emphasized that proceeds from the sale of securitized bonds must be utilized by the utility solely to reduce generation-related stranded cost, and not to subsidize any other activity of the utility. The BPU will require that utilities, within their restructuring filings, provide a schedule of various MTC charges, both with and without securitization, and the related level of rate decrease.

**CUSTOMER ISSUES**

It is the stated intent of the Phase II Report that all customers benefit from a competitive electric market . The BHU is attempting to bring about a restructured electric utility industry that will allow for retail choice while providing for continued service reliability. The plan provides for all customers to be gradually afforded to opportunity to choose their retail provider of electricity. The plan, therefore does not appear to particularly advantage one class of customers over another. The reality may be that higher load factor customers have greater opportunity to choose their provider, but as proposed, all customers are to have the opportunity to choose. As will be discussed later, the plan proposes to restructure the tax burden on utilities, and gradually reduce tax rates which should allow for rate reductions of approximately six percent.

**Universal Service/Supplier of Last Resort**

For purposes of the Report, in a competitive power supply market structure, basic generation service can be broken down into two categories of customers:

1. service for any customer who has not notified the distribution company of an alternative supplier choice. This category can be further broken down into customers with competitive supply options presented who simply decline those offers (so-called "choose-not-to-choose" customers), and those customers who have been presented with no offers for supply by alternative suppliers;

2. service for any customer who is dropped by its alternative supplier for any reason, including non-payment.

The Report concludes that, in order to provide for as orderly a transition as possible, at least during an initial transition period, the local distribution utility should be assigned the responsibility of providing basic generation service. The BPU believes that, at least until the transition has progressed and there is a greater comfort level, consumers ought to have the option of simply "choosing not to choose" and buying essentially "rebundled" electric service from the local utility.

The BPU states that prices for basic generation service must not be discriminatory, and should therefore be identical for all customers within each rate class. Importantly, however, basic generation service customers should nonetheless have access to market priced power and thereby benefit from restructuring like all other customers. Accordingly, the generation component of basic generation service rates should be based upon a pass-through of the cost incurred by the distribution company to purchase power (including electric energy and capacity) in the competitive bulk power market. These power purchase costs would be recovered via an adjustment clause, similar to the current fuel clause, in order to ensure timely recovery by the utility of these costs incurred on behalf of basic generation service customers.

## MARKET POWER

The Phase II Report requires that each electric utility file a restructuring plan. The Report also recommends that each plan provide a plan for, at a minimum, functionally unbundling its generation assets from other parts of its business. Such functional unbundling plan must include sufficient protections to ensure that the generation company is essentially functioning as a separate business unit, with the distribution company treating the affiliate generation company no differently than other competitive suppliers.

The report does not recommend mandatory divestiture of generating assets at the present, until such time as specific and detailed market power analyses have been performed and analyzed. There is concern that given a current merger among utilities in the Pennsylvania/Jersey/Maryland (PJM) Power Pool, a concentration of market power gives pause to divestiture.

## PUBLIC PURPOSE PROGRAMS

### Environmental

The BPU believes that the combination of proposed federal U.S. Environmental Protection Agency (USEPA) and possible FERC actions, along with collaborative state efforts, particularly the efforts of the Ozone Transport Assessment Group (OTAG), can effectively safeguard against the potential adverse environmental impacts resulting from open transmission access. In that regard, however, Congressional action may be needed to clarify the USEPA's ability to ensure a fair solution to pollution transport in lieu of a consensus. Because the BPU believes federal action is the most efficient and effective strategy to address the transport issue, it advocates giving the existing and proposed measures a reasonable opportunity to successfully mitigate any increases in emissions in downwind states. New Jersey, however, will develop a contingency action plan if federal action fails to mitigate adverse environmental impacts caused by electricity restructuring. The BPU will continue to work closely with the DEP on this important issue.

### Assistance Programs

Programs and policies include the following: the winter moratorium program, which prohibits shut-off of power to certain categories of disadvantaged customers for non-payment during winter months; the costs associated with serving "bad debt" customers; low income assistance and weatherization programs, and existing late payment and deposit policies which are generally more liberal than those practiced by companies in other, unregulated industries. The BPU believes that these policies, which have been in place for many years, are an important part of the State's safety net for the less fortunate. There is a legitimate concern as New Jersey moves to a competitive energy market in the State that these protections will erode. The BPU believes that it is an appropriate goal that as part of electric industry restructuring and the transition to competitive markets, the State should preserve the provision and funding of social programs currently provided for by the "bundled" electric utilities in the State.

### Demand Side Management

The Board currently has regulations in place that set the policies under which the electric and gas utilities in the State are to offer a number of conservation, energy efficiency and load management programs, collectively referred to as demand side management (DSM) programs. Contrary to the strict command and control approach begun in the late 1970's, the Board's current DSM Incentive regulations provide various financial incentive mechanisms to encourage the utilities to fund and promote various cost-effective DSM programs (cost-effectiveness in this context is generally described as a comparison of the direct and indirect costs of the program to the value of energy and capacity savings, plus environmental benefits, derived from the installation of DSM measures).

It is the expectation of the BPU that over time the distribution utilities will disengage from serving a primary role in funding and/or implementation of DSM. The BPU envisions an increasing reliance on market forces to provide the impetus for installation of energy efficiency measures at customer locations. This will include the offering of DSM services by ESCos as part of an ever broader array of energy services, including power supply, in a competitive marketplace. The BPU proposes that during the transition to a restructured industry, that DSM programs continue to be implemented by utilities, and funded through rates. Initially, that funding would continue at levels consistent with each utility's currently-approved DSM Plans, as reviewed and approved pursuant to the existing DSM rules as codified in N.J.A.C. 14:12.

For the longer term, in order to prepare for the transition to an increasing reliance on market forces, we propose modifying the existing DSM regulations to provide for a biannual filing by each electric utility for review by the Board of a "comprehensive resource analysis." The purpose of this filing would be to determine the appropriate level of energy efficiency and renewables programs that should continue to be funded through the distribution company's rates, and to identify the specific programs to be implemented by each utility.

**RELIABILITY**

Under the current electric power industry structure, the State and indeed the nation enjoys a high degree of service reliability. The BPU. states that it is an absolute requirement that the reliability of the electric power grid in New Jersey should not be compromised to any degree as a result of industry restructuring.

Reliability can generally be broken down into three main categories: First, is the assurance that there are and will be adequate supplies of generating capacity to meet customer demands at all times. This includes a reserve margin to cover such contingencies as abnormal weather and planned and unplanned power plant outages. The second area relates to the high voltage transmission system, which moves electrons in bulk from remote points of generation to local distribution systems. The third area where reliability of electric service to the end user can be affected is in the distribution system.

The BHU does not envision industry restructuring fundamentally altering the obligation of the electric utilities to connect customers into the system and deliver power to the meter. Accordingly, the responsibilities of the utility companies attendant to assuring safe and reliable distribution service will be fundamentally the same as today. The utility will continue to be obligated, pursuant to BPU regulation, to plan, size and maintain the distribution system in a manner that assures that power can be delivered at all times from the point of delivery off the transmission system to the end user.

Accordingly, the BPU has focused on the potential impacts of restructuring on transmission system reliability and the reliability of supply. Specifically, it is clear that the traditional mechanisms for ensuring both short and long term system reliability are based upon the existing industry structure, and do not entirely comport with the competitive marketplace.

Currently, both short and long term bulk power system reliability in the Mid-Atlantic region is assured in the following manner, principally through the PJM power pool. The regional ISO, as envisioned by both the Board and by the FERC as set forth in its various Orders on the subject, will continue to have the responsibilities currently performed by PJM, as described above, concerning the maintenance of short-term bulk power system reliability. This would include enforcement of applicable reliability standards on all generators participating in the regional marketplace. It is the conclusion of the BPU that it should require, as a condition for eligibility to serve retail electric customers in the State, that third party suppliers commit to meet all NERC (or successor) reliability standards.

The BPU envisions that the ISO, in appropriate collaboration with regional stakeholders, will take on the primary transmission system planning function currently performed by PJM. Utilities, or other third parties, will actually undertake transmission facility construction and maintenance, with costs being reimbursed by the ISO via transmission charges imposed on system users by the ISO.

The BPU asked that each utility specifically address in future restructuring filings how to best assure that there will be adequate generating capacity in the future to meet future customer demands, consistent with the BPU's conclusion that reliability cannot suffer as the State moves to a competitive power market. The BPU acknowledges that the centralized planning system for ensuring adequate generating capacity is poorly suited, and indeed is incompatible with a competitive market structure. The BPU, in the Phase II Report, did not recommend a particular approach for dealing with generating reliability.

**Power Plant and Transmission Line Additions**

The BPU does not envision restructuring necessitating any State-mandated changes to local zoning and land use ordinances. However, at present, electric utilities, as provided for in N.J.S.A. 40:55D-19, may file with the Board for an override of a siting denial by a municipality per local zoning ordinances, and the Board may so grant, if it is shown that a proposed power plant (or other proposed utility facility such as a transmission line) is "reasonably necessary for the service, convenience and welfare of the public." The intent of the law is essentially to provide the Board with the ability to override decisions made in a particular locale, which do not best serve the larger public benefit. Non-utility generators (NUGs) do not enjoy similar State-sanctioned redress against adverse local decisions. In order to provide for a competitive generation market, there must be equal treatment of all generators with respect to siting. N.J.S.A. 40:55D-19 must either be expanded to include NUGs, or must be amended to eliminate a utility's ability to seek override of local ordinances for purposes of constructing a generating plant.

On the other hand, the Electric Facilities Need Assessment Act (EFNAA) provides that, prior to the construction of a new electric generating plant of 100 MW or more; or the addition to an existing electric generating plant that will increase its capacity by 25% or by more than 100 MW (whichever is smaller), a public utility must apply for and obtain a Certificate of Need (CON) with the BPU. The EFNAA, adopted in the early 1980's in the wake of large and costly nuclear power plant construction programs, provides for a lengthy and detailed review by the Board of the need for a planned power plant prior to construction. This process is estimated to take up to three years to complete. In addition to addressing the need for the additional generating capacity, the EFNAA requires as a condition to issuing a CON that the proposed plant is determined to be the most efficient, economic and environmentally sound option available. NUGs are not covered by the EFNAA, and accordingly are not required to seek nor obtain a CON prior to construction. While in a regulated, monopoly electric utility industry structure the EFNAA provided important public protections against wasteful and unnecessary utility power plant construction projects, in a competitive marketplace, where the project owner and not the ratepayer is taking the risk of a poor investment, such a requirement is unnecessary. Moreover, imposition of CON requirements on one segment of the industry (i.e. utilities) and not another, results in an unlevel playing field. The BPU recommends that, concurrent with the transition to a competitive retail electric marketplace, that the EFNAA be repealed.

**Resource Planning**

As mentioned previously, the BPU solicited suggestions on how best to insure adequate generating capacity. The BPU acknowledged in discussing DSM that given the transition to a fully competitive marketplace, it no longer sees the need for a formal Integrated Resource Planning process, where decisions on the need for, and type of generation resources for the utility, in addition to the assessment of DSM, are made. The BPU will through the DSM "comprehensive resource analysis" monitor utility resource decisions, but will not have authority to mandate resource selection.

## RECIPROCITY

New Jersey has not dealt with this issue in detail at this time, according to the BHU. It is acknowledged that some neighboring states, such as New York and Pennsylvania have made greater progress on this issue.

## TAX ISSUES

Electric and gas utility rates in New Jersey currently include the State Gross Receipts and

Franchise Tax (GRF&T). This tax, which is collected on a per unit (kilowatt-hour) basis, represents about 13% of electric and gas utility revenues. The GRF&T tax rate, which is among the highest in the country, contributes to the non-competitiveness of utility rates in New Jersey relative to national and other regional averages.

The Whitman Administration, has proposed a reduction of the current energy tax rate by 45% over a seven year period. Moreover, the proposal recommends various changes, described below, to modify the energy tax policies in the State to conform with the changes taking place in the natural gas and electric power industries.

Under current State law, a minimum of $685 million in annual GRF&T revenues is guaranteed to be returned to the State's municipalities. The formula used to allocate these funds among the State's 567 municipalities is based in substantial part on the value of utility equipment located within each town. GRF&T distributions represent the second largest funding source, behind only property taxes, for the municipalities. Accordingly, GRF&T revenues have a direct bearing on municipal property taxes. In 1995 GRF&T revenues collected by the State via utility rates totaled some $1.197 billion. Of that amount, $782 million was distributed to the municipalities.

GRF&T taxes are not assessed nor collected on wholesale energy transactions. Moreover, these taxes only apply to utilities; accordingly non-utility sellers of energy, such as natural gas marketers and cogeneration facilities, are exempt from GRF&T. However, these entities pay various taxes from which the utilities are exempt as well as other taxes which are paid by utilities. These taxes are:

Corporate Business Tax
Sales and Use Tax
Real Property Tax

As a result, entities which in many cases are, or soon will be in direct competition with each other have differing tax burdens. This results in an unfair tax advantage which may skew the competition. As competition increasingly permeates the energy industries, it is imperative that these tax advantages be eliminated, and that the playing field be levelized.

The Board is proposing a phased introduction of supplier choice for electric customers in the State beginning in late 1998. Under current energy tax law, as retail competition is opened up and electric customers are provided the opportunity to switch to non-utility suppliers, the State stands to lose a significant portion of the $875 million in GRF&T currently collected from electric utility customers. These figures clearly dwarf the fiscal impacts of natural gas competition and, if remedies are not implemented, this could have significant fiscal impacts on municipalities as well as the State.

It is for the these reasons that the Board regards as essential to the efforts to introduce retail electric competition in New Jersey, a reform of the energy tax policies in the State. The proposed reforms are intended to levelize the tax playing field among competitive energy suppliers in the State in both the retail and wholesale markets, as well as to prevent the severe tax revenue erosion which would result under the current system when retail electric competition is implemented. The BPU and state Department of Treasury recommend replacing the existing GRF&T tax on utility rates with the imposition of two taxes, applicable equally to all energy suppliers, as well as a transitional tax (TEFA) paid by all users of the utility distribution system for a limited number of years. Specifically, utilities would pay the State corporate business tax (e.g. income tax) as do all other entities doing business in the State, and the State sales tax of 6% would be collected on all retail sales of energy services, whether provided by a utility or non-utility entity. The TEFA will be set to ensure that, at the outset of tax reform, the overall tax revenues collected will remain the same as under the current system. It is also proposed that there be a gradual phase-out of the TEFA over a seven year period which, upon completion, would reduce the total energy tax burden on utility customers by about 45% (the remaining imposition of the sales tax and corporate business tax would produce a total tax burden of about 7%, as compared to the current GRF&T tax rate on utility sales of 13%).

**Role of the BPU after Restructuring**

The BPU recommends that the need determination process for new generation be repealed from state law. The market will determine the timing, size, and price, for future generation in a restructured environment. Existing land use and environmental regulations over power plant siting will remain in effect. The BPU sees itself as the forum to settle disputes between power marketers and regulated distribution utilities. These distribution utilities' rates will be set using performance based regulation with a price cap.

The BPU will continue to perform the Energy Master Plan exercise, which will in part identify future needs for capacity additions. While the BPU would not have direct regulation of generation providers, the BPU will have the hammer over distribution utilities to provide reliable service to its customers. The BPU will also continue to work with the PJM power pool and/or its successor in ensuring reliable service.

**Electron Disclosure**

The BPU has discussed the idea of "green labeling" as a way to market electricity from "environmentally friendly" generation sources. There currently is no plan on verifying the source of electricity or labeling on customer's bills.

# NEW YORK

## BACKGROUND

The state of New York is served by seven investor-owned utilities: Niagara-Mohawk Power Company, Consolidated Edison, Long Island Lighting Company, Rochester Gas and Electric, Orange and Rockland, Central Hudson Gas and Electric, and New York State Electric and Gas. The state is also served by 55 municipal utilities and two cooperatives. Based on 1995 data, New Yorkers used some 130,000 gigawatt-hours of electricity with revenues of $14.4 billion. With respect to market share of this energy, 31% of retail sales in New York were residential, 41% commercial, 19% industrial and 10% were classified as "other." This compares with the national averages of 35% residential, 28% commercial, 34% industrial and 3% "other." New York has among the highest electric rates in the country. Average revenue per kWh was 11.06¢ with individual class revenues of 13.9 ¢/kWh for residential customers, 11.92¢ for commercial, and 5.79¢ for industrials.

The major impetus for competition in the electric industry in New York has been high rates. Between 1988 and 1995, electric rates in New York state rose 30%. In 1995, the average system revenue of 11.06¢, was 60 percent above the national average of 6.9¢. Long Island Lighting Company has the highest rates in the continental U.S., due in large part to the Shoreham nuclear plant, which cost about $5 billion and will never operate. New York utilities are also burdened with a large number of above-market purchased power contracts. In 1995, 35% of the generation in the state was purchased from independent power producers. The move to retail competition has been initiated by the Commission without any specific legislation mandating it. They believe their existing statutory authority allows them to open the retail market to competition on their own initiative.

On May 16, 1996, the New York State Public Service Commission (PSC) issued its plan (the "Competitive Opportunities Case", Opinion and Order No. 96-12) to introduce retail competition to the state. The vision articulated in the order included the following objectives:

1. Effective competition in the generation and energy services sectors.

2. Reduced prices resulting in improved economic development for the state as a whole.

3. Increased choice of supplier and service company.

4. A system operator that treats all participants fairly and ensures reliable service.

5. A provider of last resort for all consumers and the continuation of a means to fund necessary public programs.

6. Ample and accurate information for consumers to use in making informed decisions.

7. The availability of information that permits adequate oversight of the market to ensure its fair operation.

Consistent with the vision established, the order also set several general goals:

1. Lowering rates for consumers.

2. Increasing customer choice.

3. Continuing reliability of service.

4. Continuing programs that are in the public interest.

5. Allaying concerns about market power.

6. Continuing customer protections and the obligation to serve.

The order required the five IOU utilities to file restructuring proposals and rate plans by October 1, 1996. NIMO already filed a proposal in 1995, and Lilco was not required to file because of the involvement of the Long Island Power Authority in their restructuring. The Commission believed, due to the differing circumstances of each utility, that restructuring plans were best addressed on an individual company basis. Following the filing of the plans by the utilities, the PSC staff engaged in negotiations with each company to reach a settlement agreement. To date, all five of the companies have signed settlements with the PSC staff. The Commission, however, has not yet approved the settlements.

## MARKET STRUCTURE

### Retail Competition

The order requires a schedule for introducing retail access to all customers, a set of unbundled tariffs consistent with the retail access plan, and a rate plan for the transition period. The rate plan must include rate reductions and address Strandable costs. The plan must include an identification of public policy programs not recoverable in a competitive environment, and rate mechanisms that will fund such programs in a competitively neutral manner. It must include an examination of load pockets unique to the utility, and other market power problems, and a plan to mitigate such problems. A summary of the retail access phase-in schedules that emerged from four of the settlement agreements signed thus far is shown below:

| **Central Hudson** | **Con Ed** | **Orange & Rockland** | **Rochester Gas & Electric** |
|---|---|---|---|
| Industrials 1997 | Fall '97 - Fall '98<br>5% of load; capacity and energy | Fall 1997 - All Industrial Load; energy only | |
| Early 98 - 12/31/99<br>8% of load;<br>Energy<br>Capacity and Energy | | May 1998<br>100% of load; Energy<br>Only | July 1, 1998<br>10% of load;<br>Only |
| 1/1/99 -12/31/99<br>16%<br>and | 4/99 - 4/00<br>10% | May 1999<br>100% of load;<br>Capacity and Energy | July 1, 1999<br>20%; Capacity<br>Energy |
| 1/1/00 - 12/31/00<br>24% | April 2000<br>20% | | July 1, 2000<br>30% |
| 1/1/01 - 6/30/01<br>28% | April 2001<br>30% | | July 1, 2001<br>46% |
| July 1, 2001<br>100% | April 2002<br>100% | | July 1, 2002<br>100% |

**Obligation to Serve:** Utilities are required to insure that there is at least one supplier of energy who will serve those customers in areas where competitive alternatives are not available. The order states that the T&D companies will be required to supply power in these instances, at least in the short run.

**Individual Utility Restructuring Agreements**

**Orange and Rockland (O&R)** The settlement agreement between O&R and the Commission staff was signed on March 25, 1997. Under the settlement agreement, O&R will implement a four-year rate plan which provides an opportunity for large industrial customers to realize an average price of 6 cents per kWh, through a combination of energy choice pursuant to O&R's PowerPick retail access pilot program, and base rate reductions. The plan calls for rate reductions to the remaining classes of 1.09% in the first year, and an additional 1% the following year. These rate reductions will remain in place for the four-year term of the agreement. During this time, earnings by the regulated utility in excess of 11.5% will be shared, with 50% going to write down generation assets, 25% credited to the customers, and 25% retained by O&R's stockholders.

Under the agreement, O&R will file unbundled tariffs in August of 1997. These unbundled tariffs will consist of the following components:

- Power Supply (energy and capacity)
- Power Delivery
- Governmental Tax Surcharges
- System Benefits (mandated public policy programs)
- Competitive Transition Charge

The Power Supply component will be used to bill customers for energy and capacity costs, regardless of the provider, unless other approved billing procedures are chosen by the customer. Until the wholesale energy market becomes effective and/or full retail access is implemented, energy costs will continue to be charged through the existing Fuel Adjustment Clause and the fixed costs of generation and purchased power will continue to be recovered through the base rates approved as part of the settlement. When wholesale competition is implemented, the Fuel Clause will reflect energy purchases at market price made by the regulated delivery utility on behalf of its customers. The embedded capacity cost of O&R's generation will continue to be charged at tariff rates until the implementation of full retail access.

The Power Delivery charge will recover the costs associated with transmission and distribution, customer service (e.g. metering and billing), and O&R's Hydro and Gas Turbine facilities. The Governmental Tax Surcharge will contain all gross receipts, franchise, and governmental taxes.

On May 1, 1998, the existing PowerPick retail access pilot program (energy only) will be expanded to all customers. Effective May 1, 1999, full retail access for capacity and energy will be available to all customers. In the event the ISO is not fully operational by December 1998, and, in O&R's view the failure to implement the ISO would present technical obstacles to full retail access, the O&R may petition the Commission and show cause why relief from the retail access requirement, in whole or in part, is required.

**Consolidated Edison (ConEd)** ConEd and the PSC staff signed a settlement agreement on March 13, 1997. The plan calls for rate reductions for a five-year period beginning April 1997. Large industrial customers will receive an immediate 25% rate reduction. Under the plan, large commercial customers would receive a 10% reduction, and small commercial and residential customers would receive a 3.3% reduction. These rate reductions would be subject to change due to higher than expected inflation, new government mandates, and for a "system benefits charge" which would cover energy efficiency, R&D and other programs such as low income assistance. During the five-year transition period, ConEd would be allowed to recover stranded costs through its distribution charges. This would be accomplished through accelerated depreciation of its fossil and nuclear generation plant.

In addition, any earnings in excess of 12.9% ROE would be used to write down the assets. Any remaining fossil plant balances remaining after the five-year transition period would be recovered over the following ten years.

After the transition period, ConEd would be allowed to recover at least 90% of any remaining above-market costs associated with NUG contracts.

ConEd will begin to introduce retail competition into its service area within six months of approval of the agreement. Licensed Energy Service Companies (ESCOs), including ConEd's affiliated ESCO, will provide energy and related services. Initially, it will be offered to 10 to 15 large customers, and within 12 months the program will be expanded to include up to 60,000 customers representing 500 MW of load, with 300 MW reserved for large customers and 200 MW to all other customers. The retail access program will be expanded by 500 MW in 1999, and 1,000 MW in each year after that. Full retail access is targeted for the earlier of 24 months after the establishment of an ISO, reliability council and power exchange, or year-end 2002. Beginning in April 1998 ConEd will offer unbundled rates for those customers who choose alternate energy suppliers. The rate paid to ConEd (the T&D entity) will include customer service costs, distribution, transmission, and public policy programs such as energy efficiency and research and development.

As part of the plan, ConEd will divest to non-affiliated entities at 50% of its fossil generating capacity. The plan entails the formation of a holding company. ConEd will become a subsidiary of the holding company and will remain a regulated transmission and distribution company. This company will retain the fossil generation units until they are divested. However, the Indian Point Unit 2 nuclear unit will remain part of the T&D company.

On June 20, 1997 the Administrative Law Judge issued her Recommend Decision on the ConEd settlement plan. The Decision indicates that the plan "does not allow competition for generation and energy services to commence in a way that is fair to competitors or in the best interests of Con Edison's customers." The Decision directs the parties to meet again with regard to concerns involving market power, the transportation/delivery charge of the retail access tariff, the divestiture plan, and corporate structure.

<u>Rochester Gas and Electric Corporation (RG&E)</u> A settlement agreement with the staff was signed by RG&E on April 8, 1997. The agreement term is for the five years beginning July 1, 1997 through June 30, 2002, and includes rate reductions of 2.5% for small commercial and residential customers, 10% reductions for large industrial customers, and 4.5% reductions for all other commercial and industrial customers. The agreement also provides for a rate of $.059 per kWh for incremental manufacturing load of 50 kW or more. During the course of the agreement, any earnings in excess of 11.8% return on equity will be split with 50% retained by the stockholders and the remaining 50% to be used to write down generation and regulatory assets.

The retail access plan included in the settlement provides for phased in retail access which will allow all customers to choose their supplier by July 1, 2002. The company will submit a proposal to form a new holding company with the ability to form several subsidiaries for distribution, transmission, generation and retail energy services. RG&E's investment in the Nine Mile II and Ginna nuclear plants will remain with the T&D subsidiary. The agreement does not explicitly address Strandable costs, but does develop the rate plan to address their possible subsequent recovery. The parties agreed to meet in July of 2001 to discuss the treatment of Strandable costs.

In his recommended decision, issued on July 16, 1997, Judge Walter T. Monynihan said that the settlement agreement reached between the staff and RG&E was reasonable. To date the Commission has not voted to approve the agreement.

**New York State Electric and Gas Corporation (NYSEG)** NYSEG and the Commission staff reached agreement on July 30, 1997. As of this date, a copy of the settlement has not been obtained, however, a summary of its terms was available. Under the agreement, NYSEG will forego rate increases totaling 6% scheduled to go into effect in August of 1996 and 1997. NYSEG's rates will be frozen through July 31, 2002. Rates for large industrial and commercial customers will be reduced by 5% each year for the next five years. A retail access program will be established which will result in choice for all customers August 1, 1999. NYSEG will divest its fossil fuel generation to a regulated subsidiary. The actual fossil fuel generating units will be subject to an auction process in which NYSEG can participate. The agreement also allows for further rate reductions if NUG contracts can be renegotiated, and if securitization legislation is passed. The agreement will now be presented to the Administrative Law Judge. A Commission decision on the plan is expected by the end of October 1997.

**Central Hudson Gas and Electric Corporation (CHGE)** CHGE reached a settlement agreement with the PSC on March 20, 1997. Under the agreement, CHGE agrees to freeze its base rates through 2001. Earnings will be capped at 10.6%. Any earnings in excess of that amount are to be deferred until the July 1, 2001 termination of the agreement, at which time they will be used to offset Strandable costs.

The company has agreed to structurally separate its fossil steam generation resources, either through creation of a holding company, divestiture or other options, by November 1, 2000. The company's ownership in the Nine Mile Point 2 nuclear reactor, and its hydro and combustion turbine resources will remain as part of the T&D entity, and its costs will be recovered through its rates. CHGE would not be prohibited from establishing unregulated affiliates or subsidiaries to sell energy and related service both within and outside its service territory. They would not be prohibited from establishing non-energy related ventures, if these activities do not subject the regulated entities to undue risk.

The settlement includes a plan for the phasing in of retail access for residential, commercial, and small industrial customers. It also contains a program permitting large industrial customers to choose a 5% rate reduction, retail access, an "Energy Value Option Plan" (EVOP), or a combination of these options. The EVOP plan allows customers to take part of their service from CHGE and a portion from an alternate supplier.

Access for residential and commercial customers will begin in early 1998, and will be phased in as a percentage of total load. By July 1, 2001, all customers will have retail access.

Time recording meters will be installed for all customers who choose retail access. The meters will be selected, installed and owned by CHGE. Eventually, all customers will have time recording meters, and CHGE will be required to provide, at no charge, the most recent 24 months of metering data to any third party upon written request of the customer.

CHGE would be allowed a reasonable opportunity to recover all prudently incurred, verifiable and appropriately mitigated Strandable costs through a competitively neutral, non-bypassable wires charge, beginning at the time the company is restructured. The Strandable costs would include the difference between fair market value and book value of CHGE's fossil generation assets, production-related regulatory assets, IPP contracts, and transition costs.

On July 1, 1997, the Administrative Law Judge issued the Recommended Decision in the CHGE settlement agreement. The Decision indicates that the Settlement "does not adequately serve the policy objectives" adopted in the Commission's Order 96-12. It urges the parties to "fully consider the Settlement's potential as a foundation for a new and better negotiated agreement."

**Niagara Mohawk Power Corporation (NIMO)**

As noted above, NIMO was not required to file a plan with the PSC, because they had already filed a proposal for restructuring entitled "PowerChoice" in October of 1995. Under the plan, NIMO would separate its generation, including its two nuclear units and its NUG contracts, into an unaffiliated company.

The plan also calls for retail access for all customers by 2000. To date the PSC has not approved the Power Choice plan. NIMO is currently in the process of buying down several of their above-market purchased power agreements, and a settlement is contingent upon the outcome of that process.

## STRANDED COSTS

The plan describes strandable costs as "prudent, verifiable, and non-mitigatable utility costs that may become unrecoverable in a competitive market for electricity." The plan indicates that utilities should have a "reasonable opportunity to recover strandable costs." The calculation of the amount and timing of recovery of strandable assets must be addressed. The plan indicates that strandable costs may be recovered through a non-bypassable wires charge imposed by the distribution company, but requires that the companies use "creative means" to reduce the amount of strandable costs. None of the filed restructuring plans has attempted to fix a dollar amount for strandable costs. It is anticipated that this determination will be made later in the process of deregulation.

**Securitization**

Efforts to pass securitization legislation in New York over the past two years have been unsuccessful. Such legislation would authorize the PSC to allow utilities to securitize a portion of its regulatory assets, which includes investments required by the PSC for DSM and the costs of IPP buyouts and buydowns. In March of 1997, a securitization bill was passed by the Republican controlled Senate, however, the leadership of the Democratic controlled Assembly leadership does not support securitization legislation.

## CUSTOMER ISSUES

On May 19, 1997, the Commission issued its "Order and Opinion Establishing Regulatory Policies for the Provision of Retail Energy Services." This order addresses the oversight and consumer safeguards to be implemented when retail access becomes available in New York, including provisions for a provider of last resort and oversight of Energy Service Companies, or ESCOs. An ESCO has been defined by the Commission as "an entity that can perform energy and customer service functions in any competitive environment, including provision of energy and assistance in the efficiency of its use."

The future of the electric industry in New York as envisioned by the Commission will consist of a competitive generation market, a monopoly transmission and distribution market, and a competitive retail market. Under this regime, the transmission and distribution (T&D) companies will continue to connect customers to and deliver electricity over the transmission and distribution system.

The Commission has stated that, with the arrival of retail competition, each customer must be able to count on at least one supplier who will continue to provide electric service at reasonable rates if: (a) the customer chooses to make no change from its current situation. (b) a new supplier fails to meet its obligations, or (c) competitive alternatives are not yet available in the area. The order provides that, at least in the near term, the T&D company will act as this provider of last resort (POLR). The responsibilities of the POLR will be to: (a) accept all consumers subject to consumer protection rules, (b) meet consumers' electricity supply needs by obtaining electricity consistent with the Commission's decisions in the individual utilities' restructuring cases and the development of a competitive electricity market, and (c) provide any programs to help low-income customers that the Commission deems appropriate. T&D companies' obligation to serve will continue to consist of connecting all consumers to the electric system, maintaining the transmission and distribution system in their service territories, and delivering electricity to consumers in their service territories via the T&D system.

The order also addressed the consumer protections that will be applicable to consumers with the arrival of retail access. Currently, New York residential consumers are protected pursuant to the Home Energy Fair Practices Act, or HEFPA. HEFPA provides strong protections requiring prompt connection, limits on deposits, notice requirements for termination and continuation of service during the notice period, and assistance for payment of overdue bills for qualifying customers to avoid cutoffs. The Commission decided that the protections of HEFPA would continue to apply to those customers who receive their electricity from the POLR. However, the HEFPA requirements would not apply to ESCOs. Instead, the Commission articulated a set of protections that will be required of non-POLR ESCOs, to be implemented as a part of the ESCO oversight process:

- A requirement to give a prospective customer a disclosure statement that provides a complete description of their rights and responsibilities prior to making a commitment to the provider, including, at a minimum, a description of the complaint handling procedures available, rights and obligations regarding payment of bills, procedures for terminating the contract to provide power, and security deposit requirements and procedures.

- A minimum 15 business days' notice to the customer before ending the contractual relationship for electricity supply.

- Practices to ensure a smooth transition from one provider to another. This should include, at a minimum, procedures for how and when a switch of provider becomes effective and notification of the T&D company of such switches, and guidelines for the reporting of energy usage data.

- Protection from an unauthorized switch of provider (a.k.a. "slamming"), including, at a minimum, criteria for customer authorization of a change of the provider, verification procedures for change orders, and a mechanism for customers to "freeze" their selected provider.

- A process for resolving customers' complaints regarding the provision of electric service by ESCOs. This should involve an affordable means to resolve disputes, including convenient local access to the supplier. Customers should have an opportunity to reach the ESCO via a local or toll-free phone call, and have the right to appeal the ESCO's offered resolution to an independent third party.

The ESCOs would be allowed the flexibility to develop proposed procedures to meet the above requirements, which would be reviewed when the ESCO submits its application for eligibility. ESCOs would not be allowed to shut off electric service to any customer whose contract for service is terminated. Unless the customer arranges for service from another ESCO, the customer would continue to receive service without interruption from the POLR.

The Commission also outlined proposed changes to the existing consumer protection rules that would apply to the T&D companies in their role as POLRs. These changes would:

- Allow the POLR to require positive identification from residential applicants.

- Allow the POLR to require a deposit or other remedy if a residential customer has outstanding past due bills from another provider.

- Eliminate or streamline existing requirements for utility bill contents

- Allow the application of a partial payment by customers on a combined bill for T&D and ESCO services to be applied to the balance for T&D services before any portion is applied to the T&D portion.

The commission also said that additional requirements might be added after they consider metering and billing issues.

The Commission found that the PSC would be the central authority to oversee the operations of ESCOs in the state who intend to market or aggregate electricity for retail sale. To be eligible to sell in New York, ESCOs will be required to apply to the PSC. The filing must contain the following information:

(1) Name and address of corporate headquarters, and any energy affiliates located or operating in New York State;

(2) Name, address and contact person of any entity that holds an ownership interest of 10% or more in those affiliates listed above;

(3) Proof of registration with the New York Department of State;

(4) Proof that the applicant has met all applicable requirements of the Independent System Operator and/or the Power Exchange;

(5) A description of the customers the applicant intends to serve by type (residential, commercial, etc.) and geographic region of the State;

(6) A description of how the applicant intends to comply with the required consumer protections;

(7) If the applicant intends to render bills to customers, a sample copy of the applicant billing form sufficient to display the proposed format and content;

(8) A description of the procedures the applicant intends to follow to protect customers from any unauthorized switch of the provider;

(9) A description of the applicant's procedures for handling and resolving complaints;

(10) A copy of the applicant's disclosure statement to be provided to customers prior to a

contract offer.

The Commission order says that periodic reporting requirements will be required of ESCOs to allow the Commission to monitor the development of a competitive market in the state. However, the specific requirements have not yet been specified.

The order also outlines criteria that will be considered for the suspension of ESCOs who fail to comply with the prescribed requirements for eligibility. These suspension criteria are to be applied on a case-by-case basis, and if an ESCO is found ineligible, they will be afforded an opportunity for a hearing. The criteria to be considered are as follows:

- Failure to adhere to the policies and procedures described in the ESCO's disclosure statement;
- Failure to comply with prescribed consumer protections;
- An unacceptably high volume of customer complaints;
- Failure to comply with the requirements of the ISO or Power Exchange;
- Failure to comply with prescribed reporting requirements;
- Failure to inform the Commission of all material changes in the information contained in an applicant's initial filing.

**Pilot Programs**

**PowerPick**

As part of an electric rate case settlement agreement, O&R implemented a three-year, two-phase retail access pilot project called PowerPick. Phase I, which went into effect on July 1, 1996, and was applicable to large commercial and industrial customers, up to a target of 30 MW of off-peak load. During the first six months of Phase I, 18 customers participated. Phase II went into effect on January 1, 1997, and was aimed at residential and smaller commercial and industrial customers, up to a target of 10 MW of off-peak load.

Thirty-seven suppliers elected to participate in Phase I. Seven of the suppliers were utilities, one was an IPP, and the remainders were intermediate marketers. In the first six months of Phase I, participant bill savings ranged from 1.6% to 3.8%. This low level of savings was due to the fact that only the energy (i.e. fuel) component of service could be purchased from outside suppliers.

The participation rate of residential customers was lower than anticipated. The target for residential participation was 1,500 customers. Only 283 residential customers have elected to participate. The primary reason identified for this lack of participation was the absence of potential for significant savings. The program allows customers to avoid only the fuel portion of their bills. O&R residential customers pay approximately 13 cents per kWh of which only 2.5 cents, or about 20%, is related to fuel. The expectation was that savings for residential customers would only amount to $1.00 to $3.00 per month.

The supplier prices paid by Phase II customers ranged from $.0210 to $.0265 per kWh, compared with the O&R system average cost of $.0251 per kWh. The two most successful marketers under the program, who together captured about 75% of the market, offered customers a guaranteed 5% bill savings. It is anticipated that the suppliers will lose money by guaranteeing these savings. There were other problems identified with the program, including: (1) O&R did not promote the program widely enough, (2) The procedures for participation were excessively complex and burdensome for residential and small commercial customers, and (3) Due to the small scale and limited savings potential of the program, there were not sufficient potential profits to stimulate vigorous competition among potential suppliers to the residential market.

**Dairylea Pilot**

Pursuant to an order dated June 23, 1997, the Commission approved the Dairylea pilot retail access program, to be offered by four of the state's investor-owned utilities: NYSEG, O&R, NIMO, and CHGE. The program will be available for two years to eligible commercial farms and food processors beginning by November 1, 1997.

Under the program, customers can choose their energy supplier. Pricing of services still provided by the utilities will be determined by estimating a market price for energy and capacity, and subtracting that amount from the existing tariffed rates for power. In addition, a fixed amount will be subtracted amounting to 0.4 cents per kWh for food processors and 1.0 cents per kWh for farms. The Commission believes that these additional reductions are necessary to provide bill savings to participants that are large enough to encourage participation. Under the pilot program, energy providers who choose to participate will be required to meet the guidelines established in the Commission's Order No. 97-5 on ESCOs. The utilities will be required to offer billing services to ESCOs for a charge. ESCOs will also be allowed to bill separately.

**MARKET POWER**

The original restructuring plan envisioned by the NYPSC states that generation and energy services should be separated from the transmission and distribution functions, but does not require or describe how such a separation should be accomplished. Total divesture of generation assets is "encouraged," but is not required. The plan does allow utilities to continue to provide energy, either directly or through affiliates, "at least in the short term."

The plan also calls for the establishment of an independent system operator to ensure the reliability of the transmission system. An ISO filing for New York State was recently made by the utilities with the FERC, however no response has yet been received from them regarding its adequacy. New York has not determined if a Power Exchange will be necessary in conjunction with the ISO.

One of the goals stated in the Commission's order 96-12 on competition in the electric industry was to allay concerns about market power. The order stated its concerns regarding market power as follows:

> No competitor or group of competitors should be able to exercise undue market power over other competitors either because of market power at another stage of production (vertical market power) or because of dominance at the same stage of production (horizontal market power).

The order required the utilities to address potential market power issues within their service territories. In addition, the Commission staff formed a Load Pocket/Market Power Working Group which, following a collaborative effort with other parties, issued a report on October 1, 1996. A load pocket is defined as an area that requires supplies of energy, operating, and installed reserves to serve customers that, due to physical limits of the transmission system, must receive service from generators within that area. Such load pockets become a problem when the ownership and size of generators and an insufficient number of competitors in an area create opportunities for certain generation owners to raise prices substantially above competitive market levels for significant periods of time each year. Such load pockets may require intervention by regulators where natural force of the marketplace will not quickly introduce competitors in an area, such as through transmission upgrades and construction of new generators.

Regarding load pockets, the order stated the following:

> Additional studies and analyses of the existence and mitigation of the market power that may result from constrained transmission areas are ongoing and should continue following the issuance of this opinion and order. Parties should continue to analyze the mitigation methods that have been identified, along with other potential innovative solutions that protect ratepayers from monopoly pricing while allowing the benefits of the competitive market. Because there appear to be transmission limits in the downstate area, we expect parties to pay particular attention to market power concerns in that area of the state.

The Working Group focused on the large load pockets in the State, particularly those in the downstate service territories of ConEd and LILCO. The service territory within New York City served by ConEd constitutes a load pocket due to the limitations on available transmission capacity to import competing sources of power. The report concludes that , given the existing generation and transmission ownership, ConEd would possess a high degree of market power in the New York City load pockets, if market forces alone were relied upon to set prices.

As an island served by limited transmission interties, LILCO's service territory also constitutes a load pocket in which customers must receive service from generators on Long Island throughout the year. LILCO would thus have significant market power in their service territory. The study also indicates that load pockets exist in upstate New York in the service territories of NIMO, NYSEG, and RG&E. According to preliminary analysis, there may exist the potential for market power to be exercised by some generation owners when transmission is constrained in these areas.

The report identifies several measures which could be taken to mitigate the effects of market power caused by the existence of load pockets. One solution is to require the divestiture of generating resources within the load pockets. This would in some cases introduce competition among the generators in the load pocket, and therefore eliminate the potential for market power abuse by dominant generation owners. It may also be necessary in some cases to restructure existing IPP contracts with QFs, in order to allow them to act as independent competitors, rather than being bound to sell their full output to utilities in a position to exercise market power. Mitigation can also take the form of physical system changes, such as transmission reinforcement and new generation.

In addition to divesture and physical changes to the system, there are also financial measures which can be enacted by the Commission to mitigate market power. Call options could be used to give load servicing entities or customers the right to purchase energy, capacity, or ancillary services at prices that reflect competitive market prices in areas adjoining the load pocket. Contracts for differences (CFD) could give customers or load serving entities the right to collect the differential between market prices and the prices set by the CFD. The study also asserts that direct caps could be placed on the bids generators can make to supply power in load pockets, the prices the generators may charge customers and load serving entities, or the per station net of fuel revenues a generator may collect during the year.

The report concludes that there is no simple solution to market power problems, and that a combination of the mitigation factors described above may be required. It does assert the necessity, at least in the short run, for direct price controls overseen by the regulator, and emphasizes the need for additional detailed study of the problem, as well as the need to address market power problems in the context of each of the company-specific restructuring plans.

Following the advent of retail competition, it is not anticipated that the Commission will serve the role of insuring adequate generation capacity. Rather, it is expected that with the development of a truly competitive market for electric power, the market will ensure that an adequate supply is available. It is also expected that the market will ensure that adequate transmission capacity will be available.

## PUBLIC PURPOSE PROGRAMS

The Commission order states that "costs required to be spent on necessary environmental and other public policy programs that would not otherwise be recovered in a competitive environment will generally be recovered by a non-bypassable system benefits charge" to be recovered through base rates. The expenditures to be reflected in the charge are those for research and development, energy efficiency, environmental protection, and low income programs required by the Commission. Of the settlement agreements signed to date, only the ConEd agreement contains a specific dollar level to be recovered through the system benefits charge. The other agreements reference the charge but indicate that its exact nature will be determined at a later date, pending the outcome of a generic Commission proceeding. In discussions with the New York Commission staff, they indicated that the rate design to be used for the charge had not yet been determined. The charge may be recovered as a fixed monthly charge, or on a per kWh basis. In general, utility expenditures for energy efficiency programs have been declining sharply in New York.

## RELIABILITY

The New York Commission envisions that issues of operational reliability will be the responsibility of the ISO. With respect to planning reliability which ensures the timely addition of new transmission and generation facilities, there is an implicit assumption that this will be provided for in response to market prices. Discussions with New York Commission staff persons indicate they are exploring a system of "congestion pricing" for transmission constrained points. These signals should entice a potential builder to construct new transmission lines when it is economical to do so. There are no specific ideas to address timely generation additions, but again the assumption is that merchant or speculative units will be constructed given the necessary price signals.

With respect to distribution level standards, New York has established distribution level outage standards and has used a penalty system since 1992 to ensure reliability standards are maintained. Since these services will continue to be regulated into the foreseeable future, the Commission is expected to continue to monitor and regulate reliability for this service.

## TAX ISSUES

Legislation to eliminate the gross receipts tax on utilities was also passed by the Senate. This legislation would phase out the tax over four years beginning in 1998. The tax would be totally eliminated by January 1, 2002. The legislation has not yet been passed in the Assembly.

# OKLAHOMA

## BACKGROUND

Oklahoma utilities produced 41,392 gigawatt-hours in 1995. Residential customers accounted for 39 percent of this energy, commercial accounts used 27 percent, and industrial/others used the remaining 33 percent. Total electric revenues came to $2.3 billion. Oklahoma is considered a moderately low cost state. System wide revenue per kWh was 5.57¢ in 1995. This was 19 percent below the national average of 6.89¢. Revenue per kWh for each of the residential, commercial, and industrial classes was 6.82¢, 5.78¢, and 3.75¢ respectively.

Oklahoma Senate Bill 500, also known as the "Electric Restructuring Act of 1997", was approved on April 23, 1997. It requires that direct access be made available to retail consumers no later than July 1, 2002. In the event the state does not adopt a uniform state tax structure by this time, the start date for direct access will be deferred. The bill grants the Oklahoma Corporation Commission (OCC) considerable oversight of the details of the restructure effort, but it also requires the OCC to study and report on a number of important issues which are ultimately determined by a joint legislative restructuring task force. The task force, identified as the Joint Electric Utility Task Force, is comprised of 14 members, drawn equally from the state house and senate chambers.

## MARKET STRUCTURE

The legislature envisions an unbundled, competitive market for electricity. The Joint Electric Utility Task Force will review a report prepared by the OCC regarding unbundling, due December 31, 1998. Technical issues will be reported by December 31, 1998, and primary issues regarding market structure will be reported by February 1, 1998.

## STRANDED COSTS

The OCC is required by Senate Bill 500 to establish procedures for identifying stranded investment, quantifying stranded costs, and proposing a mechanism for the recovery of such costs. Utilities are required to determine the level of their stranded costs and identify a limited time period over which they can be recovered without raising rates. The costs are to be fully recovered over a three to seven year period. The Joint Electric Task Force must receive the O.C.'s report on stranded costs and other financial issues no later than December 31, 1999.

## CUSTOMER ISSUES

Per Senate Bill 500, the application of the transition charge designed to recover stranded costs will not advantage one class of customers over another. An O.C. report regarding consumer issues is due to the Joint Electric Utility Task Force by August 31, 2000. Minimal consumer safeguards and protections must be addressed.

## MARKET POWER

Per Senate Bill 500, the O.C. will study and report to the Joint Electric Utility Task Force regarding the following aspects of market power:

1) Issues pertaining to Independent System Operator (ISO) and Power Exchange (PX), due February 1, 1998,

2) Methods of encouraging competitive markets for electric services,

3) Methods for establishing retail choice by July 1, 2002,

4) Functional unbundling of generation, transmission, and distribution,

5) Bill Unbundling, and

6) Methods of achieving open access.

A reliability, unbundling and market power report is due to the task force from the O.C. by December 31, 1998.

## PUBLIC PURPOSE PROGRAMS

A stranded benefits report prepared by the O.C. is due to the Joint Electric Utility Task Force by December 31, 1999.

## RELIABILITY

A reliability report prepared by the O.C. is due to the Joint Electric Utility Task Force by December 31, 1998.

## RECIPROCITY

Public utilities that do not elect to become subject to the Senate Bill 500 are prohibited from selling power outside of their respective service areas, except to its own facilities.

## TAX ISSUES

As a result of Senate Bill 500, the Oklahoma Tax Commission is directed to study the impact of restructuring on state tax revenues. The tax commission will submit proposals and findings to the Joint Electric Utility Task Force, a legislative oversight group, by December 31, 1998. One area they are charged with studying is the feasibility of a uniform consumption tax

# PENNSYLVANIA

## BACKGROUND

The Pennsylvania Public Utility Commission (PPUC) spurred the competition debate in April 1994 by requiring an investigation into restructuring the state's electric industry. The PPUC prepared an advisory report for the Governor and the General Assembly. During 1994 and most of 1995, the atmosphere surrounding electric competition was hostile. In June 1995, the PPUC denied its staff's recommendation to forego any electric restructuring efforts.

In December 1995 and March 1996, three bills concerning retail electric competition were introduced in the state Legislature. These bills provided language that would be used as the starting point for subsequent legislation.

On July 3, 1996, the PPUC sent a report to the Governor and General Assembly, recommending that Pennsylvania implement retail competition within three to five years. The Governor endorsed this report and asked PPUC Chairman Quain to establish a procedure that would provide all interested parties an opportunity to participate in drafting the electric industry restructuring legislation. Among those interested parties were the Office of Consumer Advocate, the Small Business Advocate, environmental organizations, new entrants, independent power producers (IPPs), electric utilities, unions, low income consumer advocates, and industrial consumers.

On November 25, 1996, the Pennsylvania legislature voted to adopt HB 1509, "The Electricity Generation Customer Choice and Competition Act" (Act). On December 3, 1996, Governor Tom Ridge signed the Act into law.

On March 18, 1997, State Senator Vincent Fumo filed a petition for review and injunctive relief requesting the court void the Act and permanently enjoin the PPUC chairman from taking any action or rendering any decision pursuant to the law. Senator Fumo alleges that the restructuring law violates provisions of the state constitution on procedural grounds. The state's Commonwealth Court set hearings for September 1997.

The Act makes it clear that a primary factor behind its enactment is the high disparity in electric rates and costs across Pennsylvania and between Pennsylvania and many other states. As of January 1996, Pennsylvania residential electricity prices ranged from 6.69 to 11.58 cents per kWh. Industrial rates ranged from 4.53 to 7. 13 cents per kWh. Nationwide, Pennsylvania's rates are in the highest 25% of electricity rates when compared with all other states.

Additionally, there is a significant difference between the marginal cost of electric power production and existing retail rates. Existing rates include the recovery of the costs of capital investments associated with the technologies and efficiencies of the past. Current marginal costs are significantly lower than electric energy rates primarily because of reduced capital costs, improved production efficiencies, and favorable oil and gas prices. These factors combined with federal energy policy changes, such as the 1992 Energy Policy Act, have created an environment in which more low cost generation is available.

## MARKET STRUCTURE

Essentially, the Act restructures the electric industry by separating the services of generating electricity from the services of transmitting and distributing electricity. The Act permits customers to choose their electricity generation supplier but requires them to purchase transmission and distribution services from their traditional electric utility.

The Act encourages, but does not mandate, market participants to coordinate their plans and transactions through an independent system operator or a functional equivalent.

The Act requires regulated public utilities[13] to file restructuring plans with the PPUC between April 1, 1997, and September 30, 1997. These filings must include:

1. Unbundled prices for generation, transmission, distribution, and any other services that the utility intends to unbundle;
2. A proposed competitive transition charge (CTC) to recover the utility's stranded costs, as determined by the PPUC;
3. A proposed universal service and energy conservation cost recovery mechanism;
4. Procedures by which all licensed electric generation suppliers may have direct access;
5. A discussion of the impact of the proposed plan on the utility's employees; and
6. Revised tariffs and rate schedules.

The PPUC must review each plan and, after an open hearing, accept, modify, or reject the plan within nine months of filing.

The PPUC has established industry working groups to provide it recommendations on

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[13]The Act excludes electric generation supplier companies from the definition of "public utilities," except as described in certain sections of the Act concerning generation supplier requirements and tax implications.

areas of concern that have arisen in the restructuring process. These areas include consumer education, customer information and billing, universal service and conservation, reliability, direct retail access implementation schedule, metering, competitive safeguards and interaction between suppliers and customer utilities, and taxes.

The Act establishes a schedule for implementation of direct retail access. First, proposed pilot programs were required to be filed with the PPUC by April 1, 1997 (The PPUC subsequently required that pilot program proposals be filed by March 1, 1997). These pilot programs are discussed in detail below. Following the pilots, the Act provides that a maximum of 33% of the peak load of each customer class shall be eligible for direct access by January 1, 1999. A maximum of 66% of the peak load of each customer class shall be eligible for direct access by January 1, 2000, and all customers in the state shall be eligible by January 1, 2001. Customer eligibility prior to full access will be offered on a first-come, first-served basis. The Act provides the PPUC flexibility to extend the January 1, 1999, deadline by six-months if deemed necessary.

**Pilot Programs**

The Act states that utilities shall design their pilot programs to accommodate the specific geographic, demographic, and socioeconomic aspects of their customer base, while attempting to provide broad access to all customer classes. The Act provides that each pilot program must last for at least one year and must be open to roughly 5% of the utility's peak load for each customer class. Participating customers receiving direct access at the end of the first year of the pilot will be entitled to direct access in the next implementation block of state-wide retail access, beginning January 1, 1999.

Pursuant to the Act, the PPUC issued guidelines for retail access pilot programs. These guidelines include:

1. <u>Eligibility and Participation</u> Pilot program plans should propose eligibility criteria and methods for selecting participants and handling the withdrawal of participants. Waivers of participation requirements by class may be granted for economic development purposes or other special circumstances. No single customer is permitted access to more than 10% of the load available to any class.

2. <u>Goals and Evaluation</u> Pilot program plans should include stated goals and a proposed method for evaluating the utility's progress towards those goals. Interim evaluation reports shall be filed on a quarterly basis, and a full report shall be submitted by September 1, 1998.

3. <u>Licensure of and Standards for Suppliers</u> Only electric generation suppliers subject to PPUC certification or licensure and the state gross receipts tax, pursuant to the Act, may participate in the pilot programs. Pilot program plans shall describe the manner in which electricity suppliers may participate in the

program, including technical and operational standards.

4. Unbundled Rates and Tariffs For purposes of the pilot programs, each utility must file tariffs containing a preliminary unbundling of rates for generation from rates for transmission and distribution. Transmission rates and conditions must be consistent with those contained in applicable FERC tariffs. Final approval of any pilot program by the PPUC will be dependent on the PPUC's acceptance of any changes FERC may make to the utility's retail access tariff.

5. Stranded Costs The utilities may propose treatment of potentially stranded costs in their filings along with justification for such proposals.

6. Consumer Education Pilot program plans shall address consumer education, service safety and reliability, and energy supply commitments. Consumer education materials will be reviewed by the PPUC before distribution by the utility or supplier. Marketing activities shall not constitute consumer education. Information provided to consumers should be accurate and understandable and should adequately allow consumers to compare prices and services.

7. Utility Participation in its Own Pilot If the utility wishes to participate as an alternative supplier in its own pilot program, its proposal must include a plan that provides for functional separation of its generation activities from other operations and an enforcement mechanism to prohibit anti-competitive behavior.

8. Sharing of Customer Information and Billing Upon the request of a qualified or approved generation supplier, distribution companies must provide the name, address, and phone number of all potential pilot customers. Customers may specifically request that this information not be provided. Upon request, customers may receive information regarding their load and consumption from their distribution company and may release that information to the alternative supplier of their choice. Alternative suppliers may bill customers separately, but must do so on the distribution utility's regular cycle.

All utilities required to file a pilot program proposal have done so. The PPUC issued preliminary rulings on these proposals, finding generally that the proposals fall short of its expectations and are not entirely consistent with the guidelines listed above. The PPUC made the following general preliminary rulings and suggestions:

1. Eligibility and Participation To more quickly reach customer participation goals, an open enrollment process should be used. Participants should be allowed to purchase from more than one alternative supplier and to switch suppliers on a monthly basis.

2. Standards for Suppliers There should be no limit on the number of generation

suppliers allowed to participate in each pilot. Because suppliers should already be licensed by the PPUC, utilities may not set supplier qualifications in their pilot programs. Alternative suppliers should not be required to have a tariff on file with FERC in order to participate in the pilots. In addition, suppliers should not be required to meet a minimum load aggregation standard.

3. Unbundled Rates and Tariffs Utilities should file unbundled embedded rates to make energy and capacity available to customers. If a utility wishes to assess a CTC in its pilot program, it must propose a separate unbundled charge.

4. Stranded Costs The recovery of 75% of stranded costs is a reasonable sharing of costs, if an actual assessment of costs has not been made.

5. Billing and Metering The utility should retain its responsibility for providing, installing, reading, and calibrating meters. It should also retain responsibility for initiating service and billing for distribution and transmission services. Uniform metering and billing procedures will be required. Fees for connection, switching, data processing, data requests, and program administration were rejected. Ancillary and other support services may not be exclusively provided by the utility, and, unless the utility has an approved tariff for charges for these services, they must be provided at no additional cost. Partial payments from customers should be apportioned as follows: first, to current transmission and distribution charges and approved CTC and intangible transition charges (ITCs); then, to energy charges due to the supplier; next, to past due amounts incurred in the program; and finally, to pre-pilot program arrearages. If a residential customer in the program fails to pay energy bills, that customer will not be disconnected but reverted to the utility's regular service.

The PPUC hopes to reach a final decision on the proposed pilot programs in time to permit their implementation by Fall 1997.

## STRANDED COSTS

The Act defines "transition" or "stranded" costs as

> An electric utility's known and measurable net electric generation-related cost determined on a net present value basis over the life of the asset or liability as part of its restructuring plan, which traditionally would be recovered under a regulated environment but which may not be recoverable in a competitive electric generation market and which the Commission determines will remain following mitigation by the electric utility.

The Act specifically includes among these costs the following:

1. Regulatory assets and other deferred charges, including the unfunded portion of the utility's projected nuclear plant decommissioning costs and obligations under Commission-approved contracts with nonutility generation projects;

2. Prudently incurred costs related to the cancellation, buyout, buydown, or renegotiation of nonutility generation projects;

3. Net plant investments and costs;

4. Costs for the disposal of spent nuclear fuel;

5. Costs for other long term purchase power commitments;

6. Retirement costs attributable to the utility's existing generating plants;

7. Employee transition and corporate restructuring costs; and

8. Costs attributable to physical plant no longer used and useful due to industry restructuring.

The PPUC is authorized by the Act to determine the level of stranded costs that each utility is permitted to recover. The PPUC is required by the Act to allow recovery of the costs listed under 1. and 2., in the above paragraph. Recovery of the remaining costs may be allowed if deemed appropriate by the PPUC upon review. The Act requires utilities to mitigate these costs to the extent practicable. The Act precludes cost-shifting between customers as a consequence of stranded cost recovery.

The Act provides for the recovery of these stranded costs through a nonbypassable "competitive transition charge" (CTC) applied to each customer of the utility who elects to receive service from an alternative generation supplier. The CTC will be collected by utilities over a maximum period of nine years, unless the PPUC approves an alternate period. The Act requires the PPUC to establish procedures by which the CTC may be annually reviewed and adjusted to reconcile revenues collected with the annual amortization of stranded costs approved by the PPUC.

The Act provides for the issuance of transition bonds as an additional mechanism for recovering and mitigating stranded costs. These bonds will essentially allow utilities to refinance capitalization in a manner that results in lower interest costs. Proceeds from the sale of these bonds must be applied to reduce stranded costs and related capitalization. The Act provides no limit on the total amount of a utility's bonds outstanding but provides that bond maturity may not exceed 10 years.

The transition bonds will be repaid by means of an intangible transition charge (ITC). The

ITC will be charged to distribution customers who choose an alternative generation supplier, in the same manner that the CTC is applied. The amount of stranded costs that are refinanced through these bonds will be reduced from the CTC.

Before these bonds may be issued, the PPUC must approve them, after notice and hearing through issuance of a qualified rate order (QRO). Applications for a QRO are not required to be filed with the utility's restructuring plan. The Act provides that QROs should contain a complete accounting of the utility's PPUC-determined transition costs, information concerning the utility's proposal for sale of intangible property or issuance of transition bonds, and information concerning the intended use of the proceeds.

## CUSTOMER ISSUES

### Rate Caps

The Act provides that each utility's transmission and distribution rates shall be capped at rates in effect on the effective date of the Act for 54 months, or until that utility is no longer recovering stranded costs and all of its customers have direct retail access.

The Act provides for a separate cap applicable to energy rates for customers who continue to receive generation service from the local distribution company. This rate cap includes the CTC and the ITC.

The Act permits utilities to seek approval from the PPUC to exceed these rate caps for certain costs, including costs incurred due to existing nonutility purchased power contracts, changes in laws, necessary upgrades or repairs to transmission facilities, ISO funding, increases in fuel or purchased power prices, taxes, and nuclear plant decommissioning costs. Subject to the rate cap, the PPUC is given discretion to approve flexible pricing and performance-based rates.

### Provider of Last Resort and Universal Service

The Act requires that distribution companies continue to be suppliers of last resort. Until a distribution company is no longer collecting a CTC or an ITC and all of its customers have direct retail access, it is obliged to serve customers who cannot or choose not to receive service from an alternative supplier. The distribution company shall obtain energy at prevailing market prices to serve those customers and are permitted to recover all reasonable costs. However, if a customer previously chose an alternative supplier but decides to return to the distribution company for generation service, that customer will be treated as a new customer.

## Consumer Education

The Act provides that each distribution company, in conjunction with the PPUC, shall implement a consumer education program. In addition, the Act requires the PPUC to promulgate regulations to require each distribution company, generation supplier, marketer, aggregator, and broker to provide adequate and accurate information to enable customers to make informed choices.

## Billing, Metering, and Customer Service

Each customer choosing to take power from an alternative supplier has the right to receive a separate bill from that supplier. However, the Act provides that the distribution company is ultimately responsible for billing customers for all services. Bills must contain unbundled charges sufficient to enable the customer to determine the basis for those charges. If services are provided by an alternative generation supplier, that supplier is responsible for furnishing the distribution company with sufficient data for billing for its services.

The distribution company will retain responsibility for providing customer service functions consistent with PPUC regulations, including meter reading, complaint resolution, and service quality. The Act requires that customer service be maintained, at least, at current quality levels.

The Act requires the PPUC to establish regulations to prevent customer "slamming."

# MARKET POWER

The Act encourages, but does not mandate, market participants to coordinate their plans and transactions through an independent system operator or functional equivalent.

The Act permits, but does not require, electric utilities to divest themselves of facilities or to reorganize their corporate structures.

The Act does require electric utilities to separate the service of generating electricity from the services of transmitting and distributing electricity.

The Act empowers the PPUC to monitor the supply and distribution markets to prevent anticompetitive behavior or discriminatory conduct and to prevent the unlawful exercise of market power. The Act also permits the PPUC to investigate the effects of mergers and acquisitions for anticompetitive effects and market power concerns and to withhold approval of a proposed merger or acquisition if such a result is likely to occur. The PPUC shall refer findings of anticompetitive behavior to the Attorney General of Pennsylvania, the U.S. Justice Department, the Securities and Exchange Commission, or the FERC, and may intervene in any subsequent proceedings. In addition, the Act requires the PPUC to promulgate regulations to require each distribution company, generation supplier, marketer, aggregator, and broker to provide adequate and accurate information to enable customers to make informed choices.

## PUBLIC PURPOSE PROGRAMS

The Act provides that programs for low-income assistance, energy conservation, and other public purposes shall be continued at existing funding levels. The Act mandates that the PPUC ensure these programs are appropriately funded and made available. In addition, the Act provides that the PPUC shall establish for each utility a nonbypassable and competitively- neutral mechanism to recover the costs of these programs. The Act requires each utility to file with its restructuring plans an initial plan stating how it intends to meet its obligations under these programs. The PPUC is encouraged to use community-based organizations to assist with these programs.

## RELIABILITY

The Act generally places the responsibility of system reliability on the PPUC, electric utilities, and an independent system operator contemplated by the Act. The Act does not specifically address what entity or entities are responsible for long-term system needs planning.

The Act mandates that the PPUC and Pennsylvania electric utilities work with the federal government, other states in the region, and interstate power pools to accomplish the goals of restructuring and to establish independent system operators, or their functional equivalents, to operate the transmission system and interstate power pools.

The Act charges the PPUC with ensuring the continuation of safe and reliable electric service, including the maintenance of adequate reserve margins by electric suppliers in accordance with the standards of the North American Electric Reliability Council, each supplier's regional reliability council, and established industry standards and practices. The PPUC is required to impose requirements on generation suppliers to maintain current quality of service.

The Act further requires the PPUC to ensure that the installation and maintenance of transmission and distribution facilities are made in conformity with established industry standards and practices, including the standards provided by the National Electric Safety Code. The PPUC is required to set and enforce regulations establishing standards for the inspection, maintenance, repair, and replacement of the transmission and distribution systems. The Act also call for an independent system operator or its equivalent to set and enforce similar regulations.

The Act requires each distribution company to maintain the integrity of the distribution system at least in conformity with the National Electric Safety Code and in a manner sufficient to provide safe and reliable service to all customers connected to the system. The Act also requires distribution companies to implement procedures to require each alternative supplier to deliver energy to the distribution company at locations and in amounts adequate to meet that supplier's obligations to its customers.

Any entity wishing to do business as an electric generation supplier in the state is required to hold a license issued by the PPUC to certify their financial responsibility. The Act requires the PPUC to impose requirements on generation suppliers to ensure that the present quality of service is maintained, through maintenance of adequate reserve margins and compliance with standards and billing practices for residential services.

The PPUC has established interim licensing requirements for generation suppliers. These requirements will expire when permanent regulations are promulgated.

1. Along with financial information, each applicant must identify the geographic area it proposes to serve, the services it proposes to offer, and the customers it seeks to serve.

2. Applicants must provide affidavits concerning the payment and reporting of state taxes, conformance with regional electric council reliability standards, inspection of facilities and records, and compliance with PPUC regulations on standards and billing practices.

3. Applicants must demonstrate security bonding to a level of at least $250,000 for the first year of operations. The PPUC will review each licensed supplier's security bonding level on a semi-annual basis. The level of bonding required after the first year will be determined based on a percentage of the licensed supplier's gross receipts.

4. Notice of each application must be published; protest may be made regarding only the fitness of the application shall protect not address competitive concerns.

5. Licensed suppliers must report gross receipts to the PPUC on a quarterly and year-to-date basis.

6. Each licensed supplier must annually report the percentage of the electricity it supplies by fuel source.

7. Each licensed supplier must report to the PPUC any significant change in its organizational structure or operation.

8. Any licensed supplier intending to cease operations in the state must notify the PPUC, distribution companies, and its customers at least 30 days prior to halting operations.

9. For purposes of customer education and protection, each licensed supplier must:

    a. Provide accurate information about its generation services in clear language that allows consumers to compare prices and services;
    b. Upon customer request, provide information concerning the resource mix of the generation provided to the customer;
    c. Notify customers of changes in service conditions, explain the terms of service, and handle customer deposits and complaints appropriately; and
    d. Maintain the confidentiality of its customer's payment histories and maintain each customer's right to access his load and billing information.

**RECIPROCITY**

The Act provides that investor owned facilities or their affiliates may not use the distribution system of another IOU or cooperative, or make sales to customers in another electric utility's service area, unless the PPUC has approved a restructuring plan that provides for comparable direct access for the latter utility.

The Act also provides that any cooperative or municipality that distributes electricity to customers outside its traditional service territory must provide reciprocity to those customers within its territory who wish to receive service from an alternative supplier.

**TAX ISSUES**

The Act's tax provisions continue the gross receipts tax and supplement it with a "revenue neutral reconciliation" formula designed to maintain tax revenues from electric utilities at 1995-1996 levels.

The gross receipts tax is modified to apply to the new entities created by the Act - distribution companies and generation suppliers - as well as municipalities and cooperatives that choose to compete.

The revenue neutral reconciliation formula is designed to prevent shortfalls or windfalls in the current level of revenue from five taxes paid by electric industry participants: the gross receipts tax, the capital stock-franchise tax, the sales and use tax, the public utility realty tax, and the corporate net income tax. The formula takes effect when competition begins in 1999 and will last for approximately four years.

The Act requires the state Department of Revenue to submit annual reports to the governor and legislature concerning the effects of restructuring on tax revenues. The revenue neutral reconciliation formula may be modified to ensure its purpose of revenue neutrality.

# RHODE ISLAND

## BACKGROUND

Three investor-owned utilities serve approximately 99% of Rhode Island's electric customers. These companies had sales of some 6600 gigawatt-hours in 1995 and revenues of some $688 million. Market share in respect to total electric energy consumed was 37% residential, 39% commercial, 21% industrial and 3% other. Rhode Island's average system revenue per kWh was 10.38¢. Individual class revenue per kWh was 11.47¢ for residential, 10.08¢ for commercial, and 8.87¢ for industrial customers. Virtually all the investor-owned utilities in the state are structured as distribution companies purchasing electricity from affiliated wholesale power suppliers under all-requirements contracts.

In January, 1995, the Rhode Island Public Utility Commission (RIPUC) established a collaborative Electric Restructuring Task Force, consisting of state utilities, independents, industrials, environmentalists, consumer advocates, and state policy makers. In May, 1995, the collaborative filed with the RIPUC recommended principles to guide the state's transition to a restructured electric industry. Except for a proposed charge for renewables, the RIPUC unanimously adopted these principles for restructuring.

The state's three largest investor-owned utilities, the Rhode Island Attorney General, the Division of Public Utilities and Carriers, an industrial group, and Pascoag Fire District filed restructuring plans with the RIPUC in early 1996.

On February 7, 1996, Rhode Island House Speaker John B. Harwood and House Majority Leader George D. Caruolo introduced the Utility Restructuring Act of 1996 (the Act). The Act became law on August 7, 1996, representing the nation's first comprehensive legislation enacted on restructuring the electric utility industry. The Act deregulates generation and requires that retail wheeling be phased in over one year, beginning on July 1, 1997. The RIPUC, finding that the Act superseded its generic restructuring investigation, terminated its investigation shortly after the Act became law.

## MARKET STRUCTURE

### Retail Access

The Act defines retail access as "the use of transmission and distribution facilities owned by an electric transmission company or an electric distribution company to transport electricity sold by a nonregulated power producer to retail customers . . . ." The Act provides for retail access from nonregulated power producers to all customers by July 1, 1998, with specified increases in retail access beginning July 1, 1997.

- As of July 1, 1997, each electric distribution company is required to provide retail access from nonregulated power producers to: (1) all new commercial and industrial customers commencing service on or after July 1, 1997, with anticipated average annual demands of 22 kW or more; (2) all existing manufacturing customers with an average demand of 1500 kW or more; and (3) all Rhode Island state government customers. No distribution company, however, is required to release more than 10 percent of its total kWh sales to retail access by this date.

- By January 1, 1998, each distribution company must expand retail access to existing manufacturing customers with an average annual demand of 200 kW or more, and to all municipal governments in the state. No distribution company, however, shall be required to release more than 20 percent of its kWh sales to retail access at this time.

- The Act requires that distribution companies offer retail access to all customers upon either (1) the expiration of three months from the time that retail access is available to 40 percent or more of the kWh sales in New England, or (2) July 1, 1998, whichever date is reached first. The RIPUC may extend this deadline for up to six months if it determines that additional time is necessary to ensure that retail access can be offered to all customers on reasonable terms.

At least 90 days before retail access is available to any customer in a distribution company's service territory, the distribution company is required to notify the customer of its options in retaining electric service.

The Act requires that each distribution company file unbundled rates with the RIPUC by January 1, 1997. These rates must include transition charges (discussed below) and transmission and distribution charges to become effective on July 1, 1997. These filings must also include procedures for interconnecting with small scale generating units located on the distribution system.

## STRANDABLE COSTS

The Act states that "public utilities should have a reasonable opportunity to recover transitional costs associated with commitments prudently incurred in the past pursuant to their legal obligations to provide reliable electric service at reasonable costs." Most strandable costs are those of the utilities' wholesale power suppliers as recovered through the rates of all-requirements contracts. The Act authorizes distribution companies to terminate these contracts, to pay contract termination fees, and to recover these payments through a nonbypassable transition charge paid by all customers of the distribution company.

The contract termination fees paid by distribution companies to their wholesale power suppliers must include each distribution company's share of its wholesale supplier's costs associated with the following:

1. Generation-related regulatory assets, including deferred recoveries; regulatory assets of affiliated fuel suppliers; and transition obligations for post-retirement health care costs of the wholesale supplier.

2. Nuclear decommissioning costs and nuclear costs independent of operation, which consist of estimated nuclear operation and maintenance expenses that would be incurred assuming the nuclear units were to permanently cease operating on December 31, 1997.

3. Above market payments for purchased power contracts of the wholesale supplier in place with independent power producers as of December 31, 1995, including reasonable payments of the wholesale supplier to buy out or buy down these contracts.

4. The net unrecovered commitments and capital costs of all generating plants that are directly or indirectly owned by the distribution company and its wholesale suppler as of December 31, 1995, including natural gas conversion costs and above market pipeline demand charges.

Operation or maintenance expenses associated with existing fossil-fired or hydroelectric generating facilities may not be included in contract termination fees recovered through transition charges.

Due to the difficulty of estimating the timing and amounts of the decommissioning costs and the above market payments for purchased power contracts, the Act allows for recovery of these costs through transition charges until they have been satisfied, with an annual reconciliation of estimated to actual expenses. Recovery of the other stranded costs will not be annually reconciled, because they can be determined or estimated with more certainty. To moderate impact on rates, recovery of these more certain costs will be spread over the period from July 1, 1997, through December 31, 2009, with a return on the unamortized balance. These costs may not be recovered through transition charges after January 1, 2010. In recognition of the potential for existing generating facilities to have a positive residual value in the year 2010, the Act allows a reduced return on the unamortized balance of these costs.

The Act provides that distribution companies shall collect, for the period July 1, 1997, through December 31, 2000, a fixed transition charge of 2.8 cents per kWh transmitted or distributed. This period of fixed transition charges is designed to allow distribution companies time to terminate all-requirements contracts with their wholesale suppliers and to permit the administrative determination of allowable stranded costs associated with the resulting contract termination fees. After the year 2000, this fixed charge will be replaced by a RIPUC-determined transition charge to recover stranded costs. The new charge will be adjusted to reflect any over or under recoveries accrued under the initial, fixed charge.

Wholesale suppliers are required to offer to renegotiate at least that portion of their power purchase contracts attributable to their affiliated distribution companies. As an incentive, the Act allows wholesale suppliers to retain 10 percent of the savings expected to result from such renegotiated power purchase contracts.

Every wholesale power supplier receiving contract termination fees is required by the Act to subject its generating facilities, other than nuclear units, to market valuation by lease, sale, spin-off, or other method. To meet this requirement, the wholesale supplier must dispose of at least a 15 percent interest in its generating facilities. Each wholesale supplier must file an implementation methodology for accomplishing the disposition of its interest. The RIPUC may reject the wholesale supplier's proposed implementation methodology if it finds that the methodology is not reasonably likely to approximate market value.

The market valuation process must be completed within six months after retail access is available to 40 percent or more of the kWh sales in New England or the receipt of all regulatory approvals, whichever is later. Once market valuation is completed, the wholesale supplier and its affiliated distribution company must file with the RIPUC to adjust contract termination fees to reflect the distribution company's share of the market valuation amounts in the transition charge.

Any distribution company that did not purchase power from a wholesale supplier under an all-requirements contract is required to include in its restructuring plan a proposal for recovering transition costs in a manner similar to distribution companies purchasing power under an all-requirements contract.

Filings by a quasi-municipal corporation must address any unique circumstances, including special contract requirements or charter restrictions and the conditions that it must satisfy to participate in retail competition.

**Securitization**

In July 1997, the governor signed legislation permitting distribution companies to seek authority from the RIPUC to finance all or some of the contract termination fees owed by the distribution company to its wholesale power supplier. Under this law, a distribution company seeking to securitize its contract termination fees must file with the RIPUC an application containing the following elements:

1. A financing plan;

2. A statement and schedules defining that portion of qualified transition expenses that it plans to finance;

3. An analysis of the savings to the company's customers that the company expects to be realized;

4. A statement of the qualified transition charges to be recovered through rates paid by the company's customers;

5. A proposed adjustment procedure that permits the RIPUC to annually review the company's authorized intangible transition charges and make any necessary adjustments to ensure that sufficient revenues are recovered; and

6. A statement concerning the use of the bonds' proceeds and the manner in which the intangible transition charges will be billed, collected, and paid.

Under this securitization law, the RIPUC must act upon a distribution company's application within 120 days. The RIPUC shall approve an application if (1) the transaction is reasonably certain to result in quantifiable savings, (2) the terms of the financing plan are commercially reasonable; and (3) all savings (net of costs) will be credited to the customers through intangible transition charges.

If the RIPUC approves a securitization application, the state of Rhode Island has authority to limit or alter any rights established under the RIPUC's order until the bonds are paid in full and the related contracts are fully performed. The RIPUC will continue to have jurisdiction over the order, regardless of whether the assignee or financing party is an electric distribution company or other RIPUC-regulated company.

## CUSTOMER ISSUES

### Distribution Company/Customer Relations

Existing rules and regulations concerning termination of service, debt collection, and other terms of service will remain applicable to all distribution companies. At least 90 days before retail access is available to any customer in a distribution company's service territory, the distribution company is required to notify the customer of its options in retaining electric service.

Performance-based rate plans for 1997 and 1998 are required in order to prevent residential customers from paying higher rates as a result of the transition to competition in the commercial and industrial classes and to hold rate increases to the inflation level. Low-income customers will be exempt from even those increases.

For customers who choose not to purchase power from a non-regulated power producer (NPP), distribution companies are required to provide service under a standard offer. Rather then simply making arrangements with its own wholesale power supplier to provide this standard offer service, distribution companies must procure the service from the lowest price bidder through competitive bidding. Customers who initially elect the standard offer cannot be required to pay a withdrawal fee or penalty when they choose an alternative supplier, unless such a fee was agreed to as part of a contract. Under no condition may a residential customer be required to pay a withdrawal fee or penalty.

Each distribution company must arrange for a "last resort power supply" for customers no longer eligible for the standard offer and unable to obtain service from NPPs. In addition, distribution companies must preserve their low income programs. Special rates for low income customers in effect when the Act becomes effective must be continued.

**NPP/Customer Relations**

NPP/Customer relations will be largely governed by the specific service contracts entered into between the NPP and the customer. NPPs must be registered in good standing with the Division of Public Utilities and Carriers (Division) and are subject to the requirements of RIPUC's regulations on reliability. The regulations provide that any person who reasonably believes that an NPP has not or is not complying with these reliability regulations may file a complaint with the RIPUC. The regulations include a procedure for handling such complaints and allow the RIPUC to impose reasonable penalties and/or remedies for violations, including barring an NPP from serving in the state.

The Division has proposed additional requirements for NPPs. These requirements are being considered by the RIPUC in a rulemaking proceeding and include the following:

- NPPs must comply with each electric distribution company's terms and conditions for NPPs as approved by the RIPUC.

- Contracts between NPPs and customers must include (1) specific pricing information including all charges, (2) term of service, (3) rules concerning notification for termination by either party, (4) budget plan availability, (5) a dispute resolution process, (6) a customer service telephone number, and (7) any service options or additional information. Pricing information should include pricing elements, price change formulas, and the potential for price volatility through variable rates or other mechanisms.

- Information concerning fuel and environmental impacts of the NPP's generation sources must be provided to customers in a format to be prescribed by the RIPUC. Prior to adoption of a standard format, NPPs must provide customers with information that will disclose the source or sources of electricity (gas, coal, nuclear, etc.) provided by the NPP to the customer.[14]

- Discontinuance of service shall be controlled solely by the distribution company under

[14]The RIPUC has not yet determined how this information should be provided.

its current termination rules.

- Enrollment, billing, or contract disputes between NPPs and customers shall be handled solely by the NPP and the customer. The Division will intervene only in disputes regarding compliance with its requirements.

- Termination of service to a customer by an NPP requires a minimum payment period of 30 days and subsequent 10 days written notice.

Finally, the RIPUC has acquired the services of a consultant to assist it with its consumer education and information efforts.

**Performance-Based Rates**

To prevent residential customers from paying higher rates as a result of the transition to competition in the commercial and industrial classes, and to hold rate increases to the inflation level, the Act requires distribution companies to implement performance-based rate plans for the period of January 1, 1997, through December 31, 1998.

By November 15 of 1996 and 1997, electric distribution companies must file with the RIPUC an earned return on common equity report for the 12 months ended as of the preceding September 30. The distribution companies will be authorized to increase their base rates by a per kilowatt-hour factor equal to the average revenue per kilowatt-hour received by the company during the period reported, less cost of fuel and demand side management programs, multiplied by the rate of inflation for the most recent period for which data is available.[15] Distribution companies will also be authorized, with the RIPUC's approval, to include in their base rates factors reasonably beyond their control, including but not limited to changes in federal, state, and local taxes and environmental remediation costs.

Under the Act, distribution companies must credit or refund to customers 100 percent of its earnings that are more than 1.5 percent above the return on equity allowed by the RIPUC as of July 1, 1996. Distribution companies must also refund 50 percent of its earnings that are between its currently allowed return and 1.5% above that level. Distribution companies that earn less than a 6% return on equity may increase their base rates by the CPI factor and impose a surcharge to collect over a 12 month period the revenues necessary to make up the difference between the currently allowed return and a six percent return.

The RIPUC is required to establish performance standards to ensure that historic levels of safety, reliability, and customer service continue during the two-year period. These standards are required to provide each distribution company the opportunity to incur an

[15]The inflation rate will be measured by the Consumer Price Index.

annual penalty or reward equal to one percentage point return on equity for variations below or above historic levels.

Distribution companies may continue to apply for rate changes under the adjustment clauses currently in place for cost of fuel and DSM programs, purchase power clauses that do not reflect increases in wholesale rates, revenue neutral rate design changes, and accounting changes.

Rates applicable to low-income customers will not be increased as a result of any performance-based rate mechanism. None of the performance based rate provisions apply to quasi-municipal corporations.

**Universal Service/Supplier of Last Resort**

Each distribution company must make arrangements with its wholesale provider for a standard power supply offer to customers that elect not to take power from other nonregulated power producers. This standard offer must be made available within three months after retail access is available to 40 percent or more of the kWh sales in New England through the year 2009.

The price under the standard offer will be capped at the price paid by the customer during the year ended September 30, 1996. This price cap will be automatically adjusted on an annual basis for 80 percent of the rate of inflation, as measured by the CPI, and will be adjusted with RIPUC approval for other cost factors reasonably beyond the control of the distribution company and its wholesale supplier.

If a customer elects the standard offer but later chooses to buy power from an NPP, the distribution company will no longer be required to provide the standard offer to that customer.

Customers who initially elect the standard offer cannot be required to pay a withdrawal fee or penalty when they choose an alternative supplier, unless such a fee was agreed to as part of a contract. Under no condition may a residential customer be required to pay a withdrawal fee or penalty.

Each distribution company must arrange for a "last resort power supply" for customers no longer eligible for the standard offer and unable to obtain service from NPPs. Each distribution company must periodically solicit bids from NPPs for such service at market prices plus a fixed contribution from the distribution company to be included in distribution rates charged to all other customers. Acceptance of bids, and the terms and conditions for this last resort service, are subject to RIPUC approval. Bids that require the lowest fixed contribution from the distribution company must be accepted.

**MARKET POWER**

Under the Act, each electric distribution company was required to submit a plan to the RIPUC by January 1, 1997, for transferring ownership of generation, transmission, and distribution facilities into separate affiliates of the electric distribution company at prices equal to the book value of the facilities, net of depreciation and deferred taxes. The law has since been amended to give distribution companies the option of retaining their transmission and distribution facilities. The RIPUC must review each plan within 6 months of filing.

No later than three months after retail access is available to 40% or more of the kWh sales in New England, each electric distribution company must implement the reorganizations and transfers specified in its approved restructuring plan, terminate its all-requirements contract with its wholesale provider, and provide retail access for all customers in Rhode Island with a standard offer.

Consistent with the Act's schedule for implementing retail access, each transmission company is required to file open access tariffs with the Federal Energy Regulatory Commission (FERC) and each distribution company is required to file tariffs with the RIPUC. These tariffs are to provide terms, conditions, and rates for nondiscriminatory access to transmission and distribution facilities to wholesale and retail customers and to nonregulated power producers.

Following the implementation of its restructuring plan, each distribution company is prohibited from selling electricity at retail. Each distribution company will also be prohibited from owning, operating, or controlling transmission or generating facilities.

Upon termination of each distribution company's contracts with its wholesale power supplier, the wholesale power supplier (the generating company) will become a "nonregulated power producer" (NPP).[16] NPPs are free to sell electricity generated from their facilities at market prices, subject to the standard offer provisions of the Act and RIPUC-mandated reliability requirements. NPP's will be required to register with the state's Division of Public Utilities and Carriers.

Any electric distribution company that, as of January 1, 1996, did not purchase power at wholesale from a wholesale supplier under an all-requirements contract may be exempted by the RIPUC from certain provisions of the Act. First, these companies may be exempted from the requirement to transfer ownership of generation and transmission facilities to affiliated companies. Second, they may be exempted from the prohibition against selling electricity at retail with respect to sales within their respective service territory. Both are

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[16] NPPs are entities created by the law and defined as any company that produces, manufactures, generates, buys, aggregates, markets, or brokers electricity for sale at retail or wholesale to the public.

subject to the RIPUC's determination that the exemptions are in the public interest.

**Independent System Operator**

The Act established a Retail Electric Licensing Commission to submit a plan to the legislature including recommendations and proposals (1) for taxing and/or assessing electric distribution, transmission, and generation companies, (2) regarding changes to the regional power pool (NEPOOL) that would facilitate establishment of an independent system operator and voluntary power exchange, and (3) for consumer protection, access to books, and other requirements that it determines to be reasonable, necessary, and in the public interest. Accordingly, a plan discussing these matters was submitted to the legislature on January 1, 1997.

The New England state public utility commissions approved an agreement that would place an ISO in charge of NEPOOL. The agreement was approved by FERC and will become effective if ratified by a final vote of NEPOOL members.

**Standards of Conduct**

The Act provides standards of conduct aimed at regulating dealings between affiliated generating and distribution companies. These standards include requirements that the companies' employees function independently, the companies maintain separate accounting records, and the companies do not share information except through established public channels. These standards also provide that distribution companies must maintain logs, available for audit by the RIPUC, describing the circumstances in which discretion was exercised by the distribution company in relations with its affiliates.

## PUBLIC PURPOSE PROGRAMS

**Demand Side Management**

For the five-year period beginning January 1, 1997, each distribution company must include a charge of 2.3 mills per kWh to fund demand side management programs (DSM) and renewable energy sources.[17] The RIPUC will determine how to allocate revenue from this charge between DSM programs and renewables, but distribution companies will determine how these funds will be spent.

During the initial five-year period, the RIPUC may increase this charge at its discretion, after notice and public hearing. After the initial five-year period, the RIPUC must review the needs of DSM and renewables programs and establish an appropriate charge for them.

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[17]The Act defines renewable energy sources as wind energy, small scale (<100 mW) hydropower plants, solar energy, and sustainable managed biomass.

## Low Income

The Act requires that distribution companies preserve their low income programs. Special rates for low income customers in effect when the Act becomes effective must be continued. The costs of these discounts must be included in the distribution rates charged to all other customers. Distribution companies may offer other special rates or programs with RIPUC approval.

## RELIABILITY

Prior to the Act, the New England Power Pool (NEPOOL) was the entity responsible for maintaining system reliability and for determining if adequate generation and transmission facilities existed among the six New England states. NEPOOL will retain this role in the competitive environment, and Rhode Island will continue to make decisions concerning the siting of certain facilities. Pursuant to the Act, the RIPUC adopted regulations, effective January 1, 1997, governing NPPs' responsibility for reliability. These regulations intend to ensure that nonregulated power producers meet the operating and reliability standards of the New England Power Pool (NEPOOL) or any successor entity.

Specifically, the regulations provide that an NPP that serves retail load in the state must maintain an effective registration under the Act and must either (1) become a NEPOOL member, or (2) have a written agreement with a NEPOOL member through which the member will include the NPP's load in its own-load dispatch. The regulations also provide that any NPP providing the electric requirements of retail customers must (1) meet the load requirements of each customer it serves, (2) deliver the associated capacity and energy to a point or points on the integrated transmission system of the distribution companies and their affiliates pursuant to FERC-approved tariffs, and (3) provide necessary installed and operating reserves to serve each retail customer.

The regulations also require each distribution company to file for RIPUC approval of a set of nondiscriminatory accounting, billing, metering, and settlement procedures designed to implement retail access. Once approved, these procedures must be followed by all NPPs serving retail customers in that distribution company's service area. Proposed procedures must be filed as part of each distribution company's retail access distribution tariffs and, once approved, cannot be substantively changed without RIPUC approval of the change.

The regulations provide that any person who reasonably believes that an NPP has not or is not complying with these reliability regulations may file a complaint with the RIPUC. The regulations include a procedure for handling such complaints and allow the RIPUC to impose reasonable penalties and/or remedies for violations, including barring an NPP from serving in the state.

The application of these regulations to quasi-municipal corporations is subject to RIPUC action pursuant to the Act.

## RECIPROCITY

Rhode Island has not addressed the issue of reciprocity. Due to the interdependence among the six New England states for generation and transmission of electricity, as reflected by their reliance on NEPOOL, it is unlikely that this issue will be addressed by Rhode Island on the state level. Reciprocity issues would more likely be addressed by NEPOOL.

## TAX ISSUES

Legislation signed into law in July 1997 subjects all industry participants, regardless of whether their principal business is the sale, transmission, or distribution of electricity, to a 4 percent gross earnings tax. The gross earnings subject to this tax, however, are excluded from the calculation of net income. The law also provides that gross earnings may be reduced by the amount of earnings from the sale or transmission of electricity to NPPs, rather than just by the amount of earnings from the sale of electricity to other public utility companies and municipal utilities.

The law also changes the manner in which the earnings of a company operating both in and out of the state are apportioned to Rhode Island. This new method apportions earnings to the state based on the proportion of total gross earnings within the state for the calendar year.

# VERMONT

## BACKGROUND

During 1995, Vermont electric customers consumed over 5100 gigawatt-hours of electricity which generated total revenues to the utilities of $482 million. The residential customer class consumed 39% of this power; the commercial sector used 31% and the industrial class was reponsible for over 29% with a slight residual of 0.8% consumed by other customers. With respect to electric rates, Vermont's average revenue per kilowatt-hour for all customers was 9.46¢ per kWh. Revenue for the other individual classes was 11.47 ¢ /kWh (residential), 9.90¢ (commercial) and 7.56¢ (industrial).

In October 1994, Vermont's public utility commission, the Public Service Board (Board), and Vermont's public counsel, the Department of Public Service (Department), convened the Vermont Roundtable on Competition and the Electric Industry, with the aim of developing a broad-based consensus on the nature and manner of restructuring Vermont's electric industry. Represented at the Roundtable were a wide array of interests: utility companies, large commercial customers, representatives of low-usage consumers (residences and small businesses), regulators, environmental groups, and low-income advocates. That process ultimately led to the establishment and later adoption by the Board of the "Vermont Principles for Competition in the Electric Industry" ("Vermont Principles"), which identified the essential public and private goals that should give direction to the restructuring process.

On October 17, 1994, the Board opened an investigation (Docket No. 5854), with the aim of advancing restructuring through an open, more formal process. It proceeded in two stages. The first stage included workshops with the Board and collaborative negotiations among the participants that built on the achievements of the Roundtable. The second stage involved an intensive period of information exchange and Technical Conferences held before the Board. The Participants' restructuring proposals and responses were filed in June and July 1996, accompanied by two weeks of Technical Conferences in early July 1996. On the basis of the detailed filings and discussions during the technical conferences, the Board issued a draft report and order on October 16, 1996. A final report and order were issued on December 31, 1996 based on the comments received on the draft report and order. This document entitled "The Power to Choose: A Plan to Provide Customer Choice of Electricity Suppliers" included the Board's recommendations for electric restructuring.

On April 3, 1997, the Vermont Senate adopted a majority of the Board's recommendations in Senate Bill 62 (S.62). The Vermont House of Representatives did not bring S.62 for a vote and it stalled in committee. The House postponed formal consideration of restructuring. Committee hearings are to be held during the summer and fall of 1997 to further investigate restructuring. As a result of the actions in the Vermont Legislature, the

Board suspended all hearings and activities associated with its restructuring plan. Formal restructuring activities will resume pending Legislative approval. This summary of electric restructuring in Vermont is based on the Board's final report and order.

**Precedent Conditions**

Vermont's restructuring efforts are primarily a response to aggressive restructuring activities in neighboring states and the potential impacts on Vermont ratepayers. Average rates in Vermont are approximately two to three cents per kilowatt-hour higher than national averages. Vermont's average rates, however, are below both the Northeast and New England regional averages. Over the past ten years, electric rates in Vermont have declined, in real terms, by 11 percent. The majority of Vermont's load growth since 1980 has been supplied by renewable resources and demand side management. Despite these accomplishments, the Board believes steps must be taken now to deal with restructuring because of the following problems:

1. Vermont utilities now face a period of substantially increasing power costs while the other states in the New England region are expecting declining electricity prices. A substantial share of Vermont's portfolio of generation facilities consists of firm, long-term purchased power contracts. Neighboring states in the region are pursuing reforms with the intention to drive electricity costs down.

2. Investment in energy efficiency is declining. Demand-side management programs have traditionally been provided by franchised utilities; but, amid the uncertainty of industry reform, investment in cost-effective savings is declining. In Vermont, these investments declined by twenty percent between 1994 and 1995.

3. Investment in renewable energy technologies is declining. Over the past 15 years, Vermont has met all of its growth in electric demand through the addition of renewable energy facilities, but in recent years, new investment has declined.

4. Existing and new environmental challenges, from mercury and harmful small particulates to global warming, are priorities. The Board believes that restructuring offers an opportunity to address environmental problems responsibly and coherently, at the state, regional, and national levels.

5. Support for low-income households has also been declining. Between 1994 and 1996, federal funds for the Low-Income Home Energy Assistance Program (LIHEAP) were cut by 45 percent. The potential savings in costs that competition offers will help offset the cut-backs in assistance to needy families, but will likely not be sufficient. The Board believes customer choice requires new mechanisms to help Vermont's most vulnerable citizens.

6. Currently, only Vermont's large commercial and industrial customers enjoy significant flexibility in electric services and rates, albeit only from their local franchise utility. Special contracts for interruptible and other services provide them with flexibility and lower prices and offer benefits for the system as a whole; but such alternative arrangements are not now available to Vermont's smaller commercial and residential customers.

7. Today's electric utilities now confront significant financial risks and limited access to capital, while the uncertainty surrounding restructuring greatly increases the risks of new investment. The Board believes this threatens the overall reliability of Vermont's system, and calls for the swift but careful resolution of the many issues facing the industry.

8. Lastly, the market for electricity in which Vermont operates is regional in nature and has been managed for a quarter of a century as a single pool. As other New England states also move to direct retail access, the Board believes that new regional structures and institutions must be designed to give Vermont customers an equal opportunity to participate in these new markets. This requires reform within Vermont as well as continuing participation in regional restructuring activities.

For all of these reasons, the Board concludes in its final report that significant structural, financial, and regulatory reform of the Vermont electric system is now essential. The Board also believes that Vermont will be best served by charting its own plan of action, and not merely reacting to changes imposed by the federal government, the region's largest utilities, neighboring states, or other entities. The Board's principal goal is to harness the creative forces of competition and choice, while retaining the essential benefits delivered by the existing system, for the good of Vermont's economy, environment, and consumers.

## MARKET STRUCTURE

The Board recommended that direct access to all Vermont retail customers should be permitted on a scheduled phase-in starting in early 1998 and completed by the end of that year. Any phase-in, the Board stated, should be pursued in a manner that does not favor one customer class over another. The precise start and completion of the phase-in should take into account the institutional, operational, and educational prerequisites, as well as plans of neighboring states. At this time, the Board believes that a transition to direct access for all Vermont customers should be completed as quickly as possible. It is believed that to delay access for some Vermonters could contribute to consumer confusion. A lengthy transition to direct retail access would also raise some fundamental equity concerns for consumers.

The Board listed two overarching principles that should guide any development of electric industry restructuring. They are fairness and efficiency. The Board believes that restructured industry should provide opportunities to capture improved efficiencies in the production, delivery, and use of electricity, and seek to maximize customer value at the least cost to society. In addition, the system should treat all producers and consumers equitably, according to the costs they impose and benefits they derive, both during and after the transition to a restructured industry. If such efficiency gains are realized, the well being of society and the economic vitality of Vermont should be improved.

The Board's final report does not suggest any pilot programs or experiments, because of the rapid phase-in to allow all customers retail access.

The Board recognized that electricity is an essential service, critical to the health and safety of Vermonters. In order to protect consumers against unnecessary service disruptions during and, possibly, after the transition to competition, all distribution utilities will be required to establish or designate a "basic service offer" for each class of customers. This offer will be made available over a contracted period, through a retail service provider, to all customers. Terms of service will be established through a market determination. The offer will be limited to the franchised customers of the Discos. For purposes of disconnection, the Basic Service Offer will be considered a Disco service.

**Electron Disclosure**

The Board is actively studying the issue. The basic problem is the ability to tag electrons. That is, the ability track the generation source of an electron and follow it to its ultimate end-use consumption point. Two approaches are being considered. One being, if a marketer claims the ability to sell a consumer electricity from a particular type of generation, the marketer must tag those electrons sold. Disclosure must be made on the customers monthly bill. Another approach considered is a mandatory tag system. All distribution companies/marketers would have to tag all electrons and report to consumers the source of the generation of power consumed.

## STRANDED COSTS

The Board states that recovery of stranded costs will be subject to a multi-factor analysis that includes the weighing and balancing of competing considerations. The Board intends to create the opportunity for full recovery of stranded costs provided they are legitimate, verifiable, otherwise recoverable, prudently incurred, and non-mitigable. However, it is clear that a significant financial restructuring of existing purchase power obligations will be necessary to ensure the financial health of Vermont utilities and fair and reasonable rates to Vermont ratepayers. The Board believes that an opportunity for full recovery must be explicitly tied to successful mitigation.

The Stranded Cost Subcommittee developed an initial statewide point-in-time estimate of stranded costs. This estimate is preliminary only. The effort to derive an estimate of stranded costs was coordinated by the Department of Public Service after the parties agreed to use the Department's forecast of future electricity market prices under three different scenarios; a high, mid and low market price. The utilities provided their estimates of stranded costs out through the year 2025 to the Department under protective agreement, and the Department aggregated the numbers to obtain the statewide estimates. The statewide analysis of stranded costs resulted in cumulative present value estimates of stranded costs that ranged from a low of $352 million under the assumption of a high market price for electricity, to a high of $1.4 billion under the assumption of a low market price. The categories of estimated statewide stranded costs show that the most significant portion of stranded costs stems from purchase power contracts.

Two main conclusions can be drawn from the analysis of stranded costs. The first conclusion is that mitigation efforts are critical to success in reducing electric rates, which is one goal of electric industry restructuring. At the same time, the Board recognizes the need to maintain the financial viability of Vermont's electric utilities. The largest element of stranded costs in Vermont is the category of purchase power contracts. In order to realize both of these goals, the Board states that it is essential that the utilities focus their efforts on renegotiation of their purchase power contracts.

The second preliminary conclusion drawn from this analysis is that a five to ten-year transition period for stranded cost recovery appears to provide an appropriate balance of rate stability and reasonable cost recovery. The Board cannot establish the precise length of the transition at the time the final report was issued. The optimal recovery period will be determined in the context of future stranded cost proceedings.

**Mitigation**

The Board has placed great importance on the extent of strandable cost mitigation in considering those strandable costs subject to ratepayer recovery. To this end, the Board has identified the following strandable cost mitigation strategies:

1. the renegotiation and restructuring of existing purchase power contracts;

2. the buyout (or buydown) of existing power purchase contracts or unit entitlements;

3. the economic operation of existing facilities/contracts;

4. the shut-down or moth-balling of non-economic utility-owned generating units;

5. the renegotiation and restructuring of fuel supply contracts;

6. the implementation of cost control and cost reduction procedures;

7. the sale/divestiture of uneconomic assets;
8. the write-off or write-down of uneconomic assets;
9. appropriate load growth;
10. the exchange of under-utilized assets; and
11. refinancing existing obligations through low-cost, long-term bonds.

The Board believes that renegotiation and restructuring of above-market purchase power contracts should be foremost among the mitigation strategies. Uneconomic purchase power contracts appear to comprise by far the largest component of Vermont utilities' potential stranded costs. The Board expects Vermont utilities to seek to renegotiate those contracts to bring their costs closer to market costs.

**Recovery Standards**

The Board has attempted to frame the considerations that should govern the proportion of stranded costs that utilities will be allowed to recover from ratepayers. These considerations are designed to result in an equitable sharing of benefits, risks and costs in the transition to a more competitive electric industry.

Some of the participants in Vermont's restructuring docket urged the Board to apply past rulings on the recovery of prudent but excessive utility costs, and conclude that they should be split evenly between ratepayers and utilities. An equal sharing would be consistent with past Board rulings and would satisfy constitutional requirements, the Board, however, believes that it would be unwise and unnecessary at this time to declare it as a general policy. It would be unwise because it could result in unnecessary financial dislocation in Vermont's electric industry. Until a better estimate of the magnitude of stranded costs, and particularly their mitigation potential is known, the Board cannot balance the conflicting goals of allocating stranded costs and assuring customers' benefits from lower rates.

The issue of the appropriate sharing percentage will turn largely on the equities of individual cases, and on the effectiveness of utility efforts to mitigate their potentially stranded costs. The Board will consider the following critical components in their evaluation:

1. the circumstances under which the relevant costs were incurred or committed, including the degree to which specific costs resulted from regulatory mandates;
2. the extent to which the utility demonstrates actual mitigation of stranded costs compared to the potential for mitigation;

3. comparability of that utility's overall stranded cost burden with those of other utilities;

4. the rate impacts of stranded cost recovery on the state's consumers and the Vermont economy, after considering the affected utility's long-term rate trends in relation to rates in competing states;

5. commercial sustainability and the effect of stranded costs recovery on the financial health of Vermont's utilities;

6. the degree to which a formerly-regulated utility in this state implements competitive safeguards or, where required, achieves functional separation; and

7. the public health, safety, and welfare.

**Measuring and Recovering Stranded Costs**

The Board proposes a staged transition period for the recovery of stranded costs. The stranded cost transition should be completed and a final resolution of stranded costs should be made no later than December 31, 2001. The first stage will be a proceeding to set an administratively-determined *estimate* of stranded costs. The last stage will be a reconciliation proceeding that results in a final determination of stranded costs. In the interim, the Board may have sequential proceedings that would permit adjustments to the estimate of stranded costs set at the beginning of the transition period.

The first objective of a staged transition is to allow recovery of stranded costs to begin at the onset of retail competition, which will begin as early as January 1, 1998. Stranded costs are transitional by nature, and the sooner the Board begins the recovery process, the sooner the Board will complete the necessary period of transition.

The second objective of having a staged transition is to allow time for the market to develop and new policies to take hold. Uncertainty and change will be the dominant factor in the generation portion of the market, at least in the beginning phase of the transition. A key component of stranded cost determination is the market price of electricity in future years, which should be evaluated over a multi-year transition period. To provide certainty to both investors and customers, however, this transition period should be of limited duration. The Board will conclude a final proceeding no later than December 31, 2001, in which the outstanding amount of stranded costs for each utility in Vermont will be finally determined, and ongoing transition charges set.

The third and primary objective of staging stranded cost recovery is to ensure that utilities will successfully complete substantial mitigation of stranded costs. The Board believes it will be incumbent upon all the utilities of Vermont to avail themselves of mitigation opportunities to the maximum extent possible and as expeditiously as possible.

The Board believes that the recovery of allowable stranded costs should be achieved via a "wires charge." The Board refers to this charge as the Competition Transition Charge ("CTC"). This would be a charge imposed on all retail customers using the Vermont transmission and distribution system, to be collected via the billing system of the distribution companies of the state. This charge should be non-bypassable, competitively neutral, and must balance the principles of fairness, equity, and economic efficiency.

It is the Board's intent that the CTC should be set so that the total amount of allowable stranded costs for each utility, as determined after review in the final reconciliation proceeding, is recovered in full from that utility's distribution ratepayers. The recovery period and the CTC may both have to be adjusted throughout the stranded cost recovery period to achieve this result. The recovery period for some stranded costs may vary according to the nature of the asset. Certain items, such as nuclear decommissioning costs, may warrant a longer recovery period.

The Stranded Cost Subcommittee proposed that a stranded cost recovery charge should be designed so that it:

- is non-bypassable;
- is competitively neutral;
- provides accelerated payments or buyouts as an option;
- balances principles of fairness, equity, and economic efficiency;
- is adequate for collecting stranded costs amounts;
- accounts for some degree of rate stability;
- is imposed on both present and future customers; and
- takes cost causation into consideration when allocating the charge among customer classes.

The Board agrees that a stranded cost charge should be non-bypassable and competitively neutral and should balance the principles of fairness, equity and efficiency. It also proposes to structure the CTC so that it is imposed upon all retail customers in Vermont.

The Board concludes, consistent with FERC's position as set out in Order 888, that at least some portion of electric service to end-use customers is a distribution service, and will be considered as such for the purpose of imposition of the CTC. This holds true for customers that take ancillary or backup service for end-use purposes, as well as for end-use customers who take service at transmission voltage or under a transmission tariff. It is the Board's intent, consistent with the position of most parties, that the CTC shall not be bypassed by any end-use customer.

**Securitization**

The Board has seriously studied securitization as an option for funding utility stranded costs. The Board, however, has some concerns with the notion and has included securitization as an option to deal with stranded cost. This issue was not addressed in its

Report and Order.

## CUSTOMER ISSUES

The Board forsees the Distribution Utility (DISCO) as responsible for billing and metering of customer accounts during the transition period to open competition. The Board expects the Disco services to meet standards for service quality and reliability commensurate with existing standards. During the process of investigating electric competition, the participants developed the "Consumer Bill of Rights." This document details the standards of conduct for companies in dealing with customers, including billing, termination, and customer complaints. The Board intends to rely on these recommendations in guiding its actions in future proceedings. In addition the Department of Public Service will continue to take customer complaints. The Board has filed a plan on public education of restructuring.

## MARKET POWER

The Board's final report includes a lengthy discussion of market power. There is a significant concern competitive electricity markets will not be successful if a participant is able to exercise undue market power. The participants in Vermont's restructuring docket agreed that the separation of a firm's monopoly functions from its competitive activities offers the greatest protection against vertical market power abuses. The participants disagreed, however, on the precise nature and extent of the necessary separation between competitive and non-competitive elements. The Board identified three broad types of potential corporate separation. The first is full divestiture of a firm's several, distinct activities into separately owned and managed companies; the price-regulated transmission and distribution (T&D) firms would be prohibited from owning generation or selling electricity in competitive markets. The second, often referred to as "functional separation," refers to a structure of wholly-owned subsidiaries: utilities would be divided into separate firms according to activity area, but these subsidiaries would be completely owned by a single holding company. Detailed rules and processes for accounting, inter-affiliate transactions, and the shared use of assets and personnel would have to be implemented. The third type of separation is one where a firm breaks itself into various divisions or departments, but does not create distinct corporate subsidiaries; and, as with functional separation, it would be necessary to institute rules for accounting, intra-company transactions, and the shared use of assets and personnel.

The Board concludes in its final report that, although full divestiture offers certain benefits, it is not necessary at present. Two major reasons are cited for this conclusion:

- Full divestiture of generation resources at this time might remove opportunities for mitigation of potentially strandable costs, and

- It might delay progress toward customer choice at a time when utility cooperation is critical to the effective evolution of the industry.

The Board concludes that, in place of divestiture, functional separation of Vermont's largest investor-owned utilities should be required and that concerns of vertical market power should be addressed through:

- Transactions among corporate affiliates should be traceable and transparent;
- Codes of conduct imposed on firms to insure non-preferential treatment of competitors by a firm's regulated transmission and distribution companies;
- Creation of an ISO to administer the regional transmission system.

The Board directed the utilities to file detailed plans in June 1997 that describe the manner in which they will reorganize their corporate structures to, at a minimum, functionally separate their competitive generation and marketing activities from their regulated transmission and distribution services.

**Independent System Operator**

Most participants in the Board's restructuring investigation underscored the need for the current New England Power Pool (NEPOOL) to evolve its transmission operations into an independent entity that is not controlled by the present or future owners of generation facilities. The Board believes that the current dominance of NEPOOL by existing vertically integrated generation companies (especially the larger voting interests in the pool) must change. At a minimum the governance, and financial support, and the rules under which the transmission grid operates must be independent of either existing or future generation interests. *Independent* operation of the transmission system is necessary to address the majority of vertical market concerns related to bottleneck transmission services. Independence is necessary to provide a fair competitive operating environment for new market entrants as well as existing small utilities, and for customers.

NEPOOL reform efforts are underway and several draft proposals have been considered. The most recent draft of a proposed NEPOOL-ISO contract demonstrates significant progress towards empowering the ISO with the necessary authority to operate the NEPOOL system. Vermont continues to monitor that progress through the New England Conference of Public Utilities Commissioners. At this time, NEPOOL anticipates making several filings with FERC at the end of 1997 which will include NEPOOL reforms, regional transmission tariffs, and an ISO contract. The Board remains convinced that those filings must create an ISO with the authority to determine power pool and dispatch rules, operate the system, and plan for its expansion in consideration of, but not under the control of, the interests of owners of generation.

At the present time, the Board does not propose a precisely defined role for the ISO beyond that of ensuring reliable operation of the regional grid in a manner that is not unduly influenced by the financial interests of generation service providers. The Board states that if the role and responsibilities of the ISO are interpreted narrowly and limited to operational concerns, then other institutions will be needed to assure a fair and open market that is free from competitive abuses. Additional oversight of the ISO through a regional regulatory presence may also be needed.

**Power Exchange**

The Board believes that a Power Exchange should provide an efficient competitive market open to all generation service providers in the region in order to meet posted loads at efficient prices. The Exchange would not inhibit bilateral transactions, but would provide for the efficient exchange of power on a very short term basis (*e.g.*, hourly or half-hour purchases). In addition to functioning as a spot market for energy, it will likely also provide ancillary services for market participants and the ISO. It may also allow for the creation of new service options for consumers. A power exchange with a spot market will be of particular importance to small customers by allowing them easy access to the market free of the heavy administrative burden of bilateral contract negotiations.

The Board favors the creation of an exchange in conjunction with the establishment of an ISO. If independent of the ISO, the power exchange should not be owned, governed or managed by parties with a financial interest in the outcome of its operations.

The Board sees no reason for concluding that this power exchange need be granted exclusive rights to the market. Several exchanges could function within the region or across regions, so long as appropriate protections are in place to assure actual delivery by successful bidders, rather than allowing generators to bid resources to several exchanges while merely shopping for the best prices.

**PUBLIC PURPOSE PROGRAMS**

**Low-Income**

The Board states that it is critical that any proposal for customer choice directly address the needs of low-income consumers. Previously, the Board proposed an "all-fuels, broad-based" funding mechanism for supporting the energy needs of low-income consumers. By "all-fuels" the Board means to assure assistance in a manner that does not discriminate among low-income consumers according to their principal home-fuel types. By "broad-based," the Board means a program that is funded through the state's broad general taxes or, at a minimum, through a competitively-neutral charge on all major fuel types. The Board continues to support such a mechanism. The proposal has received broad support in this proceeding.

In the absence of a broad-based low-income assistance program, the Board proposes that the Vermont Legislature authorize targeted assistance for some portion of the electric bills of low-income households through a sustainable, non-discriminatory charge on all electric customers, consistent with the recommendations of the Consumer Protection and Low Income (CP&LI) Subcommittee.

The Board concludes, however, that programs targeting consumers of a single fuel type such as electricity could, unless limited, promote inefficient or uneconomic use of that energy source. Programs funded through a surcharge on a single fuel may also lead to unnecessary market distortions. The Board's proposal is intended to minimize the potential for such distortions.

The Board supports the recommendations of the CP&LI Subcommittee that programs should take into account income and other sources of assistance, family size, and the relation of electric bills to income and to overall energy bills. Program eligibility should be certified by a designated program administrator, independent of utilities and energy providers. The Board believes that (1) program participants should be expected to apply for other available energy assistance programs, such as LIHEAP and (2) that the program should be structured to encourage efficient use of energy resources.

**Energy Efficiency Programs**

Currently, the responsibility for acquiring cost-effective energy efficiency resources resides with the vertically integrated electric utility. The current standard for making such evaluations in Vermont is the total resource cost (TRC) test. To ensure that the current benefits being realized through integrated resource planning continue in a restructured industry, the Board has proposed a comprehensive strategy for efficiency, with four separate program elements.

1. Distribution Utility Programs

The Board believes that the distribution utility company (Disco) should be responsible for identifying opportunities to reduce the cost of delivering electricity to consumers. These opportunities will include upgrading distribution lines, transformers, and related equipment to reduce line losses, installing localized generation resources to enhance power quality and reliability, and acquiring demand-side resources from consumers. The Board notes that there is likely to be greater efficiency of program development and implementation of other program elements through a single statewide entity, rather than by twenty-two separate Discos. The Board concludes that while Discos may be involved in many elements of program delivery, they will not be the optimal entity for planning statewide public benefits programs. Statewide programs are discussed below.

2. Codes and Standards

The Board recognizes the important role that codes and standards can play in acquiring certain energy efficiency resources. Performance standards for new construction, appliance standards for refrigeration, air conditioning, and heating equipment, time of sale efficiency upgrades for existing dwellings, and lighting codes are a few of the options available. The appropriate codes and standards can achieve some of the goals of current utility programs that focus on equipment replacement, remodeling and renovations, commercial and residential new construction, and commercial lighting. To the extent that codes and standards can replace utility efforts, there are likely to be administrative and implementation savings to utilities while maintaining consumer savings and benefits. The Board encouraged the participants in the restructuring docket to promptly and seriously evaluate the opportunities for implementing codes and standards that will achieve or exceed the current levels of cost-effective energy efficiency resource acquisition.

3. Market-Driven Programs and Market Transformation

Almost all participants in Vermont's restructuring docket commented on the benefits of shifting current utility-sponsored energy efficiency programs to market-based programs. Utility energy efficiency programs have assisted in market transformations in increasing the availability of energy efficient equipment. The Board believes that there is significant potential for continuing market transforming activities, both through electric sector programs and other regional and national initiatives. However, the extent to which current utility efforts in Vermont can be replaced by market-based programs and the timeframe in which this transformation can occur are uncertain at this time.

4. Statewide Benefits Programs

Many participants in the docket stated that during the transition to more market-based programs and the adoption of codes and standards, and even after that transition period, there will remain a need for cost-effective energy efficiency programs designed to overcome remaining market barriers. The Board, also, is not persuaded that market barriers will disappear once retail choice is available. It concludes that mechanisms and procedures must be developed for identifying, funding and delivering statewide energy efficiency programs.

The Board endorses a funding proposal defined by an appropriately structured, non-discriminatory, non-bypassable wires charge collected by the distribution utility. Initially, the revenues raised from this System Benefits Charge (SBC) will fund the continuation of cost-effective utility energy efficiency programs during the transition to distribution utility programs, codes and standards, market-based initiatives, and statewide benefits programs. After that transition, SBC revenues will fund the statewide benefits programs.

The Board proposes the creation of one or more "efficiency utilities" to oversee the development and implementation of statewide benefits programs. It is envisioned that an efficiency utility will be able to solicit and review bids for cost-effective energy efficiency programs and fund these programs with revenues from the SBC. The efficiency utilities are envisioned to focus on proposals that would seek to overcome specific market barriers to energy efficiency measures with the goal of transforming statewide benefits programs to market-delivered programs. The Board believes that opening competition among would-be providers of efficiency services will ensure development of the most cost-effective programs.

**Renewable Energy**

The Board believes that even a restructured industry must maintain the current efforts that promote the use, development, research, and commercialization of renewable energy resources. Since 1980, Vermont has installed over 100 MW of in-state renewable resources, an amount that (after accounting for efficiency and load management measures) exceeds the growth in the state's peak demand during that period.

The Board believes that in order to sustain current levels of renewable resources and to incorporate soon-to-be commercialized technologies, a portfolio requirement, or renewables portfolio standard ("RPS"), is best suited to accomplish this public policy objective. The Board envisions a two-part portfolio requirement that all sellers of energy for end-use consumption in Vermont would be required to meet. The first part would be a percentage of generation requirement for existing, commercialized renewable resource technologies. The second part of the portfolio requirement would be a percentage requirement for renewable resources that are very close to commercialization—for instance, photovoltaics and fuel cells.

There evidently is no consensus on how could or should contribute towards the support for the commercialization of promising renewable technologies and continuing research and development efforts to identify new renewable resources. The Board suggests two means of funding these efforts. First, and preferable, is a non-bypassable *national* wires charge that would generate sufficient revenues to fund meaningful commercialization and research and development activities. This would require federal legislation and administration through DOE or FERC. Second, the Board would consider the creation of a Vermont wires charge to support commercialization and research and development of renewable resources once a significant number of other states confirmed their willingness to make similar commitments.

## RELIABILITY

The Board believes that an ISO must operate and maintain the regional transmission system. Ancillary services to assure system reliability, may be provided through market mechanisms, such as a bidding program through a power exchange. However, the Board believes overall responsibility for bulk power reliability must be assumed by the ISO, which will act in accordance with non-discriminatory rules for operation and will have appropriate enforcement authority to meet its obligations.

Transmission companies, whether combined with or independent of distribution companies, will continue to be regulated (for transmission, by FERC) as monopoly service providers on the basis of price or cost. Vermont has an established, and nationally-unique transmission company in the Vermont Electric Power Company (VELCO). VELCO's mission is to design, construct, acquire, contract for, maintain and operate a system of transmission facilities in Vermont as part of an integrated, regional network that serves the needs of the electric distribution companies in Vermont. VELCO is also responsible for statewide transmission planning and for coordinating utility plans with those of the regional network.

VELCO is owned by Vermont's electric utility companies. The majority of VELCO's stock, 57 percent, is owned by Central Vermont Public Service (CVPS). VELCO is governed by a board of fourteen directors, comprised largely of Vermont electric utility company representatives. At least until the roles of the ISO and, possibly, a regional transmission group ("RTG") become well defined, the Board believes that VELCO is the appropriate entity to assure transmission open access in Vermont. Nevertheless, VELCO's independent, neutral role could be compromised if the owners of generation assets and services (currently the vertically integrated Vermont electric utilities) remain in substantial control of VELCO. The Board expressed its concerns about the ability of VELCO to operate in the future in a manner that is independent of the affiliated generation interests of its owners. Because there are uncertainties regarding the control over transmission in restructuring, the Board was hesitant to make any recommendations. It did, however, express its desire that services be provided in a non-discriminatory manner.

**Generation and Transmission Siting**

The Board recognizes that it should retain environmental jurisdiction over generation and transmission line siting additions. However, determinations of "need" may no longer be required in a competitive regime, since the risks of an investment being unneeded—*i.e.*, uneconomic—will be borne entirely by the developer, and not by the ratepayers.

Currently, Vermont imports the majority of its power. This trend is expected to continue due to proximity to Canadian hydro facilities, and its interconnection with NEPOOL. The Board believes that an ISO should have the responsibility for transmission pricing and planning. NEPOOL is a tight power pool with a long history of good reliability. Vermont appears to be confident that an ISO, while independent of the NEPOOL members, would continue to adequately provide reliable service to distribution companies and ultimately the ratepayers.

## RECIPROCITY

The Board believes that open access is the appropriate environment for the electric industry. This structure is good for consumers in the long run. Reciprocity requirements would be destructive to open access. However, the Board appears committed to restructuring regardless of reciprocity requirements other states may enact. Because

Vermont is in a tight pool, and because neighboring states are moving toward deregulation, Vermont may be in a less vulnerable position regarding reciprocity than other states.

## TAX ISSUES

The Board will, in determining stranded cost, take into account the tax implications of stranded cost mitigation strategies when assessing the dollar impact that a strategy has on investors and ratepayers. The Board expects to consider only the net after-tax effects of mitigation in applying the standard for stranded cost determination.

## ROLE OF THE BOARD IN A RESTRUCTURED MARKET

The Board would have rate setting authority on the basis of costs over only distribution utilities in a restructured environment. The Board has recognized, however, that greater efficiency may be promoted through alternative forms of price regulation, referred to as Performance-Based Regulation ("PBR"). Briefly, PBR approaches do not set prices strictly on the basis of historic (or accounting) costs, but rather in a way that encourages companies to reduce their costs over time, by providing profit incentives to stimulate innovation, efficiency, and service quality improvements. PBR regulation is already permitted for local service telecommunications providers in Vermont. The Board believes that the legislature should permit, but not require, such regulation over Discos.

Generation rates, currently set by the Board on the basis of cost, will eventually be market based in a completely restructured industry. However, during a transition period price caps may be utilized.

The Board intends to have a significant role in determining abuses in vertical market power. State statutes give the Board authority to determine if mergers and acquisitions are in the public interest. Under restructuring, the Board would retain this authority over distribution companies. The Board expects that if and when restructuring becomes a reality, a proceeding before the Board on mergers and acquisitions will take place.

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